Oil and Gas Investor

SPECIAL REPORT

SHALE 2025

What's Next for Grown-Up U.S. Shale?

BYOP: BRING YOUR OWN POWER

The Great AI Race for Electrons

U-TURN

E&Ps Get Lucky With Horseshoe Laterals

LENDERS TO THRIFTY E&PS: WE'RE BACK

Rewards for Reining in Spending

HARTENERGY.COM

JANUARY 2025

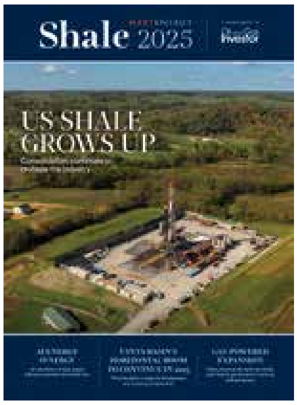
Oil and Gas Investor

JANUARY 2025/VOLUME 45/NUMBER 1

FEATURES

8

SPECIAL REPORT: SHALE 2025



Information contained herein is believed to be accurate; however, its accuracy is not guaranteed. Investment opinions presented are not to be construed as advice or endorsement by Oil and Gas Investor.

Oil and Gas Investor (ISSN 0744-5881, PM40036185) is published monthly by Hart Energy Publishing, LP, 1616 S. Voss Rd., Suite 1000, Houston, Texas 77057. Periodicals postage paid at Houston, TX. Ride-along enclosed. Advertising rates furnished upon request. POSTMASTER: Send address changes to Oil and Gas Investor, PO Box 5020, Brentwood, TN 37024. Address all correspondence to Oil and Gas Investor, 1616 S. Voss Rd., Suite 1000, Houston, Texas 77057. Telephone: +1.713.260.6400. Fax: +1.713.840.8585. oilandgasinvestor@hartenergy.com

Subscription rates: United States and Canada: 1 year (12 issues) US$297; 2 years (24 issues) US$478; all other countries: 1 year (12 issues) US$387; 2 years (24 issues) US$649. Single copies: US$30 (prepaymentrequired). Denver residents add 7.3%; suburbs, 3.8%; other Colorado, 3%.

HARTENERGY.COM

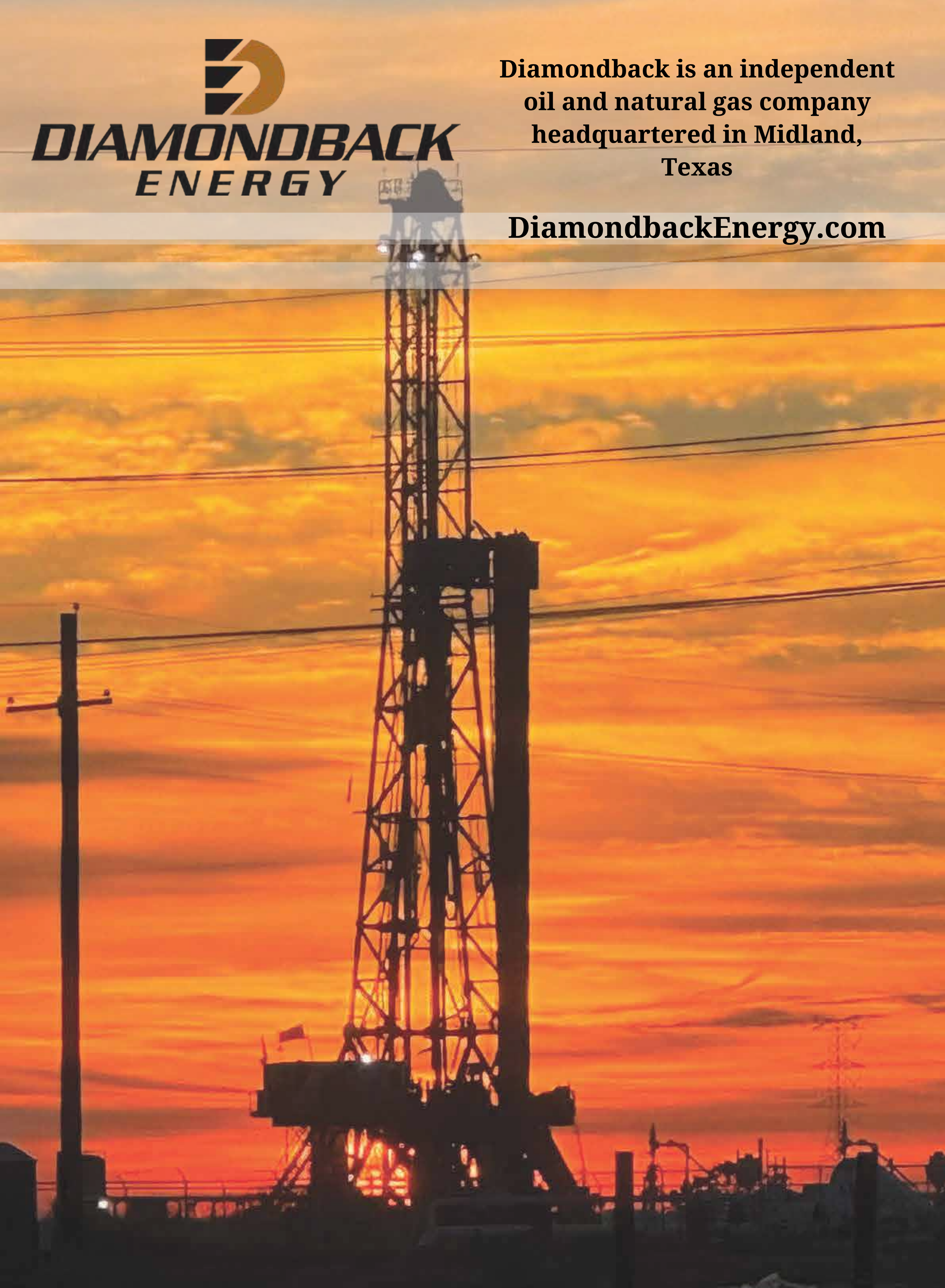
Oil and Gas Investor

COMMENTARY

FINANCE & INVESTMENT

ACQUISITIONS & DIVESTITURES

MIDSTREAM

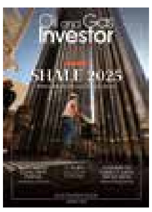

DIAMONDBACK
ENERGY
Diamondback is an independent oil and natural gas company headquartered in Midland, Texas
DiamondbackEnergy.com

Oil and Gas Investor
by HARTENERGY

1616 S. Voss Rd., Suite 1000
Houston, TX 77057
1-713-260-6400 Fax: 1-713-840-8585
HartEnergy.com

LAW & POLICY

NEW ENERGIES



ABOUT THE COVER:
Photojournalist Tom Fox captured this image of drilling operations in Andrews County, Texas.


unconventional thinking generates
exceptional results
AETHON
Aethon Energy is a private investor and operator of onshore oil & gas properties across North America. We believe unconventional thinking can generate exceptional results and are always looking for talented individuals to join our team.
Visit AethonEnergy.com to learn more about us.
AETHON
sequitur superbia excellentiam

Fasten Your Seat Belts

2025 is going to be a thrilling year for U.S. shale.

DEON DAUGHERTY
EDITOR-IN-CHIEF
@Deon_Daugherty
ddaugherty@hartenergy.com

No doubt, the year ahead will be a fascinating one—especially in the U.S. oil and gas industry.

We're giving you the lay of the land in this issue with our Shale 2025 outlook. If the word of the year for 2024 was consolidation, plan on it remaining fresh on everyone's lips in 2025. Fiscal discipline, mindful production growth and paid-down debt set the stage for historic combinations in the E&P sector, reshaping the upstream corporate landscape. What's the way forward in 2025 following a tumultuous year?

This annual special report examines the hottest trends in upstream, midstream and technology, and how those dynamics are likely to play out in the year ahead. We highlight what you'll need to know as you navigate the shale horizons of the Permian, Uinta, Eagle Ford and Appalachia. We also look at the top 50 public producers, which we present along with our partners at Enverus. A Q&A with Enverus CEO Manuj Nikhanj provides insights into how and why the rankings have changed.

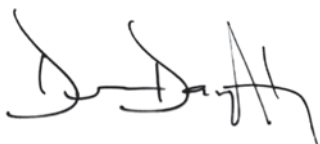
Among the game-changing trends we have covered is the emergence of data centers and what that means for the industry that relies on and fuels them. Our executive editor-at-large, Nissa Darbonne, takes a deep dive into the phenomenon with exclusive reporting.

After several years of relative austerity, it appears that E&P companies' belt-tightening may be getting some acknowledgement from their banking investors. Leverage is a key denominator in lending, and as it lowers, some of the stricter requirements of credit agreements are loosening. Check out our story on page 62 that analyzes the Haynes Boone Fall Borrowing Base Redetermination Survey to get the full scope of what's happening in the upstream banking space.

Other top stories include the ongoing fight for a CCUS system in the Midwest, how funds from the Inflation Reduction Act will be spent and oilfield services M&A. And be sure to read the prognostications of industry guru Dan Pickering as he weighs how the policies of President-Elect Donald Trump will impact the industry.

We've got an exciting year of coverage planned for you at *Oil and Gas Investor* as we endeavor to provide the insights you value with in-depth special reports, conversations with industry leaders and reporting on critical issues from the best energy journalists in the field. Thank you for your continued readership. We wish you a very happy new year.

All the best,



DEON DAUGHERTY
EDITOR-IN-CHIEF

BYOP (Bring Your Own Power): The Great AI Race for Electrons

Data-center developers are scrambling to secure 24/7 power as generative AI has upped the tech game to, well, a nuclear level. U.S. gas producers are being called to meet demand as natgas is the quickest way to get more electrons into the taps.

NISSA DARBONNE
EXECUTIVE
EDITOR-AT-LARGE
ndarbonne@hartenergy.com

Tech executives' uproar when OpenAI rolled out ChatGPT on Nov. 30, 2022, was spun as concern that generative AI was dangerously immature to reliably share facts rather than fiction.

It was about money, though.

Google, Meta, Microsoft, Amazon and the others weren't ready to spend what was needed to release their own gen AI to compete in the "adapt or die" and "win or become IBM" contest of 1s and 0s.

The cost? Top-shelf GPUs, miles of racks in massive data centers and access to 24/7 electrons–up to 50 times more electrons than relatively lower-tech data storage and computing centers.

Curious, *Oil and Gas Investor (OGI)* asked ChatGPT itself what the fuss was about. It cited the "financial readiness for AI infrastructure" as the No. 1 reason for the upset.

Gemini, which Google rolled out a few months after ChatGPT hit browser tabs, disagreed when queried but acknowledged "the cost of developing and running AI models can be significant."

In addition to Google and its Gemini, Microsoft quickly launched Copilot and Meta came out with Meta AI.

Tech companies have had to step up or go the way of those that lost the tech race to them in the past 30 years, analysts and investment managers say.

"Winners and losers are going to be decided," said Matt Stephani, president of BOK Financial's Cavanal Hill Investment Management. "If Microsoft is saying, 'Hey, we're looking at this $100 billion data center and we need 5 gigawatts (GW) of power,' these other guys have to be looking at the same thing.

"They have no choice…. If you lose your edge, you lose your business."

Thus "the power demand is real," Stephani said. "The necessity to win the AI future is the most critical decision Microsoft, Apple, Amazon and [others] face: Either they [win] or they're going to become IBM, and they know that."

The AI revolution has made a winner and a loser in the chip industry itself with Intel Corp. bumped out of the Dow Jones industrial average in November after a 25-year run.

It was replaced with Nvidia Corp., which went public in 1999 at the same time Intel joined the Dow, at the equivalent of 4 cents a share, factoring for stock splits since. Shares were $140 in early December.

'Blindsided Utilities'

The seismic wave OpenAI made formed a tsunami of data-center-power-for-generative-AI that is now shocking U.S. utilities and natural gas demand forecasts with 10 GW thunderbolt upon thunderbolt.

Maeghan Rouch, a Bain & Co. partner, reported in October, "The late 2022 breakthrough in generative AI and the ensuing data-center boom blindsided utilities just as demand was also rising because of repatriated manufacturing, industrial policy

The explosive growth in data centers could revolutionize the U.S. energy industry.

SHUTTERSTOCK

and vehicle electrification."

Eric Peters, CEO and CIO of Coinbase Asset Management, wrote this spring that an entrepreneur told him, "Every day, I'm surprised by how fast power consumption is growing. Take any application, add AI and you need seven times to 50 times the compute power.

"AI is a black hole; it'll suck money out of everything else and into its vortex. The arms race between [tech] industry giants is a 20 on a scale of 1 to 10."

Credit-analysis firm S&P Global Ratings researchers Aneesh Prabhu and Sudeep K. Kesh described the AI transformation as the fourth industrial revolution, following mechanization, electrification and digitization.

SHUTTERSTOCK

"When the dust settles, America's power needs and the consequent capital expenditure will be staggering," Berkshire Hathaway's Warren Buffett told shareholders in 2024, adding that his power outlook is "ominous."

Nvidia's new Blackwell chip's processing speed, which is faster than its Hopper H100s, needs 4 megawatts (MW) of power for 2,000 GPUs in 90 days of training the newest ultra-large AI models, Prabhu and Kesh reported.

Evercore ISI energy analyst James West wrote, "Those seeking more power have begun to take matters into their own hands through onsite or islanded power solutions."

He added, "The lag in deployment of generating assets support our bullish stance on natural gas and the 'Bring Your Own Power' thematic.

"… While we remain confident that solar-plus-storage solutions for utility-scale operations will become viable and more economic in time, the reality is the [data-center] demand pull is here and needs a reliable and accessible fuel source."

'More, Like Way More'

"When you look at the numbers, it is staggering," Jason Shaw, Georgia Public Service Commission chairman, told The Washington Post this past spring. "It makes you scratch your head and wonder how we ended up in this situation.

"… This has created a challenge like we have never seen before."

Data centers use "eye-popping amounts of power," Bain's Rouch reported. "Serving a 1 GW data center requires the capacity of about four natural gas plants or around half of a [two-reactor] large nuclear plant."

She determined that, "all told, meeting global data-center demand could cost more than $2 trillion in new energy-generation resources."

Chips working on AI jobs may use between 35 kilowatts (kW) and 300 kW per rack, according to Prabhu and Kesh. (A data-center rack contains IT equipment like an IT cabinet but isn't enclosed.)

"Models like ChatGPT can consume 80 kW/rack or more, compared with 15 kW for classic cloud," they reported in October.

International Data Corp. anticipates AI clusters may grow to up to 100 kW/rack by 2030, they added.

Rebekah Eggers, innovation director, energy and resources sector for IBM, recalled a gathering at the Edison Electric Institute while speaking at the Gastech conference in Houston in September.

"There was a conversation between one of the utility executives and Elon Musk and the executive was super proud that we were going to have 60% more capacity on the grid, while Elon sat back and kind of said, 'You're going to need more, like way more,'" Eggers said at Gastech.

Berkshire Hathaway's Warren Buffett said in his 2024 letter to shareholders that his outlook for U.S. power supply was "ominous."

"When the dust settles, America's power needs and the consequent capital expenditure will be staggering."

At Gastech, Palantir Technologies' Matt Babin, head of energy and natural resources, added that there was a recent meeting at the White House among chip manufacturers. "The numbers that came out of that meeting are staggering."

While U.S. power generation and transmission aren't looking like they're going to catch up to this rapid growth in demand, Babin said, "you see all of these tech companies moving to say, 'We're going to generate our own power if we can't rely on baseload from the grid to do this work.'"

Natural gas is the only means to fill all of the demand, Babin added, which is 24/7 for data centers. "There's a cliche now in tech, 'Move fast and break things,' that was made famous by Meta," he noted.

"That's fine and good to say, but you can't say that when the thing you're breaking is the grid."

Plus 50 GW

By early November, there were 2,602 data centers in the U.S. with another 139 under construction and 268 more planned, according to the Energy Policy Research Foundation (EPRINC).

It tallied additional 24/7 power needed for these as totaling 19.27 GW with 7.54 GW of this for those under construction and 11.73 GW for those that are planned.

For context, 19.27 GW would be the equivalent power from 23 nuclear plants the size of Three Mile Island's Unit 1 reactor. Also, the largest U.S. nuclear plant is Southern Co.'s four-reactor Vogtle facility in Georgia, with capacity of 4.66 GW, according to the U.S. Energy Information Administration. The two newest reactors cost $37 billion and took 15 years to build.

E&P analyst Arun Jayaram with J.P. Morgan Securities came up with a similar number: 18.68 GW of additional demand in 2027 versus 2022 demand.

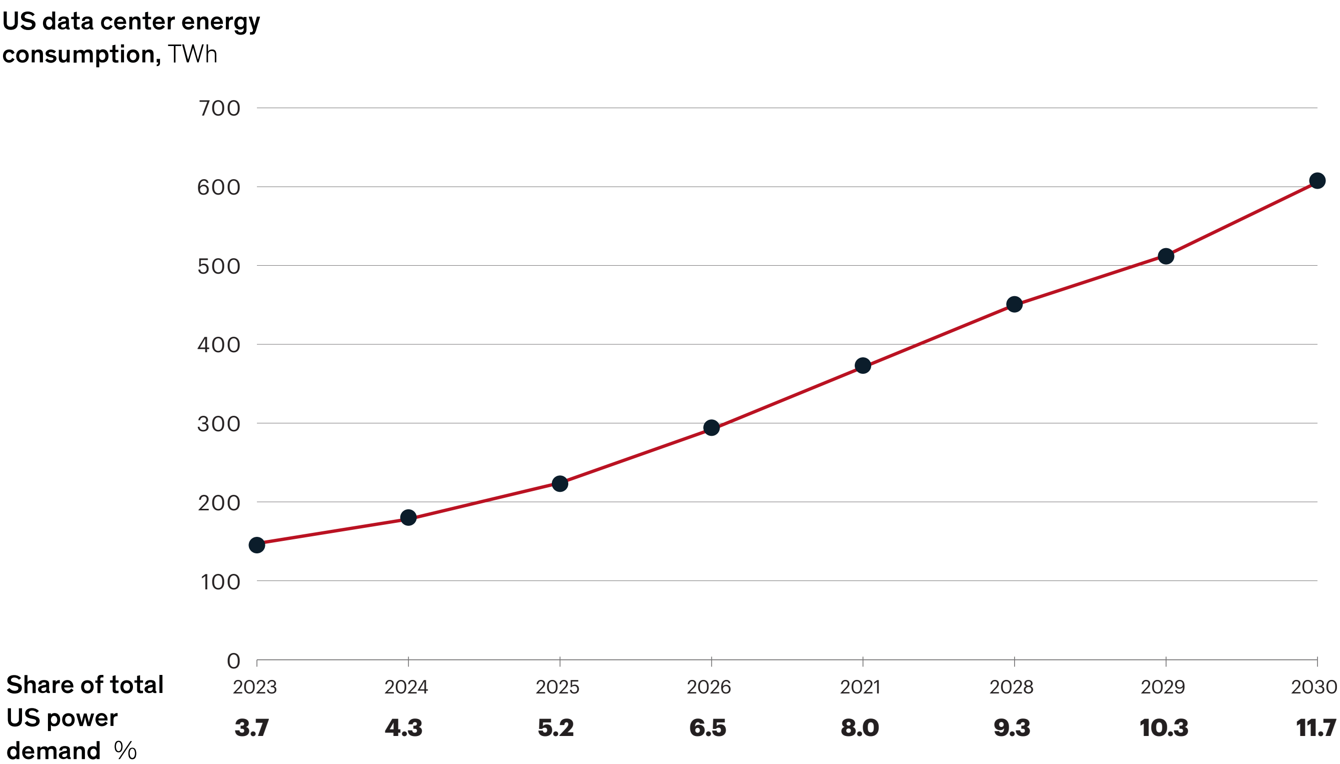
Meanwhile, McKinsey & Co. analysts are forecasting U.S. data-center power needs will grow from 25 GW to more than 80 GW in 2030.

