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# Shale 2022

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# Shale 2022

***Unconventional industry enters a new era of disciplined growth and responsible sourcing.***

By Brian Walzel, *Senior Editor*

As the calendar turns onto 2022, the shale industry finds itself in unfamiliar territory, but not totally unwelcomed territory. Both Henry Hub and WTI prices have surged and, perhaps more importantly, stabilized in the $3-plus and $80/bbl range, respectively. Global demand for energy is approaching global output, creating an environment for long-term supply/demand economics that should remain favorable for both producer and consumer.

But even beyond price and demand stabilization, the shale industry is enjoying something it hasn't before, at least not to the extent that it is now: profitability. Discipline in spending, managed production growth and rising prices are leading to cash flow generation that investors have long demanded.

According to Bloomberg, free cash flow by U.S. oil producers will likely increase by 38% in 2022. Devon Energy reported free cash flow gains of $1.1 billion in third-quarter 2021, an 8x improvement over fourth-quarter 2020. During the third quarter, Pioneer Natural Resources reported free cash flow gains of $1.1 billion, EOG generated $1.4 billion and ConocoPhillips created $2.8 billion.

Even with disciplined capex, the modest growth practices enacted by shale producers are steadily moving the needle back toward pre-COVID-19 production levels. According to Rystad, shale production was expected to reach 8.68 MMbbl/d in December 2021, the highest since March 2020.

Part of the production growth stems from producers working through their DUC inventories. According to Rystad, the number of DUCs in major U.S. shale basins had fallen to 2,381 wells by June 2021; this was the lowest level since 2013. With the number of DUCs decreasing, U.S. producers are finally drilling new wells and subsequently deploying more wells.

According to Westwood's U.S. land rig count, the number of operating land rigs by the week of Nov. 12 was 533, with more than half (272) in the Permian Basin. However, that figure is still far from pre-COVID levels. According to Westwood, there were 775 rigs operating in mid-November 2019.

Despite the still-depressed rig count, production levels are expected to continually climb. The U.S. Energy Information Agency (EIA) estimates the U.S. will produce 11.9 MMbbl/d of crude in 2022, nearly matching pre-COVID levels, and peak U.S. output of 12.2 MMbbl/d. The EIA explains that the growth in oil production "will come largely as a result of onshore operators increasing rig counts, which we expect to offset production decline rates."

Meanwhile, the substantial free cash flow generation and continued production recovery is occurring at a time when the shale sector is needing to rapidly decarbonize. Between pressures from investors and simply retaining a social license to operate, shale producers are looking for new ways to cut down on their carbon and methane emissions.

Service companies are responding, bringing to market leading-edge technologies that cut down on $CO_2$ emissions and reduce flaring. But the oilfield services (OFS) sector, amid surging gains for producers, are also working to adjust pricing that ensures the OFS sector thrives in the same environment.

Going into 2022, producers should expect to see cost inflations to the tune of about 10%, according to a Goldman Sachs report.

The Shale Gale is long over, and such pricing and spending will not return to the sector. But so is the latest industry downcycle. In 2022 unconventional development is poised to return to pre-COVID production levels while generating billions of dollars in free cash flow and substantial returns to shareholders. While the shale industry of the past is receding in the rearview mirror, ahead is a new, cleaner, more profitable landscape that will ensure the shale industry will remain a key player in the new energy mix. ■

**After facing a multitude of headwinds over the past few years, the shale industry is poised to continue its rebound to profitability in 2022. (Source: Southwestern Energy)**


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Between high-return—and stabilized—pricing and the role it is likely to play in the future, natural gas' place in the energy mix is quickly growing.

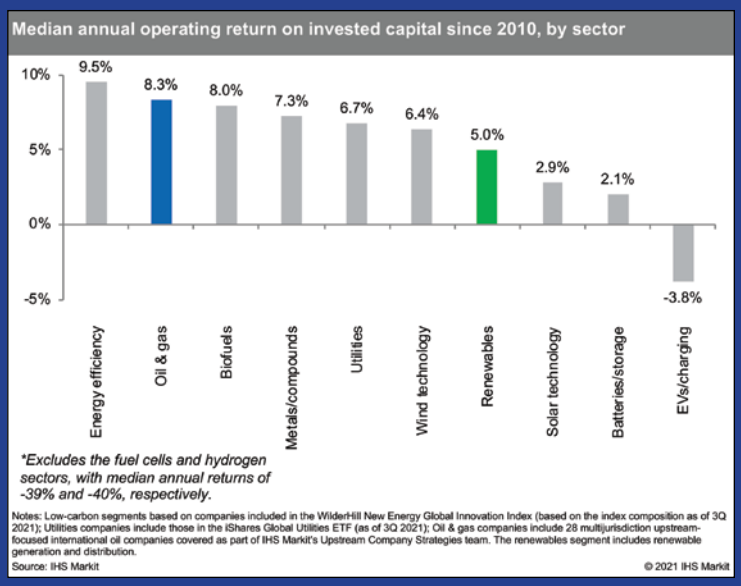
# Market Conditions in 2020 Demonstrate Value Proposition of Renewables for O&G Companies, But Can These Returns be Sustained?

## High-risk/high-reward nature of oil and gas contrasts with a traditionally more stable—but lower—returns profile of renewable energy.

By Chris DeLucia, *Director IHS Markit-Upstream, Companies & Transactions*

For a growing number of oil and gas companies, the low-carbon segment has become an increasing area of emphasis—and investment—within overall portfolio strategies. IHS Markit estimates that for the global integrated oil companies (IOCs)—bp, Chevron, Eni, Equinor, ExxonMobil, Shell and TotalEnergies—aggregate annual organic low-carbon spending will reach nearly $16 billion by 2025 (accounting for 13% of total organic investment by that time), up from approximately $6 billion (or a 6% share) in 2020. Given the growing materiality of these investments, the question of how these new business lines can contribute to operational and financial performance has become increasingly pertinent.

Analysis by IHS Markit has shown the upstream oil and gas segment tends to deliver some of the highest returns within the energy industry, albeit with some of the highest volatility. Per this analysis, the oil and gas sector has generated a median annual operating return on invested capital of 8.3% between 2010 and 2020; however, these returns have involved a standard deviation of 8.1% over the past decade. Such results highlight the relative high-risk/high-reward nature of the sector.




(Source: IHS Markit)

Conversely, most of the low-carbon segments in which oil and gas companies are investing have historically generated relatively lower returns. In particular, the bulk of low-carbon investments made to date by oil and gas companies have been focused on renewable energy, with the renewable generation and distribution sector entailing a median annual return of 5% since 2010. However, these returns have also been remarkably stable, with a standard deviation of only 1% over the past decade. For renewables, these returns have been underpinned by long-term (generally 15- to 30-year) power purchase agreements (PPAs) with relatively stable and more predictable prices, which contrast with the elevated exposure to market and commodity price fluctuations seen in the oil and gas segment.

### Market volatility in 2020 highlights the benefits of lower-risk sectors, such as renewables.

The benefits of this lower-return but lower-risk business model are evident from trends over the past two decades, and from 2020 in particular. While median oil and gas returns have ranged from a high of 28% in 2005 to -7% in 2020, returns from the renewable generation and distribution sector have generally remained between 4% and 8% during that period, spanning multiple economic and commodity price cycles.

Furthermore, renewable returns declined to only 4.6% in 2020 (compared with 7.2% in 2019), despite the economic and market dislocations brought on by the pandemic. Even prior to 2020, however, the renewables segment has outperformed oil and gas on the basis of median returns in five of the past six years. These trends point to the potential benefits of a growing presence within renewables for oil and gas companies, and particularly for the global IOCs. Given an emphasis from this peer group on returns and cash-flow generation to support growth in shareholder distributions, a lower volatility business model can underpin these objectives (with greater portfolio diversification also helping reduce overall risk).

### Renewables performance will become increasingly important as this segment rises in prominence for some of the IOCs.

For oil and gas companies that have begun deploying material

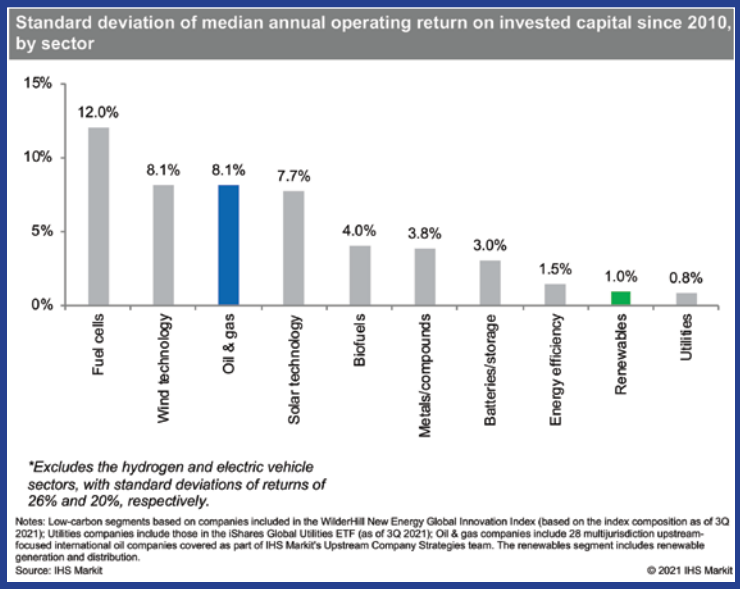
capital toward renewables, the returns profile of these investments will become increasingly important. Accordingly, several of these companies have introduced returns objectives tied to these segments. Generally, these companies have indicated base returns targets in the mid-to-high single digits, with upside into the low double digits based on the ability to leverage existing capabilities and advantages relative to some incumbents in the industry, including

- **Project management:** Oil and gas companies have significant experience in managing large-scale, capex-intensive, long lead time projects, and much of this expertise can be applied to renewable project development. Offshore wind, in particular, offers those companies with offshore oil and gas experience the ability to leverage basin-specific and technical expertise.
- **Portfolio integration:** In contrast with some of the pure-play competitors (such as independent power producers) within the renewable generation sector, several oil and gas companies are aiming to participate across the energy value chain, thereby creating synergies by maintaining exposure from generation to distribution and commercialization. In addition, companies may be able to enhance returns through their energy trading capabilities.
- **Leverage:** Aided by a relatively lower risk profile, renewable projects can be financed with a debt-focused capital structure, with this leverage generating higher project IRRs.
- **Portfolio management:** Similar to the strategy for oil and gas portfolios, farm-downs of renewable projects that have reached the development or operational stage can help companies book realized gains on these assets, accelerate monetization of future cash flows and de-risk the project through reduced exposure.
- **Differentiated risk profile:** A higher risk tolerance from oil and gas companies may provide access to opportunities in which competition may be limited, thereby creating a competitive advantage versus traditional renewables players. This may include PPAs with shorter tenors or pursuing projects in which volumes may still be uncontracted.
- **Brand recognition:** For oil and gas companies with an existing retail presence, name recognition can help support customer growth.
- **Global presence:** Oil and gas companies are aiming to leverage their global reach and existing relationships with governments and state agencies (including national oil companies) to gain access to opportunities within new low-carbon business lines.

## Historical performance may not reflect future results.

However, the ability of these historical results to be repeated—and improved upon—may be tested going forward.

For one, a flood of new entrants and capital—including from the oil and gas sector—into the renewables space threatens to erode returns as competition increases. This trend has been apparent in both the M&A segment, where activity has surged from oil and gas companies within the renewables space, and in bid round activity, including with surging lease prices for offshore wind acreage.




(Source: IHS Markit)

In addition, renewables returns in some jurisdictions may be inflated by existing support mechanisms, which may be phased out as these industries and markets mature. Furthermore, a shift in power markets toward shorter PPAs and spot trading could reduce the predictability and certainty of returns from the renewable generation segment.

Meanwhile, for the oil and gas segment, the combination of a sharp recovery in commodity prices and demand over the past year, improved capital efficiency and growing concerns around a possible supply shortfall amid underinvestment in the industry all point to the potential for a sharp rebound in returns.

Notably, these questions are arising at the same time that strategic divergence is increasing among oil and gas companies. This trend is particularly acute among the global IOCs, with some members of this peer group opting to focus on the core oil and gas business, while others have begun to materially diversify into low-carbon business lines. As companies' portfolios and investments become increasingly differentiated, the outcome is likely to be greater divergence in terms of financial and operational performance—raising the stakes in terms of how these returns trends ultimately play out across different sectors. ■

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**A drilling rig operates on Ascent acreage in Ohio. (Source: Ascent Resources)**

# Top 40 US Shale Players

By Madison Ratcliff,
*Associate Editor*

***Hart Energy highlights the latest activity details from the supermajors, public and private companies that lead U.S. shale production.***

After the devastating effects of the COVID-19 pandemic on the energy market, the oil and gas industry did what it could to rebound—and with a fair amount of success. According to the Energy Information Administration (EIA), however, the market isn't close to seeing its 2019 success rates.

"A return to 2019 levels of U.S. energy consumption will take years; energy-related carbon dioxide emissions fall further before leveling off or rising," the EIA's 2021 annual report presentation stated.

Stay-at-home mandates contributed to the decline in energy consumption and GDP seen in 2020, and "the pace at which both will return to 2019 levels remains uncertain," the report stated.

"Petroleum remains the most-consumed fuel in the United States, as energy-related carbon dioxide emissions dip through 2035 before climbing in later years," the EIA said. "The energy intensity of the U.S. economy continues to fall as end-use sector intensities decline at varying rates."

Even amid the energy crisis, the U.S. is one of the largest global suppliers of crude oil and natural gas. The processing of crude oil in the U.S. is expected to bounce back to 2019 levels by 2025 after falling in 2020.

"The oil and natural gas industry was already headed toward relying on capital from cash flow instead of debt and equity," the EIA stated. "COVID-19 has accelerated this trend, leaving producers more dependent on internal sources of cash flow because outside funding sources are less available or require higher rates of return."

The EIA expects a lower price path to decrease U.S. oil production rates in the short and medium term in AEO2021 compared to AEO2020. According to the report, "the oil price is the primary driver of projected drilling activity and accompanying U.S. crude oil production rates" in AEO2021.

In partnership with Rystad Energy, Hart Energy has identified the top 40 key players. Rystad compiled the list of companies based on first-quarter 2021 gross operated production as well as number of wells put on production in that same quarter. This section highlights a year review of U.S. activity for these shale leaders.

***Editor's note:*** *The following profiles were written based on the companies' second- and third-quarter 2021 results, as this is what was available when the publication went to print. If available, links to the companies' fourth-quarter reports will be included in the online version of this article on HartEnergy.com/publications.*

## *KEY PLAYERS >>>*

### Aethon Energy – private

Aethon Energy is a private investor and operator of onshore oil and gas properties in the U.S. based in Dallas. Founded in 1990, it has grown through its vertically integrated business model to become the largest private natural gas producer in the core of the Haynesville Shale.

The concentration and scale of Aethon's assets across the Haynesville Shale benefit from the proximity to growing demand centers along the Gulf Coast. Aethon is a leading operator with significant midstream gathering assets to support its upstream development. The scale of Aethon's vertically integrated approach provides one of the lowest overall cost structures in the dry gas industry.

Aethon's net acreage exceeds 350,000 acres, generating more than 1.5 Bcfe/d in net production, and its midstream infrastructure encompasses ~1,400 miles of pipe, nine treatment facilities and throughput capacity of approximately 2.8 Bcf/d.

### Antero Resources – public

Antero Resources operates in the Marcellus Shale with 515,000 net acres and operated more than 1,000 producing horizontal wells as of fourth-quarter 2020, as well as 91,000 net acres in the Utica Shale as of fourth-quarter 2019, according to the company's website.

In third-quarter 2021, Antero produced a net average of 10,131 bbl/d of oil, 2,232 MMcf of natural gas, 111,505 bbl/d of NGL, 47,519 bbl/d of ethane and 3,247 MMcfe/d of combined natural gas equivalent, according to its third-quarter financial and operational report. The company placed 16 horizontal wells in the Marcellus Shale with an average lateral length of 13,448 ft, nine of which have been online for at least 60 days. The average 60-day rate was 24.9 MMcfe/d per well, including about 1,370 bbl/d of liquids.

Antero set a company record during the third quarter for completion stages with 23 stages per day in the Marcellus, a 28% increase in the company's first simul-frac. It is operating three drilling rigs and one completion crew.

## APA Corp. – public

Apache Corp., a wholly owned subsidiary of APA Corp., operates in the Permian Basin (4.9 million acres) with more than 7,000 wells as of Dec. 31, 2020, according to the company website. The company also has smaller holdings in the Eagle Ford Shale and Austin Chalk Basin, its website stated.

APA's third-quarter 2021 report stated that the company produced 237,498 boe/d in the U.S., a slight decrease from 241,525 boe/d in the previous quarter, of which 38% was gas, 32% was oil and 30% was NGL. The company drilled 10 gross wells and completed seven net wells with an average of two rigs in the third quarter, with nine new wells placed on production in the southern Midland Basin. In 2020 the U.S. total production was 93.7 MMboe.

## Ascent Resources LLC – private

Ascent Resources Utica Holdings LLC is a private equity-backed company with operations in the Utica Shale in southern Ohio. The company has approximately 335,000 net leasehold acres, including 79,100 mineral acres in the heart of the play, according to the company's website.

Net production as of third-quarter 2021 was about 2 Bcfe/d, of which 93% was natural gas, Ascent Resources stated. The company operated four rigs during the third quarter and spud 19 wells, completed 20 wells and turned inline 17 wells with an average lateral length of 13,220 ft.

"Ascent Resources is one of the largest private producers of natural gas in the U.S. based on daily production and the largest producer of natural gas in Ohio," the website stated.

## Bayswater – private

Bayswater is a Denver-based private equity company that primarily operates in the Denver-Julesburg Basin Wattenberg Field (21,000 net acres) and the Midland Basin (36,200 net acres). The company has also accumulated interests in the Delaware Basin (11,000 net royalty acres) and the Powder River Basin (24,000 net acres), according to the company website.

"Bayswater prides itself on creating substantial value for our partners and shareholders and enhancing the wealth and well-being of the communities in which we work by linking technology, opportunities, talent, capital and executional excellence," the website stated.

Bayswater's website reports that the company is producing 17,000 boe/d in the Wattenberg and 6,000 boe/d in the Midland Basin. Bayswater has also amassed a mineral profile in the Delaware Basin, which is projected to cash flow $25 million in 2021.

## bp – supermajor

BPX Energy, which comprises bp's onshore oil and gas operations in the Lower 48, operates in the Haynesville Shale (1.7 million net acres), Eagle Ford Shale (588,000 net acres) and Permian Basin (84,000 net acres), according to a December 2020 bp investor presentation.

In bp's third-quarter 2021 results, the company reported an average of two rigs in the Permian, two rigs in the Eagle Ford and two rigs in the Haynesville. This is comparable to the eight rigs operating in second-quarter 2021, as stated in the report. Between the three shale plays, BPX produced 130,000 bbl/d of liquids (crude oil, condensate and NGL), 1,115 MMcf/d of natural gas and 322 Mboe/d of total hydrocarbons in the third quarter, according to the report. This is an 18% increase from the previous quarter's production, which reached 106,000 bbl/d of liquids, 971 MMcf/d of natural gas and 273,000 boe/d of total hydrocarbons.

Comparing the third quarter of 2021 versus 2020, bp reported underlying production was higher reflecting major project ramp-up partially offset by impacts from reduced capital investment, decline and weather impacts in the U.S. Gulf of Mexico. Looking ahead, the company stated fourth-quarter 2021 production is expected to be higher than third-quarter 2021 levels "reflecting major project ramp-up, mainly in gas regions, recovery from seasonal maintenance activity and continuing impacts from Hurricane Ida on our non-operated production in the U.S. Gulf of Mexico."