S&P Global Ratings' through-2030 figure is similar: 50 GW.

"That looming demand has taken the power sector by surprise … necessitating about $60 billion of investment in generation and $15 billion in transmission," the S&P analysts, Prabhu and Kesh, reported.

Like electric utilities and regulators, they added that they

Terawatt-hours (TWh) of Electricity Demand, Medium Scenario



SOURCE: MCKINSEY & CO.

McKinsey & Co. forecasts U.S. data centers' power consumption will grow from 4.3% of U.S. market share in 2024 to 11.7% in 2030.

and their colleagues were surprised, too.

PJM–the independent system operator (ISO) in the Appalachian region, serving Pennsylvania and 12 other states, plus the District of Columbia–reported at the start of 2024 that the CAGR (compounded annual growth rate) of demand in its area through 2030 would be 1.7%–more than double the 0.8% it forecast in January 2023.

"The news did not grab our attention because we are used to industry revising forecasts and tweaking them later," Prabhu and Kesh wrote. "But then, forecast revisions started accelerating."

By June 2024, their colleagues in S&P's commodities group revised their CAGR expectations for U.S. Lower 48 power demand to 2.1% through 2030 rather than the 1.2% expected six months earlier.

Overall, the new S&P forecast is that net Lower 48 power demand growth into 2030 will be 542 terawatt-hours (TWh) to total 4,699 TWh. This includes power for data centers but also for EVs, general U.S. economic growth and conversions to electric heating, while deducting for behind-the-meter solar (personal power plants that feed excess electrons onto the grid) and energy efficiency.

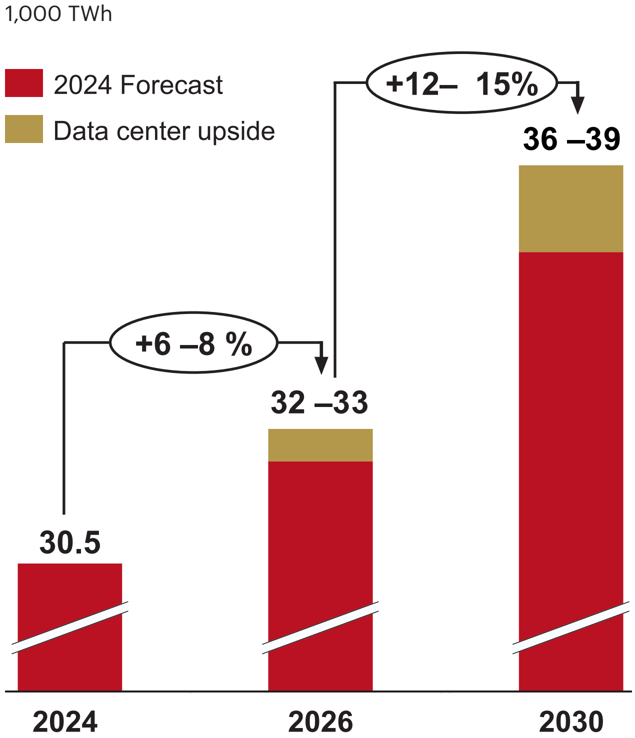
"For perspective, the annual consumption of New York and California is 150 TWh and 250 TWh, respectively," Prabhu and Kesh wrote.

Gas Turbines Talk

Orders globally for natural gas turbines grew 33% in the first nine months of 2024 to 42.8 GW of generation capacity compared with 32.1 GW of orders in the first nine months of 2023, according to McCoy Power Reports.

The 2024 orders are for 279 turbines. When excluding

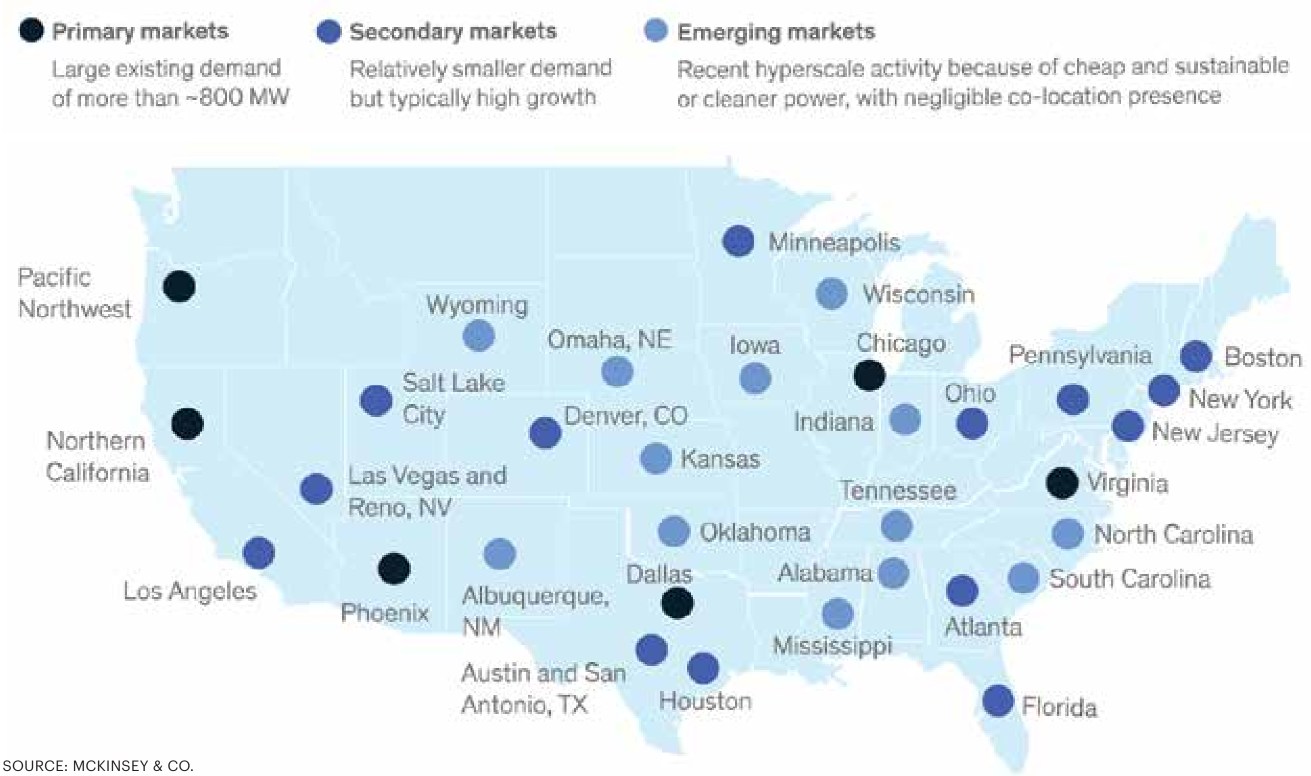
Global Electricity Demand



SOURCE: SIEMENS ENERGY

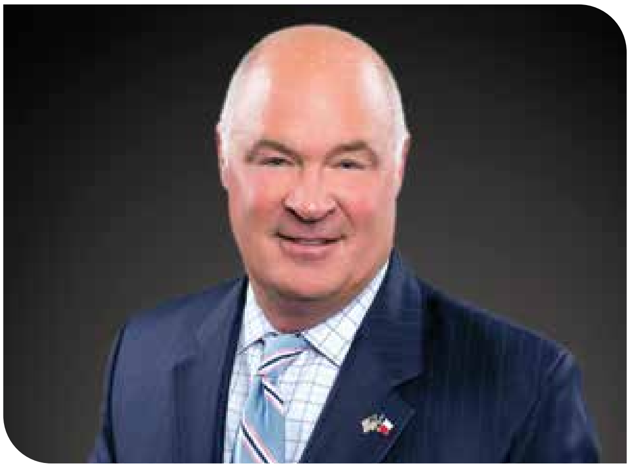
Siemens Energy forecasts global power demand will grow by up to 8,500 TWh into 2030 with 1,600 TWh of this coming from data centers.

Three Tiers of US Energy Markets



SOURCE: MCKINSEY & CO.

Data-center developers are taking their GPUs on the road, seeking plentiful, affordable and reliable power outside the six U.S. concentration areas on the West Coast, Arizona, Dallas, Chicago and Virginia.



PRIORITY POWER

"They just want to get power as fast as they can," said Danny Smedley, a managing director for Priority Power.

COTERRA ENERGY

"There's no other solution in the timeframe … and the reliability that will be required for this power … other than natural gas for the bulk of it," said Tom Jorden, chairman, CEO and president of Coterra Energy.

HART ENERGY

"We have clients that have requested anywhere from 25 [MW] to 30 MW of power for a data center. And in the last two months, that number's increased to 50 MW," Vincent McCullough, a vice president with construction firm Hines, said at Hart Energy's recent DUG Appalachia conference.

orders from China, which declined in 2024, the demand was up 61% to 36.7 GW year over year, J.P. Morgan's Jayaram reported in December.

"North America saw an 88% year/year increase over the first nine months of 2024, with the U.S. contributing 92% growth–9.2 GW vs. 4.8 GW–driven by increased electricity demand," Jayaram reported.

Maria Ferraro, CFO for Siemens Energy, said in a November investor call, "We have an order backlog of EU$123 billion of which I can say is a record."

Siemens forecasts global power demand will grow by up to 8,500 TWh to total 39,000 TWh by 2030 with 1,600 TWh of this coming from data centers.

McKinsey counted 21 utility companies mentioning data centers in their earnings calls this past spring compared with only three in 2021.

"The demand for data centers and power shows no sign of slowing," McKinsey reported. "… Advances in gen AI will create even more data, increasing the need for data storage centers to avoid issues that come with managing large quantities of data."

Stephen Tusa Jr., an industrials analyst for J.P. Morgan Securities, wrote in August that "commentary by utility companies around their data-center pipelines [were] all indicating that this is not showing any signs of slowdown and comfortably extends until the end of this decade."

Permian Gas

Texas' Electric Reliability Council of Texas (ERCOT)–one of three power grids in the Lower 48–forecasts that customers' peak power demand could reach 152 GW in 2030. This is 62 GW more than the 2024 peak, Tusa noted, and nearly twice what ERCOT had estimated in 2023 for 2030 demand.

Texas produced 1 Tcf of natural gas in August, according to Railroad Commission of Texas (RRC) data. Half of this was from Texas' side of the Permian Basin, which is frequently overwhelmed by associated gas supply from its oil wells, resulting in a negative market price in the area.

Of the U.S.' existing data centers, 251 are in Texas–third-most after Virginia's 341 and California's 269–according to EPRINC.

For the 14 additional data centers under construction in Texas and 24 more planned, the state will need an additional 3.114 GW of power, EPRINC calculated.

In the Permian, conversations with data-center builders have started, but developers largely "have not been focused on the Permian yet," Kaes Van't Hof, CFO of Diamondback Energy, said in a November investor call.

Diamondback is the Permian's largest independent producer, including a total of 2 Bcf/d of associated gas following its September merger with Endeavor Energy Resources. All of that is from the Texas side of the Permian Basin, according to RRC data.

"We're kind of putting the flag out there that this [gas] is a very cheap way to execute their business model," Van't Hof said.

Separately, Riley Exploration Permian, which produced 1 Bcf in August, is in a 50:50 joint venture with Conduit Power, building 10 MW of gas-fired power generation to sell onto the ERCOT grid beginning this year.

Danny Smedley, a managing director for Priority Power, has customers looking for where to site their data centers to get access to the grid, including in West Texas.

"It's a crazy busy time for us," Smedley said.

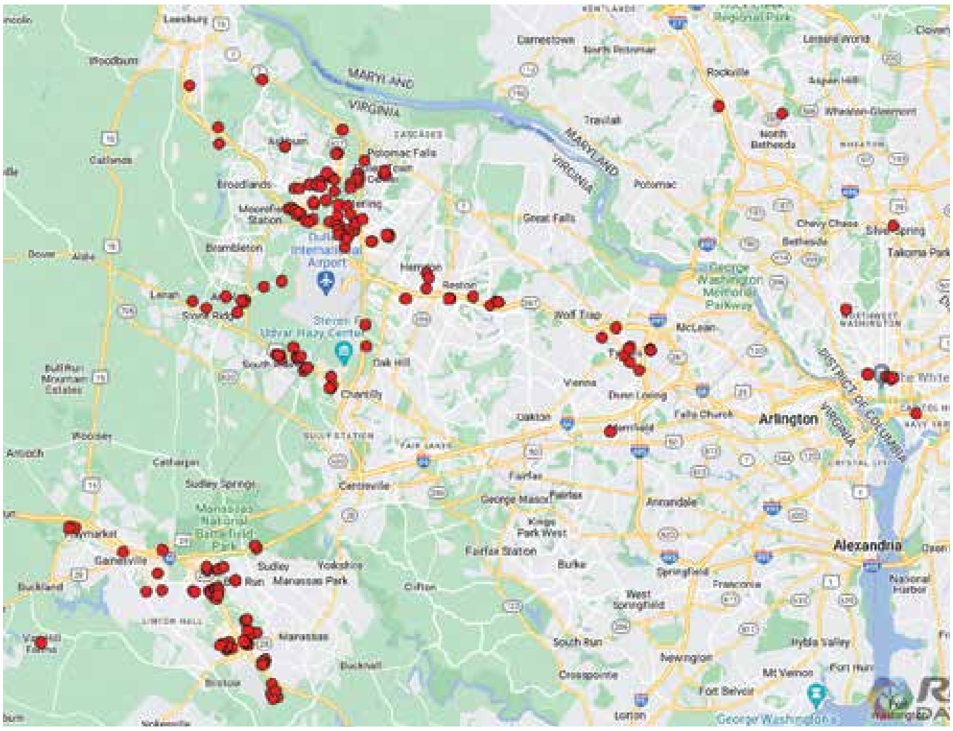
Among the firm's services is sourcing power solutions for clients from offices in Texas, New York and Chicago.

The priority in choosing a data-center location—in "Data Center Alley" in northern Virginia or elsewhere—is access to power, Smedley said.

"I haven't heard of anybody saying, 'Hey, I don't want to be in Virginia' or 'I don't want to be here,'" Smedley said. "They're more about 'Get me to market' and 'Where can I get power the fastest?'"

The hyperscalers are less concerned about price. "They just want to get power as fast as they can," Smedley said.

Data Center Alley



SOURCE: REXTAG

The world's largest concentration of data centers is in northern Virginia in what is known as Data Center Alley.

'No Solution' Other Than Gas

Tom Jorden, chairman, CEO and president of Permian, Appalachian and Midcontinent producer Coterra Energy, was asked in a November investor Q&A for his view on the call on U.S. natural gas for power demand.

"We study this as well as anybody can," Jorden said, "and we try to look at viewpoints that don't have economic or ideological investment in the outcome."

No matter the projections, the power will have to come from natural gas, he said.

"There's no other solution in the timeframe in which this power will be required and the reliability that will be required for this power," Jorden said. "There's no solution available other than natural gas for the bulk of it.

"So, even if you're at the low end of the projection, it'll be very, very constructive for natural gas demand."

Shane Young III, Coterra's CFO, added, "When it comes and exactly how big it is—[from] the materials that we look at and the conversations that we have—there's a bit of a wide berth of where that could ultimately end up."

But somewhere between 30% and more than 40% of the power growth could come from gas, Young said.

"And it's going to have to be something like [gas] that's got that kind of reliability and dispatchability.... We can't wait to see it materialize and manifest itself into gas prices."

Appalachian Gas

The largest concentration of U.S. data centers is in

HART ENERGY

The call on U.S. gas will be "structural and long-term and provide a pretty important tailwind," Expand Energy President and CEO Nick Dell'Osso told investors.

WILLIAMS COS.

The gassy eastern Uinta and the Piceance are "going to have to step it back up and start drilling again a bit more," Candyce Fly Lee, Williams Cos. general manager in Salt Lake City, said of regional gas-demand growth.

northern Virginia–Data Center Alley–with 341 of the 2,602 in the Lower 48.

Of the 19.27 GW of additional U.S. data centers under construction or planned, 6.34 GW are sited in Virginia with 43 under construction and 93 planned, according to EPRINC.

Between 2009 and 2019, Virginia's commercial power demand growth averaged 1.4% per year. This grew to 5.8% per year between 2019 and 2023, EPRINC reported.

"At this rate, [Virginia's] commercial power demand will double within 12 years," it reported.

Bill Appicelli, head of North American power and utilities research for UBS Securities, reported after Appalachian utility PPL Corp.'s earnings call in November that "requested load in-service increased in Pennsylvania to 8 GW from 5 GW and in Kentucky to 400 MW from 350 MW.

"… Active data-center requests now total 31 GWin Pennsylvania, up from 17 GW previously."

Vincent McCullough, a vice president with construction firm Hines, said at Hart Energy's DUG Appalachia conference in Pittsburgh, "We have clients that have requested anywhere from 25 [MW] to 30 MW of power for a data center.

"And in the last two months, that number's increased to 50 MW."

McCullough added, "The gas market has an opportunity to pick up where the utility grid is kind of dropping the ball right now because their infrastructure is so aged."

Ravi Srivastava, president of new technologies for Appalachian gas producer CNX Resources, said expectations are natural gas will fuel at least 50% of power demand growth.

Power provider Vistra Corp., which operates from California to Maine, sees a 40 GW supply deficiency by 2030 in each of its two largest markets, for example: PJM and ERCOT.

The 40 GW deficit in each factors for plant retirements and is derived from PJM and ERCOT's own forecasts, Stacey Dore, Vistra chief strategy and sustainability officer, said in a Federal Reserve program in November.

"We're going to have a supply gap because retirements are happening more quickly than we're bringing on new supply," Dore said.

This is no matter what the data-center demand-growth figures turn out to be, she added.

'Pretty Important Tailwind'

The largest U.S. natural gas producer, Expand Energy, is in conversations to directly supply some of its nearly 7 Bcfe/d of net gas output to data centers, executives confirmed in an October investor call.

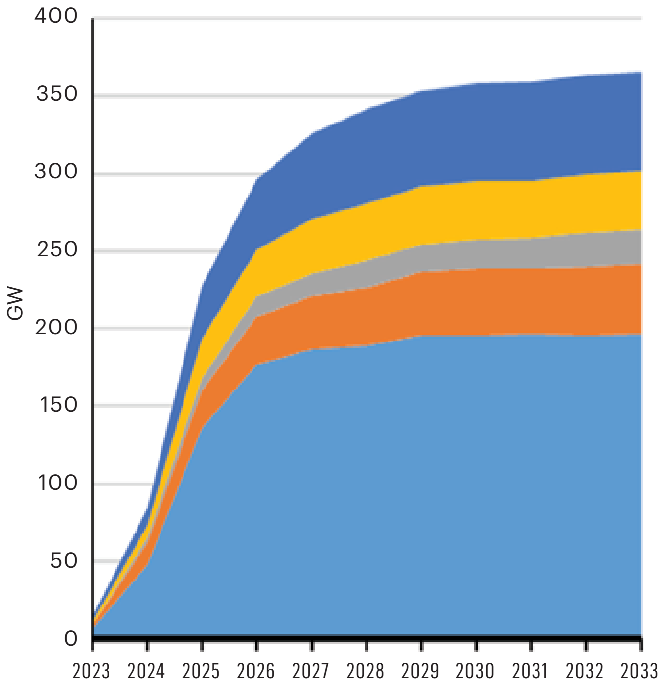
Expand produces from the Appalachian Basin, which has reached is pipe-takeaway capacity, and from the Haynesville Shale in northwestern Louisiana, which has virtually unlimited takeaway to the Gulf Coast industrial and LNG demand centers.

The producer was formed in October by the merger of Chesapeake Energy and Southwestern Energy in a $7.4 billion deal. Of its combined production, about 63% is from the Appalachian Basin.

"Those conversations have been happening in the background," Expand CFO Mohit Singh said.

"We are in the process of consolidating the efforts that legacy Southwestern was doing on its end and what legacy Chesapeake was doing on our end," Singh said.

U.S. and Canadian Power Supply Forecast



SOURCE: NERC

The North American Electric Reliability Corp. (NERC) sees U.S. and Canadian power supply growing by 350 GW into 2033 with up to 50 GW of this coming from gas-fired plants.

Participants in the discussions include data-center developers, power-generation companies, end-users, midstream operators and gas producers.

"It's fair to say there is lots of interest from all the different stakeholders involved in that value chain," Singh said.

Expand President and CEO Nick Dell'Osso said, "Demand domestically is clearly growing–and growing faster than I think a lot of models were predicting … one to two years ago."

A lot of the power demand for AI "is going to take several more years to develop," he added. But the call on U.S. gas will be "structural and long-term and provide a pretty important tailwind."

Up to 118 Bcf/d

Fellow Appalachian producer EQT Corp. told investors that data-center buildout and other U.S. power-demand growth is expected to result in an additional 10 Bcf/d of U.S. gas demand by 2030–and possibly as much as 18 Bcf/d.

U.S. gas demand is currently some 100 Bcf/d.

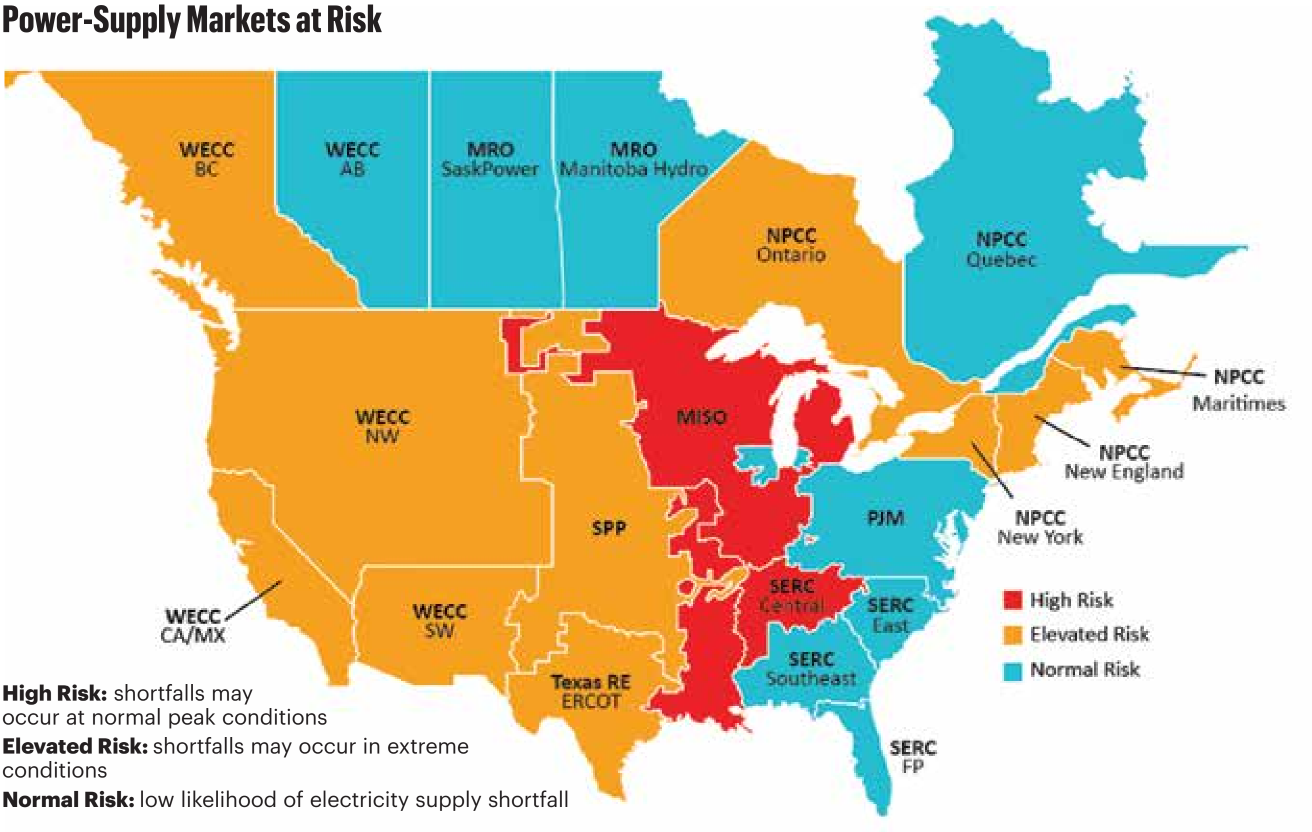
At Range Resources, also an Appalachian gas producer, executives confirmed that positioning for Marcellus gas-fired power generation is heatedly underway in the region.

It added a slide on this to its investor presentation in October "to try and put some color around that," said Dennis Degner, Range president and CEO. "There are a lot of conversations that are starting to materialize around data centers' future power demand."

A PJM auction in July "probably shed some light on the critical movement … around power in the future," he said.

In the capacity auction, bids reached $270 per MW/d from $29 a year before, according to PJM. In the Baltimore area,

Power-Supply Markets at Risk



SOURCE: NERC

Using just 2023 demand data, the North American Electric Reliability Corp. (NERC) expects most of the Lower 48 will be underserved into 2028 in extreme conditions and some of the Lower 48 will have problems in just normal peak conditions.

capacity went for $466 per MW/d.

In utility Dominion Energy's area–including Data Center Alley–capacity sold for $444 per MW/d.

"So, there's some early indication that movement [on securing power supply] has taken shape," Degner said.

Five governors in the PJM area pushed back. They estimate the auction results will cost homes and businesses $14.7 billion, they wrote to PJM.

Bain's Rouch reported, "In the U.S. alone, adequately funding the capital investments to serve data-center growth over the next decade would require utilities to generate 10% to 19% in additional revenue each year than previously forecast."

PJM reported after the July auction that it "remains concerned with the slow pace of new generation construction."

Some 38 GW have been approved "but have not been built due to external challenges, including financing, supply chain and siting/permitting issues," it reported.

Hines' McCullough said at the DUG Appalachia conference, "I could take you to probably five, maybe six, facilities that are in northern Virginia right now that are only operating on 40[%] to 50% of the power that they requested.

"And that's because those grid utility providers can't get them the power."

Rockies Gas

Utah Gov. Spencer Cox announced "Operation Gigawatt" in October. "We need to double the power production in the state of Utah over the next 10 years," he said.

He had just returned from meeting with tech leaders and government officials in South Korea and Japan.

"Everywhere I went, the same conversation happened: It was a conversation around energy," Cox said.

In Utah, 24/7 power supply was already facing a deficit while a prior administration had been "pushing to phase out baseload power before we had baseload dispatchable power to take its place," Cox said.

But the situation is more urgent now as "something else happened that I wasn't prepared for … and nobody else was prepared for," which is power demand for generative AI.

One data-center developer in Utah is requesting 1.4 GW of power. Utah itself currently operates on 4 GW. All of Wyoming operates on 900 MW. So the 1.4 GW data-center campus planned for Utah needs 1.6 times the power of all of Wyoming, he noted.

Most of Utah's natural gas reserves are in the eastern Uinta Basin, which is adjacent to Colorado's gassy Piceance Basin across the Utah-Colorado border.

Two of energy investor Quantum Capital Group's portfolio companies bought Caerus Oil and Gas' Uinta and Piceance assets for $1.8 billion in August.

QB Energy is picking up the Piceance property; Koda Resources, the eastern Uinta property. Chuck Davidson, a Quantum partner, said in the announcement, "Natural gas plays an increasingly important role in our energy grid …

"The Caerus assets provide access to some of the largest natural gas resources in the western markets, which have experienced repeated, localized energy shortages in recent years."

'Start Drilling Again'

Williams Cos.' Candyce Fly Lee, general manager who runs the pipeline company's Salt Lake City-based operations, told *OGI*, "We're starting to see a lot of regional demand with the push for electrification and data centers.

"We're getting a lot of regional crypto-mining, coal-to-gas switching and data centers," Lee said.

South of Salt Lake City on the western edge of the Uinta Basin, Novva Data Centers built its own on-site 200 MW substation that uses some 50 MMcf/d of natural gas for its 1.4 MMsq ft facility.

In Wyoming, Meta announced in July that it is putting an $800 million data center in Cheyenne across a highway from one of three Microsoft already has in the area.

Williams, which moves one-third of U.S. natural gas, added MountainWest to its portfolio in 2023 for $1.5 billion of cash and debt assumption, picking up some 2,000 miles of transmission pipe across Utah, Wyoming and Colorado, as well as 56 Bcf of gas storage.

The area includes the Uinta, Piceance, Denver-Julesburg and Greater Green River basins.

"Most of your major transmission pipelines in the West touch our pipeline," Lee said. "I consider us the gas hub of the Rockies."

The gassy eastern Uinta and the Piceance, "they're going to have to step it back up and start drilling again a bit more," Lee said.

Data Centers By State

State	Operating	Under Construction	Planned	Total
Virginia	341	43	93	477
Texas	251	14	24	290
California	269	5	11	285
Ohio	125	14	25	164
Illinois	129	6	21	156
New York	128	1	0	129
Florida	118	2	1	121
Oregon	97	7	8	112
Arizona	77	4	14	95
Washington	88	2	1	91
Georgia	72	12	6	90
Pennsylvania	70	1	0	71
New Jersey	68	1	1	70
North Carolina	59	3	2	64
Connecticut	28	3	29	60
Minnesota	44	1	14	59
Rest of U.S.	638	20	18	676
Total U.S.	**2,602**	**139**	**268**	**3,010**

SOURCE: ENERGY POLICY RESEARCH FOUNDATION

There are roughly 2,600 data centers in the U.S. with another 139 under construction and 268 more planned.

U.S. Data Center Power Consumption

State	Under Construction	MW	Planned	MW	Total MW
Virginia	43	1,643	93	4,701	6,344
Texas	14	2,324	24	790	3,114
Arizona	4	72	14	2,418	2,490
Nevada	4	1,075	1	1,200	2,275
Georgia	12	1,196	6	300	1,496
Illinois	6	157	21	1,032	1,189
Connecticut	3	96	29	640	736
Minnesota	1	75	14	180	255
California	5	89	11	135	224
Colorado	1	177	1	18	195
Rest of U.S.	46	639	54	313	952
Total U.S.	**139**	**7,543**	**268**	**11,727**	**19,270**

SOURCE: ENERGY POLICY RESEARCH FOUNDATION

Data centers under construction and planned currently in the U.S. total 19.27 GW of additional demand, including 6.3 GW in the Appalachian Basin and 3.1 GW in Texas.

International Gas

Naser Al Yafei, a senior vice president with gas exporter ADNOC Gas, said at Gastech, "As a reliable, efficient and lower-carbon-intensity source of energy, natural gas is the most viable and flexible solution for the increasing power demands for data-center servers, cooling and backup generation."

Arun Kumar Singh, chairman and CEO of India-based international operator ONGC, said the numbers he's seeing are that data centers currently consume some 460 TWh and it is likely to grow to 1,000 TWh by 2026.

Renewables alone won't work, he added. "I'm 100% sure for a country like us, the cheapest power is solar," ONGC's Singh said.

"The only problem of solar is that at night, it doesn't work.… There is no substitute to gas for some years."

Bain's Rouch noted in October that power suppliers worldwide "face the same pressing issue," notably in Canada, Ireland, Germany, the United Arab Emirates and India.

Ireland recently forbade more data-center development in Dublin through 2028. Data centers consume some 20% of the country's electricity.

Rouch wrote, "Data centers' annual global energy consumption could more than double by 2027 from 2023 levels, growing at a compound annual rate of 10% to 24% and potentially surpassing 1 million GWh in 2027."

Nuclear Options

In stunning news, Microsoft and Constellation Energy Group struck a deal in September to restart the Three Mile Island nuclear plant's Unit 1 reactor in Pennsylvania to power new data centers.

But the 835-net-MW reactor's restart is "not a needle-mover" against natural gas demand growth from the AI boom, EQT president and CEO Toby Rice told *OGI*.

"There's only 3 GW of nuclear potential if we restart all facilities that could be restarted."

Meanwhile, new power demand to fuel–and cool–data centers as well as other demand growth could be as much as 75 GW, he said.

The Three Mile Island plant, which became uneconomic in the wake of new Appalachian natural gas supply beginning in the late aughts, was shuttered in 2019. (It was the plant's Unit 2 reactor that experienced a partial meltdown in 1979 and was shuttered at that time.)

The target date for Unit 1's restart is 2028.

The deal comes at a price, noted Julien Dumoulin-Smith, power and utilities analyst for Jefferies: $110/MWh, which is "higher even than investors' expectations for a behind-the-meter contract," he reported.

David Arcaro, an analyst with Morgan Stanley, calculated the price as $100/MWh. That is "a substantial premium to market power prices of about $50/MWh."

In addition, Microsoft's deal has it "still receiving power directly from the grid, paying an approximately $30/MWh transmission charge on top of this payment to Constellation," he added.

"From our perspective, we think this shows that Microsoft was willing to pay a $130/MWh all-in power price for nuclear power."

Meanwhile, Amazon and Google have announced deals for SMRs–small modular nuclear reactors–Google with Kairos Power; Amazon with Energy Northwest, Dominion and X-Energy.

SMRs aren't the near-term power solution, though, Priority Power's Smedley said, mostly due to regulatory and permitting constraints. "It would be years and it's still not proven."

But they could be helpful when they come onto the market, he added. "I hope the technology proves out. We need every possible source to produce power."

SMR developer Oklo Inc. reported in November that it had orders for another 750 MW from two data-center developers, bringing its total pipeline to 2,100 MW. Separately, it has nonbinding letters of intent from Diamondback Energy as well as Centrus Energy, Prometheus Hyperscale and others.

Its SMRs, which remain in R&D, are expected to produce between 15 MW and 50 MW, delivered directly to the customer's facilities. First deployment is expected in 2027.

Behind-The-Meter Options

Data-center developers would prefer to have their own power plant or plug directly into someone else's, skipping the grid. This is known as a "behind the meter" solution and typically involves "co-location" with the power source.

"You almost essentially have a microgrid onsite that you self-distribute to the data center itself," Colleen Turley, senior manager for mobile power operator AMP, said at the DUG Appalachia conference.

"And by having a partner on the gas end, you can almost insulate your risk,"

A behind-the-meter nuclear deal met in November with Federal Energy Regulatory Commission (FERC) rejection, though.

In it, Amazon was to buy Houston-based Talen Energy's 960 MW data center, Cumulus Data Assets, that is plugged into Talen's 2,700 MW Susquehanna nuclear plant in eastern Pennsylvania, for $650 million.

Power producers Exelon Corp. and American Electric Power filed a complaint.

Two FERC commissioners said they didn't see a need for the deal. Another commissioner said rejecting it created "unnecessary roadblocks to an industry that is necessary for our national security." Two other commissioners did not vote.

The deal was rejected 2-1.

Talen has appealed. OGI

Pickering Prognosticates 2025 Political Winds and Shale M&A

For oil and gas, big M&A deals will probably encounter less resistance, tariffs could be a threat and the industry will likely shrug off "drill, baby, drill" entreaties.

DEON DAUGHERTY
EDITOR-IN-CHIEF
ddaugherty@hartenergy.com

NISSA DARBONNE
EXECUTIVE EDITOR-AT-LARGE
ndarbonne@hartenergy.com

As unofficial oracle of oil and soothsayer of shale, Dan Pickering bought the boom as a co-founder of Tudor, Pickering, Holt & Co. in 2004, tracking and investing in the evolution of the shale revolution.

Now, as the founder and chief investment officer of the Pickering Energy Partners financial services firm, he's focused on the maturing next era of the domestic oil and gas boom and everything that comes with it.

But, apart from the lateral lengths and frac intensity, the industry's future is just as tied to U.S. policy, global geopolitical tensions and the rapid wave of industry consolidation.

Before and during Hart Energy's DUG Executive Oil Conference in Midland, Pickering chatted with Oil and Gas Investor's *Editor-in-Chief Deon Daugherty and Executive Editor-at-Large Nissa Darbonne about dealmaking, the upcoming Trump administration, and global pricing and political trends.*

Deon Daugherty: How might the new Trump administration shape energy policy, given what we know now?