## Chesapeake – public

Chesapeake Energy operates in the Haynesville Shale (348,000 net acres, six active rigs), Marcellus Shale (540,000 net acres, three active rigs), Eagle Ford Shale (220,000 net acres, one active rig), Brazos Valley Basin (420,000 net acres) and Powder River Basin (190,000 net acres, 25 active rigs), according to the company website.

In third-quarter 2021, Chesapeake's average net production rate was approximately 436,000 boe/d, comprising approximately 80% natural gas and 20% total liquids, the company stated in its third-quarter earnings press release. It operated three rigs in Appalachia, six rigs in the Gulf Coast, one rig in the Eagle Ford and one rig in the Powder River Basin.

In fourth-quarter 2021, Chesapeake completed the acquisition of Vine Energy. Chesapeake president and CEO Nick Dell'Osso said in regard to the acquisition, "We are pleased to integrate the outstanding Vine operations and assets into our portfolio, strengthening our position in the Haynesville Shale with over 900 additional drilling locations, immediately improving our free cash flow profile and accelerating a significant return of capital to our shareholders at a time of favorable natural gas prices."

## Chevron – supermajor

Chevron Corp. develops unconventional oil and gas resources, primarily operating in the Permian (2.2 million net acres) and the Denver-Julesburg Basin (327,000 net acres), according to the company's website.

For Chevron's U.S. upstream operations, third-quarter 2021 net production was 1.13 MMboe/d, up 145,000 boe/d compared to a year earlier, according to Chevron's third-quarter 2021 earnings report. The surge in net oil equivalent production is in part due to the acquisition of Noble Energy in fourth-quarter 2020, allotting Chevron an additional 224,000 bbl/d, partially offset by a 69,000-bbl/d decrease related to the Appalachian asset sale. Chevron completed its acquisition of Noble Midstream in second-quarter 2021.

In October 2021, Chevron announced it had adopted a 2050 net-zero goal for equity upstream Scope 1 and 2 emissions.

## Civitas – public

Civitas formed in May 2021 from a merger between Extraction Oil & Gas and Bonanza Creek Energy Inc. The company operates in the Denver-Julesburg Basin with 525,000 net acres, according to its website.

As of the end of third-quarter 2021, Civitas produced approximately 159 Mboe/d, of which 40% was oil, 35% was gas and 25% was NGL, the company's November 2021 investor presentation stated. The company holds 315 MMcf/d of gas gathering capacity with 280 miles of gas gathering, gas-lift and sales lines, and 77 MMbbl/d of oil capacity with 35 miles of total oil gathering.


**Chesapeake Energy operates in the Haynesville Shale with 348,000 net acres and six active rigs. (Source: Chesapeake Energy)**

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In the second quarter, shortly after the formation of the company, Civitas acquired Crestone Peak Resources in an all-stock deal, according to a press release issued June 7. The acquisition increased Civitas' production to 160,000 bbl/d and increased proven reserves of the equivalent to 530 MMbbl.

## CNX Resources Corp. – public

CNX Resources Corp. operates in the Marcellus and Utica shales, with an average well lateral length of 12,000 lateral ft in the Marcellus and 14,500 lateral ft in the Utica, according to the company's third-quarter 2021 earnings results report.

The report stated that CNX's average daily production increased to 1,668.7 MMcfe in the third quarter from 1,562.5 MMcfe in the first quarter and 1,515.6 MMcfe in the second quarter. Shale sales volumes rose to 130.3 Bcf from 121.1 Bcf in the first quarter and 115 Bcf in the second quarter, but coalbed methane sales volumes fell to 12.2 Bcf from 12.7 Bcf in the first quarter and 12.6 Bcf in the second quarter. NGL sales volumes increased from 6.5 Bcfe in the first quarter and 9.5 Bcfe in the second quarter to 10.1 Bcfe, and oil and condensate sales volumes rose from 0.3 Bcfe in the first quarter and 0.7 Bcfe in the second quarter to 0.8 Bcfe in the third quarter.

CNX Resources operates in the Marcellus and Utica. (Source: CNX Resources Corp.)

## Comstock Resources – public

Comstock Resources operates in the Haynesville/Bossier Shale with 323,000 net acres, according to the company website.

In its third-quarter 2021 financial report, Comstock reported its total production increased 25% to 1,424 MMcfe/d from the same quarter in 2020. Oil production dipped 2% to 3.67 Mbbl/d from 3.85 Mbbl/d in 2020, and gas production increased 26% from 1,115 MMcf/d in 2020 to 1,401 MMcf/d. The company completed 15 operated wells in the third quarter with an average lateral length of 7,925 ft. and an average IP rate of 22 MMcf/d.

In fourth-quarter 2021, Comstock partnered with MiQ "to independently certify its natural gas production in North Louisiana and East Texas," according to a press release on Nov. 2. The release stated that Comstock will use the MiQ Standard for its facilities in North Louisiana and East Texas, "which currently produce approximately 2 billion cubic feet per day of natural gas."

## ConocoPhillips – public

In the Lower 48, ConocoPhillips operates primarily in the Permian (~750,000 net acres), Bakken (~610,000 net acres) and Eagle Ford (~200,000 net leasehold and mineral acres) basins, with smaller holdings in the Anadarko (~283,000 net acres) and Wyoming/Uinta (~44,000 net acres) basins, according to the company's year-end 2020 Lower 48 report.

ConocoPhillips reported third-quarter 2021 total production of 1,507 Mboe/d, up 441 Mboe/d from 981 Mboe/d in third-quarter 2020, according to a press release containing its third-quarter earnings. In its Lower 48 holdings, third-quarter 2021 production averaged 790 Mboe/d, with 445 Mboe/d from the Permian Basin, 217 Mboe/d from the Eagle Ford Basin and 95 Mboe/d from the Bakken.

ConocoPhillips operates primarily in the Permian with about 750,000 net acres. (Source: ConocoPhillips)

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## Continental Resources – public

Continental Resources operates in the Bakken Shale in North Dakota and Montana and the STACK/SCOOP in Oklahoma, according to its third-quarter 2021 earnings report. The company also acquired a position in the Powder River Basin play in Wyoming and acquired Pioneer Natural Resources' Delaware Basin assets in fourth-quarter 2021.

The report stated that the company's Bakken holdings produced 167,604 boe/d in the third quarter, up from 160,661 boe/d the same time in 2020, and the STACK/SCOOP holdings produced 152,543 boe/d, increased from 129,583 boe/d in third-quarter 2020. Between the two shales, average crude oil production was 157,153 bbl/d, average natural gas production was 1,045,521 Mcf/d and average production of crude oil equivalents was 331,407 boe/d.

Continental Resources had 143 gross operated wells and 85 net operated wells in the Bakken, with an average of seven rigs in second-quarter 2021. In the STACK/SCOOP, it had 67 gross operated wells and 54 net operated wells with four average rigs, according to the company's second-quarter 2021 earnings press release.

## Coterra Energy – public

Coterra Energy Inc. was formed in early fourth-quarter 2021 through a merger between Cabot Oil & Gas Corp. and Cimarex Energy Co. The company operates in the Permian Basin (234,000 net acres), Anadarko Basin (189,000 net acres) and Marcellus Shale (173,000 net acres), as stated on its website.

According to the company's earnings presentation, during third-quarter 2021, Coterra's average production for the combined assets was 645 Mboe/d, including 81.5 Mbbl/d of oil and 2,945 MMcf/d of natural gas. The company's earnings press release stated that the Marcellus Shale operated two rigs and two completion crews in the third quarter, and the Permian operated five rigs and two completion crews.

The presentation stated that Coterra put 25 net wells on production in the Permian, 31 wells in the Marcellus and five wells in the Anadarko. It also drilled 17 wells and completed 30 wells in the Marcellus. It anticipates putting 17 to 20 wells on production in the Permian and drilling 19 wells in the Marcellus in fourth-quarter 2021.

## CrownQuest – private

CrownQuest is the operating name for CrownRock LP, which was formed with private equity provider Lime Rock Partners in 2007. The company operates almost exclusively in the Midland Basin (~90,716 net acres). The company also holds acreage in the Eastern Shelf (~105,000 net acres) of the Permian Basin as well as smaller amounts of acreage in other basins, according to the company website.

CrownQuest produces about 125,000 net boe/d from approximately 1,372 wells, more than 400 of

**Coterra's acreage position spans across the Permian Basin, Marcellus Shale (pictured) and Anadarko Basin. (Source: Coterra Energy)**


# Essential Partner for Smarter Energy.

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which are horizontal. Current and forward-looking development plans include drilling and completing roughly 150 multi-layer horizontal wells per year in its core Midland Basin position, where the company has already invested approximately $3.6 billion since 2015. CrownQuest assets also include significant surface ownership, a water source and disposal system, and a mineral position in the Permian Basin.

## Devon Energy – public

Devon Energy operates in the Delaware Basin (400,000 net acres), Williston Basin (85,000 net acres), Powder River Basin, Anadarko Basin and Eagle Ford Shale, according to the company's website.

According to Devon's third-quarter 2021 earnings supplement, the Delaware Basin produced 213 Mbbl/d of oil, 100 Mbbl/d of NGL, 578 MMcf/d of gas and 409 Mboe/d of total oil equivalent. The Anadarko Basin produced 14 Mbbl/d of oil, 25 Mbbl/d of NGL, 219 MMcf/d of gas and 75 Mboe/d of total oil equivalent. The Williston Basin produced 39 Mbbl/d of oil, 9 Mbbl/d of NGL, 59 MMcf/d of gas and 58 Mboe/d of total oil equivalent. The Eagle Ford produced 20 Mbbl/d of oil, 11 Mbbl/d of NGL, 67 MMcf/d of gas and 42 Mboe/d of total oil equivalent. The Powder River Basin produced 14 Mbbl/d of oil, 3 Mbbl/d of LNG, 19 MMcf/d of gas and 20 Mboe/d of total oil equivalent.

Devon's third-quarter 2021 earnings presentation stated that the company brought 81 wells online as well as ran 16 operated rigs and five completion crews across its assets.

**Devon Energy operates in the Delaware Basin with 400,000 net acres. (Source: Devon Energy)**

## Diamondback Energy – public

Diamondback Energy is a pure play Permian operator after closing the divestiture of its Williston Basin assets on Oct. 21, 2021, according to the company's third-quarter announcements press release.

The release also stated that oil production averaged at 22,058 Mbbl in the third quarter compared to 22,067 Mbbl in the second-quarter. Natural gas production rose to 45,571 MMcf from 44,506 MMcf in the second quarter, and NGL increased from 7,047 Mbbl in the second quarter to 7,540 Mbbl in the third quarter, with combined volumes averaging at 37,193 Mboe in the third quarter as opposed to 36,532 Mboe in the second quarter. Oil volumes dipped from 242,495 bbl/d in the second quarter to 239,761 bbl/d, and combined volumes rose from 401,451 boe/d the previous quarter to 404,272 boe/d.

In third-quarter 2021, Diamondback drilled 47 wells and completed 63 wells in the Midland Basin and drilled 11 and completed 10 wells in the Delaware Basin, according to its third-quarter announcements press release. In the first three quarters of the year, the company drilled 135 gross horizontal wells in the Midland Basin and 28 in the Delaware Basin.

## Encino Energy – private

Encino Energy is backed by the Canada Pension Plan Investment Board. Encino Acquisition Partners LLC was formed in 2017 in partnership with CPP Investments to build a sustainable and profitable large-scale gas, oil and liquids production company. It operates in the Utica Shale with 1 million net acres with 29 Tcfe of recoverable reserves.

Since 2018 Encino has driven down well costs per lateral foot by about 50% and doubled productivity per foot. With what Encino thinks are the lowest costs per foot in the basin, combined with the oil and liquids revenues, the company's margins are approaching best in class, according to Encino.

With a primary focus in the Utica Shale, the company's long-term strategy of building a sustainably profitable business considers value-driving strategic acquisitions. Encino is looking actively at multiple transactions and expects it will continue growing both with the drill bit and through acquisitions.

## Endeavor Energy Resources – private

Endeavor Energy Resources operates in the Permian Basin with more than 250,000 net acres in the Midland Basin and 500,000 net acres in the rest of the Permian, the company's website stated.

"With a large asset position of over 350,000 net acres in the Midland Basin, Endeavor is poised for unparalleled growth as it executes its drilling program," the website stated. "An estimated 98% of Endeavor's assets in the Midland Basin have yet to be drilled."

In a press release reporting the company's second-quarter 2021 results, Endeavor reported net production of 185.2 Mboe/d, which is an 18% increase from its production of 156.5 Mboe/d at the same time in 2020. Total net production in second-quarter 2020 was 14.2 MMboe, increasing to 16.9 MMboe in second-quarter 2021, in part due to higher prices for crude oil, natural gas and NGL. Endeavor also spud 72 gross operated wells and placed 31 gross operated wells on production in the quarter, the release stated.

## EOG Resources – public

EOG Resources operates in the Williston Basin, Powder River Basin, Permian Basin, Anadarko Basin, Eagle Ford Shale, Barnett Shale, South Texas Shale and Upper Gulf Coast Shale in the U.S., according to the company's website.

In EOG's second-quarter 2021 earnings press release, it reported a total of 828.0 Mboe/d in crude oil equivalent volumes across all its holdings. The U.S. reported 446.9 Mbbl/d in the second quarter in crude oil and condensate production, up from 428.7 Mbbl/d in the first quarter and an increase of 5.9 Mbbl/d from its second-quarter guidance midpoint. NGL production totaled 138.5 Mbbl/d, increased from 124.3 Mbbl/d in the first quarter and 6 Mbbl/d higher than the second-quarter guidance midpoint. U.S. natural gas production totaled 1,199 MMcf/d, increased from 1,100 MMcf/d in the first quarter and 39 MMcf/d higher than the second-quarter guidance midpoint.

For third-quarter 2021, EOG reported its guidance range for crude oil and condensate production is 440

Mbbl/d to 447 Mbbl/d, 135 Mbbl/d to 145 Mbbl/d for NGL production, 1,150 MMcf/d to 1,250 MMcf/d for natural gas production and 766.7 Mboe/d to 800.3 Mboe/d for crude oil equivalent production.

## EQT Corp. – public

EQT Corp. is the largest natural gas producer in the U.S., producing 5.6 Bcfe/d and owning or leasing approximately 640,000 net core acres in Pennsylvania, 240,000 net core acres in West Virginia and 60,000 net core acres in Ohio, according to EQT's latest investor presentations.

According to the company's third-quarter earnings press release, EQT horizontally drilled three wells with an average net lateral of 12,700 ft and completed two wells with a net average lateral of 11,700 ft. In southwest Pennsylvania, it horizontally drilled 12 wells with an average net lateral of 15,320 ft and completed 21 wells with an average net lateral of 10,960 ft. In West Virginia, it horizontally drilled nine wells with an average net lateral of 12,820 ft. In the aggregate, the company turned inline 40 wells to sales with an average net lateral of 10,830 ft.

The release continued that the company plans to horizontally drill five wells in the fourth quarter in northeast Pennsylvania with an average net lateral of 12,190 ft, 26 wells in southwest Pennsylvania with an average lateral of 11,820 ft and one well in Ohio with an average net lateral of 12,960 ft. In the aggregate, the company plans to turn inline 25 wells to sales with an average net lateral of 11,820 ft.

**A Patterson-UTI rig operates among a scenic landscape in Greene County. (Source: EQT Corp.)**

## Exxon Mobil – supermajor

Exxon Mobil Corp. operates in five states in the U.S.—California, Texas, Wyoming, Louisiana and Alabama—primarily in the Permian and Bakken shales.

In third-quarter 2021, Exxon Mobil reported 758,000 bbl/d in net production of crude oil, NGL, bitumen and synthetic oil, compared to 665,000 bbl/d in the first quarter and 687,000 bbl/d in the second quarter, as stated in the company's third-quarter 2021 results report. Additionally, natural gas production decreased from 2,804 Mcf/d in the second quarter to 2,701 Mcf/d in the third quarter. Upstream U.S. capex for third-quarter 2021 totaled $976 million.

In December 2020, Exxon Mobil announced plans to reduce the intensity of operated upstream greenhouse-gas emissions by 15% to 20% by 2025, compared to 2016 levels, according to a company news release. The emission reduction plans, which cover Scope 1 and Scope 2 emissions from operated assets, are projected to be "consistent with the goals of the Paris Agreement," the release stated. "The company also plans to align with the World Bank's initiative to eliminate routine flaring by 2030."

## Great Western Oil & Gas – private

Great Western Oil & Gas operates in the Denver-Julesburg Basin in northern Colorado, specifically in the Wattenberg Field, according to the company's website.

"As we expand our growth plans by extending our core areas, we are following proven strategic fundamentals," the website stated. "We seek a lower risk, multi-faceted value creation proposition through operational efficiency improvements and enhanced recovery potential."

In July 2021, Great Western's Raindance Pad in Windsor, Colorado, began operation. The pad will help manage the company's field locations by reducing emissions and "increasing pipe movement to have the most up-to-date facilities," according to the company.

## Gulfport Energy – public

Gulfport Energy operates in the Utica Shale of the Appalachian Basin with approximately 193,000 net acres and the SCOOP play of the Anadarko Basin with approximately 73,000 net reservoir acres, according to the company website.

In third-quarter 2021, Gulfport's quarterly earnings press release reported the company produced 958 bbl/d of oil and condensate in the Utica shale, dipping slightly from 1,579 in third-quarter 2020, and 4,335 bbl/d in the SCOOP play, increasing from 3,204 bbl/d.

Natural gas production decreased from 763,387 Mcf/d to 678,154 Mcf in third-quarter 2021 in the Utica but rose from 139,233 Mcf/d to 188,292 Mcf/d inthird-quarter 2021 in the SCOOP. NGL production in the third quarter 2021 totaled 2,516 bbl/d in the Utica, decreasing from 2,917 bbl/d, and 9,918 bbl/d in the SCOOP, increasing from 7,128 bbl/d.

On May 17, Gulfport completed its restructuring process after emerging from bankruptcy. The company applied fresh start accounting, marking its start date May 17, according to the company's second-quarter 2021 earnings press release.

## Hess – public

Hess Corp. has a key position in the U.S. shale play—the North Dakota Bakken and Three Forks formations. The company is one of the largest producers in the Bakken and has approximately 460,000 net acres and an average working interest of about 75%.

The company's focus remains on maximizing value from its current acreage position. Hess has approximately 2,200 future locations, which is over 70 rig years of inventory. Net production averaged 193,000 boe/d in 2020. In 2021 Hess added a second rig in February and a third rig in September.

## Kaiser-Francis Oil Co. – private

Kaiser-Francis Oil Co. is a private oil and gas E&P company based in Tulsa, Okla., and operating in the Denver-Julesburg Basin.

According to a report by offshore-technology.com, which quoted data from GlobalData's USL48 database, "The oil and gas production of Kaiser-Francis Oil grew 141.66% in August 2021 from 18,883.04 boe/d in August 2020. On a YTD [year to date] basis, the company's total oil and gas production increased by 147.35% from the same period in 2020."

The report also stated, "On a YTD basis, oil production increased by 128.73% in 2021 when compared with the same period in 2020, while gas production rose by 186.6%. Out of the total oil and gas production in August 2021, oil production held a 63.1% share, while gas production held a 36.78% share."

## Laredo Petroleum – public

Laredo Petroleum operates in the Permian Basin in 140,000 gross acres across the Wolfcamp and Cline formations, according to Laredo's website.

In the company's second- and third-quarter 2021 results press releases, it reported 3,250 Mbbl/d in oil production in the third quarter, up from 2,406 Mbbl/d in the second quarter, and 7,057 Mboe/d of production in the third quarter, a decrease from 7,819 Mboe/d in the second quarter. NGL production fell to 1,830 Mbbl/d from 2,551 Mbbl/d the previous quarter, and natural gas production decreased from 17,169 MMcf/d to 11,860 MMcf in the third quarter.

In the third quarter, Laredo had two drilling rigs and one completions crew in operation. It completed 18 wells and turned inline 19 wells, according to a press release.

On July 1, 2021, Laredo acquired Sabalo Energy, a portfolio company of EnCap Investments.

## Marathon Oil – public

Marathon Oil operates in the Bakken Shale, Delaware Basin, SCOOP/STACK and Eagle Ford, according to the company's website.

Marathon Oil's third-quarter 2021 results press release stated that total U.S. production was 284 Mboe/d, up from 275 Mboe/d in the first quarter. In the Eagle Ford, it produced 60 Mbbl/d in crude oil and condensate, 18 Mbbl/d in NGL and 99 MMcf/d in natural gas. The Bakken area produced 67 Mbbl/d in crude oil and condensate, 22 Mbbl/d in NGL and 84 MMcf/d in natural gas. The SCOOP/STACK produced 12 Mbbl/d in crude oil and condensate, 19 Mbbl/d in NGL and 146 MMcf/d in natural gas. The Delaware produced 12 Mbbl/d in crude oil and condensate, 4 Mbbl/d in NGL and 30 MMcf/d in natural gas.

In the third quarter, 63 gross company-operated wells were brought to sales across Marathon's assets, enabling the company to produce an average of 284,000 net boe/d and 157,000 bbl/d.

## Matador Resources – public

Matador Resources operates in the Delaware Basin (~120,700 acres), Eagle Ford Shale (~25,700 acres) and Haynesville Shale (~17,700 acres), according to a press release reporting the company's third-quarter 2021 earnings results.

Average production for Matador was 90.0 Mboe/d, with 84.0 Mboe/d from the Delaware Basin, 3.8 Mboe/d from the Haynesville Shale and 2.2 Mboe/d from the Eagle Ford Shale, the report stated. Across the three plays, the company produced 4,669 Mbbl, 50,747 bbl/d, in oil, down from 4,855 Mbbl and 53,354 bbl/d in the second quarter.

Natural gas production volume decreased slightly from 21.8 Bcf and 239.1 MMcf/d in the second quarter to 21.7 Bcf and 235.7 MMcf/d in the third quarter. Additionally, total oil equivalent production fell to 8,283 Mboe and 90,003 boe/d in the third quarter from 8,482 Mboe and 93,210 boe/d in the second quarter.

Compared to the same time last year, Matador reported oil production of ~50,700 bbl/d up 20% year-

over-year from third-quarter 2020, natural gas production of ~235.7 MMcf/d up 28% year-over-year from third-quarter 2020 and total production of ~90,000 boe/d up 23% year-over-year from third-quarter 2020.

## Mewbourne Oil Co. – private

Mewbourne Oil Co. is one of the largest privately owned oil and gas companies in the U.S. Headquartered in Tyler, Texas, Mewbourne has more than 56 years of successful experience operating in the Permian and Anadarko basins.

Mewbourne professionals generate, acquire and develop successful prospects in New Mexico, Texas and Oklahoma. With 19 rigs actively drilling, the company is currently one of the most active drillers in the country.

The company anticipates continued stable, long-term growth.

## Occidental – public

Occidental operates in the Permian Basin with approximately 3 million net acres. It is a leading producer in the Denver-Julesburg (D-J) Basin in Colorado and holds assets in the Powder River Basin in Wyoming, according to the company website.

In its third-quarter 2021 earnings press release, Occidental produced 292 Mbbl/d in the Permian, increasing from 271 Mbbl/d in the first quarter, and 85 Mbbl/d in the D-J and Powder River basins, decreasing from 92 Mbbl/d in the first quarter.

NGL production rose to 116 Mboe/d in the Permian from 97 Mboe/d in the first quarter and increased to 94 Mboe/d in the D-J and Powder River from 92 Mboe/d the previous quarter.

Natural gas production increased from 531 MMcf/d in the first quarter to 548 MMcf/d in the second quarter in the Permian Basin, and from 673 MMcf/d in the first quarter to 675 MMcf in the second quarter in the D-J and Powder River basins.

Overall, the Permian reported a net total of 499 Mboe/d, and the D-J and Powder River reported a net total of 292 Mboe/d.

Occidental surpassed its total production guidance midpoint by 15 Mboe/d, reporting a combined total of 1,160 Mboe/d from continuing operations, the press release stated.

## Ovintiv – public

Ovintiv operates primarily in the Anadarko and Permian basins with lesser operations in the Bakken and Uinta shales, the company's website stated.

In its second-quarter 2021 supplemental report, Ovintiv reported a total of 310.8 Mboe/d produced among its U.S. operations, up from 292.8 Mboe/d in the first quarter. It produced 158.7 Mbbl/d of oil and plant condensate, an increase from 155.3 Mbbl/d the previous quarter. Total NGL production rose from 70.7 Mbbl/d in the first quarter to 79.7 Mbbl/d the following quarter, and natural gas production rose to 497 MMcf/d in the second quarter from 459 MMcf/d in the first quarter. Combined oil and NGL produced from U.S. operations totaled 227.9 Mbbl/d, an 11.6 Mbbl/d increase from the first quarter.

**Ovintiv's second-quarter 2021 Permian production averaged three gross rigs, drilled 21 net wells and had 33 net wells turned inline. (Source: Ovintiv)**

Ovintiv's second-quarter 2021 production in the Permian averaged three gross rigs, drilled 21 net wells and had 33 net wells turned inline, according to its second-quarter 2021 results press release. The Anadarko averaged two gross rigs, drilled 16 net wells and had 22 net wells turned inline, 21 of which were operated by Ovintiv.

## PDC Energy – public

PDC Energy operates primarily in the Denver-Julesburg Basin, with about 180,000 net acres in the Wattenberg Field, and secondarily in the Permian Basin, with about 25,000 net acres in the Delaware Basin, the company's website stated.

PDC's third-quarter 2021 earnings press release reported that the company's crude oil production rose 1% to 4,925 Mbbl in the Wattenberg Field and 4% to 1,184 Mbbl in the Delaware Basin compared to the holdings' production third-quarter 2020. Crude oil equivalent production rose 8% to 16,047 Mboe in the Wattenberg and decreased 6% to 2,717 Mboe in the

Pioneer Natural Resources is the largest producer in Texas with more than 900,000 net acres in the Permian Basin. (Source: Pioneer)

Permian. Natural gas production rose 12% to 39,538 MMcf from 2020 in the Wattenberg but decreased 10% to 5,664 MMcf in the Delaware. Similarly, NGL production increased 13% to 4,532 Mbbl in the Wattenberg but fell 17% to 590 Mbbl from 564 Mbbl in the Permian.

In the Wattenberg Field, PDC operated one drilling rig and one completion crew, resulting in 20 spuds and 57 turned inline, according to the report. PDC had approximately 160 DUC wells by the end of the third quarter.

## Pioneer Natural Resources – public

Pioneer Natural Resources is the largest producer in Texas with more than 900,000 net acres in the Permian Basin, with an average 2021 rig count of 22 to 24, in addition to over 500 wells being drilled in 2021, according to the company's third-quarter 2021 earnings presentation.

Pioneer's total Permian production in the third quarter was 675,770 boe/d, up from 629,434 boe/d in the previous quarter, the presentation stated. Oil production totaled 388,820 bbl/d in the third quarter, an increase from 363,033 bbl/d the previous quarter. NGL production increased from 147,124 boe/d in the second quarter to 156,863 boe/d in the third quarter, and gas production rose from 715,673 Mcf/d in the second quarter to 780,515 Mcf/d in the third quarter.

Pioneer completed its acquisition of Parsley Energy Inc. in January 2021, and the company acquired private operator DoublePoint Energy in second-quarter 2021. In fourth-quarter 2021, the company sold its Delaware Basin assets to Continental Resources, according to a press release issued Nov. 3.

## Range Resources – public

Range Resources Corp. is a top 10 U.S. producer of both natural gas and NGL with operations focused in the Appalachian Basin. Range operates approximately 1.5 million net effective acres in the core of the Appalachian Basin that includes potential from the Marcellus, Utica/Point Pleasant and Upper Devonian shales.

According to Range Resources' third-quarter 2021 report, the company produced 137.7 Bcf of natural gas, 9.1 MMbbl of NGL and condensate production of 711,000

A Range Resources producing well site operates in Washington County, Pa. (Source: Range Resources)

bbl, as total production from Appalachia increased approximately 1% compared to the prior year.

According to Range Resources, the company has the lowest development costs per unit of production in Appalachia. It has approximately 3,100 undrilled wells in the Marcellus with an estimated well inventory of 2,600 liquids rich wells and 500 dry gas wells.

Range has set emission reduction targets, including to achieve a goal of net zero direct greenhouse-gas emissions by 2025.

## Rockcliff Energy – private

Rockcliff Energy is a private equity company operating in the Haynesville Shale with more than 270,000 net acres, of which more than 90% is HBP, according to the company's website.

"We have built nine companies across various basins, commodities and economic cycles, all with outstanding project-level and corporate-level returns to our investors," the website stated.

Rockcliff produced more than 1 Bcf/d from its assets in East Texas and has a strategic partnership with Trace Midstream.

"Rockcliff consistently keeps four rigs and two frac crews busy exploiting 156,000 net acres in Harrison and Panola counties, Texas, where the company has 1,000 future well sites that will keep Rockcliff busy in the area for a long time," The American Oil and Gas Reporter reported in March 2021.

Shell's iShale well pads and a mini-modular central processing facility are powered by large solar panels and wind turbines, which reduce the company's GHG footprint. (Source: Shell International Ltd.)

## Shell – supermajor

Royal Dutch Shell operated for years in the Delaware Basin of the Permian, but it sold its Permian assets to ConocoPhillips in late 2021.

"Shell Enterprises LLC, a subsidiary of Royal Dutch Shell Plc, has completed the sale of its interest in the Permian to ConocoPhillips for $9.5 billion in cash," a Dec. 1 company press release stated. "The agreement covers the sale of Shell's 225,000 net acres and existing production of around 175 thousand barrels equivalent per day."

In Shell's second-quarter 2021 and half-year unaudited results report, the company reported a total of 162,000 bbl/d of liquids production available for sale, compared to 170,000 bbl/d in the first quarter of the year. Shell also stated that it produced 4,502 MMscf/d in second-quarter 2021, decreasing 3% from 4,621 MMscf/d in first-quarter 2021.

Additionally, production of LNG liquefaction volumes fell 8% from 8.16 mT in the first quarter to 7.49 mT in the second quarter. Total production available for sale and

LNG sales both decreased 3% within the first half of the year, with total production falling from 967,000 boe/d in the first quarter to 938,000 boe/d in the second quarter as well as LNG decreasing from 16.38 mT in the first quarter to 15.92 in the second quarter.

"Shell's Shales business focuses on safely and responsibly producing gas, oil and their liquid components," the company stated on its website. "We have robust GHG [greenhouse-gas] targets and—even with production ramp-up—we are on track to meet top quartile GHG intensity targets for our hydrocarbon assets by 2021 and gas by 2025."

## Slawson Exploration – private

Slawson Exploration Co., Inc. is a private E&P company based in Wichita, Kan., with unconventional operations in the Williston Basin.

"Beginning with its first strike in 1957 in Kansas, Slawson has drilled more than 4,000 operated oil and gas wells in 10 states," Slawson's website stated.

"Slawson continues to lead the way in the modern development of the Bakken Petroleum System in the Williston Basin," a company spokesperson told Hart Energy. "It has drilled and completed over 525 wells using horizontal drilling and hydraulic fracturing technology since 2004. These include the individual well records within the basin for single-month oil production with 136,924 barrels, total measured depth at 28,186 ft and completed lateral length at 17,676 ft."

**A well operated by Slawson Exploration drills in Mountrail County, N.D. (Source: Slawson Exploration)**

## SM Energy – public

SM Energy operates in the Maverick Basin (~155,000 net acres) in South Texas and the Midland Basin (~82,000 net acres) in West Texas. As of Sept. 30, 2021, the company had drilled 64 net wells and completed 97 net wells year-to-date, according to SM Energy's website.

The company's third-quarter 2021 operating and financial results highlighted production outperformance in both the Midland Basin and South Texas, which resulted in strong cash flows, SM Energy told Hart Energy. Third-quarter production was 155.8 Mboe/d and consisted of 56% oil, 34% natural gas and 10% NGL. Total third-quarter production increased 14% from the previous quarter and 23% from compared with the prior year period. Oil, natural gas and NGL production increased 19%, 9% and 6%, respectively, compared with the previous quarter. Production from the Midland Basin represented 68% of total production for the quarter.

The company's third-quarter production outperformance was related to higher base production, reduced flaring and the effect of larger fracture stimulations in the Midland Basin and the successful early completion of certain wells in South Texas, SM Energy told Hart Energy. The larger fracture stimulations in the Midland Basin were highlighted during the company's latest earnings call.

President and CEO Herb Vogel stated in the third-quarter report, "On the ESG front, operations and IT have teamed up with a new effort to focus on evaluating and implementing emerging field technologies that will help the company measure, monitor and decrease emissions. The team has already initiated a pilot project at Sweetie Peck [in Texas] with technology to provide continuous methane monitoring."

## Southwestern Energy – public

Southwestern Energy operates in the Appalachian Basin (789,000 net acres) and the Haynesville Shale (275,000 net effective acres, 149,000 net surface acres), according to the company's website.

In Southwestern's latest quarterly results press release, the company reported NGL production at 8,011 Mbbl in the third quarter, up from 6,687 Mbbl during the same time in 2020. Oil production totaled 1,729 Mbbl compared to 1,294 Mbbl the previous year, and gas production totaled 251 Bcf, increasing from 173 Bcf in third-quarter 2020. Total production in Appalachia was 280 Bcfe, and Haynesville total production was 30 Bcf after the acquisition of assets in early September. Between the two shales, Southwestern drilled 17 wells, completed 23 wells and placed 24 wells to sales.

On Sept. 1, Southwestern completed the $2.7 billion acquisition of Indigo Natural Resources. The company updated its total year guidance to reflect the additional production from the acquisition, increasing it to 1,217 Bcfe to 1,235 Bcfe. In fourth-quarter 2021, the company also agreed to acquire GEP Haynesville by year-end 2021, according to a press release issued Nov. 4. ■

# Predicting the Performance of Polymers

## By connecting chemical data and digital technology, Kemira is improving the flow of information between the laboratory and the field.

*Contributed by Kemira Chemicals Inc.*

Digital solutions are dramatically changing the way we live and work in today's world. The digital oil field is no different and has been evolving rapidly, leveraging technology to make improvements in safety, productivity and sustainability.

As a supplier of chemical solutions into the stimulation market, Kemira Chemicals has generated decades of laboratory information and 1,000s of datasets. Combining this information with a digital platform, Kemira is offering a unique digital solution to its customers that models and predicts chemical performance, KemConnect Flow.

"Developing data-driven tools is a smart way to create value for our customers whether it's bringing improvements in operational efficiencies or helping to optimize their resources," said Fredrik Enell, business development manager for Kemira's Industry & Water businesses. "For Kemira, sustainability is at the heart of our strategy, and we see digitalization as an essential tool contributing to our sustainable development goals"

### A legacy of chemical data

Kemira has 100 years of expertise manufacturing quality emulsion and powder polyacrylamides for water-intensive industries. Our KemFlow friction reducers (FRs) and high-viscosity FRs are being used globally to improve frac performance and enhance well productivity.

Don Rutz, director of oil and gas special projects, explained, "Our FRs reduce friction and lower energy demands during frac'ing, but performance is subject to changes in water composition. Kemira's comprehensive portfolio of products are designed with optimal operating windows; selecting the wrong product can greatly impact the overall frac performance."

He continued, "Typically polymer screening and dosages are recommended in the laboratory, but lab performance is merely indicative of what is expected to be seen during the frac. The dynamic nature of the oil field means that what you expect isn't always what you get. Water that was meant to be fresh can be delivered containing high levels of total dissolved solids or vice versa, making the lab recommendation sub-optimal, and this will impact frac performance."

### Improving the flow of data

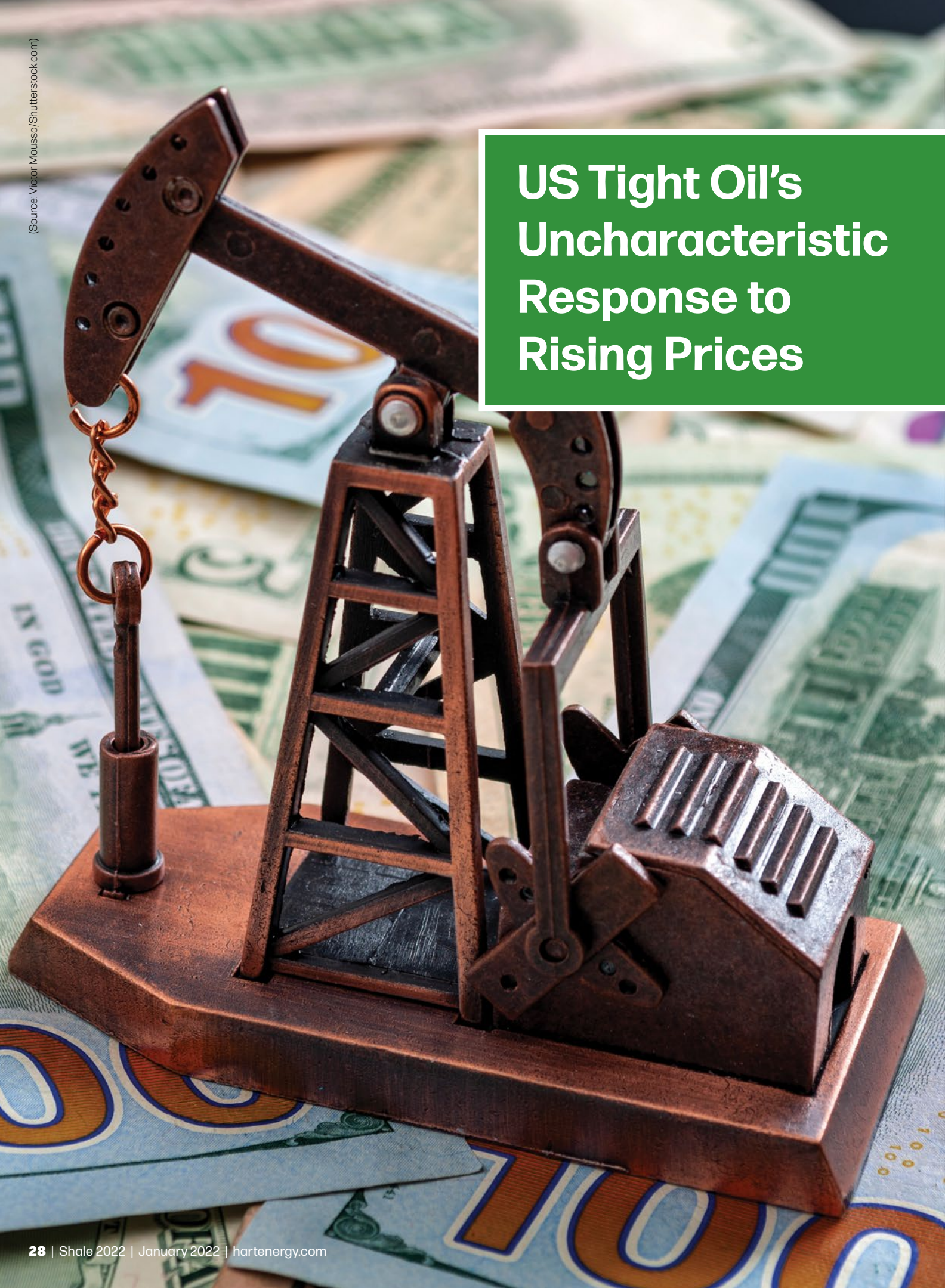
Kemira has combined their chemistry and digital knowledge to develop a predictive tool that converts laboratory data into actionable information to be used in the field.