Dan Pickering: Energy has a broad definition, right? We're getting some hints already for … what's overarching beyond probably less regulation and more access for the traditional energy companies. That probably translates to things like LNG. The LNG permit halt that is in place probably gets undone, right? We probably see LNG stuff move ahead, easier-to-do things like pipelines and new projects. I think that better access and faster permit approvals are going to be two obvious things in the oil and gas space.

It's probably tougher in the decarbonization space. They've kind of floated this concept that they were going to remove the EV tax credit. They didn't say anything about wind and solar production tax credits or investment tax credits. Maybe wind and solar are a little safer. They didn't say anything about carbon capture. Maybe it's a little safer. I think what you're going to see is the subsidies to green energy are going to be tougher.

The other question that is lurking is what happens with the FTC (Federal Trade Commission), and does that change how dealmaking in the space is approached? It would probably make it easier for larger transactions to happen. All we saw from Exxon [Mobil]-Pioneer [Natural Resources] was [former Pioneer CEO] Scott Sheffield couldn't go on the board. All we saw from Hess [Corp.]-Chevron was [Hess CEO] John Hess couldn't go on the board. But, does a friendlier FTC make for really big deals? Chevron for Conoco[Phillips]? Exxon for EOG [Resources]? I'm just throwing those out as examples of big transactions. Does that make them more palatable or less risky than they would've been under a different administration?

DD: Second requests did come more frequently than on pre-Biden administration E&P deals.

DP: I think Trump wants to be friendly to business. I do think we're going to have a kind of a new FTC. Remember, a lot of the work gets done by staffers who are there regardless of the political climate. I think things might go a little faster, and they might be a little bit more lenient.

DD: Are there deals that were on hold, waiting to see what happened in the 2024 presidential election?

DP: Well, it's probably not a coincidence that we didn't see really any meaningful announcements in the oil patch for the six or eight weeks in front of the election. We saw two in the 10 days after (Coterra Energy acquiring Franklin Mountain Energy and Avant Natural Resources; Ovintiv buying Montney Shale assets from Paramount Resources and selling its Uinta Basin position to FourPoint Resources). I think it does generally give some confidence to the industry. It's not just the Trump administration; it was a pretty sweeping process. Republicans have the House, the Senate and the [White House]. I think that it provides more comfort to the industry

> "I think that, as we get closer to turning on these new LNG projects, we'll see a more normal and flattish gas curve. When we do, we'll see more M&A."
>
> **DAN PICKERING,** CHIEF INVESTMENT OFFICER, PICKERING ENERGY PARTNERS

that there's a decent chance of favorable treatment or, at a minimum, not negative treatment. I think that builds confidence.

Remember, a bunch of folks have just completed things or are still in the process of completing things. The election results probably give those companies more confidence to take another bite at the apple once they've finished integrating the deals that they've done in the past year. I think that it's going to be easier to transact in 2025 than it might've been in 2024.

Nissa Darbone: Permian inventory remains a concern. Where are we with Permian Basin "next" inventory? What do we have and where are we going?

DP: It's kind of "the question" right now. So, if you look, I think we've seen a ton of M&A over the last two years, and I think there are three or four factors. Inventory, first and foremost; size and scale—companies want to be bigger; and then value: things are pretty inexpensive. The real driver here [is] inventory, though. Folks are getting concerned that they might not have enough kind of core acreage, and we wouldn't see the acquisitions and the M&A if that weren't the case, right? People are speaking with their actions. Talk to folks and the view is, at $70/bbl oil, you've got three to seven years worth of inventory in the basin.

I think the companies are trying to shore up and make sure they're above average, not below average. That's driven a lot of activity. I think the basin's maturing. We've got a lot of wells left to drill. There may be an upward creep of costs, which is probably going to translate to an upward creep in pricing over time. But inventory, I think, is on the mind of every energy executive these days out in the Permian.

ND: Let's just take the Wolfcamp, for example. Have we really settled in on what's the optimal spacing and numbers of laterals in different formations? Could we probably put a lot more laterals in the Wolfcamp in each drilling spacing unit?

DP: I think the industry's continuing to learn and get more efficient. It kind of amazes me how effective the industry's been. The rig count has trended lower and production has trended higher, so we're getting better every day. That answer, the optimum answer, is probably changing on an ongoing basis. At this stage of maturity for an existing [target] formation like the Wolfcamp, there are pretty good rules of thumb on what it's going to take. There are more wells to drill there at higher prices. It's all a function of price. I think that we're not going to downspace in some of these mature benches unless you've got triple-digit oil prices, and I think that's still a ways away sustainably. I think folks have settled in on a pretty good recipe, plus or minus 10%. The error bars aren't big right now.

ND: For the natural gas basins—particularly the Haynesville and Appalachia—clearly, they're not running out of inventory. What are you seeing in terms of potential for M&A?

DP: For gas, step back and do the big picture. There's a lot more oil M&A than gas M&A in the last two or three years. Folks view oil prices as pretty much in the zone, $70/bbl plus or minus. Gas has this upward sloping price curve, $2.75/MMBtu now, $3.75 in the future. Who wants to be the seller today? I think that, as we get closer to turning on these new LNG projects, we'll see a more normal and flattish gas curve. When we do, we'll see more M&A.

The Haynesville is the hottest spot in the country because it's so close to all of the export capacity that's coming online. I think we'll see a lot of drilling in the Haynesville as the LNG projects start to turn on. Then, you go to Appalachia. Fabulous economics up there, [but] capacity-constrained in terms of getting gas out of the basin. Maybe the new administration's going to make it easier to [transport] gas out of the Marcellus. But the Haynesville continues to be, I think, a focus area for the industry just because of access to those waterborne export [facilities].

DD: Speaking of exports, there's a lot of speculation about what may or may not happen with regard to Trump's tariff threats. These might end up as negotiating tactics, but there could be trade wars and trickle-down effects and problems in the industry. What do you think?

DP: Tariffs probably translate to a stronger dollar. Historically, oil has done better in weaker dollar environments. It makes oil more expensive globally when the dollar's strong and oil is priced in dollars. There are two ways that it might have an impact on the demand side. One is a stronger dollar, and the other is just on China. Generally, they're the second-biggest consumer in the world. Their consumption has been at much slower growth than it had been historically. If they do tariffs and it hurts China, then that's not great news for oil demand. The ripple-through effects are really around demand implications.

DD: China and all of Asia, in general, is the largest demand center for LNG, but how might tariffs affect Asia's interest in buying U.S. LNG when other places can provide it, too?
DP: What we've seen is that energy access has been more important than most other geopolitical issues. Almost everybody from around the globe has been more interested in relatively inexpensive oil prices as opposed to punishing bad actors. Russia's production is making its way to the market, no problem. Iran has produced a lot of barrels, even though they're bad guys. Nobody's bombing oil infrastructure in the Middle East. I bring that up to say that I think the economic importance of energy sort of transcends some of this potential trade war stuff. I would say the Asians are going to be no less interested in our LNG than with or without tariffs because access to energy continues to be really important.

DD: Do U.S. producers even want to support a "drill, baby, drill" kind of policy when it can negatively impact prices?
DP: I'm glad you asked that. This is the area where I'm very skeptical that "drill, baby, drill" will get any sort of traction with the industry. It wasn't those words, but Biden asked for that when oil was in the $100s (per barrel). And the industry didn't respond. If you step forward to today, the supply-demand dynamics are more tenuous than they were a few years ago. OPEC has 3 million-plus barrels a day off the market, and investors have demanded capital discipline from the oil and gas companies. To see them accelerate and shoot themselves in the foot with additional supply and potentially lower prices, just because somebody says, "drill, baby, drill," I'm skeptical of that. I think we're going to have a more conducive environment to deploy the capital, but I don't think it's going to be "drill, baby, drill,"

DD: What do you make of the energy stock rally immediately after the election?
DP: I think that you had two very different reactions. You had oil and gas companies outperform and you had clean energy companies underperform. I think it's directly reflective of the fact that, on the margin, the oil and gas business got better, and the clean energy business got worse. Fewer subsidies, harder to do business in clean energy. And less interference, fewer regulations and better access for oil and gas. I think it was reflective of the sort of directional shift in both of the businesses. At the same time, I think it's relatively transitory. The fact that it was such a resounding message from the voters, I think, added fuel to any "Trump trade," if you will, in both directions. It's like, "Holy cow, the mandate is strong." If you thought there was a 50% chance of something happening, now it has to be 60% or 70%. I think the market rally was a reflection of the improved prospects for oil and gas and, on the margin, the tougher prospects for clean energy. But I don't think the election was transformational. I think it was incremental, not transformational.

DD: There's been a general slowdown in the momentum of the ESG movement. How does that factor in with the election outcome?
DP: There are really two pieces to the ESG movement. There's the social and governance piece, and then you have the decarbonization piece, and they've kind of been linked together, but they should be different. I think that we moved to peak wokeness and moved away from that. The election probably just reinforces that. As it relates
to the industry, I think the industry has done a pretty good job of making smart, measured, appropriate investments on the environmental side. So, I don't see this making a huge difference other than it goes back to maybe some of the regulations that might've been imposed in a Harris administration that won't be imposed in a Trump administration.

DD: Before we wrap up, what are we overlooking?
DP: The biggest issues that I think the energy patch is going to face in 2025 and 2026? It's not going to be who's president. It is going to be supply and demand. Is the economy OK? Does China pick back up? What does OPEC try to do? There's zero room for more barrels from OPEC, in my opinion. While we're all thinking about what the implications of energy policy might be, the supply-and-demand dynamic is really the one we've got to keep our eye on. I think OPEC is super important on the oil side.

And how does [U.S.] foreign policy wind up influencing the energy market? Trump has the strongest foreign policy hand as it relates to energy that any president has had in 50 years. We're producing so much oil and gas that we're not beholden to the Middle East or Saudi Arabia or anyone. If Iranian sanctions come on the table, we can manage that better than almost anybody. Let's keep our eye on how that translates to what happens in the Middle East, what happens with Russia [and] Ukraine, etc. The other component of this election is, how does foreign policy get adjusted? We have one of the three biggest producers in the world, Russia, that's in the middle of a war that maybe something happens with. We have Iran in the middle of this conflict in the Middle East and with nuclear aspirations. What do we do there? Because that will matter to the oil and gas markets, also.

DD: I'm glad you brought up policy. Trump has a better relationship than most it would seem with people like Vladimir Putin and Saudi Crown Prince Mohammed bin Salman (MBS). Will he have any sort of influence on OPEC+?
DP: Look, the president of the United States is a damn powerful position. And, you're right, Trump isn't afraid to pick up the phone and talk to these folks. Could we see a situation where we indicate sanctions on Iran and 2 or 3 million of their barrels come off the market? And we ask and get from Saudi and OPEC offsetting volumes? Nobody, no elected official wants to see the equivalent of $5 a gallon gasoline in the U.S. You know what I mean? Biden didn't want to see it. Trump doesn't want to see it. You've heard him say "drill, baby, drill," Why? Because he likes low oil prices, which means consumers get cheap gasoline prices. I think that wielding that influence again, with a pretty strong energy hand in his back pocket, does he have the ability to get Russia and Ukraine to calm down? If he does, then, Russia's ability to be in the market more freely, does that bring oil prices down a little bit? Certainly might. I think it matters. We just don't know how yet. OGI

This interview was edited for length and clarity.


PETRO - HUNT
ph
L.L.C.
www.petrohunt.com


SAVE THE DATE
MAY 14-15, 2025 | FORT WORTH, TX
SUPER DUG
CONFERENCE & EXPO
THE LARGEST SHALE EVENT OF THE YEAR!
2000+ INDUSTRY PROFESSIONALS
50+ INDUSTRY SPEAKERS
130 EXHIBITORS
10+ hrs NETWORKING OPPORTUNITIES
INTERESTED IN SPONSORING?
Contact: Darrin West | dwest@hartenergy.com | 713.260.6400
LEARN MORE
HARTENERGY

HARTENERGY
Shale 2025

A SUPPLEMENT TO
Oil and Gas Investor

US SHALE GROWS UP

Consolidation Continues to Reshape the Industry

AI ENERGY SYNERGY

An Abundance of Data Sweetens the Bottom Line

UINTA BASIN'S HORIZONTAL BOOM TO CONTINUE IN 2025

It's Ready for Development and Stacked Pay Exploration

GAS-POWERED EXPANSION

Rising Electrical Demand May Finally Push Natural Gas Demand to Catch Up with Production

Ongoing consolidation in the U.S. shale industry, the lingering themes of 2024 and an uncertain political outlook greet the new year, with the industry set to take advantage of a friendlier administration and the slow return of capital in the E&P space.

ADVANTAGE VIDEO & MARKETING

Back To The Future: US Shale is Growing Up

The Patch's maturity will be tested in 2025 amid ongoing consolidation and geopolitical dissonance.

DEON DAUGHERTY | EDITOR-IN-CHIEF

U.S. shale has consolidated to the point that its upstream players number about half of just a few years ago. The industry is mature—and so are its top basins. Producers run a tight, efficient ship of an industry that exercises capital restraint, returns cash to shareholders and sports yields better than the S&P 500. The incoming president is a big fan and is naming a cabinet that promises to make it easier to do the business of oil and gas. And capital is slowly—very, very slowly—returning to the E&P space.

The timing is impeccable because the new year will carry with it challenges that will likely call upon all of the industry's resources.

Lingering themes from 2024—managing a disciplined capital structure as inventory life matures; constraints around natural gas infrastructure, water management and Permian Basin electrification; and volatile demand—continue to resonate, said David Deckelbaum, managing director at TD Cowen.

"I think all of these are really just another way of saying that the challenges will be replicating the success that you have with efficiencies in 2024," he told *Oil and Gas Investor (OGI)*. "It would be inconceivable that you would be able to achieve the same rate of change in '25."

Still, regular capital efficiency gains may now be a necessary part of the industry's go-forward strategy.

"There's still very much an existential struggle of how you balance the need for more resource [with] the need to go into more secondary zones while not showing a degradation of capital efficiency," Deckelbaum said.

'Doing More with Less'

Whether in terms of remaining independent E&Ps, the rig count or capital invested, the industry did more with less in 2024.

U.S. oil production set a new record in August with an average of 13.4 MMbbl/d, topping the previous monthly high of 13.3 MMbbl/d, according to the U.S. Energy Information Administration (EIA). For the full-year 2024, the EIA forecast an average of 13.2 MMbbl/d, which topped the record 2023 annual average of 12.9 MMbbl/d.

And the record gain is expected to continue in 2025, when the EIA predicts U.S. oil production will average 13.5 MMbbl/d.

But the U.S. rig count began trending downward in 2023, when it fell 20% from the previous year, according to Baker Hughes data. The count moved in fits and starts in 2024. For the week ending Dec. 6, the number of oil rigs had increased

"I would imagine that, in this more benign environment, you'll likely see continued industry consolidation."

DAVID DECKELBAUM, MANAGING DIRECTOR, TD COWEN

The Majors and Large Shale Producers Intend to Grow Shale Production in 2025 and Beyond

Exxon Mobil	>1.4 mboe/d Permian volume in 3Q24 increasing to 2 mboe/d in 2027
Chevron	950,000 boe/d in 3Q24 to 1 boe/d in 2025, then 1.2 boe/d by 2030
ConocoPhillips	single-digit shale growth year over year
EOG Resources	single-digit oil CAGR between 2024 and 2026
Diamondback Energy	2% increase in oil output in 2025 from 4Q24 estimate of 480,000 b/d\
Coterra Energy	>5% oil CAGR between 2024 and 2026

SOURCE: COMPANY FILINGS, MORGAN STANLEY

2025 Oil and Gas Price Outlook

	2024E	2025E	2026E
WTI crude oil ($/bbl)			
UBS	$75.94	$71	$71
Strip	$76.21	$68.29	$66
Consensus	$76.52	$71	$70
Brent crude oil ($/bbl)			
UBS	$80.10	$75	$75
Strip	$79.98	$72.03	$70.15
Consensus	$80.95	$76	$74
Henry Hub Natural Gas ($/mcf)			
UBS	$2.32	$3.35	$3.75
Strip	$2.30	$3.20	$3.74
Consensus	$2.40	$3.40	$3.64

SOURCE: UBS

Natural Gas Outlook - Demand Drivers and Sources of Supply (estimated)

	2024	2025	2026	2027	2028	2029	2030
Residential and Commercial	20.9	21.4	21.4	21	21.1	21.2	21.2
Power Generation	36.5	36.6	37.2	38.3	39	39.4	39.9
Industrial	23.5	24.1	24.5	25	25.5	26.1	26.6
Pipeline Exports	6.4	6.7	7	7.4	7.7	8.1	8.5
LNG Exports	12.2	15.3	18.3	19.1	22	23.5	24
Other	8.8	8.7	8.7	8.7	8.7	8.7	8.7
Total Demand (bcf/d)	**108.4**	**112.7**	**117.2**	**119.5**	**124.1**	**127**	**128.8**
Appalachia	32.3	32.7	33.9	35	35.7	36.3	37.3
Haynesville	15.1	16	17.4	18.1	19.7	21.7	22.9
Permian	23.1	25.9	28.1	29.1	29.5	29.9	30.3
Eagle Ford	6.6	6.8	6.9	6.9	7	6.8	6.6
Bakken	3.1	3.4	3.7	3.9	4.1	4.2	4.3
Rest of Lower 48	19.9	19.3	18.8	18.4	18.2	18	17.8
Gulf of Mexico	1.8	1.8	1.8	1.7	1.7	1.7	1.7
Pipeline Imports	5.7	6	6.2	6.6	6.9	7.2	7.6
Total Supply (bcf/d)	**107.7**	**111.9**	**116.8**	**119.7**	**122.6**	**125.8**	**128.5**

SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION, COMPANY REPORTS, UBS ESTIMATES

Crude Oil Outlook - Sources of Demand and Supply

(estimated)

Demand	2025	2026	2027	2028	2029	2030
U.S.	20.6	20.5	20.5	20.5	20.5	20.5
Other OECD countries	4.5	4.5	4.5	4.5	4.5	4.4
OECD Europe	13.3	13.2	13	12.9	12.7	12.4
OECD Asia-Pacific	7.1	7.1	7	7	6.9	6.8
Total OECD	45.5	45.3	45.1	44.9	44.5	44.1
Former Soviet Union	5.1	5.2	5.3	5.4	5.5	5.6
Other Europe	0.8	0.8	0.8	0.9	0.9	0.9
China	16.9	17.1	17.2	17.3	17.3	17.3
Other Asia	15.3	15.6	16	16.2	16.5	16.7
Latin America	6.4	6.5	6.6	6.6	6.7	6.7
Middle East	9.4	9.7	9.9	10	10.2	10.3
Africa	4.4	4.5	4.6	4.7	4.7	4.8
Total Non-OECD	58.4	59.5	60.4	61.2	61.8	62.2
TOTAL DEMAND	**103.9**	**104.7**	**105.5**	**106.1**	**106.3**	**106.3**

Supply	2025	2026	2027	2028	2029	2030
U.S.	20.7	21	21.1	21.1	21.1	21.1
Other OECD countries	6.1	6.2	6.2	6.2	6.2	6.1
OECD Europe	3.2	3.2	3.1	3	2.9	2.7
OECD Asia-Pacific	0.4	0.4	0.4	0.4	0.4	0.4
Total OECD	30.5	30.9	30.8	30.8	30.5	30.3
Former Soviet Union	0.3	0.3	0.3	0.3	0.3	0.3
Other Europe	0.1	0.1	0.1	0.1	0.1	0.1
China	4.4	4.4	4.3	4.1	4	4
Other Asia	1.9	1.8	1.7	1.6	1.6	1.5
Latin America	6.7	7.3	7.8	7.9	7.9	7.8
Middle East	1.9	1.9	1.9	2	2.1	2
Africa	2.5	2.4	2.3	2.2	2.1	2.1
Total Non-OECD	17.7	18.1	18.3	18.2	18	17.8
Biofuels	3.5	3.6	3.8	3.9	4	4.1
Processing Gains	2.4	2.5	2.5	2.5	2.6	2.6
Total Non-Opec+	54.2	55.1	55.4	55.4	55.2	54.9
Opec non-crude	5.7	5.8	5.9	6	6.2	6.3
Opec partners non-crude	2.7	2.7	2.6	2.6	2.6	2.6
Opec crude production	27.1	27	27.3	28.1	28.8	29.3
-Saudi Arabia	9	9	9.2	9.5	9.8	9.9
-UAE	3.4	3.6	3.6	3.7	3.9	4.2
Opec partner crude production	14.4	14.2	14	13.8	13.5	13.4
-Russia	9.3	9.1	8.9	8.7	8.5	8.5
Opec+ crude production	41.5	41.2	41.3	41.8	42.3	42.7
*Call on Opec+	41.3	41.1	41.6	42	42.3	42.5
TOTAL SUPPLY	**104.1**	**104.8**	**105.3**	**105.9**	**106.3**	**106.5**

SOURCE: EIA, IEA, OPEC, BLOOMBERG, UBS
*FOR MARKET BALANCE

SHUTTERSTOCK

Oilfield workers in Huntington Beach, Calif., celebrated Donald Trump's first presidential victory in 2017 by displaying his photo.

by five to 482 rigs—the highest figure since mid-October, but still 6% less than the same time in 2023, the services firms said.