"KemConnect Flow uses water composition data and algorithms to predict friction reduction and viscosity building performance. We can recommend products and dosages in a matter of minutes," Enell said. "The benefit is that the correct KemFlow polymer can be selected and changes made quickly to accurately reflect field conditions, without having to wait for lab measurements."

### Putting data to good use

With the predictive capabilities of KemConnect Flow, and KemFlow FRs sited locally in six of the main North American basins, Kemira customers can adapt quickly to unforeseen changes in water composition, providing optimal frac fluid performance.

KemConnect Flow is part of Kemira's wider digital solutions offering that is being conceptualized and designed to provide tools that will help our customers quickly solve problems they might encounter in the field while using our chemistries. ■



(Source: Victor Moussa/Shutterstock.com)

# US Tight Oil's Uncharacteristic Response to Rising Prices

***The 2021 run-up in oil price is an important test for the sector, and so far, it's passing with flying colors.***

By Linda Htein, Director, Americas Region Consulting, *Wood Mackenzie*

Many doubted tight oil's ability to show restraint. But after a hard reset in 2020, the sector continues to resist the temptation to grow, even with oil prices above $80/bbl. A look back at history shows how unique this moment is—never before has tight oil investment been so low with prices so high.

So what are the macro trends shaping the near-term trajectory of U.S. tight oil?

Several issues are worth noting. First, year-to-date, there has been no meaningful supply response to rising prices, and Wood Mackenzie does not expect to see material growth until 2022. Additionally, the rig recovery is sluggish compared to the previous downturn and uneven across the major oil plays.

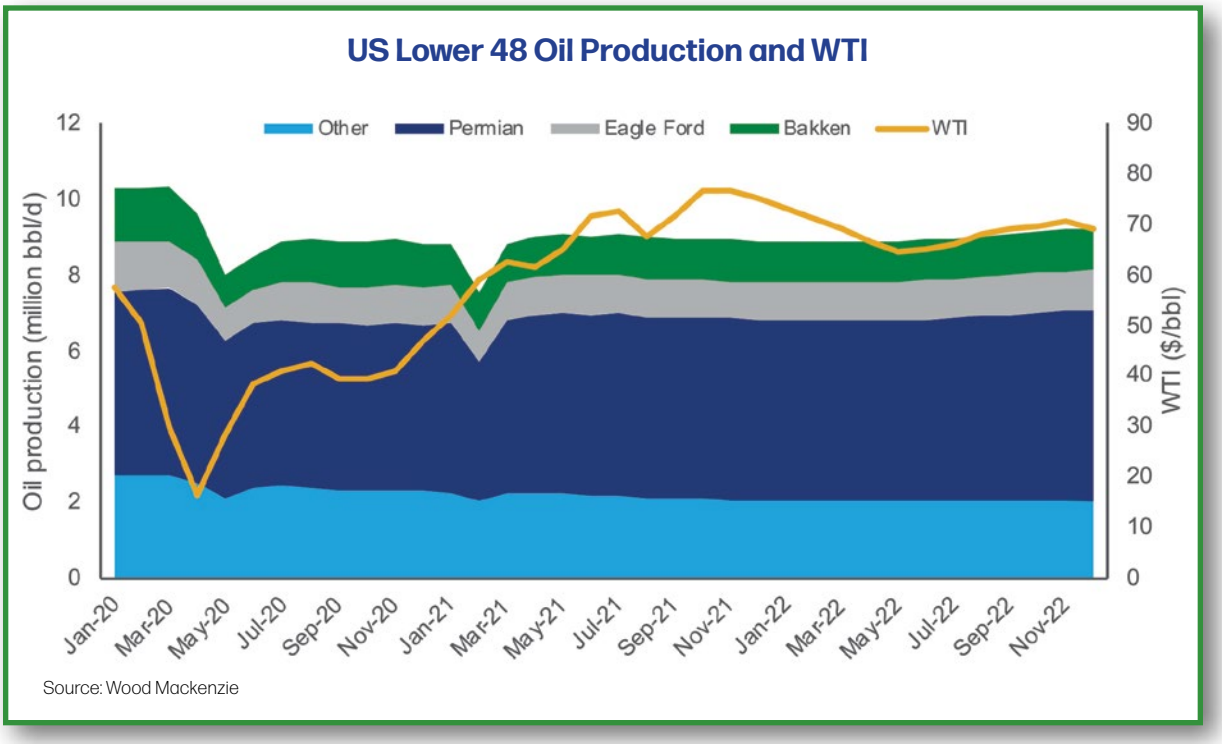
Meanwhile, capex restraint from publicly listed producers is driving the lack of supply response and slow drilling rebound. Annual budgets are low and inelastic to prices. Spending must increase in 2022 if supply is to grow. Private operators, on the other hand, do not face the same pressure to limit spending and are playing an outsized role in the ongoing activity recovery.

When oil prices crashed in 2020, so did shale production. But despite 2021's surge in prices, there has been very limited supply response at the macro level. Lower 48 oil production has been remarkably flat, hovering around 9 MMbbl/d for the last 12 months, except for weather-related outages in February 2021.

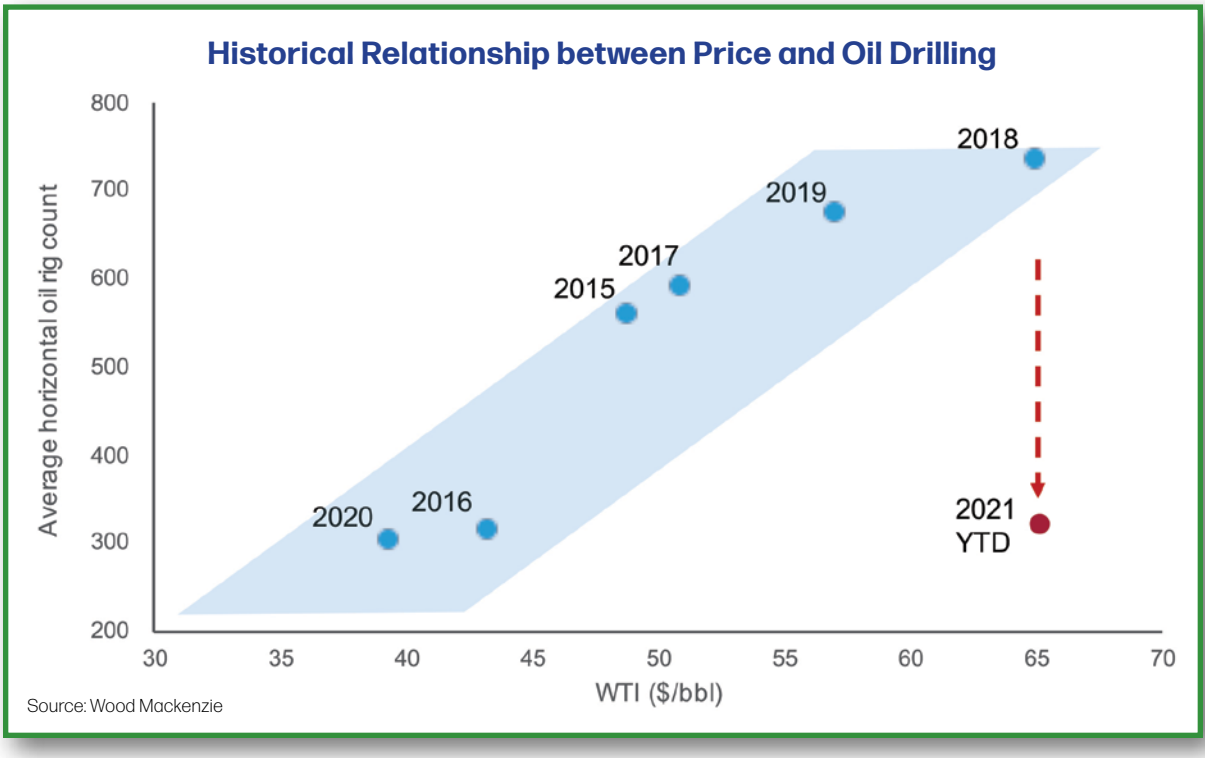
In Wood Mackenzie's October Macro Oils short-term outlook, the company forecast a flat trajectory for the remainder of 2021 and a decline of about 360,000 bbl/d on an annualized basis. By 2022, drilling should return to levels that support supply growth again. Wood Mackenzie expects a material increase in capital investment in 2022 and corresponding growth of 165,000 bbl/d year-on-year.

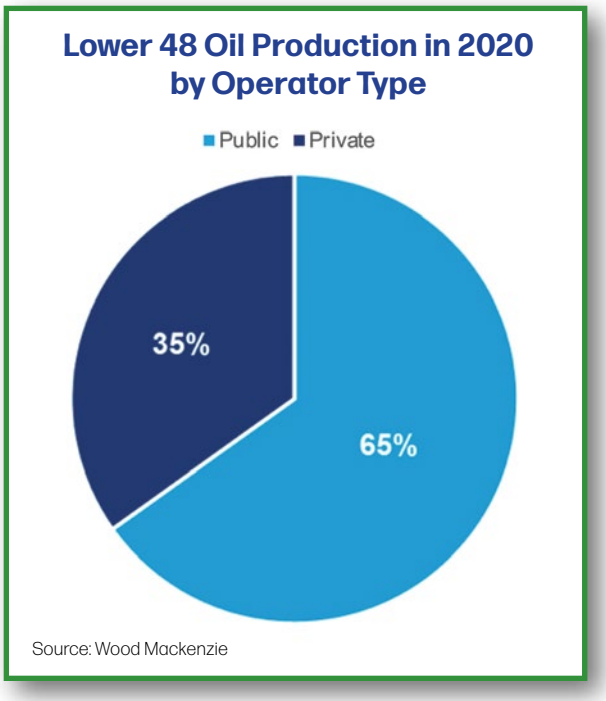
Wood Mackenzie's best leading indicator for supply is drilling activity, and today's rig trends indicate the industry should not expect significant production growth any time soon. While rig count has been on a steady rise since October 2020, the recovery rate has been tepid at best. Thus, in the context of historical drilling relative to price, 2021 is a clear outlier.

Oil drilling has increased nearly 170% from its low point in August 2020, but it is still about 35% below pre-price crash levels. The majority of returning horizontal oil rigs—53%—have been in the Permian Basin. Drilling is particularly slow to bounce back in Rockies oil plays. The rig count in the Bakken is at about 23 to 24 horizontal rigs—a mere fraction of the 50-plus rigs that were operating there in early 2020.



Source: Wood Mackenzie




Smaller rig additions more recently have been a clear signal of deceleration in the drilling recovery. By contrast, the previous downturn saw an accelerated rig build six months after reaching the trough. History would have indicated a faster rig recovery this time since drilling fell lower and prices have bounced higher, yet the opposite is true.

Why has shale been so unresponsive to higher prices? Firmly anchored capex budgets are at the heart of it. At the start of 2021, U.S. producers set annual capital guidance 7% lower than 2020 and roughly half that of 2019. The reduced budgets came as little surprise given the financial suffering brought on by 2020 and continued investor pressure to reduce debt and generate free cash flow.

But their stickiness at today's prices underscores the sector's resolve. ConocoPhillips, Marathon and Matador were among the many tight oil producers that explicitly committed to fixed capex targets, regardless of price. Indeed, budgets have not crept up despite rising prices.

Hedges have somewhat dampened the upside from higher prices. But despite this, first-quarter 2021 was one of the best in the history of U.S. shale by many measures. For example, the aggregate reinvestment rate was below 50%, and the peer group reduced net debt by $2.6 billion during the quarter, an astonishing transformation for a sector once notorious for piling on debt to fund new drilling.

After servicing debt, investors were the next priority. About a dozen companies either initiated, reinstated or increased a quarterly dividend. Many more outlined plans for dividends or share buybacks once they reach target leverage. Devon and Pioneer each paid out a variable dividend in addition to the base dividend, and EOG issued a substantial special dividend of $1/share after generating a record $1.1 billion of free cash flow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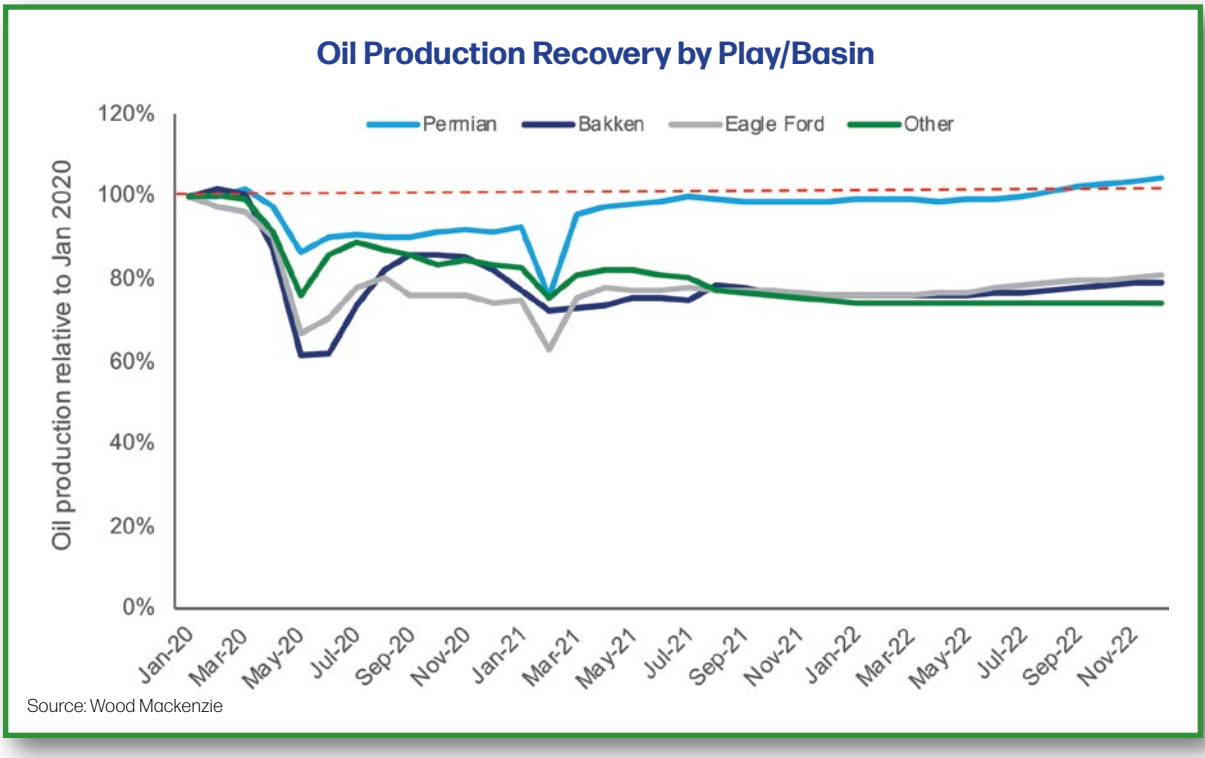



in the quarter. In aggregate, the group paid out $1.6 billion in dividends, and these payments will continue to serve as the outlet valve for any surplus cash in 2021.

The current model is working, and there's little incentive for producers to spend more for the time being. Investors have responded favorably to capex restraint and no production growth; U.S. oil and gas indices are up nearly 40% since the start of 2021. Debt reduction and shareholder distributions will remain the top priority for the next several quarters, at minimum.

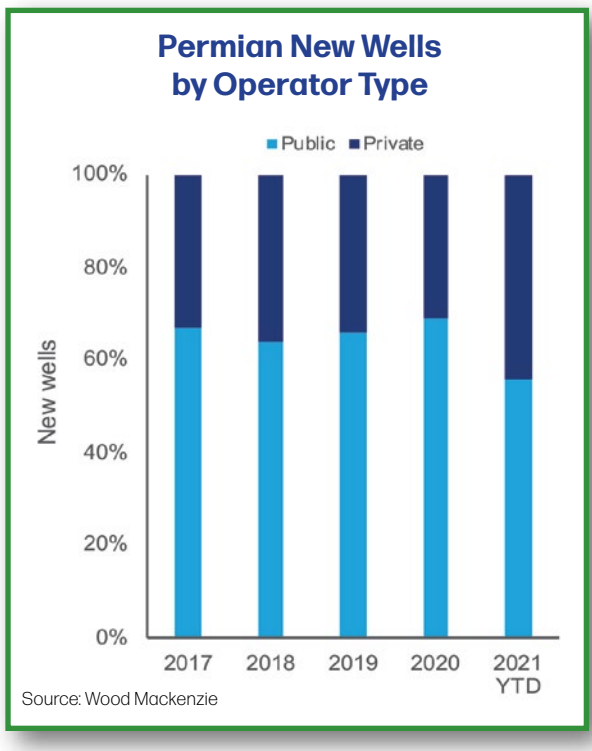
Uncertainty around global dynamics is part of the calculus too. Devon, for instance, intends to avoid all growth projects until demand has recovered.

Richard Muncrief, Devon's president and CEO, told analysts on the company's third-quarter earnings call "OPEC+'s spare capacity is effectively absorbed by the world markets."

Tight oil producers and investors have learned the hard way not to grow production while OPEC+ is curtailing its own.

Any changes to the model will have to originate from investors. Improved balance sheets and more predictable macro conditions in 2022 could be enough to trigger a shift. The share of proceeds going to debt reduction will shrink, opening the door for more investment in high-return projects.

Not all U.S. producers are beholden to the same capex pressure though. While publicly traded companies must answer to shareholders, the same is not true




of private producers that operate about one-third of all U.S. Lower 48 oil production.

Private equity-backed companies have long followed a buy-and-flip model. Little value is ascribed to undrilled potential in most asset sales today, so private equity companies may very well be increasing

activity to build up a valuation based on flowing barrels. Founder- and family-owned producers will also have different drivers and criteria for making investment decisions. The absence of rigid annual targets and quarterly reporting requirements allow these companies to be nimbler and retain flexibility to respond to fast-changing conditions.

Wood Mackenzie is seeing this demonstrated as private companies are playing an outsized role in the ongoing activity recovery.

In addition to the advantage of higher prices, private companies are benefiting from service availability and continued low costs without the usual competition from large public companies. In the Permian, private operators typically account for less than half of new wells, but that share grew to two-thirds in first-quarter 2021. They've also been the driving force behind 2021's rig build. Endeavor and Mewbourne, both privately owned, are operating about as many rigs in the Permian as EOG and Devon, two of the largest public independents.

Will this trend hold up? Wood Mackenzie believes public companies will play catch up in 2022. It is quite possible that private companies become the true "swing producers" of tight oil, uniquely responsive to short-term price volatility. But Wood Mackenzie's outlook for future growth depends heavily on continued investment from public E&Ps given their top-tier assets and potential for much larger capex programs.

With WTI sitting above $80/bbl, the lack of response from U.S. tight oil is highly uncharacteristic yet not surprising. Talk of limiting reinvestment rates dates back to 2019—well before the price crash—and the premise of fixed capital was clearly stated. Caution is further dialed up given the unique circumstances of this moment. The oil market is still precariously balanced with uncertainty on both the demand and supply side.

After years of abysmal returns, tight oil investors are finally starting to get what they asked for. Producers are benefiting too—raking in cash, lowering debt and reestablishing shareholder trust. The 2021 run-up in oil price is an important test for the sector, and so far, it's passing with flying colors. ■

# Shale Sector Embraces Carbon Management

*Technologies and investments are helping service companies and operators meet emissions reduction goals.*

By Deon Daugherty, *Contributing Editor*

Oil and gas companies must operate today in an evolving environment that demands they provide energy to power the world, turn a profit for their shareholders and do it all while reducing their carbon footprint.

Shale players are increasingly meeting the energy transition with a fundamental shift in their business models to incorporate—and in some instances, embrace—carbon management and the technology necessary to reduce their emissions.

Shareholders in public companies and investors in small and large firms continue to ratchet up the pressure on shale producers to align with the Paris Accord, which set an ambitious goal of capping global warming to about 34.7 F (1.5 C).

Engineers and business leaders will need to harness the technological prowess and spirit of cooperation that many demonstrated during the early years of the shale revolution, when U.S. producers upended global supply dynamics.

Still, it's a daunting task at hand.

The U.S. Energy Information Administration (EIA) projects that global energy consumption will almost double by 2050. Petroleum and other liquid fuels will still be the largest source of energy, but renewables, including solar and wind, will be closing in, according to EIA data.

Throughout the supply chain, companies recognize there will be a continued role for oil and gas even as the world shifts toward a cleaner future.

"The world economy is forecast to grow, is going to need energy and we're going to be a significant part of it, the oil and gas industry," said Simon Edmundson, Schlumberger's low-carbon technologies marketing manager. "We have to help and provide this energy while decarbonizing."

Edmundson said it's going to be a big challenge.

"Within the industry, we have a history of innovation and collaboration and solving some extremely tough engineering challenges with amazing technology," he

added. "The whole history of the oil industry is littered with these examples of amazing engineering projects where we've collaborated and been able to achieve things previously considered impossible."

## Servicing the transition

With an enterprise value of $55 billion at the end of the third quarter in 2021, Schlumberger is almost double the size of its nearest competitor.

While most of the public angst about the industry's carbon emissions targeted the upstream sector, executives with Schlumberger noticed and executives decided to take action. The firm aligned with the United Nations Net Zero Coalition in June 2021 to achieve net-zero emissions by 2050 across Scopes 1, 2 and 3.

"The majority of our emissions accounting is within Scope 3, and the majority within that scope is associated with products and services that we provide for our customers," Edmundson said. "For us to get to net-zero by 2050, it's going to be very important for us to reduce our Scope 3 emissions, which corresponds to reduction in our customers emissions because we're operating on their projects. By reducing our Scope 3 emissions, we'll simultaneously help our customers reduce their Scope 1 and Scope 2 emissions, and even their upstream supply chain Scope 3 emissions in some cases.

"Or you could look at it the other way around," he added. "By providing technologies to reduce our customers' Scope 1 and Scope 2 emissions, [it] will help reduce our Scope 3 emissions. It's really a sort of collaboration between us and our customers."

Schlumberger has announced a portfolio of products and technologies that is aimed at sustainability with a focus on reducing emissions on customer operations.

"These are called our transition technologies," Edmundson said. "With these, we're aiming to reduce emissions across the entire value for our customers' operations and simultaneously drive down our own net-zero emissions toward our net-zero commitment."

At this point, there are about 25 technologies aimed at five different themes in oil and gas: addressing methane emissions, minimizing well construction, $CO_2$ footprint, reducing or eliminating flaring, electrification of infrastructure, and full-field development solutions.

To qualify as a transition technology, a product or service must have a repeatable, significant and scalable impact, Edmundson said.

"We are quantifying the impact reductions that come by use of these transition technologies with a very clear, transparent quantification process," he said. "If we say something has a benefit that will reduce emissions in a certain operation, we can back that up with clear numbers and calculations."

Moreover, the transition technologies disprove the common perception that decarbonization comes with a negative connotation attached.

"The transition technologies offer sustainability benefits, such as reduced emissions while driving on traditional values such as performance and cost," Edmundson said.

Indeed, the new paradigm is breaking a long-established mold, said Lisa Rushton, a partner in the environmental practice at law firm Womble Bond Dickinson.

"While ESG is perceived by some to be difficult to implement, and it may seem like a profit-killer, the irony is that for most companies that implement ESG programs, including those within the oil and gas industry, it has the opposite effect," she said.

For example, Schlumberger's PowerDrive Orbit G2 rotary steerable system technology can shave off two to three days' drilling time in a shale play such as the Permian Basin.

"That's going to have a significant amount of emissions reduction simply from the rig," Edmundson said. "We're going to have to work together—service companies and operators alike—to develop and deploy the best combinations of technologies to reduce emissions and combine these with digital solutions that will help us rapidly figure out what's going to be the best option in a given scenario to decarbonize, no matter how complex it might be, so we can act quickly."

**The largest category of Schlumberger's Scope 3 emissions is technology, which accounts for 75% of the company's total $CO_2$ footprint. Transition technologies launched this year are designed to assist its customers' decarbonization ambitions. (Source: Schlumberger)**

**ConocoPhillips strengthened its Scope 1 and 2 greenhouse-gas emissions intensity reduction targets in fall 2021. The firm's new target is a reduction of up to 50% by 2030 from baseline levels in 2016. (Source: ConocoPhillips)**

Pioneer Natural Resources CEO Scott Sheffield was an early adopter of limits on the flaring of natural gas associated with oil production in the Permian Basin. Shortly after returning to the top job at Pioneer in 2019—just as news reports and satellite data unveiled the scope of flaring in the Permian Basin—Sheffield deployed a comprehensive methane leak detection and repair program that includes routine aerial surveys. The firm reported this summer that annual flaring is down to less than 1% of its production.

## Adding scope

Occidental Petroleum is pressing ahead of its peers to solve the industry's emissions problem. The company released an ambitious plan in 2020 to zero out $CO_2$ from the combustion of its oil and gas by 2050.

Most viable U.S. independents and majors are working on methods and technologies to limit Scope 1 and 2 emissions. But Occidental stands alone in crafting a technological plan to shut in Scope 3 emissions. Meanwhile, ConocoPhillips has pledged to advocate for a price on carbon to offset Scope 3 releases.

Scope 1 emissions represent those emitted by the fuel combustion that occurs in vehicles, furnaces, boilers and other equipment; these are direct emissions from controlled sources. Scope 2 covers the indirect emissions from purchased electricity, steam, heating and air conditioning; they are consumed by those who control the Scope 1 category. Scope 3 emissions account for the rest of the value chain, such as transporting the hydrocarbons and delivering them as fuel or other products. Historically, producers have argued the category is tricky to quantify; moreover, it is unfair to hold them accountable for how customers use their products.

For many businesses, Scope 3 emissions comprise more than 70% of their carbon footprint, according to a Deloitte analysis. For example, a manufacturer may have to accelerate its emissions release by extracting, producing and processing its raw materials.

Occidental is designing the world's largest direct air carbon capture facility, which will have the capacity to suck up to 1 million tons of $CO_2$ from the atmosphere annually.

The facility, in the heart of the Permian Basin, is intended to support Occidental's existing EOR operations; the $CO_2$ would be injected into aging reservoirs to boost recovery rates and permanently store carbon underground.

Dozens of carbon capture technologies have been deployed around the world, according to the Global CCS Institute. Combined, these facilities have the capacity to capture and store 97.5 million tons per year

*"With direct air capture, not only can we remove $CO_2$ from the atmosphere, but also that helps us to develop and produce oil that's either net-zero or net-negative carbon."*

*–Vicky Hollub, Occidental Petroleum*

of $CO_2$. Still, that is a fraction of the 33 billion tons of $CO_2$ annually produced by global energy consumption, according to the International Energy Agency (IEA).

Managing their carbon footprint to reduce emissions, particularly those within their own Scope 1 and Scope 2 categories, will be an expensive enterprise, bankers and attorneys say.

An infusion of investment worth trillions of dollars is critical to investors' apparent mandate that oil and natural gas companies work to cap global warming to less than about 35.6 F (2 C) relative to pre-industrial temperatures.

Bankers also say the money will flow to those companies willing to evolve.

"One out of every three professionally managed investment dollars in the United States is in an ESG fund," said Pavel Molchanov, Raymond James' senior vice president and energy analyst. "That's $16 trillion debt plus equity."

The figure was about half that size four years ago, Molchanov said during a discussion of public and debt capital in the energy transition during Hart Energy's Energy Transition Capital Conference on Oct. 19 in Houston.

"It's not a matter of whether there was a Democrat in the White House or oil prices were high. It has nothing to do with any of that. It's just a secular trend that there's more money flowing into ESG funds," he said. "And believe me, you do not want to be on the wrong side of ESG funds."

Isaac Griesbaum, a partner in the oil and gas practice of Winston & Strawn's Houston law office, said the focus on carbon management is present throughout the industry and translates into enormous investment in the technology necessary.

"Money is available for that," he said. "Close to $1 in every $3 of assets under management is earmarked for ESG-related activity" particularly when it is geared toward carbon sequestration, emissions reductions or other ways that help firms decarbonize.

"There's going to be a lot more change coming," Griesbaum said. "Throughout the shale revolution, these energy companies are going to have to become more and more like technology companies to survive."

Oil and gas companies that developed technology to become more efficient producers—both in capital and operations—must pivot to either develop their own carbon management technology or invest in it.

As such, these firms are making different kinds of investments in technology. Griesbaum said the investments will be less headline-grabbing but no less effective.

"They're taking minority stakes in tech companies, kind of the Silicon Valley venture capitalist style model. They may take a bunch of minority stakes in a lot of technology development companies just to essentially ensure they have access to what is developed," he said. "And that is going to be a bigger and bigger part of their portfolio, as well as their long-term survival and ability to actually go carbon emissions neutral in the next two years."

## Making markets

While there are instances in which emissions reduction efforts don't have a negative impact on other parts of the business, there are also opportunities for companies to create new streams of business.

"Oil and gas companies can create markets they didn'' have before," said Alan Trench, a director with consultancy Partners in Performance who leads the oil and gas practice. "For instance, if you have one operator looking at building solar power and they're working at building enough supply to where they can also sell that power to other operators. I do think there's some opportunities if you look at it from a more holistic view of not just your operations, but a base of operations and how you can be the developer."

Occidental has been in the carbon capture business for 40 years, and the company intends to leverage that experience beyond its initial role in EOR. As such, Occidental is exploring ways to reduce its emissions via direct air capture and carbon capture, utilization and sequestration.

Occidental CEO Vicky Hollub said that ultimately the carbon capture business is going to grow into a trillion dollar industry on the strength of how much carbon will need to be captured worldwide to meet emissions goals.

"It's going to be a probably $3 [trillion] to $5 trillion industry if you look at how much carbon capture is

*"A lot of operators are struggling with how to balance the goal of emissions reduction with the goal of delivering oil and gas at a cost that makes it economic."*

*–Todd Blackford, Partners in Performance*

going to be needed around the world," Hollub said in an October episode of CERAWeek Conversations. "We think ultimately it's going to generate as much earnings and cash flow as our oil business does today. We believe it's a long-lasting business."

Occidental is still moving toward "becoming a carbon management company," Hollub told investors during a third-quarter 2021 earnings call.

"We think that's going to be needed for the energy transition, and we're actually filling a gap with what we're doing," she said. "Direct air capture is going to be critical for that to happen. With direct air capture, not only can we remove $CO_2$ from the atmosphere, but also that helps us to develop and produce oil that's either net-zero or net-negative carbon."

That effort will enable Occidental to provide the offsets to help decarbonize other industries, such as aviation or maritime, with fuels that are net-zero carbon, Hollub added.

Given the magnitude of the carbon that needs to be offset around the world, thousands of such facilities will need to be constructed, she said.

"It provides us the opportunity to be a big part of that and to actually be a leader in developing the technology," Hollub said. "The transition will take some time. But over the next 10 to 15 years, I think we'll make a lot of progress toward becoming a net carbon management company and a go-to company for those that need the $CO_2$ offsets."

## Integration

Ultimately, the industry needs more integration of its best practices to give the various technologies the best chance of success, said Todd Blackford, a director at Partners in Performance. But they also need to earn a profit.

"A lot of operators are struggling with how to balance the goal of emissions reduction with the goal of delivering oil and gas at a cost that makes it economic," he said.

Midstream companies, like Targa Resources Corp., intend to source renewable electricity from Concho Valley Solar to power its natural gas infrastructure in the Permian Basin. Concho Valley Solar will deliver low-cost, renewable electricity to Targa under a long-term power purchase agreement (PPA). This PPA continues to advance Targa's long-term sustainability strategy to reduce its emissions intensity, the firms said in a November statement.

As joint owner in much of Targa's Midland sub-basin gas processing infrastructure, shale giant Pioneer Natural Resources may use the renewable electricity sourced from the Concho Valley Solar project, enhancing its emissions reduction initiatives through renewable electricity purchases and related renewable energy credits.

## Shareholders say

Whether it is doubling down on legacy business lines like Occidentl or reaching out to renewables, shale companies and those that work with them to produce oil and gas in the U.S. are making broad strokes to paint a cleaner portrait of their carbon management.

At the end of the day, the time is right for shale producers to clean up their emissions because it is what their shareholders and investors want.

"That's driving the industry to wake up and say, 'We need to do better,'" Blackford said. He added that, in general, the industry does strive to reduce its environmental impact. "They've put a lot of effort in, but it just happens that their product is environmentally intensive," he said.

At Pioneer Natural Resources, the top executive has warned peers that shareholders and investors will abandon the space if executives decline to make changes. Shareholders and private equity firms may "end up not doing business or sell" their interests in firms that refuse to reduce flaring, Sheffield said.

Executives at the largest independent firms are listening to their shareholders. Dominic Macklon, ConocoPhillips' executive vice president for strategy, said the ongoing dialogue is important.

"As an [E&P] company, we continue to believe our Paris-aligned climate risk framework that we launched about a year ago is both credible and ambitious and addresses the realities of our triple mandate," he said, adding that the mandate calls for meeting transition pathway demand, delivering competitive returns and achieving net-zero emissions on Scope 1 and Scope 2 emissions.

To that end, ConocoPhillips established a dedicated low-carbon technology group in 2021 to support the firm's net-zero ambition.

"But we are not ignoring Scope 3 end-use emissions," Macklon said. "Our new low-carbon group is also working to develop new opportunities in low-carbon businesses with a focus on carbon capture and storage and hydrogen, both of which have a strong adjacency to our core business and our competencies."

However, he added, all options must "deliver competitive returns for shareholders." ■


NOV's Ideal eFrac system simplifies fracturing operations and lowers greenhouse-gas emissions. (Source: NOV)

# Frac Efficiencies Continuing to Help Drive Down Costs

*Major service companies continue to push out leading-edge technologies.*

By Paul Wiseman, *Contributing Editor*

In the aftermath of the industry upheavals in 2020 and 2021, some experts have proclaimed the death of shale. Many of those prognostications came before oil broke the $80/bbl ceiling not seen since 2014. But doubters persist.

In fact, many of the major service companies have left the U.S. market, concentrating instead on more stable and less competitive international markets. Depending on the company, these markets include South America, the Middle East and Russia, among others.

Companies active in shale plays realize that its future is in the balance, relying on greater efficiencies in drilling and completions as well as improving production. The heady days of the early shale boom, when oil grazed $100/bbl and capex budgets knew no limits, died quickly in the downturns of 2015 and 2020. Service companies and the manufacturers that provide much of their equipment are now combining Big Data with human ingenuity to make shale viable at any price level.

## Efficiencies in simul-fracs

One of those equipment suppliers is SPM Oil & Gas. They specialize in well service and stimulation pumps, flow control products, replacement expendable parts and supporting engineered repair services. Bryan Wagner, the company's director of engineering for pressure pumping, confirmed that boosting efficiency is what's driving the market—and their R&D.

"The oil and gas industry is continuing to get squeezed for margin, not only in the major E&P com-

panies, but also down to the oilfield service providers and, ultimately, down to us in the equipment provider perspectives," he said.

Perhaps the most basic shift is toward replacing diesel on site with produced natural gas. This has opened up new opportunities for equipment providers to go bigger, running equipment with gas turbines. Using electricity, either from site generation or through the grid, is also opening new options.

Power demands from simul-fracs—pumping frac fluid into two wells at a time—have energized equipment updates as well. Standard fracs requiring 40,000 hp need 20 pumps on location. Wagner noted that a simul-frac doubling that amount of power and putting 40 pumps on site would create major space challenges.

"But you're doing that to drive toward efficiency," Wagner said. "You're hoping that, with efficiency, you can do more work in a year and, ultimately, your cost will come down."

Onsite electricity has "broken the ceiling" of diesel engines because "those engines can only be so large and still be driven over the road," he added.

Engines hit this ceiling at about 3,000 hp.

In comparison, a gas turbine with a capacity of 5,000 hp "is smaller than a refrigerator," Wagner said. Turbines are less flexible, speed-wise, than reciprocating engines, which somewhat limits their use in direct-drive applications. However, converting that power into electricity offers more diverse power options. This reduces the equipment footprint on site, and it opens options for larger pumps.

Previously, pumps were limited to the same 3,000 hp as their prime movers. With new power options, SPM has introduced 5,000 hp continuous duty pumps.

"With the combination of the increase in capability and in duty cycle, customers may be able to reduce the number of pumps on location by about 60%," according to the company.

Originally, simul-fracs also required doubling much of the peripheral equipment such as manifolds and trailers—and people to operate all that. So providers like SPM are working on how to develop a truly optimized system. The design of prime movers, electric motors, turbines, gear reduction, trailers, pumps and down to flow iron must work together to maximize efficiency while reducing the site footprint. Half of the SPM's 5000-hp e-frac pumps in operation are e-frac and half are turbine direct drive, all operating at capacity.

Early simul-fracs also pumped the two wells at about 50% of flow instead of the standard 120 bbl/min, but with the development of more powerful equipment, flows may soon increase.

E-fracs currently make up about 10% of frac activity, Wagner said, quoting figures from Rystad Energy Research.

With the intense drive toward greater efficiency, interest in simul-frac operations is likely to grow. Some may actually be turbine-driven, but they will fall under the idea of alternative fracs.

As operators continue to enhance their operations, simplifying natural gas delivery to the frac site through conditioning and LNG conversion or pursuing grid power options will be top of mind. Deciding who owns the power will become another issue, whether it's the third-party equipment provider, the service provider or the E&P company.

## Taking advantage in a downcycle

While the 2020 pandemic and oil price crash were painful for the entire industry, many companies like NOV used this time to concentrate on innovation.

"We spent a lot of the downturn really focusing on technology and improving our product portfolios," said Ryan Supak, NOV's global sales director for pressure pumping and cementing equipment. "We've been looking at new, innovative products that would help various niches in the market. It's the continual high-grading of products that create the most value for customers. That is the driving force behind much of the innovation in today's oil patch."

"The Holy Grail," he added, "is to optimize everything."

NOV's innovation in the shale frac arena during this time focused on optimizing fluid handling and extending wear life.

A revamped frac pump valve called Orange Crush is one of those technologies. It is designed for longer life at

**To accommodate the increased power demands of simul-fracs, SPM has developed a line of 5,000-hp frac pumps like the one pictured. (Source: SPM Oil & Gas)**

competitive prices, with the goal of reducing downtime and repair costs due to its optimized valve geometry.

Another challenge is the number of frac iron connections on site to transfer high-pressure fluid from frac pumps to wellheads. While iron and flowline are thought to be only a small part of the overall wellsite equipment, Supak said, there is more to it, including safety, rig-up time and environmental implications.