Following incremental spending increases in 2022 and 2023, most E&Ps are keeping their 2025 budgets flat compared to 2024.

"We're getting better at doing more with less," said James Wicklund, PPHB managing director.

"We are no longer globally in a growth market for oil and gas [unless] growing by 1.5% a year is considered a growth industry. The goal is going to be to maintain production rather than to grow production, at least dramatically."

Successfully setting production records with fewer rigs and services is a function of efficiency gains, he said.

"If efficiency gains continue to outpace demand growth, then oil prices go down. Now, if an oil company spends less to produce the same amount, they make more money," Wicklund told *OGI*.

Indeed, efficiency gains and consolidation left a mark on the industry in 2024, Deckelbaum said. Advanced drilling times, drilling speeds and completion speeds demonstrated that operators are just doing more with less.

"I think that there was a huge field-level thematic that is probably going to carry some pretty nice tailwinds going into 2025," he said.

"Particularly as you saw quite a bit of consolidation on

"If efficiency gains continue to outpace demand growth, then oil prices go down. Now, if an oil company spends less to produce the same amount, they make more money."

JAMES WICKLUND, MANAGING DIRECTOR, PPHB

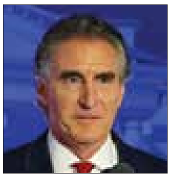
private packages [and] some of those efficiency gains being laid on top of those acquired assets as a way of generating returns. It's one of the reasons why I think you could see for some names, capital spending on an absolute basis, just as perhaps the maintenance capital relative to your production is going down on the margin because of efficiency gains."

Consolidation benefits in 2024 came through with efficiency gains, analysts said, and that will continue in 2025. In part, UBS analysts said, the valuation arbitrage of 2.2x enterprise value between small- to mid-size E&Ps and large cap E&Ps will force consolidation. The gap reflects the gains that companies made via consolidation, which heightened scale for greater efficiencies.

Production Plans, Budget Base

Most E&Ps are budgeting for flat oil production off maintenance programs in 2025, according to third-quarter reporting. Shale growth will happen at the majors and large-cap producers, including EOG Resources, ConocoPhillips and Diamondback Energy.

Most shale gas producers are open to deferring activity if the macro view calls for it. Their preference is to use efficiency gains to trim activity, not accelerate growth, said Devin McDermott, Morgan Stanley's managing director of oil and gas research.



Devin McDermott

Efficiency gains in drilling and completion activity, coupled with some deflation, will continue to be a tailwind to some E&P budgets. These advances account for a $25/ft reduction in well cost at Diamondback, allowing it to reduce its 2025 capital expenditures plan by up to $400 million. Occidental Petroleum's well costs in the Denver-Julesberg Basin dropped 20% between the first and third quarters of 2024, and management said that momentum will continue throughout 2025. EQT expects operational efficiency will reduce its capex by $50 million for the new year.

Gas Rises to the Top

Analysts' estimates for 2025 oil prices are screening soft with expectations of surplus supply at or slightly above 1 MMbbl/d; Morgan Stanley's head of European oil and gas research Martijn Rats reckons the surplus could be as much as 1.3 MMbbl/d.

The UBS outlook on oil of $71/bbl WTI in 2025-2026 reflects an offset of the OPEC+ extension of its supply cuts from slower global GDP growth weighing down demand.

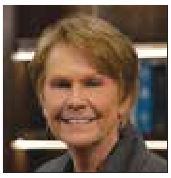
Still, the bank forecasts that companies within its upstream coverage universe will average an 8% return of capital yield next year, surpassing the S&P 500.

"Upside comes from weaker non-OPEC supply and/or geopolitical impacts reducing supply; downside comes from stronger non-OPEC supply, poor OPEC+ compliance, and/or weaker demand," Josh Silverstein, UBS managing director and head of energy research, said in December.

UBS has lowered its 2025 demand growth estimate to 1.01 MMbbl/d based mainly on weaker Chinese demand, an impact of the U.S. presidential election and likely trade policy changes aimed at China and other nations.

Beyond 2025, UBS expects oil demand growth to moderate to 800,000 bbl/d in 2026 and 2027 from the weight of the energy transition.

"We expect global oil demand to peak at 106.3 million bbl/d in 2029 before gradually declining," Silverstein said. A rising rate of electric vehicle uptake will replace 3.3 MMbbl/d of oil for passenger vehicles around the world in 2030.



"Without a doubt, there's going to be consolidation, not just in the Permian, not just in the U.S., but around the world. Large companies are going to have a very hard time replacing what they produce. That's created a lot of need for the largest oil companies to do M&A—or they become a declining business."

VICKI HOLLUB, CEO, OCCIDENTAL PETROLEUM

Stephen Richardson at Evercore ISI might say it best: "Balances in 2025 are ugly, and continued OPEC+ action will be needed to support price."

The weaker oil outlook is offset by Wall Street's forecast of an increase in natural gas prices in 2025-2026. While the Lower 48 is currently oversupplied, the weaker oil outlook may support gas prices.

Silverstein at UBS puts the bank's Henry Hub outlook price for 2025-2026 at $3.35-$3.75/MMcf, supported by rising demand—especially from LNG exports—and lower activity supporting the supply/demand balance.

UBS is forecasting domestic natural gas balances will decline into an undersupplied position of up to 1 Bcf/d, producing a stronger outlook for 2025 pricing. Both public and private E&Ps will continue to prioritize free cash flow generation over volume growth, Silverstein said.

Long-term UBS projects that Henry Hub prices will stabilize in a $3.50-$4/MMBtu range, an improvement driven by growing LNG exports and higher power generation demand from AI and data center development.

"We see a mixed outlook for energy in 2025," Silverstein said. "To the positive side, we see natural gas momentum building, the benefits of sector consolidation coming through and shareholder returns ramping as balance sheets have improved. However, crude oil prices face downward pressure, and attractive valuations may not be enough to bring in new investors."

Consolidation Carryover

In 2023, oil and gas E&Ps spent some $234 billion on M&A—the most since 2012, according to the U.S. Energy Information Administration (EIA). And by mid-2024, the year's upstream M&A activity was already tracking to top the 19 deals in 2023 valued at more than $1 billion, an Enverus report showed.

And that trajectory could have been more dramatic if not for the slow-walk tactics of the U.S. Federal Trade Commission

Top Public Operators [mcf/d]

Operator	mcf/d	Most Active Region	Rigs (10-10-2024)
EXPAND ENERGY	10,038,049	EASTERN U.S.	9
EQT	5,680,642	EASTERN U.S.	3
EXXON	5,524,288	PERMIAN	37
COTERRA ENERGY	3,868,576	EASTERN U.S.	9
ANTERO RESOURCES	3,233,684	EASTERN U.S.	2
EOG	3,133,180	PERMIAN	21
OCCIDENTAL	3,048,547	PERMIAN	26
CHEVRON	2,823,688	PERMIAN	14
DEVON	2,548,458	PERMIAN	23
CONOCOPHILLIPS	2,219,436	PERMIAN	25
COMSTOCK	2,211,997	GULF COAST	5
RANGE RESOURCES	2,134,927	EASTERN U.S.	3
DIAMONDBACK	1,887,072	PERMIAN	21
BP	1,866,510	GULF COAST	11
CNX	1,580,495	EASTERN U.S.	1
CRESCENT ENERGY	1,428,834	GULF COAST	4
GULFPORT	1,295,232	EASTERN U.S.	2
NATIONAL FUEL GAS	1,242,733	EASTERN U.S.	2
PERMIAN RESOURCES	1,223,930	PERMIAN	12
CIVITAS RESOURCES	1,135,356	PERMIAN	4
MARATHON	1,083,949	GULF COAST	5
REPSOL	1,067,127	EASTERN U.S.	1
OVINTIV	994,747	PERMIAN	7
APA CORP	982,635	PERMIAN	8
DIVERSIFIED ENERGY	808,111	GULF COAST	1

SOURCE: ENVERUS

(FTC). The agency has aggressively targeted dealmaking and E&P mergers have been in the crosshairs of FTC Chair Lina Khan and Senate Democrats.

Indeed, closing on most of the largest E&P deals announced since fall 2023 was delayed by the agency's second notice requests. The flurry of notices was unusual in oil and gas, insiders told *OGI*.

The Hart-Scott-Rodino Act charges the FTC and the Department of Justice with review of proposed transactions that may affect commerce; either agency can take legal action to block deals that it believes would "substantially lessen competition." In December 2023, the agencies released updated merger guidelines. Among them: any deal that creates a company with a market share greater than 30% could be problematic.

The mergers caught in the guidelines include:

- Chesapeake Energy's $7.4 billion merger with Southwestern Energy to create Expand Energy;
- ConocoPhillips' $22.5 billion acquisition of Marathon Oil;
- Exxon Mobil's $60 billion purchase of Pioneer Natural Resources;
- Diamondback Energy's $26 billion acquisition of legacy private producer Endeavor Natural Resources; and
- Chevron's $53 billion purchase of Hess Corp., a deal that Exxon is challenging because it seeks to take over Hess' assets in Guyana.

But the tide appears to be turning in favor of more consolidation in the space, which many top executives say is greatly needed. And it's more than simply divesting the non-core assets that recent mergers have added to the portfolio, Occidental Petroleum CEO Vicki Hollub said during Hart Energy's Executive Oil Conference in November.

"Without a doubt, there's going to be consolidation, not just in the Permian, not just in the U.S., but around the world," Hollub said. "Large companies are going to have a very hard time replacing what they produce. That's created a lot of need for the largest oil companies to do M&A—or they become a declining business."

The timing appears to be ripe in 2025 for a new

Top Public Producers [boe/d - Mid-Continent]

Operator	boe/d	bbl/d	mcf/d	% Liquids	Well Count
MACH NATURAL RESOURCES	106,190	29,719	458,764	28%	4,246
TOTALENERGIES	73,691	14	442,039	0%	1,544
SANDRIDGE	17,962	3,292	88,007	18%	993
UNIT	8,975	2,036	41,630	23%	586

SOURCE: ENVERUS

Top Public Operators [bbl/d]

Operator	bbl/d	Most Active Region	Rigs (10-10-2024)
EXXON	1,040,221	PERMIAN	37
OCCIDENTAL	715,061	PERMIAN	26
EOG	663,393	PERMIAN	21
CONOCOPHILLIPS	595,690	PERMIAN	25
DIAMONDBACK	583,639	PERMIAN	21
DEVON	554,792	PERMIAN	23
CHEVRON	484,564	PERMIAN	14
MARATHON	259,168	GULF COAST	5
PERMIAN RESOURCES	235,442	PERMIAN	12
CHORD ENERGY	221,763	ROCKIES	5
CIVITAS RESOURCES	213,485	PERMIAN	4
OVINTIV	211,473	PERMIAN	7
APA CORP	179,997	PERMIAN	8
COTERRA ENERGY	158,504	EASTERN U.S.	9
CRESCENT ENERGY	133,993	GULF COAST	4
CALIFORNIA RESOURCES	129,058	WESTERN U.S.	0
HESS	117,335	ROCKIES	4
MATADOR RESOURCES	114,576	PERMIAN	8
VITAL ENERGY	93,847	PERMIAN	5
SM ENERGY	93,631	PERMIAN	6

SOURCE: ENVERUS

administration with a friendlier stance toward oil and gas than shown by President Joe Biden.

President-elect Donald Trump has already produced a litany of names for top agency jobs, including Andrew Ferguson, currently one of the FTC's five commissioners, to replace Khan.

"One of the aspects of the new administration would be inherently a less scrutinous FTC, which I think did hinder some deals in 2024. And certainly, we saw several large headline deals being slowed by the FTC," Deckelbaum said. "I would imagine that, in this more benign environment, you'll likely see continued industry consolidation."

Gaming 2025 M&A

Consolidation is expected across the upstream space in the Lower 48. After billions of dollars' worth of significant deals, the Permian Basin remains in play for consolidation, insiders told *OGI*.

"It has compelling interest for a variety of reasons," Deckelbaum said.

The Matterhorn Express Pipeline, which came online in October, is flowing an average of 317 MMcf/d of natural gas. The new takeaway capacity will presumably start alleviating gas pricing locally in the basin, he said.

And the successful testing of some secondary benches in the Permian is gathering interest.

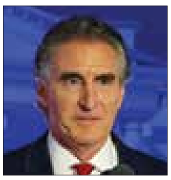
"I would expect that you're just going to see more focus around additional fences in areas like the Permian that maybe didn't get as much airtime over the last couple of years. Certainly, areas like Woodford, some areas like the Wolfcamp XY, I think that those are probably where you see the most focus," Deckelbaum said.

Excitement around LNG expansion and the likelihood that Trump will repeal the Biden administration's pause on new LNG facilities could heighten activity along the Gulf Coast gas basins, as well as those in Appalachia, he said.

The Macro

The next president brings a whole deck of wildcards with him to Washington. While many of the most-likely scenarios of a Trump presidency tip in favor of the industry, given Trump's coziness with oil and gas interests, some of his reported plans have received mixed reactions.

Chris Wright



Doug Burgum

Some of the good in his promises is obvious.

Trump's choice of Chris Wright, co-founder, chairman and CEO of Denver-based Liberty Energy, for Secretary of Energy was endorsed by none other than shale wildcatter and policy influencer Harold Hamm.

The president-elect also followed the counsel of Hamm, CEO of Continental Resources, on choosing North Dakota Gov. Doug Burgum as Interior Secretary and chairman of the newly formed National Energy Council. The council, Trump said in a statement, is designed to "oversee the path to U.S. ENERGY DOMINANCE by cutting red tape, enhancing private sector investments across all sectors of the Economy, and by focusing on INNOVATION over longstanding, but totally unnecessary, regulation."

Other items are concerning.

- Trump has repeatedly pledged to levy tariffs on all imports, including Canada and Mexico, and especially China.
- Among his campaign ditties, chants of "drill, baby, drill" were revived at most of his oil-weighted campaign rallies, especially those in so-called blue wall states like Pennsylvania, which fell to the Republicans in November. Trump has promised to reduce the price of gasoline, which would come with more oil supply; oversupply reduces the price of oil, too, and U.S. producers have expressed little interest in watching oil supplies surge and the price of crude plummet.

Most analysts don't see U.S. shale giving in to the president-elect's urging. At Wells Fargo, Roger Read said the bank doesn't expect a greater-than-FCF reinvestment rate among E&Ps, nor does it foresee a return to excessive annual production growth.

"We base this outlook on three key reasons: shale resource maturity, scale and ownership; changed investor demands for returns; and sector consolidation of both public and private E&Ps. The industry's structure is inconsistent with high growth," Read said in a December report.

And some of Trump's ideas are head-scratchers. For example, he promised to fast-track certain permitting for high-dollar investors, posting on his Truth Social site:

"Any person or company investing ONE BILLION DOLLARS, OR MORE, in the United States of America, will receive fully expedited approvals and permits, including, but in no way limited to, all Environmental approvals. GET READY TO ROCK!!!"

But it's unclear how that would work, given the review process that is built into statute, such as those required by the National Environmental Policy Act.

And then, there's the bevy of geopolitical variables that could impact U.S. shale.

OPEC+ decided in December to extend its production cuts of 1.65 MMbbl/d though the end of 2026. However, analysts noted some concerns, not the least of which is member compliance, that hover over the announcement.

Mukesh Sahdev, Rystad Energy's global head of commodity markets/oil, said "a lot depends on how the Trump 2.0 rhetoric on U.S. production growth and sanctions on Iran [and] Venezuela plays out along with tariffs on Canada and Mexico.

"The delayed phase-out also signals that OPEC+ acknowledges the weakness in Chinese demand and is not anticipating a surprise rebound anytime soon, given Trump's possible tariffs against China."

Still, OPEC discipline remains a concern, Read said. And even if OPEC shows restraint, Read points to other wildcards at play: Chinese demand trends, tariff/trade risks, OPEC+ discipline, easing/rising global conflicts and winter weather in the Northern Hemisphere. ■

PriorityPower

WE ARE THE ULTIMATE ADVANTAGE

REDUCING
Energy Spending

OPTIMIZING
Energy Efficiency

ENSURING
Energy Reliability

DECREASING
GHG Emissions

At Priority Power, we're your dedicated partner in navigating the energy landscape, offering comprehensive services to optimize operations and drive results. From infrastructure optimization to procurement and risk management, our tailored solutions prioritize efficiency, sustainability, and savings. With a proven track record and commitment to innovation, we empower your energy strategy for a brighter, sustainable future.

Enverus CEO On Why the Big Getting Bigger is a Big Deal

Widespread consolidation has reshaped the list of top public producers, says Manuj Nikhanj.

OIL AND GAS INVESTOR

Enverus and Oil and Gas Investor *have again partnered to present the annual ranking of top public producers. The list of top private companies will be published in July. Manuj Nikhanj, who took over as CEO of the research and analytics firm in mid-2024, shares his perspective on the changing landscape and what's next for the industry's top players.*

Oil and Gas Investor: How did the concentration of production among the top 10 names change from 2023 to 2024?

Manuj Nikhanj: [In 2023], the top 10 names represented 56% of production out of the top 50 on a boe/d basis. Due to mergers … that same figure is 62% of production—in part due to Pioneer Natural Resources being a part of Exxon Mobil, and Chesapeake a part of Southwestern [and] rolling together into the newly formed Expand Energy. This new entrant finds itself at the second position, with an impressive production of around 1.69 million boe/d, mainly from the Eastern U.S. region.

Oxy, Devon Energy and Diamondback Energy are now including pro forma volumes coming from private operators CrownRock, Grayson Mill and Endeavor Resources, respectively.

A little bit lower down the list, you see Civitas Resources with a significant jump, moving up 11 places to rank 14th based on its larger production base from closed 2023 and early 2024 deals. Mitsui also climbed 11 spots, now ranking 46th. Mach Natural Resources is also a new entrant on our list. These kinds of developments highlight the dynamic nature of the oil and gas industry, with shifts in production, regional focus and operational efficiency playing crucial roles in our rankings.

OGI: Given this year's M&A activity in which large public companies are acquiring private producers, how do you think the landscape will continue to change?

MN: The most notable shift in the just-completed quarter was the lack of consolidation between publicly traded E&Ps, the first time that has happened in a quarter since 2022. The $188 billion in public company consolidation since the start of 2023, with 11 public deals over $2 billion, leaves significantly fewer targets to pursue.

In addition, large buyers like Chevron, ConocoPhillips, Diamondback Energy and Exxon Mobil have been busy closing and integrating deals, with timelines often delayed by extra antitrust scrutiny by the Federal Trade Commission.

OGI: What is separating the upper echelon of operators from the rest?

MN: We see four names breaking at 1 million boe/d. For now, they are in a category of their own. However, if (or when) the ConocoPhillips-Marathon Oil and the Chevron-Hess deals close, those combined entities would join these ranks and round out the top six on our list.

OGI: The Permian Basin has dominated the scene for years—how much longer can this continue?

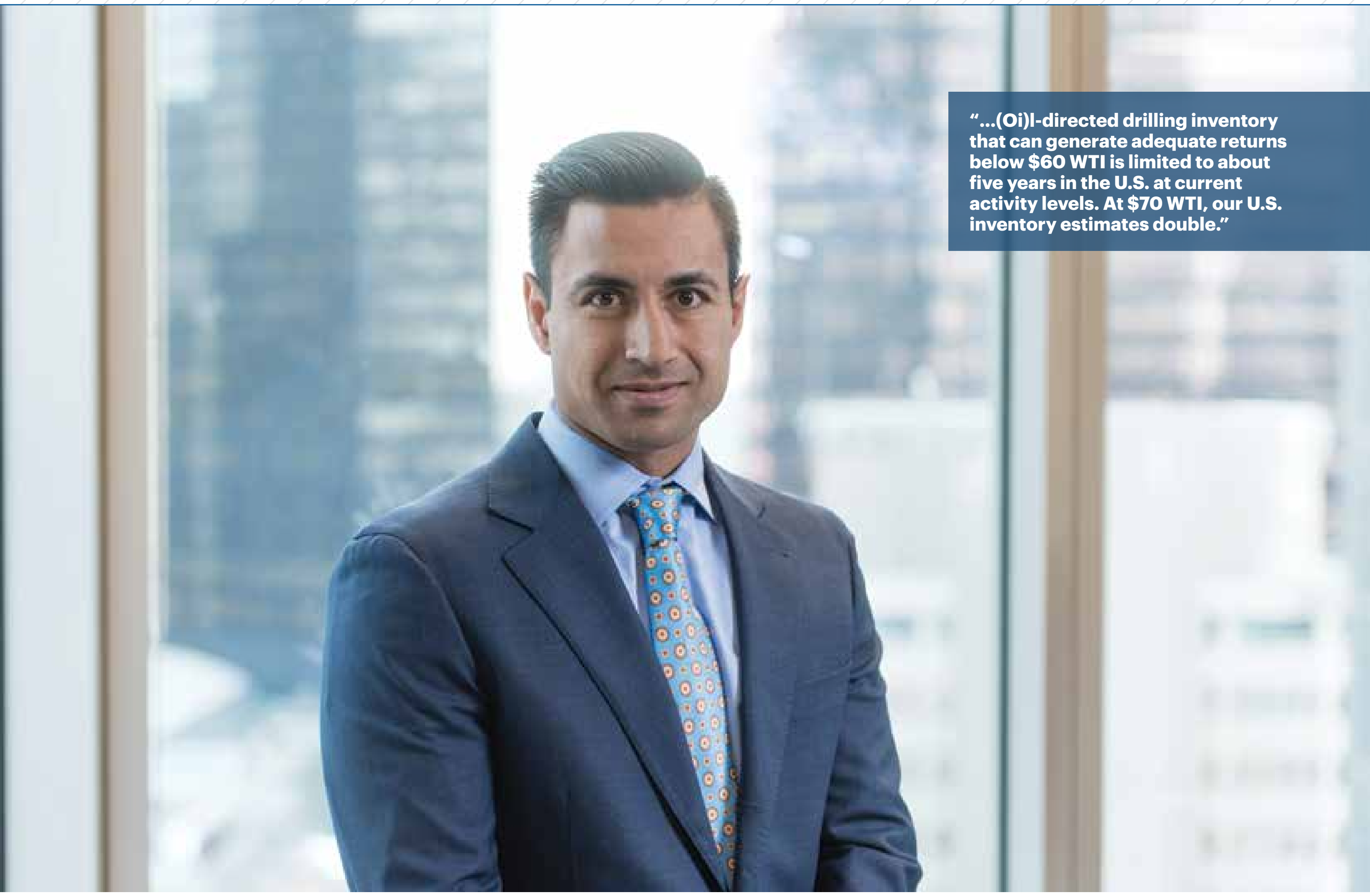
MN: Counting out the most active region operated by the Top 50 operators, the Permian appears by far the most with 20 operators counting this as their most active region—seven of the top 10 list the Permian as their most active region.

Volumewise, the Permian dominates the rankings—81% of oil production and 40% of gas production from the top 50 names come from this one basin. In terms of gas production, this puts it nearly in line with the Eastern U.S. Appalachian names on the list, which in total contribute 44% to the total gas sum.

As we've publicly shared, oil-directed drilling inventory that can generate adequate returns below $60/bbl WTI is limited to about five years in the U.S. at current activity levels. At $70/bbl WTI, our U.S. inventory estimates double.

OGI: Which regions have the most opportunity?

MN: While the market waits for further corporate consolidation, asset deals by public companies are likely to play a more prominent role in upstream M&A. Companies that were buyers are now likely to sell parts of the combined portfolios. APA Corp., which purchased Callon Petroleum in early 2024, has already



"...(Oi)l-directed drilling inventory that can generate adequate returns below $60 WTI is limited to about five years in the U.S. at current activity levels. At $70 WTI, our U.S. inventory estimates double."

ENVERUS

been active on that front, selling a portfolio of Permian conventional assets for $950 million to a private buyer. Occidental also sold off a piece of its Delaware Basin position to Permian Resources for $818 million after closing the CrownRock acquisition. Future non-core sales by public companies could target lower quality or extensional areas of the Permian, the Midcontinent and areas like the Uinta Basin, where Ovintiv has been reported to be shopping its position.

OGI: What about well count?
MN: EQT stands out with the highest natural gas production, at over 5.68 Bcf/d, despite having a relatively lower liquids percentage. Exxon and Chevron have the highest well counts, with over 20,000 wells each.

OGI: What do the current rig counts (in mid-October) indicate about operator sentiment and production trends?
MN: A snapshot of rig counts at the points in time provides some color in operator sentiment. The top 50 names are running a total of 298 at the time of compilation, compared to 322 from the prior year list compiled at a similar seasonal point. Increasing rig efficiencies have led production growth while pulling back rig counts.

Exxon leads in rig activity with 37 rigs, followed by Occidental with 26 rigs. Companies like EQT and Antero Resources have fewer rigs but maintain high production levels, indicating efficient operations.

OGI: Public versus private operators, and the ways they are trending, is a question that comes up a lot. What are you seeing between the two?
MN: With fewer opportunities to get into the main shale plays, private firms are broadening the search to areas without competition for deals from public companies. That is also leading to more private-to-private transactions between groups that have been invested for a lengthy time to ones that have raised fresh capital. The sale of Caerus Oil and Gas, which operates gas assets in Colorado's Piceance Basin and Utah's Uinta Basin, to Quantum Capital Group for $1.8 billion is an example. ■

Editor's Note: All data referenced includes the average daily rate calculated from total gross operated volumes produced over between January and June 2024, and accounts for deals that closed as of Oct 1. 2024

Shale drilling rig and storage tanks in the Permian Basin.

SHUTTERSTOCK

Permian Basin: The Once and Future King Keeps Delivering

The core is in full-scale manufacturing mode, with smaller intrepid operators pushing the basin's boundaries further and deeper.

CHRIS MATHEWS | SENIOR EDITOR, SHALE/A&D

Some counties in the Permian Basin are among the least populated areas in the contiguous U.S., where electricity, water or basic infrastructure are relative luxuries.

But this remote corner of West Texas and southeastern New Mexico plays a key role in U.S. energy security and broader global geopolitics.

The Permian Basin is expected to drive U.S. crude oil production growth for the foreseeable future as other domestic basins wane and decline, industry experts say.

It's a matter-of-fact outlook for the basin today. But not long ago, experts considered the Permian drilled up and exhausted.

The speed in which horizontal drilling ignited the Permian's meteoric rise surprised U.S. rivals, the OPEC+ cartel and even the producers themselves.

"The Permian is a basin unlike any other in the world," said Occidental CEO Vicki Hollub during Hart Energy's Executive Oil Conference in Midland, Texas, in November.

"The Permian is going to be one of the last remaining basins, I believe, to produce oil in the world."

Permian oil production averaged 6.36 MMbbl/d in the third quarter, according to U.S. Energy Information Administration figures. Production is expected to average 6.42 MMbbl/d in the fourth quarter and over 6.5 MMbbl/d in 2025.

E&Ps are willing to pay their weight in gold for a piece of the Permian. Several of the largest shale oil transactions in history were inked there in just the past year.

The Midland Basin attracted the most M&A investment. Exxon Mobil acquired Pioneer Natural Resources for $60 billion, cementing the Midland as a key asset in its global portfolio.

Diamondback Energy acquired private producer Endeavor Energy Resources for $26 billion, while Occidental acquired private E&P CrownRock for $12 billion.

Producers are after the Midland's popular Spraberry and Wolfcamp benches. But they're also increasingly exploring the Dean sands and Barnett Shale zones.

The more western Delaware Basin—where targets are deeper, and the geology is more complex—has attracted a healthy amount of M&A, too.

The Wolfcamp and Bone Spring benches are king in the Delaware. Operators are also landing in the Harkey, Avalon and Woodford zones as they search for new locations.

Even the fringier conventional zones on the shelves of the basin are attracting drilling capital. Operators like Riley Permian and Ring Energy are developing the Permian's Central Basin Platform and Northwest Shelves, targeting the San Andres, Blinebry and Paddock intervals.

Permian producers are also seeing benefits of drilling fewer wells with longer laterals underground, leading to meaningful savings on D&C costs. Exxon Mobil has drilled a handful of 4-mile laterals in the New Mexico Delaware Basin—and the company is now looking to drill more 4-mile wells in the Midland Basin after closing the Pioneer acquisition.

SM Energy, Permian Resources, Franklin Mountain Energy and GBK Corp. are other players drilling 3- to 4-mile laterals in the Permian, according to Enverus data.

Producers will be manufacturing the Permian Basin's stacked pay for decades to come. But the kingly Permian is not without challenges.

The gas-oil ratio (GOR) across the basin is creeping up, spooking some watchful public investors.

Operators should also expect to see higher GORs from certain secondary Permian zones, Hollub said.

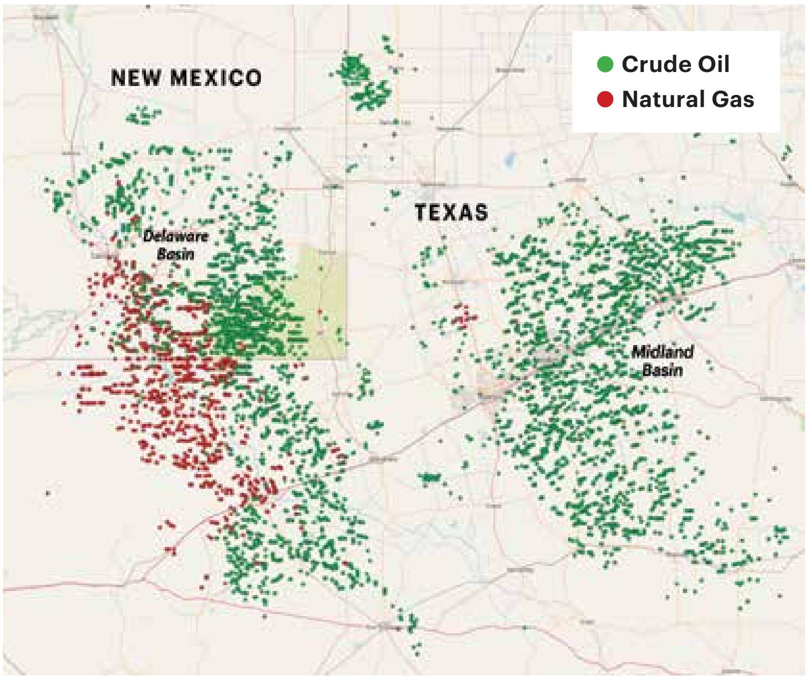
"We have the ability to complete secondary intervals that may be gassier," she said, "but the value from those intervals, because the infrastructure already exists, is tremendous—and in some cases, even better than the primary development."

Gas takeaway capacity from the basin does need to be addressed, Hollub said. But several pipeline projects coming online or in progress are alleviating some of the stress.

The Matterhorn Express Pipeline, a 2.5-Bcf/d project that started operations in the fourth quarter, is filling up faster than any other natural gas pipeline in the basin's history, according to East Daley Analytics. Five weeks after startup, flows had already reached 1.5 Bcf/d.

In 2026, Kinder Morgan's recently announced Gulf Coast Express expansion project will add about 500 MMcf/d of capacity, and the WhiteWater-led Blackcomb Pipeline project is expected to add 2.5 Bcf/d of capacity. ■

Permian Basin Wells



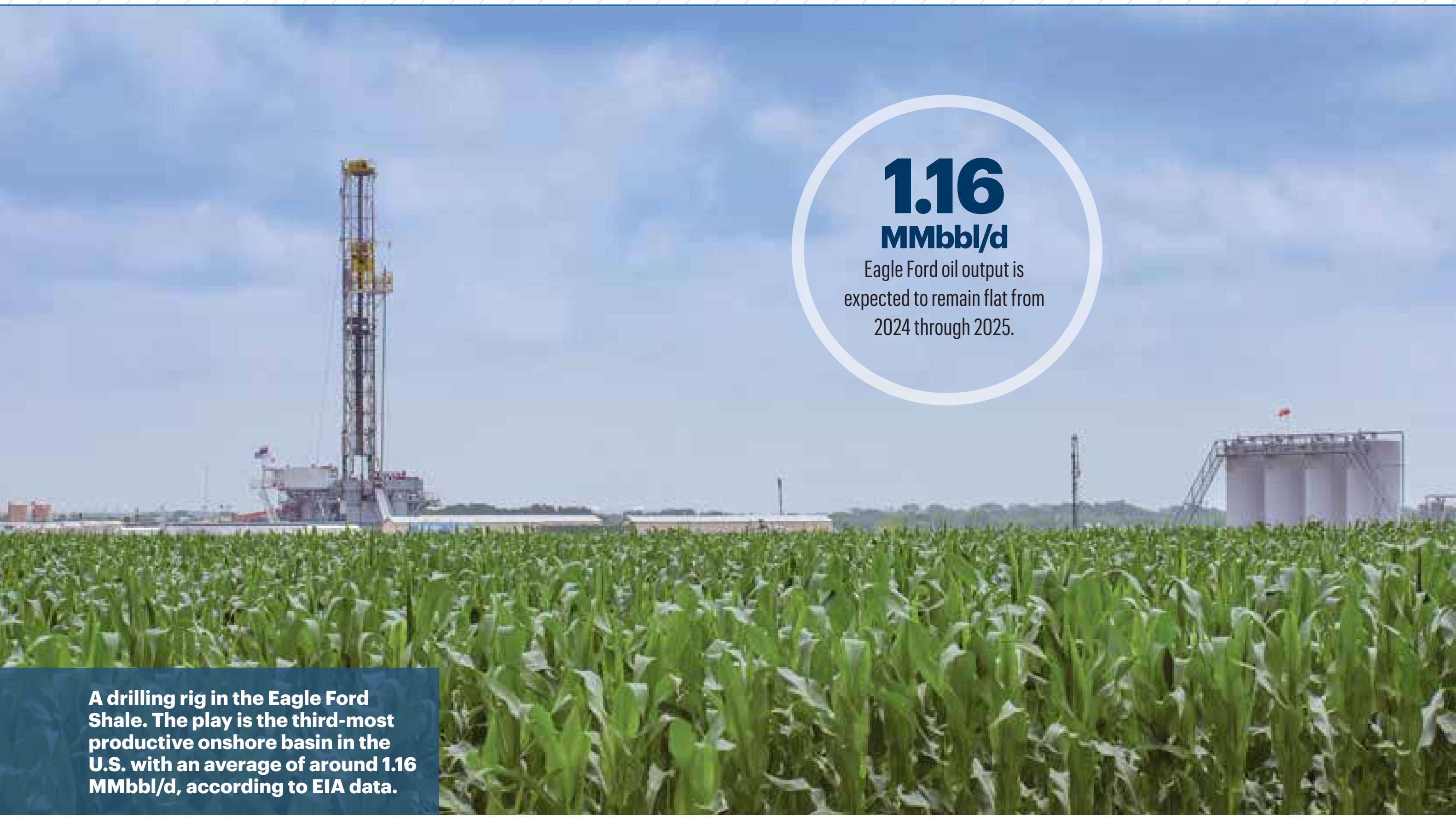
SOURCE: REXTAG

Horizontal wells online in the Permian Basin since Jan. 1, 2020, according to available Rextag data

Top Public Producers [boe/d - Permian]

Operator	boe/d	bbl/d	mcf/d	% Liquids	Well Count
EXXON MOBIL	1,960,962	1,040,221	5,524,288	53%	20,263
OCCIDENTAL	1,223,169	715,061	3,048,547	58%	17,516
EOG	1,185,606	663,393	3,133,180	56%	9,818
DEVON	979,550	554,792	2,548,458	57%	7,444
CONOCOPHILLIPS	965,607	595,690	2,219,436	62%	8,319
CHEVRON	955,191	484,564	2,823,688	51%	20,477
DIAMONDBACK	898,156	583,639	1,887,072	65%	7,948
PERMIAN RESOURCES	439,435	235,442	1,223,930	54%	2,632
CIVITAS RESOURCES	402,719	213,485	1,135,356	53%	3,846
OVINTIV	377,270	211,473	994,747	56%	4,001
APA CORP	343,778	179,997	982,635	52%	7,491
MATADOR RESOURCES	194,224	114,576	477,877	59%	1,044
SM ENERGY	185,983	93,631	554,101	50%	1,412
VITAL ENERGY	179,587	93,847	514,428	52%	2,088
HIGHPEAK ENERGY	66,224	52,563	81,969	79%	469
KINDER MORGAN	62,951	37,628	151,936	60%	1,743
RILEY EXPLORATION PERMIAN	28,275	18,980	55,764	67%	641
RING ENERGY	21,423	15,969	32,722	75%	906
BATTALION OIL	15,881	8,728	42,916	55%	116
EMPIRE PETROLEUM	3,320	2,760	3,359	83%	493

SOURCE: ENVERUS



A drilling rig in the Eagle Ford Shale. The play is the third-most productive onshore basin in the U.S. with an average of around 1.16 MMbbl/d, according to EIA data.