"When you look at the safety record, it's one of the major items that has caused leaks and other issues," he said. "Rigging up takes a lot of time and energy. How many people have been injured over the years in that process? And what can we do to prevent these injuries in the future?"

NOV has developed its FlexConnect, a continuous high-pressure hose that connects to the frac unit on one side and the manifold on the other to mitigate these safety issues and connection speed on site.

"Having a hose that reduces the total number of connections from frac unit to manifold and manifold to manifold via big-bore hoses reduces the opportunities for leaks and greatly speeds the connection process," Supak said. "The added benefit is in driving efficiency on the well site, including a reduction in the repair and maintenance costs required to inspect and maintain the hoses versus hard iron."

The FracMaxx articulated flowline is another technology NOV deployed during this time. Supak described it as "an articulated arm that can quickly disconnect, then connect to other nearby wells without using a zipper frac manifold." The FracMaxx system connects between wellheads without the additional valve maintenance required of zipper manifolds.

It also eliminates the need to spend several days ahead of the frac job rigging up all the iron. The challenge is that the system is limited to use on one well at a time, so it will not be useful in simul-fracs. But Supak pointed out that there are still plenty of traditional single-well fracs in the system, so it should be useful for the foreseeable future. That is the driving force behind much innovation in today's oil patch.

## e-frac trends

As frac jobs grow in size and complexity, they require more energy density than reciprocating diesel engines can supply without adding more units than are practical on a well site. This dilemma has given rise to e-fracs, using electric motors to increase the power density on site.

Into this market, NOV offers the Ideal e-frac fleet. Supak said the Ideal e-frac system includes 5,000-hp pumps and a reimagined process plant with optimized fluid and power distribution. Compared to traditional


**FlexConnect hoses reduce the connections down to two instead of the multiple connections needed with traditional iron products, offering improved performance and an easy solution to rigup and rigdown. (Source: NOV)**

diesel engines limited to 2,500 hp to 3,000 hp due to size and weight, the Ideal e-frac system reduces the number of frac units on location while increasing equipment reliability.

"This is especially true for simul-fracs, where they have to run up to double the pumps depending on what they're trying to achieve," Supak said. "Simul-fracs started by just trying to add a few pumps and run half-rate on each well. Now they're creeping higher and higher to get the full rate on two wells at the same time. That's a true doubling of equipment and resources on location—double the amount of fluid, double the amount of sand, chemicals, all that has to be incorporated into that fleet as they drive the total rates being pumped downhole at any given time."

For the future, NOV looks to the Ideal e-frac platform to drive additional technologies as higher horsepower allows for continued equipment efficiencies and longer service life. "e-fracs have more upside to drive increased efficiencies through fewer rotating components and additional data from the equipment and controls," he said.

## Simul-frac trends

In the U.S., simul-fracs are a small but growing segment of the completions market as E&Ps look to save money and speed up return on investment of new wells, said Kevin Schey, Liberty Oilfield Services' area sales manager, Permian Basin. Simul-fracs may account for about 10% of Permian completions over the last few months.

At current horsepower levels, simul-frac just means fracturing two wells at the same time, Schey pointed out. It does not necessarily equate to a doubling of the speed of completions. Usually, in fact, the two wells are pumped at 60 to 90 bbl/min each, less than the number for a single frac.

He recalled that Liberty initiated its first simul-frac in the Denver-Julesburg Basin in 2019, at about 40 to 50 bbl/min per side.

"The Permian usually does between 120 and 180 (total of the two wells in a simul-frac), and there are some folks trying to go to 200 as the envelope is always being pushed," he said. "In those scenarios, you're not talking about your typical frac fleet. You're bringing in additional horsepower to meet these higher demands."

Schey said while a simul-frac doesn't double the speed of completions, at least not yet, it does speed the process with about a 25% increase in equipment but not a corresponding increase in cost.

"The big push right now is the cost savings metric," he said. "You get a little bit of savings on the frac, and you also get these wells producing sooner, which produces money and pays back the wells sooner."

This increase in power demand has returned almost all the frac equipment to full use, a situation not seen since pre-COVID-19 days. The downside is the delivery of new equipment is delayed by supply chain issues common to most industries, where lack of a single small part can delay an entire shipment.

Meanwhile, the technology of e-fracs continues to evolve, Schey said. It started with mostly gas-turbine-driven horsepower, with 20-MW to 30-MW turbines powering a frac fleet. There were also smaller, trailer-mounted direct-drive turbines powering a single pump.

But because reciprocating gas-powered engines appear to have lower emissions, companies are beginning to make that change. Schey attributes this interest to ESG-driven net-zero $CO_2$ goals.

"From the operator's perspective, if they run a frac operation off a grid, that's technically net zero, even though there are still emissions further up the power cycle," he said.

Some have said that a frac job's power use during the day is equivalent to a city of 30,000, then it drops to 1 MW to 2 MW at night. That much volatility sends ripples all through the grid—volatility it may not be able to handle.

Liberty plans to build two new frac fleets in 2022, assuming resolution of supply chain issues.

## International market

All of Baker Hughes's frac operations are in the international market and offshore Gulf of Mexico. Tom Royce, the company's director of treatment applications technology for pressure pumping, and Javier Franquet, reservoir techno-commercial manager for pressure pumping services, explained the difference.

Because the international market is dominated by national oil companies, those companies' strategies are more country-centric, longer term and generally less affected by wide swings in price fluctuations than are those in the U.S.

"International contracts tend to be multiyear and longer term, whereas in the Permian, for example, work is more on a shorter term or call-out basis, and is often focused more on chasing pricing as opposed to including more substantive technologies" Royce said. "That long-term view lets companies like Baker Hughes tie together enhanced products and services that seamlessly take a well from predrilling planning to production and even final remediation. The advantage here is that products, services and technologies are better coordinated, communications enhanced and data information integrated for maximum outcome."

This strategic planning approach, more tortoise than hare, also means fewer multi-fracs happen overseas. Few international fields are in full factory mode development, so the single well, multistage strategies

prevail. Additionally, some of the lower multi-frac and simul-frac count is because "much of the arena also doesn't have the service infrastructure and logistics that are available in the U.S.," Royce said.

Proppant, chemicals, water and equipment are often imported and must travel greater distances to arrive at the well, slowing every process. This has become especially true as worldwide shipping and logistics struggle to recover from the recent downturns.

The upside is that drilling fewer wells leaves more time to fully evaluate and integrate technologies for each one.

"When you're only doing 30 unconventional wells per year, you want to make sure that every well is done correctly," Royce said.

Drilling 30 wells per week in the U.S. "is all about cost," he added. "However, each strategy optimizes for what brings value for the customer's business model and for differing customer objectives."

Not all unconventional wells are the same, and as the rest of the world tries to implement U.S. processes and procedures, they've found that those procedures don't always translate well.

"We see challenges of higher salinity waters, differing tectonics, minerology, stresses and breakdown pressures for unconventional," Royce said. "We're treating deeper wells, longer laterals and at higher temperatures, [and] 15,000-psi frac operations are almost becoming standard in operations around the world."

## Big Data applications

In addition to frac technologies, Baker Hughes is a leader in data analysis.

Today the oil industry has access to massive amounts of detailed information about formations, production methods, histories and more. With leaps ahead in artificial intelligence (AI) and other data mining and analysis systems, those data can inform every aspect of planning and execution.

"There is no one single recipe that is good for every shale play," Franquet said. "It's almost unique with each shale play when you run AI to find the best cluster separation, number of clusters per stage [and] number of stages."

He added that AI is more advanced in the U.S. than elsewhere due to the large number of wells and the availability of production data.

Baker Hughes, due to its size, extensive product line and numerous databases, accesses Big Data almost by default, Royce said. "The trick is, with any Big Data, how do you handle that much data?" Royce asked.

Within the company, the emphasis is on coordinating those data so a well's frac design can seamlessly incorporate reservoir and drilling information to anticipate issues and challenges as well as to optimize engineered fracturing treatment designs.

"Baker Hughes' Digital Services have key alliances with C3.ai and Microsoft for tackling AI applications in the oil and gas sector," Franquet said.

Some data are forward-looking and used to analyze formations to find the best well locations and depths. Other data look back to analyze failures of various types and to understand how to minimize the chances of a repeat.

As an energy technology company, Baker Hughes is making a major transition toward smaller carbon footprints and greener solutions. The company was one of the first in the oil and gas industry to make a net-zero carbon commitment, Royce said. Baker Hughes is constantly looking for ways to advance procedures and technology and to partner with customers to keep them at the top of the game into the next century. That includes expanding into other energy options while simultaneously innovating sound technologies for oil and gas. Royce listed hydrogen, geothermal and carbon sequestration as areas of interest for the company.

"Our strategy is simple," he said, "along with our customers, continue transforming our core business, invest for growth and position for new frontiers."

## South American shale

Weatherford's focus on the international scene is in tight gas in Russia and South America. In the Southern Hemisphere, their top plays are Argentina's Vaca Muerta, the Neuquen Basin and conventional Colombia and tight gas Chilean markets.

The company departed the U.S. frac market in 2016 to focus on those international opportunities. At that time an oil price drop coincided with rising operating expenses. The move to finer, locally produced sand (100 mesh as opposed to the previously preferred 40-70) greatly increased maintenance costs, which combined with other factors to shrink profitability, said Francisco Fragachan, Houston-based engineering director for pressure pumping with Weatherford.

With what the company learned about frac efficiency and technology in the U.S., it is working to implement it abroad. That includes "technologies like friction reducers, efficiencies and stages per day into a tight gas formation where you would need greater proppant concentration, along with how to fight back against the nightmare of settling associated with friction reducers."

In that vein, Weatherford has worked to develop a fluid system geared toward maintaining good friction reduction while simultaneously keeping the proppant suspended at up to 8 to 10 ppa, without settling, all across the frac zone. The company's Amplifrac product addresses those issues.

Fragachan added that slicker fluids allow higher injection rates, leading to the completion of more stages per day. It also helps in simul-fracs in the U.S., where pumping two wells at once had previously meant each


**Weatherford's fracturing logs help improve the efficiency and accuracy of each job. (Source: Weatherford)**

well's flow was reduced by half. Higher injection rates could reduce the onsite footprint required for pump horsepower. That brings benefits in logistics and cost savings while reducing the carbon footprint.

In Argentina, last-mile logistics are a major challenge, said Victor Exler, the company's stimulation technical manager. "Movement of proppant, movement of chemicals, trying to move everything in bulk" are some examples, he said. To Exler, shipping in bulk means getting it by rail instead of trucks.

Shortening the travel distance of those supplies is also on the table.

"One of the biggest changes was to develop local mining for proppants," he said.

With local mines growing in number, providing 40-70 mesh, this has significantly improved cost efficiencies in that area. Previously, proppant was shipped from worldwide locations such as the U.S. and China.

In Weatherford's Russian operations, wells are deeper with more stages—a situation that also benefits from reduced friction. Controlling friction for stages at the heel is different from managing it for stages at the toe, and both present challenges because of the different transit times.

Reducing water consumption in fracs is a focus. "Ramping," or increasing proppant density from the old standard of 1 to 2 ppa or to 8 to 10 ppa, dramatically reduces the water needed for even large frac jobs, Fragachan said. Because of its greater density, ramping also requires less proppant.

Generally, international companies take a longer-term view of fields than E&Ps in the U.S. Costs are still a concern overseas, but Fragachan said they are less willing to cut corners in drilling and completion because that could reduce a well's productive life. They expect wells to produce for 10 to 15 years.

One way to extend a well's life is to refrac, which is a major focus for Weatherford.

"How do we go back and selectively frac a zone that was bypassed earlier?" Fragachan asked. "You have 15 stages and you want to refrac stage four, seven or nine without affecting overall production."

New technologies allow a refrac to straddle zones to achieve this.

Russia is the hotbed of refracs, he noted. Producers there often realize they've missed key producing zones the first time around and ask Weatherford how to effectively and safely reenter to capture that production.

Fragachan and Exler see a future where the learnings from today's frac jobs transfer to the development of geothermal wells.

"It's going to be that frac industry's know-how that will optimize and enhance the production of energy from geothermal wells by massively fracking those wells conveying the flow of water to bring the heat to the surface that will be enhanced by fracturing know-how, with some adaptation," Fragachan said.

Everyone—from operators to service companies to equipment manufacturers—understands that the future of shale fracturing is in being dollar-efficient on the front end while performing completions (or recompletions) that extend the well's life on the back end. Perhaps never in history has innovation reached such a frantic pace. Perhaps it's never been as necessary. ■

# Midstream 2022: Long-term Planning Paying Off

*By staying the course, midstream operators are not only surviving but thriving as 2022 beckons.*

By Frank Nieto,
*Contributing Editor*

No one was prepared for a global pandemic, especially one that placed a vice grip on the world economy with lockdowns enforced in just about every country. Demand for various commodities suffered even as production fell in 2020. The oil and gas industry was hit especially hard as people stopped driving much on a daily basis. When WTI hit -$36/bbl in April 2020, it seemed as though it would be a long slog to recovery. Yet 18-plus months on, the industry—including the midstream sector—is performing at levels not seen in years, even as remote work has become the norm for many.

Part of this quick recovery can be attributed to the cyclical nature of the industry. Consistent volatility caused midstream operators to look at changes to steady the ship. One of the most prominent of these companies was DCP Midstream, which instituted a new strategy in 2016 called DCP 2020.

This strategy, designed to make DCP the safest, most reliable, low-cost midstream service provider sustainable in any environment, has become the company's long-term vision. As part of this strategy, DCP introduced DCP 2.0, a digital transformation initiative designed to modernize the way the company operates and runs its assets.

This is no small undertaking. Currently the company's Integrated Collaboration Center, similar to a digital central nervous system, monitors major field assets 24/7, can remotely operate 26 facilities and reviews up to 8 billion datapoints, including

EnLink's Project War Horse relocated an underutilized natural gas processing plant in Oklahoma to the Midland Basin. Volumes began flowing from the relocated 95-MMcf/d facility in third-quarter 2021. (Source: EnLink Midstream)

engineering, commercial, real-time customer information, contract and commodity prices, on a daily basis to improve its operations.

As part of this strategy, DCP Midstream also formed the DCP Tech Ventures group. This arm of DCP is focused on partnering with accelerators, venture capitalists and universities to find emerging technologies around safety, reliability, digital enablement and energy transition that can be incorporated into the company's operations and help drive long-term value and sustainability.

Although these initiatives were not created to help the company navigate through a global pandemic, they were designed to help the company quickly adjust to market changes.

## Financial discipline restoring balance

So what happens when prices go back up?

"If a company's set up really well to weather commodity prices going down, then there is a lot of confidence that it will be well positioned when prices go back up," Wouter van Kempen, chairman, president and CEO of DCP Midstream told Hart Energy. "For us, that has meant having financial discipline, significant free cash flow and a strong balance sheet. These foundations allow us to run a safe and reliable company no matter what the market throws at us."

There have been a lot of headwinds for the midstream industry over the past five years, but van Kempen said there are now more tailwinds with commodity prices soaring.

"We're in this completely different cycle coming out of the COVID-19 pandemic shutdowns and seeing really strong demand, both domestically and internationally, for all of our products," he said. "I look at natural gas growth over the next 10 or 20 years as pretty bullish."

## Adapting to the end of the growth cycle

A great deal of this bullishness can be attributed to midstream players becoming more financially disciplined as the substantial growth cycle that marked the start of this century has come to an end.

"We knew that the super cycle of growth we were in had to come to an end and that we needed to prepare for the eventual contraction that would take place," van Kempen said. "That is why we decided to embark on a smart growth strategy we called 'supply long and capacity short,' and what that basically meant was that instead of spending hundreds of millions of dollars to build a new plant and new systems, we'd partner with other companies to utilize their excess capacity."

The Denver-Julesburg (D-J) Basin is one of DCP Midstream's most active regions with tighter overall system capacity. In 2019, rather than build a new natural gas processing plant for up to $500 million, the company sought to rent capacity from operators that were sitting on idle capacity.

"It has created a win-win scenario," he said. "For us, we make good margins, we still keep the NGL in our system, we reduce our environmental impact and we save money by utilizing existing infrastructure. It's good for everyone in the industry."

He noted this strategy has proven to be so successful that DCP Midstream is applying it in other areas, including the Permian Basin.

Cost reductions and improved margins have created enough cash flow to help DCP Midstream pay off debt and improve its leverage over the past two years. Paying down debt is helping the company reach its goal of obtaining an investment grade credit rating. According to van Kempen, DCP is on track to hit this goal in the second half of 2022.


**DCP Midstream's in-house Tech Ventures group helps identify and integrate emerging technologies to strengthen the company's core business. This battery-less smart sensor installed on the equipment pictured provides always-on condition monitoring. This technology combined with machine learning and DCP's robust equipment health monitoring program has reduced downtime events by 24%, year-over-year, and cut downtime hours by 13%. (Source: DCP Midstream)**

## Growing responsibly

Looking ahead to 2022, van Kempen shared that DCP Midstream will continue to emphasize optimization and emission reductions. An example of these efforts would be running fewer compressors at a higher capacity.

"When you do that, you can continue to have reliable service while reducing costs and emissions," he said.

DCP Midstream has reduced Scope 1 and Scope 2 greenhouse-gas emissions from its assets by 16% since 2018, and the company has long-term goals of reducing emissions by 30% by 2030 and reaching net-zero emissions by 2050.

"Sustainability, financial stability and generating free cash flow and returns for our shareholders are all top priorities," van Kempen said. "Our industry has a great opportunity to set itself up really well for the future, and I think we've struck the right balance between growing our company and doing so in a responsible way, from both a sustainable point of view and from a capital allocation point of view."

*"In my mind, operating more cleanly and more efficiently is not an option—it is table stakes."*

*—Wouter van Kempen, DCP Midstream*

DCP Midstream is also working with Kairos Aerospace to find and mitigate fugitive emissions across the company's systems in the Permian, D-J Basin and Mid-continent by flying airplanes with specialized sensors over these assets.

"Our partnership with Kairos came from our DCP Tech Ventures group and has led to the largest voluntary, industry-led methane mapping and resolution program in the country," van Kempen said. "We saw this as an important way to reduce our emissions and to make our systems more sustainable."

The company has a three-pronged approach to emission reduction. The first prong, "cleaning the core," is focused on controlling emissions from its owned assets by improving efficiencies and modernizing existing operations. The second prong, "adjacent to the core," seeks to explore opportunities to expand the company's business portfolio, leveraging intellectual capital and existing infrastructure.

This could include carbon capture and sequestration (CCS) and other emerging technologies that reduce emissions. DCP's primary focus of CCS has been in the company's New Mexico footprint, but it could be expanded elsewhere. The third and final prong is called "beyond the core," which has a longer timeline and is focused on tracking emerging green technologies and positioning the company to leverage and

deploy tomorrow's energy solutions. For DCP this could include hydrogen, large-scale solar and other renewable projects.

"In my mind, operating more cleanly and more efficiently is not an option—it is table stakes," van Kempen said. "That's what we have to do as an industry. It's a requirement and part of our social license to operate. We have a responsibility to our customers, employees, stakeholders and community members to operate as cleanly, reliably and environmentally sustainably as possible."

Producers have also shown more discipline this cycle by not bringing production back as quickly as they have in the past after price downturns. This has been a positive for the industry as it's helped to create better supply and demand balance.

## Focus on efficiency

Like DCP Midstream, EnLink Midstream is also focusing on optimizing its existing operations and improving efficiencies throughout its asset base. This strategy helped EnLink reduce its operating and administrative costs by 20% in fiscal year 2020.

Additionally, EnLink is focused on maintaining financial flexibility by using its cash flow to pay down debt while maintaining deliberate and disciplined growth.

"We have an intense companywide focus on improvement and innovation," EnLink Chairman and CEO Barry E. Davis said. "Every single employee has been empowered to look at how they do things and think, 'How can this be better?' We call this 'The EnLink Way,' and it's driving our current results higher and creating real, long-term value, while also reducing inefficiencies and transforming our business."

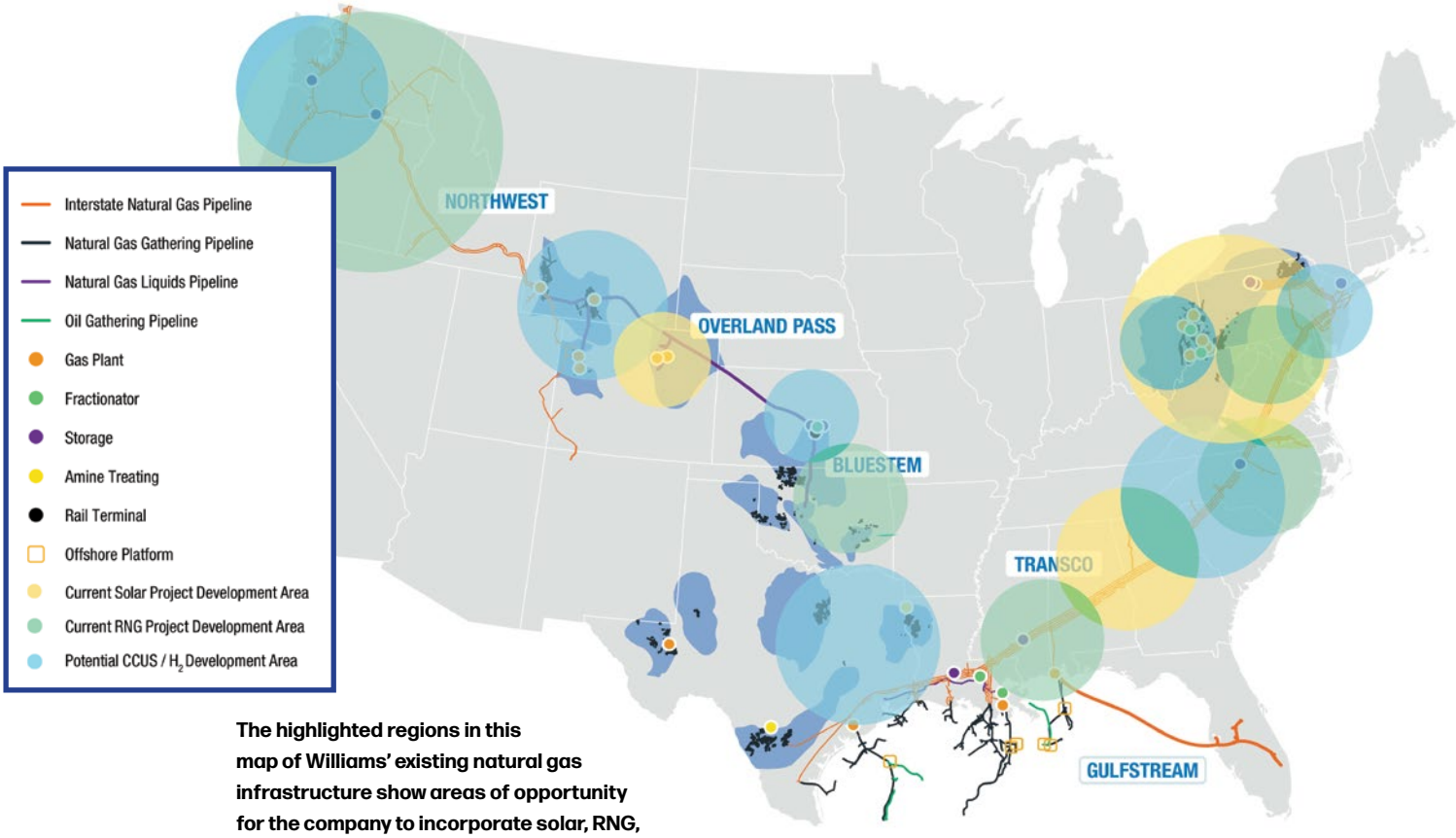
A few recent examples of this approach include utilizing technology to debottleneck EnLink's purity product pipelines to accommodate incremental volumes, leveraging real-time data and expertise from a cross-functional team to optimize plant recoveries, and implementing robotic process automation to save hours of spreadsheet manipulation, giving the EnLink team valuable time to analyze and make improvements.

EnLink's innovation and efficiency focus led to the company's first plant relocation from Oklahoma to the Midland Basin. Project War Horse began flowing volumes in third-quarter 2021. EnLink has since announced Project Phantom, its second plant relocation, which will move their underutilized Thunderbird Plant from Oklahoma to the Midland Basin. This relocation will add 200 MMcf/d of processing capacity at about half the cost of a newbuild plant and is expected to be online in fourth-quarter 2022. With the addition of Project Phantom, Midland processing capacity will increase approximately 70% by year-end 2022.

EnLink is also actively working on furthering its decarbonization path, along with advancing projects that allow the company to participate in the energy transition. EnLink formed a Carbon Solutions Group in early 2021 that is pursuing opportunities to provide a complete carbon capture, transportation and sequestration offering. The company operates an extensive Louisiana footprint that contains approximately 4,000 miles of pipeline and is connected to one of the nation's largest concentrations of industrial $CO_2$ emissions. According to EnLink officials, this makes it well positioned to execute a carbon solutions offering.

"Our unique ability to utilize existing pipeline in the ground to transport $CO_2$ to potential sequestration locations nearby allows us to offer a cost-efficient transportation solution for all parties involved and, of equal importance, significantly reduces the environmental

**EnLink's Project War Horse relocated an underutilized natural gas processing plant in Oklahoma to the Midland Basin. EnLink stated in a 2021 release this was "a low-cost, high-return natural gas plant expansion." (Source: EnLink Midstream)**




**The highlighted regions in this map of Williams' existing natural gas infrastructure show areas of opportunity for the company to incorporate solar, RNG, hydrogen and carbon capture. (Source: Williams Cos.)**

impact when compared to new pipeline construction in environmentally sensitive areas," Davis said. "Additionally, we recently announced a 15-year agreement to sell 100,000 metric tonnes per year of $CO_2$ emitted from our Bridgeport plant to be purified for use in food, beverage and similar applications, which advances us down our decarbonization path while making a modest profit."

EnLink is also taking full advantage of its large-scale positions in key basins. In the Permian, the company is aligned with solid operators and growing with them through capital-efficient, high-return projects.

EnLink acquired Amarillo Rattler for $75 million in April 2021. Amarillo Rattler is a Midland Basin natural gas gathering and processing system that provides significant operational synergies and minimal incremental capex to integrate the system. In connection with the acquisition, EnLink signed an amended and restated gathering and processing contract with Diamondback Energy.

"This very attractive acquisition has an excellent customer behind it, and we are very confident in achieving a 6x multiple on 2022 EBITDA," Davis said.

## Making money, not excuses

The first half of fiscal year 2021 saw the midstream as a whole improve cash flows as demand for natural gas and crude oil returned as society and the global economy continued to reopen. According to Enterprise Products Partners LP officials, natural gas volumes transported on its pipeline system equaled 2019 levels, while fractionated volumes hit record levels in the quarter. The company continues to see a surge in demand for petrochemicals, notably propylene.

Enterprise was able to achieve such levels because of its ability to quickly adapt to life and business during the global pandemic by reopening its offices early and instituting various protocols such as masking before mandates were in place, having Plexiglas around the office cubicles and social distancing.

"By this time [in 2020], we had already returned to our headquarters in what was virtually an empty downtown Houston," said Enterprise Co-CEO Jim Teague during the company's second-quarter 2021 earnings call. "I think it was a competitive advantage being back because we worked as a team, we moved products for our customers and producers, we were buying and selling, we were in the system and collecting on steep contango in about every product we touched. We were determined in the middle of the pandemic to make money, not excuses."

He noted that around fourth-quarter 2020, the industry was slipping deeper into the pandemic, but the resurgence is proof that the markets work and was to be expected.

"Strong prices, backward-dated markets and lower inventories at Cushing, Okla., are signaling that volumes need to stay at home, at least for now," he said.

As the market recovery continues, Teague said it feels like a period of hyper-growth. Enterprise remains on track to complete the expansion of its Acadian natural gas system out of the Haynesville Shale to the LNG market in Gillis, La., as well as expansions to its ethylene

and propylene pipeline systems. Expansion won't be limited to the 2021 fiscal year for Enterprise either.

"Our growth capex in 2022 and 2023 projects is currently sanctioned at $800 million and $400 million, respectively," Teague said. "We expect these to increase as some of the projects under development are sanctioned."

Company officials noted larger-scale projects could be announced in the near term.

## New energy sources

If there is one consistent theme among midstream players in 2021, it has been sticking with a strategy and relying on market fundamentals. Similar to DCP Midstream, EnLink and Enterprise Product Partners, The Williams Companies remained focused on its long-term goal while managing its way through the pandemic-driven downturn.

The company has continued to work toward connecting the fastest-growing natural gas markets with the best supplies. This focus has resulted in strong growth in 2021 with volumes transported on the Williams system growing even as production fell slightly.

While market fundamentals remain strong and are leading a revival in fiscal results for midstream operators, Williams is studying ways to diversify itself with more sustainable energy sources. Company officials noted that Williams' footprint is well suited and adaptable to energy sources like clean hydrogen and renewable natural gas (RNG) blending.

Williams is also building 16 solar projects awaiting approval that are expected to cost a combined $250 million in capex with another $150 million of similar projects in development. As an example of Williams leveraging its current asset base and footprint to drive clean energy solutions, the company has 1.2 million acres in the Wamsutter Basin dedicated to its midstream assets and another 200,000 acres that it intends to utilize for clean energy development.

According to company officials, renewable energy projects will be focused in areas where the company can leverage its assets to get a competitive advantage. This would largely point to transportation, but there are opportunities on the processing front as well.

Williams anticipates operating slowly when it comes to some energy sources like hydrogen to ensure the technology is developed in a way that complements its assets.

An example of this type of investment strategy is with its Regional Energy Access project that is designed to provide Northeast consumers with access to natural gas by the 2023-24 winter heating season. It will also include a pilot project involving the production of hydrogen.

It is a similar story with the RNG capture processing and delivery front. Williams officials anticipate small investments to prove their footprint and infrastructure can work with this energy source's technology.

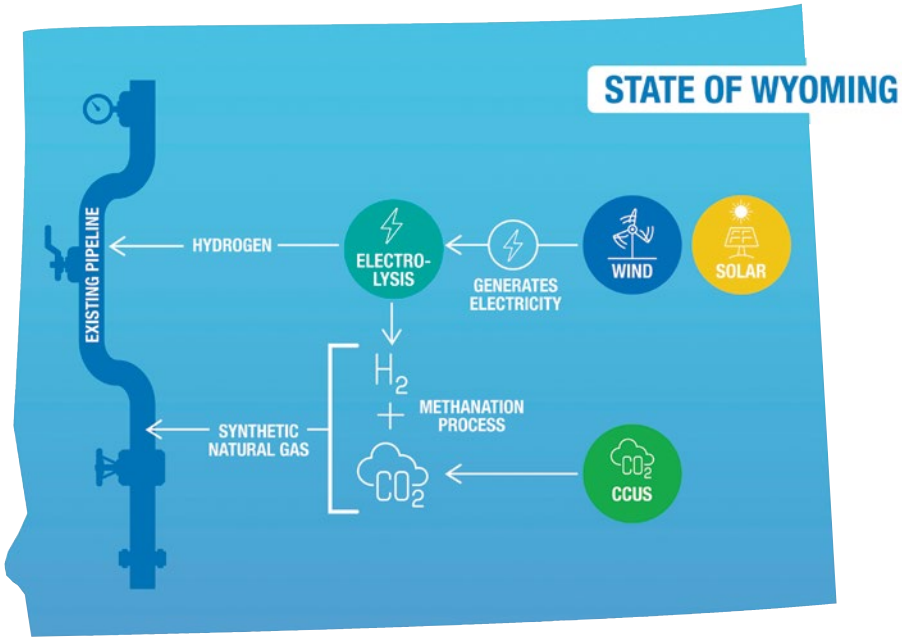
Besides looking to future energy sources, Williams remains committed to immediate opportunities to reduce carbon emissions. The company has up to seven RNG sources flowing into its natural gas transportation systems with nine more in progress.

## Culture is key

One aspect that hasn't been getting as much attention as sustainability and financial flexibility— but is equally important—is the cultural journey taking place throughout the midstream industry, including at DCP, according to van Kempen.

"As a company and as an industry, we deliver products that make people's lives better—through fueling transportation and heating and cooling homes," van Kempen said. "Everything we do is touching lives [and] enabling better lives. It's part of our company's purpose and something we're tremendously proud of. At the same time, I think we also have a responsibility to do these things in a cleaner and better way and that includes having a strong culture where people can express themselves and learn."

Social change has also been at the forefront of discussions for many industries over the past two years, and the midstream industry is no different. Inclusion and diversity efforts have been a major focal point.




**In partnership with the University of Wyoming, Williams has a $1 million grant from the state of Wyoming to fund a feasibility study to evaluate the creation of a green hydrogen hub near Williams' operations in southwest Wyoming. (Source: Williams Cos.)**

"We think inclusion and diversity are extremely important," van Kempen said. "Last year we focused lots of energy on stressing to our leaders that how they deliver results is equally important as the results they deliver. That means not just doing the work but also building an inclusive workplace environment and creating a sense of belonging."

In an effort to create this sense of belonging, DCP Midstream formed a diversity and inclusion committee and set goals for the makeup of its workforce and leadership from a racial and gender point of view.

DCP's diversity and inclusion goals will be tracked using clear metrics, and employees are already incentivized around the company's people and culture measures. Similar systems are used by DCP to help reach its companywide financial, safety and reliability goals.

"Culture is part of the way we measure, reward and incentivize our people," van Kempen said. "If you invest in it, measure it, if you make it part of people's short-term incentive structure, you're going to get results."

## Assessing risk

Midstream operators aren't the only ones keeping a close eye on spending, as private equity is also assessing risk in this current environment.

"Private equity has experienced two significant drops in oil prices over the past seven years, and they're not accustomed to that kind of risk," Dan Lippe, managing partner with Petral Consulting, told Hart Energy. "Their risk assessment of providing capital to oil producers to drill more shale oil wells is one of the most important aspects impacting the sector heading in 2022."

Lippe said private equity investors have been focused on their return on investment since fourth-quarter 2018 after experiencing sharp price decreases. This adjustment has resulted in a slower recovery in the rig count, but that should change if crude prices remain at $75/bbl as some private equity investors decide that the risk is far less. As growth in crude production from the Permian and other key shale plays resumes, NGL production growth rates will also increase and that will increase the utilization of midstream assets such as pipelines and fractionators.

The factors that drive growth in crude oil exploration activity eventually require growth in midstream capacity.

"Private equity investors, for now anyway, are also focused on ESG concerns with regard to providing capital funding for midstream projects," Lippe said. "Because midstream companies provide necessary services, they will continue to base major projects on take-or-pay contracts. With sufficient customer support, they can always get money. That's not a problem. As long as there's a need for additional midstream capacity, midstream companies will find the money. The subjective factors that affect the flow of capital into the upstream are less relevant to what happens in the midstream."

As crude demand slows over the next few decades with electric cars replacing more gasoline-powered vehicles, Lippe said there is likely to be an increase in demand for reliable energy sources, including natural gas, on the power grid.

It's unlikely that many new midstream construction projects will be announced in the coming year, but two petrochemical projects are expected to be fully operational in 2022. One is Bayport Polymers, a joint venture (JV) of Total Chemicals and Borealis. Bayport Polymers has completed construction and began startup of the 1.1 million tonnes per year (mtpy) ethylene plant in the fall of 2021. The other major project is Gulf Coast Growth Ventures. This petrochemical JV between Exxon Mobil and SABIC in Corpus Christi, Texas, will have the capacity to produce 1.8 mtpy of ethylene.

"You're talking about shrinking the surplus ethane producibility in West Texas and New Mexico by 50%, which is enough to change the psychological dynamics of the buyers and to encourage more optimistic aggressive behavior on the part of the sellers," Lippe said. "Ethane prices are already improving, but that's mostly because natural gas prices are stronger, not because demand is up yet. This will change that."

## Declining oil demand

Looking ahead to 2022, the majority of midstream operators anticipate demand for most hydrocarbons to continue to grow. There may be continued price fluctuations as the market balances at times, but most midstream executives anticipate steady demand growth.

Looking further out, demand for crude oil will begin to decline, according to Lippe.

"I've done some long-term demand forecasting based on various scenarios for sales of electric vehicles [EVs]," Lippe said. "Unless all global vehicle manufacturing companies have completely misjudged their ability to sell EVs, I do not see any upside for long-term oil demand (2030-2050). I can only see downside. The No. 1 thing that convinced me of this long-term decline is that every major auto manufacturer in Europe has declared they're going to be 100% electric. That process is starting in 2022. Those manufacturers sell a lot of cars in the United States, which means Europe and the United States are going to be at the leading edge of the end of the oil business monopoly on transportation fuels."

Lippe was quick to add that this decline will take a long time after peak demand is reached. "We'll still be producing crude oil 30 years from now," he said. "It just won't be at the 80-90 million barrel per day level we see now. It will be more like 55 million barrels per day."