SHUTTERSTOCK

Eagle Ford: Sustaining the Long Plateau in South Texas

The play lacks the growth profile of the Permian Basin, but thoughtful M&A and refrac projects are extending operator inventories.

CHRIS MATHEWS | SENIOR EDITOR, SHALE/A&D

One of the nation's earliest and most mature shale plays, the Eagle Ford's runway is being extended through consolidation and recompletion projects.

The Eagle Ford Shale remains the third-most productive onshore basin in the U.S., behind only the mighty Permian Basin and North Dakota's Bakken Shale, according to U.S. Energy Information Administration (EIA) figures.

But while oil output from the Permian and Bakken grows, production from the Eagle Ford is expected to remain largely flat through 2025—at an average of around 1.16 MMbbl/d, per EIA forecasts.

ConocoPhillips and Crescent Energy have been notable consolidators in the Eagle Ford to extend their inventories in the basin.

The $17.1 billion merger between ConocoPhillips and Marathon Oil, closed in late November, brings together two of the top producers in South Texas.

Of the approximately 2,000 additional drilling locations added through the Marathon transaction, roughly half are in the Eagle Ford.

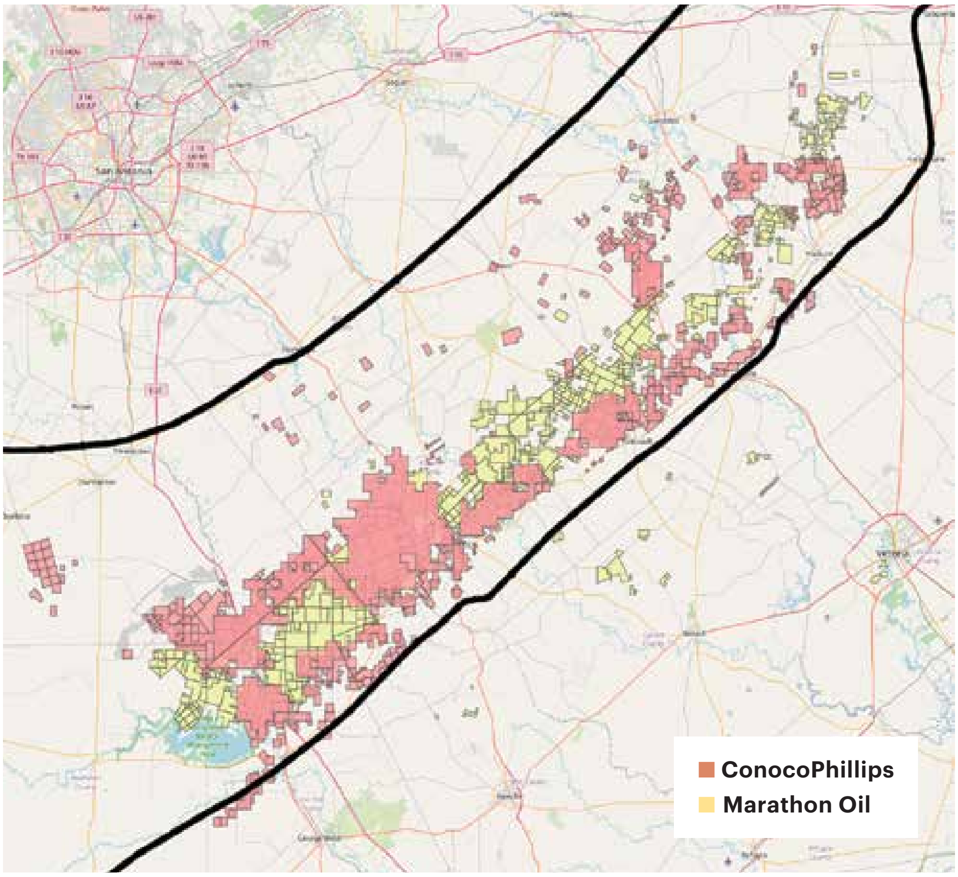
Crescent Energy also continued to roll up acreage across the Eagle Ford in 2024, closing a $2.1 billion acquisition of SilverBow Resources and a $905 million acquisition of Ridgemar Energy.

In the Austin Chalk play, Magnolia Oil & Gas continues to add leasehold to its position in the Giddings Field.

Refrac Attack

As one of the first shale plays to be developed horizontally, the Eagle Ford has relatively little white space left. Most of

Eagle Ford



SOURCE: REXTAG

The combination of ConocoPhillips and Marathon Oil brought together two of the largest Eagle Ford producers.

Top Public Producers [boe/d - Gulf Coast]

Operator	boe/d	bbl/d	mcf/d	% Liquids	Well Count
MARATHON OIL	439,833	259,168	1,083,949	59%	4,559
BP	387,017	75,929	1,866,510	20%	1,706
CRESCENT ENERGY	372,145	133,993	1,428,834	36%	9,391
COMSTOCK	368,808	139	2,211,997	0%	1,528
DIVERSIFIED ENERGY	139,711	5,011	808,111	4%	7,545
MAGNOLIA OIL & GAS	91,509	44,671	281,014	49%	1,606
BAYTEX ENERGY	61,141	43,825	103,887	72%	1,024
MURPHY OIL	31,414	22,884	51,182	73%	945
MITSUI	12,001	-	72,007	0%	21

SOURCE: ENVERUS

the highest quality drilling inventory is already owned in the portfolios of a handful of large producers.

With new drilling locations scarce, operators are increasingly evaluating recompletion projects to breathe new life into older horizontals.

A growing number of Eagle Ford producers are leaning into refracs, re-entries, recompletions and other redo jobs—using modern drilling techniques to extend production from declining wells.

Eagle Ford operators touting refrac projects include ConocoPhillips, Devon Energy, BPX, Crescent Energy, Baytex Energy and Verdun Oil.

Refracs are a hot topic today, but they're old news for Verdun, a private E&P backed by EnCap Investments. The company started developing a refrac strategy around 2018, when Verdun completed what it says was the first full linear isolation refrac performed in the Eagle Ford trend.

The wells Verdun identifies for refracs generally have average lateral lengths of around 6,000 ft and were completed before 2016.

LNG Future

Certain operators see future opportunity stemming from the natural gas windows in the far western Eagle Ford.

EOG Resources is developing the Dorado gas play in the southwestern area of the play near the Texas-Mexico border.

Last year, EOG brought online the 100-mile Verde Pipeline, a 1 Bcf/d project transporting Dorado gas to the Agua Dulce sales Hub near Corpus Christi, Texas.

EOG is running a single rig on its Dorado gas play, but the company anticipates growing activity in South Texas as demand for LNG, and gas prices, increase in the future.

"As the market starts to open up for us, we'd like to increase that," EOG CEO Ezra Yacob said during the company's third-quarter earnings call.

A handful of large-scale LNG export facilities are under construction near the Agua Dulce Hub, including Rio Grande LNG and Corpus Christi LNG State III. Several more are under construction along the U.S. Gulf Coast, including Golden Pass LNG and Port Arthur LNG.

LNG export capacity from the U.S. is expected to grow by nearly 10 Bcf/d through 2027, according to EIA data, as new liquefaction projects tick online, including Plaquemines LNG, which started production in December.

Gas production from the Eagle Ford will grow from 6.7 Bcf/d to 7 Bcf/d this year, the EIA forecasts. ■

Range Resources operations in the Marcellus Shale.

ANTHONY MUSMANNO

Appalachia: Natural Gas is Poised to Pay

Increasing demand for gas is expected to rally prices and boost midstream planning as the new administration pledges to loosen permitting and set the stage for M&A in the region.

SANDY SEGRIST | SENIOR EDITOR, GAS AND MIDSTREAM • **DEON DAUGHERTY** | EDITOR-IN-CHIEF

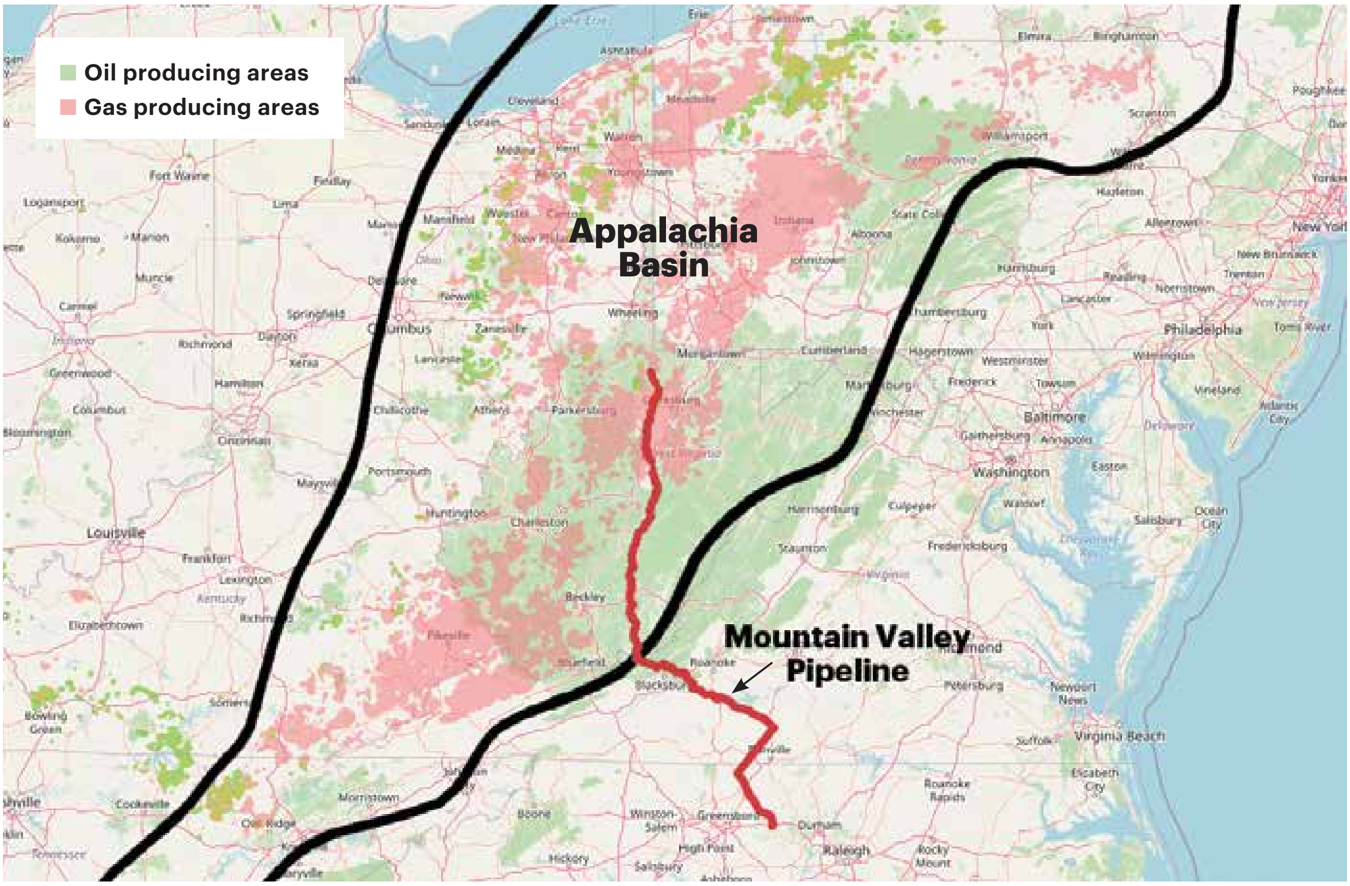
Producers in Appalachia may see their loyalty to the northeastern part of the country rewarded in 2025. They just need the promises of 2024 to come through and coalesce into a natural gas price rally and regulatory certainty.

Ongoing protests have stymied or slowed pipeline construction projects in the prolific natural gas-producing region. The June 2024 start of service on the Mountain Valley Pipeline (MVP) was not a moment too soon in Appalachia.

But MVP came online only after a torturous, decade-long process blocked several times by lawsuits filed by environmentalists and residents along the pathway. The stalled pipeline was only completed after U.S. Sen. Joe Manchin (I-W.Va.) insisted a finished project was a condition of his vote for the congressional debt ceiling agreement in 2023.

An unpredictable regulatory environment is a key problem for the industry, said Tom Sharp, director of permitting intelligence at Arbo.

Appalachia Region Oil and Gas Production



SOURCE: REXTAG

Top Public Producers [boe/d - Eastern US]

Operator	boe/d	bbl/d	mcf/d	% Liquids	Well Count
EXPAND ENERGY	1,693,491	20,472	10,038,049	1%	4,972
EQT	952,178	5,396	5,680,642	1%	3,147
COTERRA ENERGY	803,274	158,504	3,868,576	20%	2,961
ANTERO RESOURCES	554,109	15,158	3,233,684	3%	1,374
RANGE RESOURCES	364,147	8,322	2,134,927	2%	1,556
CNX	263,687	261	1,580,495	0%	4,305
GULFPORT	219,607	3,733	1,295,232	2%	628
NATIONAL FUEL GAS	207,131	6	1,242,733	0%	1,006
REPSOL	189,588	11,731	1,067,127	6%	1,275

SOURCE: ENVERUS

"When you have an environment where you have a lot of uncertainty with respect to what's going to happen to any project—not just a midstream pipeline project, it's infrastructure at large—then what you had resulted in chilling investment or caused fear of investment in large projects," Sharp said.

Incoming President Donald Trump could ease this problem in the coming years. He campaigned in this part of the country largely on his pro-oil and gas stances, particularly in terms of loosening regulations and permitting.

Still, the primary mover for a new infrastructure project will be the market for the product it carries, said Amber McCullagh, Rystad's senior vice president for onshore North America.

The driving force to build the next pipeline will be the same force behind the fight to build the MVP—commercial viability.

"It starts with demand, and the industry is pretty resilient," said Greg Floerke, executive vice president and COO of MPLX, during Hart Energy's DUG Appalachia

Range Resources operations in the Marcellus.

ANTHONY MUSMANNO

Conference in November.

"I actually think the bigger challenge to Appalachian pipeline development is commercial," McCullagh said.

The supply of natural gas in the U.S. was historically high for most of 2024, and Henry Hub prices remained well below $3/MMBtu for most of the year. Depressed prices mean potential builders tend to hold onto their money and wait for a better forecast.

"When you're not confident that the commodity will be more than $3, even if your wealth at breakevens is sub-$2, it's very hard to make that worth a 15-year commitment," McCullagh said.

Analysts forecast that natural gas prices will increase—perhaps as oil prices struggle with oversupply—from growing demand from LNG exports and power generation for artificial intelligence data centers.

M&A in Appalachia

Gas-price instability caused a disconnect between what buyers were willing to pay for gassy assets and terms sellers were willing to accept. But with greater clarity on future gas demand, LNG export growth and increasing prices, gas deals have started to cross the finish line.

Appalachia, with its low-cost and bountiful gas supplies and unique infrastructure challenges, could also be a hotspot for gas-weighted M&A in the next two years, Dan Crowley, a managing director in Houlihan Lokey's oil and gas group, told *Oil and Gas Investor*.

"In the conversations I have with some producers in Appalachia, people are very carefully watching that contango and sort of queueing up to come to the market at the right time," Crowley said.

Since the advent of horizontal drilling and fracking techniques, Appalachia operators have largely targeted the gassy Marcellus Shale play. But the area has long been known for crude oil potential: The Drake Well, drilled by Edwin Drake near Titusville, Pa., in August 1859, kicked off a bonanza that effectively birthed the U.S. oil industry.

But gas is still king in Appalachia, and the basin is home to some of the nation's largest natural gas producers. EQT Corp., second only to Expand Energy on a gas production basis, owns leasehold spread across Pennsylvania, West Virginia and Ohio.

Across the entire Appalachian Basin, Crowley has identified roughly two dozen companies that could be logical sellers or could potentially sell off non-core Appalachia asset packages over the next two years or so. Private equity-backed E&Ps probably make up about half of that list, he said.

By private equity standards, several of the investments in E&Ps operating in the region are relatively mature—some sponsors have held onto their Appalachia investments for 10 years to 12 years at this point, Crowley said. PE firms may look to monetize their investments.

The third category of potential Appalachia dealmaking could focus on the small- to mid-cap publics generating a healthy amount of investor buzz.

"Some of the smaller public operators in Appalachia are logical candidates to be taken out or merged into somebody else," Crowley said.

Most of the biggest M&A deals inked across Appalachia in recent years included some component of midstream capacity, Crowley said.

EQT is paying $5.5 billion in stock to acquire Equitrans Midstream, the developer behind MVP.

Integrating midstream into M&A transactions in Appalachia isn't as big of a hang-up as it can be in other basins. Some operators, such as Occidental Petroleum, are looking to divest midstream interests to pay down other debts.

But midstream access is a key consideration in Appalachian dealmaking.