Regardless of where crude demand is in this long-term outlook, the midstream will continue to adapt and add new sources of energy to its mix as it always has and always will. ■

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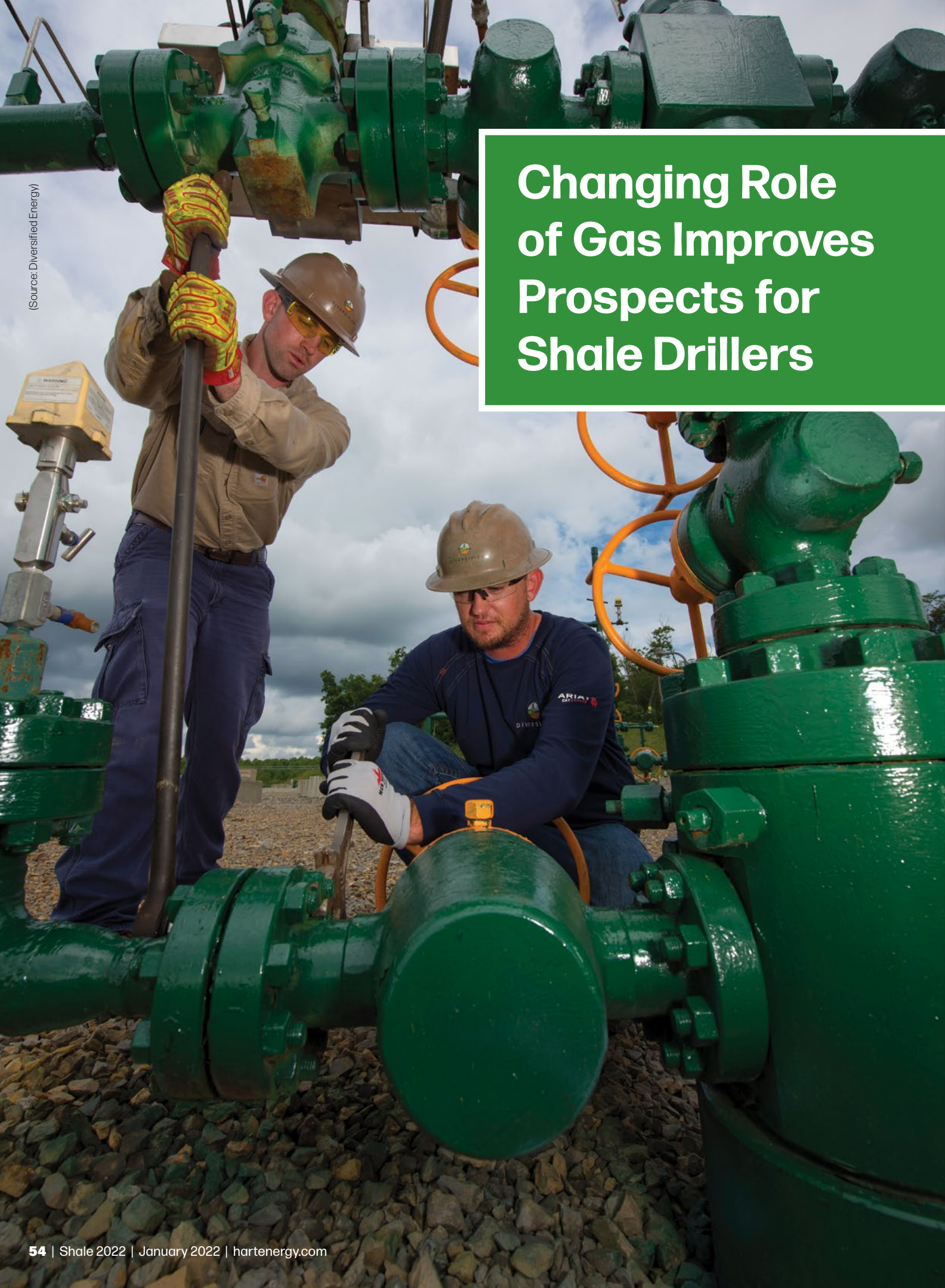
# Changing Role of Gas Improves Prospects for Shale Drillers



(Source: Diversified Energy)

***Between high-return—and stabilized—pricing and the role it is likely to play in the future, natural gas' place in the energy mix is quickly growing.***

By Anna Kachkova,
*Contributing Editor*

Natural gas is on the up following a turbulent decade. After booming in the early days of the shale revolution, it largely fell out of favor as gas prices collapsed in the early 2010s, and many shale drillers turned their focus to oil, which was more profitable at the time. Both oil and gas have subsequently gone through price downturns, the latest of which was brought on by the arrival of the COVID-19 pandemic in 2020.

Now, while the pandemic continues to affect how trends are playing out, demand is on the upswing as economic activity picks up again amid global supply chain challenges brought about by the disruptions seen since early 2020.

"It's been interesting if you've been watching natural gas for the last decade," said Campbell Faulkner, a senior vice president and chief data analyst with commodity broker OTC Global Holdings. "It was very hot 15 years ago, particularly in East Texas and onshore, then it kind of fell into irrelevance due to associated dry gas production. And then you have the pandemic disrupt a pretty finely tuned system, and that's where we are."

Further uncertainty lies ahead as winter begins, bringing with it the prospects of cold weather and spikes in heating demand.

"The winter story is the same as ever for U.S. gas markets—prices will depend on winter weather," said Jen Snyder, Enverus' managing director of intelligence. "In 2021, though, it's not just weather in the [United] States but also weather in Europe and Asia that will drive prices."

This was echoed by Faulkner. "This winter, the interesting thing is, we're not just talking about North America, and we're not just talking about the Netherlands like we typically would have been even 18 months ago—gas has gone global," he said.

This increased interconnectedness of gas markets, along with rising demand, bodes well for U.S. LNG exporters and the gas producers—largely shale—that supply them with feedstock.

"Without a doubt, the demonstrated resilience of the global gas market has been a catalyst for long-term commitments to U.S. LNG development, and we expect additional FIDs [final investment decisions] in the years ahead," Snyder said. "We look to the Haynesville and gassier Eagle Ford areas to feed new trains."

Feed gas could also come from the prolific Permian Basin, but as the majority of the gas output there is a byproduct of drilling for oil, it has different drivers behind it.

"In the Permian, development will depend on oil prices, but savvy operators will position to sell into the global market," Snyder added.

Certain shale producers are keen to capitalize on this boom in demand from LNG terminals and other gas users on the Gulf Coast. This can be illustrated by some major recent deals focused on the nearby Haynesville Shale play spanning Louisiana and East Texas. In early November 2021, Chesapeake Energy completed its acquisition of Haynesville player Vine Energy in a deal valued at about $2.2 billion. Days later, Southwestern Energy announced it had agreed to buy GEP Haynesville for roughly $1.85 billion. Southwestern said the transaction would make it the largest Haynesville producer, in addition to the major presence it already has in Appalachia.

The deal came as Appalachia-focused companies continued to struggle to get new pipelines built. In September 2021, PennEast Pipeline became the latest natural gas pipeline project in the region to be abandoned amid ongoing legal and regulatory challenges. Against this backdrop, Southwestern has been building up its position in the Haynesville, having also acquired Indigo Natural Resources in September for $2.7 billion, before announcing its latest deal to buy GEP Haynesville.

"The deal indicates the overall view of the Haynesville as a superior investment for dry gas," said Faulkner of the latest transaction. "The Marcellus has been consistently stymied by the lack of investment in takeaway capacity along with a negative regulatory environment."

He continued, "Natural gas basis prices in the Haynesville also indicate the current view of sufficient future pipeline takeaway capacity. The Haynesville has superior unit economics for dry gas with great existing infrastructure for takeaway. Additionally, the overall location is positioned well for LNG offtake as well as export to the East Coast via existing/older gas pipelines."

Snyder said Enverus had been expecting consolidation in the Haynesville and that Southwestern was "definitely leading the pack" among buyers.

"Haynesville is well positioned because of the play's location close to the coast and in a state friendly to pipelines, and deep quality inventory," she said. "For now, the consolidation is a headwind to activity, but the mid to long term should bring stability to the play."

Even as some operators expand in the Haynesville, though, others continue to maintain a focus elsewhere,

**Encino is bullish on the Utica's prospects, with CEO Hardy Murchison saying the play is reemerging as one of the best gas plays on the continent. (Source: Encino Drilling)**

including Appalachia and the Permian. Not all players wish to focus on dry gas, and some will be content with associated gas production, or a balanced portfolio of oil, gas and NGL that enables them to pivot depending on which commodity is more profitable.

## Betting on the Utica

Appalachia remains the single largest U.S. gas-producing region, despite some of the challenges it has experienced recently, such as building significant new takeaway capacity. Much of the focus among Appalachian producers has centered on the Pennsylvania portion of the Marcellus Shale. However, this is not the only part of the basin that is considered to have potential.

Other operators have been targeting the Utica Shale play, which also spans several Northeastern states, but it is not renowned for its gas content alone. One of the operators in the Utica—privately owned Encino Energy—is banking on the play's mix of gas, oil and NGL to help offset the risks of future commodity price volatility.

Encino, which is backed by CPP Investments (CPPIB), was founded in 2011. In 2017 Encino and CPPIB jointly formed an acquisition company, Encino Acquisition Partners.

The partnership was aimed at building "a sustainably profitable, large-scale gas, oil and liquids production company," according to Encino President and CEO Hardy Murchison.

In 2018 Encino closed a $2 billion acquisition of Chesapeake Energy's Utica assets in Ohio, consisting of 1 million net acres and holding an estimated 29 Tcfe of recoverable reserves.

"Given the improvements we've seen since we bought the assets and the running room the properties still have, we're extraordinarily pleased with the acquisition," Murchison said. "We knew the Utica play was underappreciated, but it has turned out better than we expected, so far. With the right people, capital and strategy, we've effectively turned this asset around."

It has not all been positive, with Murchison pointing to the pandemic and the brief oil price war between Russia and Saudi Arabia in 2020 as particularly notable setbacks to the company's plans. However, he said the asset quality, people and technology had allowed Encino to weather the commodity price volatility that played out.

"The diversity of our reserves—about 70% natural gas along with roughly half a billion barrels of oil and nearly a billion barrels of NGL—allows us to develop and produce profitably in a variety of commodity price environments," Murchison said. "We've driven down well costs per lateral foot by about 50% since 2018 and doubled productivity per foot. With what we think are now the lowest costs per foot in the basin, combined with the oil and liquids revenues, our margins are approaching best in class."

As of mid-November, the company had been producing almost 1 Bcfe/d in 2021, including roughly 15,000 bbl/d of oil.

"We added a third drilling rig [in October], which brings our undeveloped inventory life down to about

*"We knew the Utica play was underappreciated, but it has turned out better than we expected, so far. With the right people, capital and strategy, we've effectively turned this asset around."*

*—Hardy Murchison, Encino*

30 years and allows us to start growing oil production much faster," Murchison said.

This growth in oil output is a key component of Encino's strategy as it targets an oil and gas production mix that balances higher margins with lower greenhouse-gas emissions.

"We've had a constructive view on natural gas for years, and we think current market events worldwide are demonstrating the value of gas for many years to come," Murchison said. "However, margins are still higher in many oil and liquids plays."

The company's commodity mix in the Utica "drives our cash margins much higher than most gas producers and our emissions intensity far lower than most oil producers," he added. "That optionality across all three phase windows of hydrocarbon development—part of what initially attracted us to the Utica—has proven important over the past three years. We think the high margins and depth and diversity of inventory will be key drivers of Encino's success going forward."

Murchison said the ability to choose between natural gas and oil wells within the same field is a critical differentiator for Encino. "The ability to pivot allows us to be nimble with capital allocation and maintain high cash margins in the face of commodity price volatility," he added.

Encino is bullish on the Utica's prospects, with Murchison saying the formation is reemerging as one of the best gas plays on the continent.

"High-rate dry gas wells with lower costs and lower decline rates compare favorably with the Haynesville," he said. "Our oil and liquids are big differentiators compared with most of the Marcellus. I think the Utica will probably 're-rate' as a play, much as the Haynesville has in recent years. Given the liquids component, it may compare more closely with the Eagle Ford and parts of the Permian."

Those other regions could also potentially be of interest to Encino if it finds the right asset at the right valuation.

"Encino is built to do more, and consolidation is clearly picking up steam in the oil patch," Murchison said. "We're looking actively at multiple transactions, and I expect we'll continue growing both with the drill bit and through acquisitions."

## Location benefits

As demand for natural gas, including from liquefaction plants, on the U.S. Gulf Coast grows, producers in the Haynesville Shale play are hoping to benefit from their proximity to the region.

The Haynesville had been in large part neglected after natural gas prices collapsed in the early 2010s, causing many shale producers to pivot to crude oil. For those Haynesville producers that stayed, however, prospects continue to improve. Indeed, recent consolidation in the play, with independents Chesapeake and Southwestern making major acquisitions, illustrates the desire by gas-focused producers to increase their exposure to the region. On the sellers' side, strengthening gas prices appear to have bolstered private investors' appetites for exiting the play.

Some private operators remain, however, including Rockcliff Energy II, which is focused on developing the East Texas portion of the Haynesville.

"Rockcliff is an active operator, running four Haynesville rigs and two frac spreads, and has achieved significant size and scale over the past four years through the drilling and completion of over 160 Haynesville wells achieving current net production of over 1 Bcfe/d," said Alan Smith, Rockcliff's co-founder, president and CEO. "Rockcliff's acreage is located near the highly strategic Gulf Coast markets, which provides direct access to multiple natural gas buyers, including LNG buyers."

Smith sees the Haynesville as being increasingly at an advantage given the trends that are playing out on the Gulf Coast, and some of the challenges that other gas-producing regions, such as Appalachia, are facing.

"It is now becoming well understood that the Haynesville Shale is very strategically located close to the Texas and Louisiana Gulf Coasts, which are the best natural gas markets in the United States," he said. "The largest natural gas producing area today, which

# A Different Approach

A decade into the shale boom, unconventional plays are maturing, and with this, questions are increasingly arising over what to do with older, unwanted wells. Such questions become all the more pressing when such wells could be leaking methane, given that new U.S. methane regulations are being brought in and ESG issues are increasingly being treated as a priority.

It is some of these trends that Diversified Energy, which is headquartered in Alabama and listed in the U.K., is tapping into. The company's business model involves buying aging, producing gas wells and continuing to operate them until the end of their economic life, at which point the wells are retired. It does no exploration of its own, but rather targets already producing wells that are no longer wanted by their previous operators.

Diversified was initially focused on conventional operations, but now its portfolio comprises 67,000 wells—both conventional, vertical wells and unconventional, horizontal ones. Its core operating area is Appalachia, which is a region renowned for shale gas production. The company is interested in taking on more unconventional wells as shale plays mature. It is also expanding its operations in the Central Region, comprising Texas, Louisiana and Oklahoma, having made several acquisitions there.

According to Diversified CEO Rusty Hutson Jr., the company chooses what wells to acquire based on a "disciplined evaluation process." This includes considering the emissions related to new acquisitions and assessing the impact they could have on the company's overall emissions profile.

"From the beginning, we set out to establish Diversified as an owner-operator model, focused on optimizing mature assets, being good stewards of those assets, and responsibly retiring them when the wells run dry," Hutson said. "There's steady, long-term value in the natural gas that many of these conventional and unconventional assets produce, and we believe our approach, in which a well-capitalized, disciplined operator manages the wells, creates environmentally responsible energy production and delivers long-term value to our stakeholders."

At its first capital markets day, held in mid-November 2021, the company talked up its environmental credentials, including the fact that it had moved its deadline for net-zero greenhouse-gas emissions to 2040, from 2050 previously. Diversified executives said the company had zero tolerance for gas leaks from its wells, planning not only to identify them but also to eliminate them. They also noted that Diversified plugs more wells in Appalachia than any other operator—and said it does this more cheaply than other companies.

Diversified expects natural gas to play a key role in the energy transition, in which it is planning to play a part. According to comments made by company executives at its capital markets day, Diversified will consider accelerating its well plugging program to generate carbon offsets. It will also evaluate the potential of repurposing its assets for carbon capture and for advancing the growth of the nascent clean hydrogen industry.

Diversified has already bought wells from some leading Appalachian Shale producers, and over time more sellers are expected to emerge as they figure out what to do with their unwanted wells. Given the sheer number of shale wells that have been drilled over the past decade, the need for plugging and abandonment is set to grow, and it would not be surprising if producers are keen to offload their older assets in anticipation of this. ■

**Diversified is interested in taking on more unconventional wells as shale plays mature. (Source: Diversified Energy)**

is the Marcellus/Utica up in Appalachia, is takeaway constrained. This means that companies located in the Appalachia area with significant inventory can only drill with a limited number of rigs due to pipeline constraints out of the area. Some companies have secured more takeaway capacity than others, but this generally limits the growth potential for these companies.

"The Haynesville, on the other hand, is not takeaway constrained and is located in a more friendly regulatory environment when additional takeaway capacity construction is necessary," Smith continued. "Gulf Coast demand continues to increase due to new plants, manufacturing and, of course, LNG exports. Operators in the Haynesville generate outstanding returns, very strong operating margins (lower differentials and no/lower minimum volume commitment costs, which enhance Haynesville margins) and have great flexibility in their desired development plans, which is a huge advantage for the Haynesville Shale."

As the U.S. oil and gas industry has evolved, so too have the operators. In Rockcliff's case, the company said its team has built nine companies across various basins, commodities and economic cycles over time.

"While each company, business environment and commodity cycle is different, the core ingredients that have contributed to the success of Rockcliff are the people and the application of the best technologies available," Smith said. "The difference when compared to our past endeavors is that our current company is a shale company instead of a conventional assets com-

pany. We did not do this with the conventional team from the past—instead, it required recruiting the leadership and technical expertise to be able to locate and access the best shale assets we could get our hands on."

Some consistencies have remained across the previous conventional-focused companies and Rockcliff in its current, unconventional-focused, form, however. Smith described all of these companies as "big hedgers," consistently opting to hedge a high percentage of future output to mitigate against the risks of significant commodity price fluctuations.

"During the life of Rockcliff II, which began in 2016, we have already experienced a massive commodity cycle, with natural gas prices ranging from $1.33 per MMBtu to $6.37 per MMBtu," he said.

The company's strategy of hedging some of its production up to three years into the future paid off during the 2020 price downturn amid the pandemic-driven collapse in demand and prices.

"In 2020 when natural gas was hovering in the $1.50/MMBtu range, we never laid down a rig or reduced our workforce thanks to our hedge program," Smith said.

While gas prices are stronger now, publicly listed companies remain under pressure to generate returns for their investors, meaning that they continue to act with caution when it comes to new capex and drilling. Private operators such as Rockcliff, meanwhile, do not have to contend with such constraints.

"The private equity-backed companies continue to be focused on value creation and cash-on-cash returns over the four- to seven-year life spans of most of these companies," Smith said. "The big question for the public companies is for them to continue to have ample inventory and the growing concern of viability for decades to come—can they achieve this if they are not reinvesting in their respective businesses? In other words, if they pay out all their free cash flow to their investors, how do they discover new reserves and inventory to propel them into the future?"

Despite such questions, the expectation is that new discoveries will be needed as far as natural gas is concerned. Smith sees gas as "a key transition fuel in power generation going forward," as efforts are made to balance decarbonization with reliability and affordability.

"We don't disagree that wind and solar should absolutely be part of the equation, but until battery technology can improve to the point that wind and solar are reliable, then it will continue to be a supplement to the reliable power provided by natural gas, and to some extent coal and nuclear," Smith said.

## Looking ahead

In the short term, cold winter temperatures can be expected to bolster gas demand. In the longer term, there is some uncertainty over how the energy transition will play out and what that means for natural gas. However, there are reasons for the gas industry to be confident that it could have a role to play.

"We can't get rid of the thermal fraction. It's not something that's just going to magically be replaced," said Faulkner of power generation against the backdrop of the energy transition. "At the end of the day, we need thermal energy sources, so I actually think it bodes very well, particularly for the domestic shale-producing, gas-focused folks.

"I think it's going to continue to drive domestic production, both from an LNG export standpoint, and just the domestic consumption. We've been killing the coal fleet, we're retiring a large number of nuclear plants, [and] it's going to put more demand on gas."


**Rockcliff has drilled and completed more than 160 Haynesville wells, achieving current net production of more than 1 Bcfe/d. (Source: Rockcliff Energy II)**

*"It is now becoming well understood that the Haynesville Shale is very strategically located close to the Texas and Louisiana Gulf Coasts, which are the best natural gas markets in the United States."*

*–Alan Smith, Rockcliff*

While natural gas continues to make up a part of the energy mix, however, the operators responsible for its production from shale plays, which is where the majority of new U.S. gas output is expected to come from, may evolve further. Public companies, which were instrumental in kicking off the shale boom a decade ago, have stepped back and are continuing to prioritize returns to investors at the expense of new capital spending, even as the gas price environment has improved. And while private companies have played a significant role in keeping production going as their public counterparts started holding back in recent years, a number of them are now taking advantage of improved prices to exit their shale investments.

"There's not a lot of private equity-backed cash floating around anymore. A lot of the smaller players have exited," Faulkner said. "What we're going to see is a continuation of small public companies. Those are going to be who really flourish."

Enverus also expects public companies to remain comparatively significant producers of shale gas even as larger players maintain restraint.

"We do expect most public companies to grow at low rates, but with solid production bases in place, the volumes are nonetheless significant," Snyder said. "Some earlier-stage publics will differentiate with growth."

Different operators will have different strategies, depending on whether they are public or private, and focused on a single basin or multiple ones. However, there are plenty of trends for gas producers to take advantage of currently, whatever their particular circumstances are. ■

**Rockcliff was founded in 2015 and has more than 270,000 acres. (Source: Rockcliff Energy II)**