"Appalachia is basically producing right on the brink of its takeaway capacity, so everybody's competing for offtake," Crowley said. "Having control of your midstream is important to protect yourself in that regard." ■


Wright & Company, Inc.
Petroleum Consultants
Reserves Reports
Acquisition & Divestiture
Expert Testimony
Gas Storage
Production Engineering
Reservoir Engineering
Sustainability Reporting
Integrating Experience & Technology
Divisions of Wright
Wright Energy Advisors
Wright Analytics Group
Serving the petroleum industry for more than
36 YEARS
Founded by D. Randall Wright, President - 1988
wrightandcompany.com

A multi-frac job being completed for Berry Corp. in Duchesne County, Utah.

BERRY CORP.

Uinta Basin: Horizontal Boom to Continue in 2025

After two large-scale transactions by SM Energy and Ovintiv, the Uinta Basin is ready for development—and stacked pay exploration.

CHRIS MATHEWS | SENIOR EDITOR, SHALE/A&D

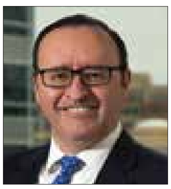
Step aside, Permian Basin. Utah oil country is stealing headlines as operators search for new drilling runway.

With asking prices sky-high for Permian inventory and the best acreage locked up, E&Ps are digging deeper into the Uinta Basin's stacked pay potential.

The Uinta Basin saw several large-scale transactions in 2024, and experts anticipate horizontal development of the basin will continue growing this year.

Operators including SM Energy and privately held FourPoint Resources entered Utah through large-scale M&A in 2024, picking up some of the Uinta's highest quality inventory.

The most coveted Uinta rock is now in SM's portfolio.



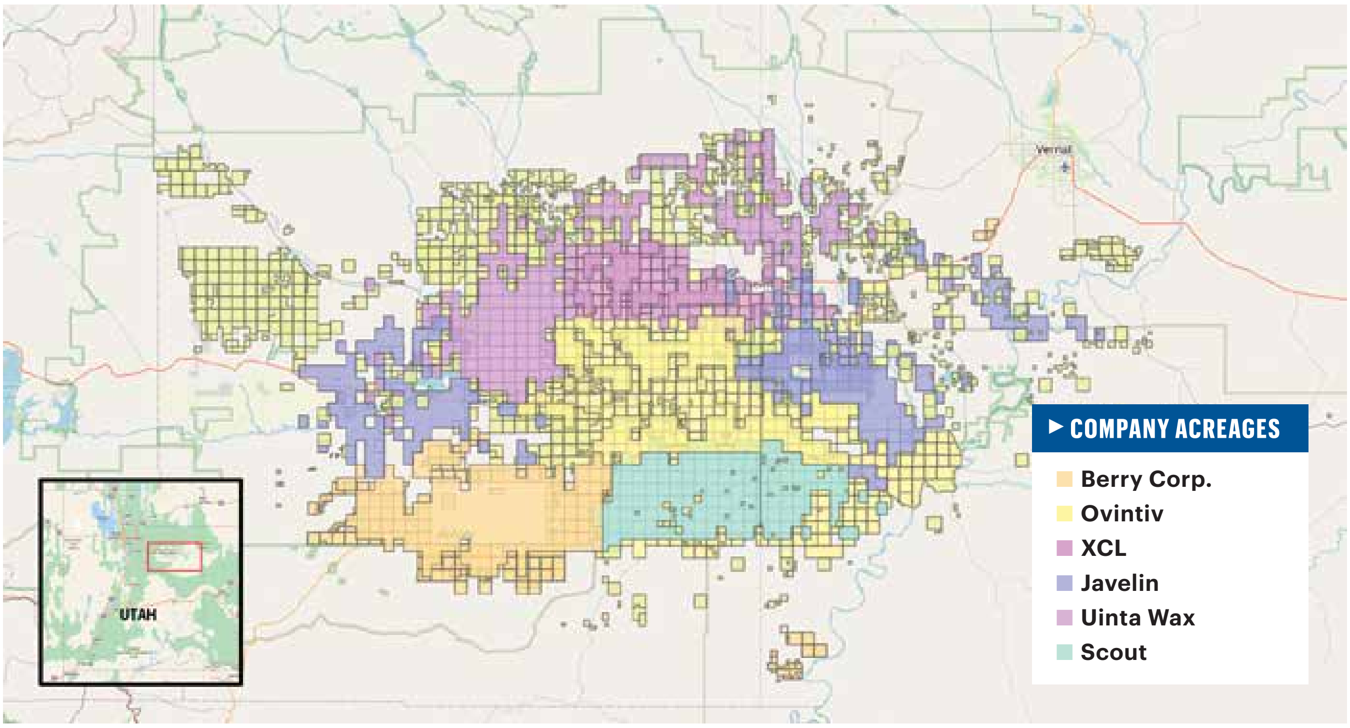
"[The Uinta Basin] could be transformational for Berry."

FERNANDO ARAUJO, CEO, Berry Corp.

SM teamed up with non-operating partner Northern Oil & Gas (NOG) to acquire leading Uinta E&P XCL Resources for $2.6 billion.

SM acquired an 80% undivided interest in XCL's assets for $2.1 billion, while NOG picked up the remaining 20% non-op stake.

Uinta Acreage Positions



SOURCE: REXTAG

Analytics firm Novi Labs views SM's Utah asset as the highest productivity rock in the Uinta Basin, with higher average reservoir pressure than most of its nearby producers. The Uteland Butte, the primary horizontal target in the basin, is fairly homogenous across the SM asset.

Building on the M&A momentum, Ovintiv agreed to sell its Uinta Basin position to private equity-backed producer FourPoint Resources for $2 billion in November. Using the money from the Uinta sale, Ovintiv deepened its legacy roots in Canada's Montney Shale and the Canadian oil sands.

$2.6B
Sale of XCL Resources to SM Energy, Northern Oil and Gas

Ovintiv's Uinta asset includes 126,000 net acres and production of around 29,000 bbl/d, primarily in Duchesne and Uintah counties, Utah.

The Ovintiv asset screens as the second-highest quality rock in the basin, by Novi Labs' analysis. Although it has lower reservoir pressure than SM's asset to the north, FourPoint's assets include significant upside in the secondary Castle Peak and Douglas Creek benches.

$2B
Sale of Ovintiv's Uinta position to FourPoint Resources

Other publics are active in the Uinta Basin. Crescent Energy operates as Javelin Energy Partners and ranks as one of Utah's top oil producers.

Publicly traded Berry Corp. has a long history of vertical conventional development in California, but the company aims to build momentum on its Utah asset, Berry CEO Fernando Araujo told *Oil & Gas Investor*.

Berry has been in the Uinta Basin since 2003, managing production from roughly 1,200 vertical wells targeting five different benches. But the company farmed into four horizontal wells adjacent to its acreage earlier this year.

The Uinta horizontal wells Berry farmed into outperformed expectations, with average gross peak production of around 1,100 boe/d, per well.

Berry later signed an expanded farm-in agreement to drill up to 12 Uinta horizontals, a few of which will target the deeper Wasatch bench, Araujo said.

"This could be transformational for Berry," he said.

Private E&Ps in the Uinta include Scout Energy Partners, Wasatch Energy Management and Uinta Wax Operating.

With most of the best Uinta rock owned by SM and Ovintiv, producers are searching for upside in secondary benches. SM has identified 17 layers of stacked pay on the Uinta asset it acquired from XCL Resources.

Utah state records show that Anschutz Exploration drilled horizontal wells in Uintah County targeting the deeper Mancos Shale formation. ■

The AI-Energy Synergy

An abundance of data enables automation that saves time, cuts waste, speeds decision-making and sweetens the bottom line. Of course, there are challenges.

RICHARD STUBBE | SENIOR EDITOR, TECHNOLOGY

What's next in shale technology is just what you might expect: data, data and more data, and a powerful shot of artificial intelligence (AI).

"There's a huge buzz about AI as we all know, it's seen as a trillion-dollar industry," said Sushma Bhan, non-executive director at Ikon Science, and technical director for data science and engineering analytics at SPE, at Hart Energy's DUG Executive Oil Conference in November. "There's a lot of anticipation about the results."

It's not just a matter of turning everything over to the machines, Bhan said. It's about people and machines working together.

"It's all about automation," she said. "How we can automate and augment human results, the skills SMEs bring, bringing that together with the automation, so things or actions that can be done in hours or days can be done in minutes."

Ikon specializes in subsurface applications, rock physics and reservoir characterization.

"If you look at how we take subsurface data and use it in our end-to-end exploration to production, we're talking about thousands of subsurface data types," she said. "And the ability to access that data with automation is talking about tremendous saving of time and effort."

A quick example:

"Let's say we're looking at the equipment used previously in a certain area," she said. "You can quickly access that information and deploy solutions rather than reinventing and searching and spending time. Your time savings can be almost 10x if you're doing that kind of process."

AI also offers the power of visualization, Bhan said.

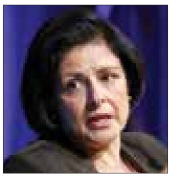
"We have tools where you can quickly bring your predrill data, your pressure data, and integrate it with the real-time in-stream data. We used to create PowerPoints and bring information, and it would take weeks and months. With AI, the efforts have just expedited.

"It's about saving time, eliminating waste, expediting your decision-making, and the bottom-line impact."

Push Button Frac

Halliburton is seeing quick adoption of AI both internally and externally, said Steven Jolley, the Permian Basin technology manager.

"Most of the ones that we run with today are utilizing AI in some form or fashion," he said. "They're looking at reservoir drilling and completion variables to see which type of variables really drive uptake in production."



"It's all about automation. How we can automate and augment human results, the skills SMEs bring, bringing that together with the automation, so things or actions that can be done in hours or days can be done in minutes."

SUSHMA BHAN, non-executive director, Ikon Science; technical director for data science and engineering analytics, SPE

The company is also using it regularly.

"In the past six months is where we really started to drive the AI piece for our business," he said. "We rolled out Auto Frac and Sensori within our business here in the Permian Basin about six months ago."

The company says Auto Frac is the first automation service that enables customers to execute their fracture design without human intervention.

"Auto Frac is, in simple terms, push button frac," Jolley said. "You can come in, push a button and let it pump the design as intended without any human intervention. Customers are able to access that from an app-based platform and make changes based on what they see, as well. That's been huge."

Sensori is a fracture monitoring service that lets operators evaluate well performance. It's also app-based.

Data from Sensori and elsewhere have led to changes in the field. Operators have been upsizing their spacing to take advantage of their fracture complexity, Jolley said.

In December, SLB introduced an autonomous drilling system called Neuro, sort of a Waymo for drillers. The company deployed Neuro to drill a lateral in Ecuador.

"The system automatically selects the best route for drilling the well based on high-fidelity downhole measurements, bringing the well trajectory in line with the real-world conditions of the reservoir," said Jesus Lamas, SLB president of well construction.

Jeff Beach, vice president of reservoir performance at NexTier, said at the conference that his company is using

The Sensori fracture monitoring service provides true, real-time data acquisition and processing of near-well and far-field subsurface measurements. Data from Sensori and elsewhere have led to changes in the field.

HALLIBURTON

> “We’re running all of our analytical data that we’re capturing after completion or after a drilling event or just during production in general, feeding that back through the machine learning models.”

RICKY KOSTNER, Permian Basin regional manager, ChampionX

fiber-optic technology with a customer “to find that balance of how much sand we’re going to put in place versus that spacing, so you can have a wider spacing and put more sand per stage, or closer spacing and reduce that amount of sand.”

“There’s a balance point for each particular operator in that respective basin,” he said. “Leveraging the fiber-optic technology and then the offset well monitoring is certainly a way to maximize that.”

Other companies are finding value in data as well. Ricky Kostner, Permian Basin regional manager for ChampionX, said it’s making the team smarter.

“We’re running all of our analytical data that we’re capturing after completion or after a drilling event or just during production in general, feeding that back through the machine learning models,” Kostner said. “It’s expediting decision-making, it’s allowing our customers to expedite decision-making. It’s a huge competitive advantage that we’re seeing.”

Kostner also noted the changes in well spacing.

“With increased density and smaller spacing, we definitely see increased activity of frac hit,” he said, when fracking in a new well affects an existing well. That “affects us chemically, it affects the whole operation all the way to the pipeline and the produced fluids that are coming back up.

“We’ve got frac protect programs that we put in place with our customers to help offset the impact of these events,” he said. “We see larger spacing largely being a benefit to try to find that optimal place where you’re not going to get the frac hit events and the communication between wells.”

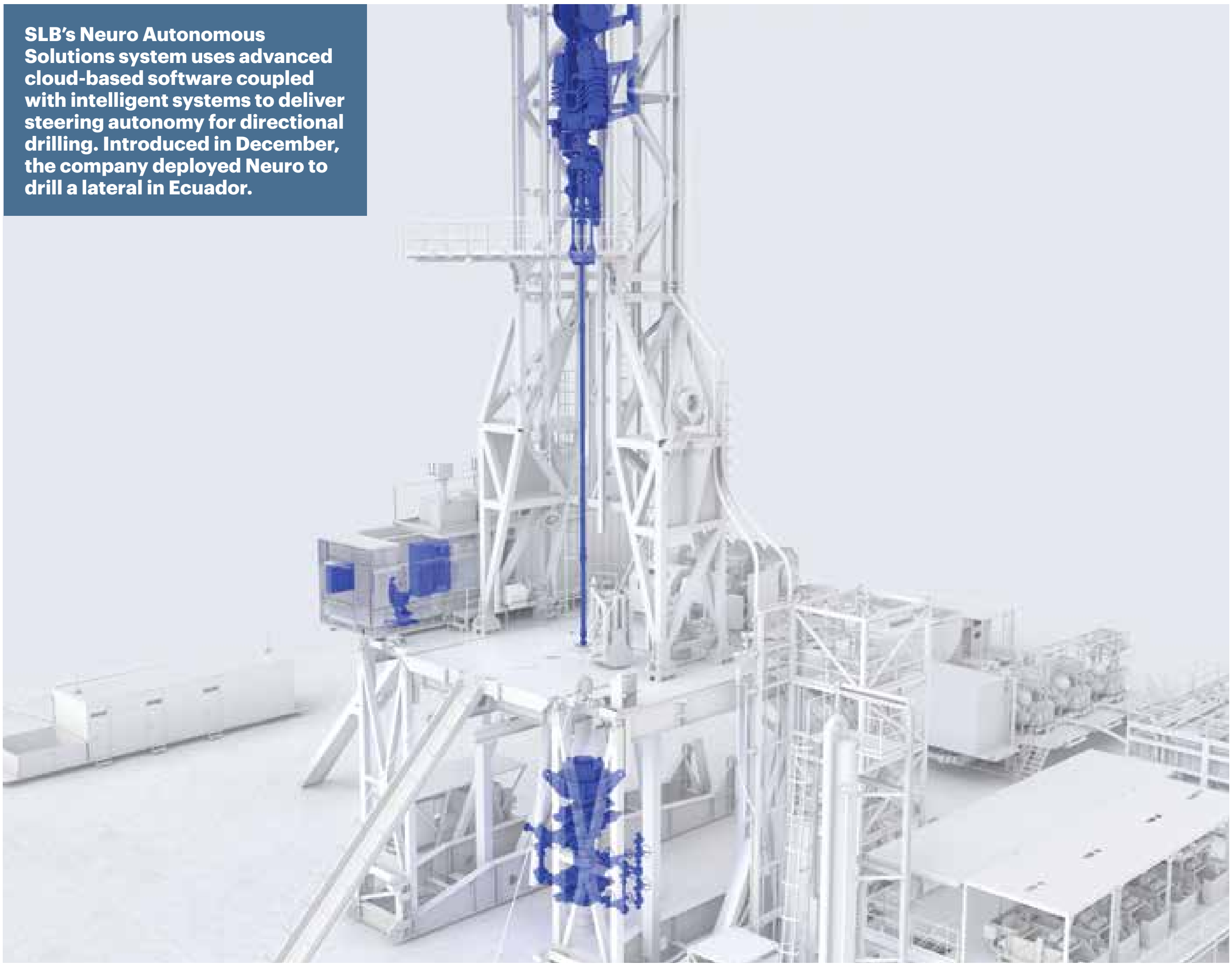
M&A’s Impact

The wave of consolidation in the Permian is also increasing efficiencies as operators create larger continuous lease holds.

“The continuous acreage makes things much more efficient,” Jolley said. “You see more of a manufacturing environment there. Anywhere where you have a lot of activity in one place and you can be a part of that development, you’re going to learn a lot more about the reservoir, the completion design, all of those things.”

The advantages of scale are far-reaching, Beach said.

“It enables you to bring in techniques, simul-frac or trimal-frac or what we may refer to as remote simul-frac, where you can have the horsepower on one location and



SLB's Neuro Autonomous Solutions system uses advanced cloud-based software coupled with intelligent systems to deliver steering autonomy for directional drilling. Introduced in December, the company deployed Neuro to drill a lateral in Ecuador.

SLB

through pipeline completing wells on an adjacent pack."

Under the surface, lateral length may be nearing a peak at about 4 miles, at least until innovation allows further extension.

"Four miles, that's a long way," Jolley said. "We continue to push the limits, innovate with technology. Going beyond 4 miles, you're taking on quite a bit of risk. You've got to push the drill pipe that far, the casing connections have got to last through the torque and force to get to that length as well. So, there's definitely some complexities to get around."

ChampionX's Kostner said the longer laterals bring in more variables.

"I think about the change in pressures and temperatures and some of the molecular things that are going to happen with that fluid on the way up," he said. "Knowing that in the design package before we go take on the capital and get the equipment going is going to be essential."

"We see operators that deal with some of the mistakes that were made early on," he said. "I just think extending the lateral length is going to exacerbate those issues whether it's from a lift perspective or a chemical perspective."

One more item on the shale development list is water management, a part of the industry that has evolved from tanker trucks operated by mom-and-pop businesses to dedicated pipeline infrastructure built by companies like Aris Water Solutions and Deep Blue.

"This basin is producing just a tremendous amount of water and it's got to go somewhere," Aris CEO Amanda Brock said at the conference. "If you don't have a place for the water to go, it impacts production."

As the cost of disposing produced water increases, the demand for more innovations increases as well. Concerns that injection wells are causing more seismic activity are adding to the scope of the problem.

Some of the answers are recycling, beneficial reuse and extraction of useful minerals like lithium—not one solution but many.

"Everybody in our space is trying to figure it out," said Robert Norton, chief commercial officer for the water management company Deep Blue. ■

New pipeline construction project announcements could indicate that an oversupplied U.S. gas market could finally see the light at the end of a very low-priced tunnel.

SHUTTERSTOCK

Gas-Powered Expansion

Rising electrical demand may finally push natural gas demand to catch up with production.

SANDY SEGRIST | SENIOR EDITOR, GAS AND MIDSTREAM

Energy Transfer's new pipeline project is an encouraging sign for people keeping an eye on the gas market.

In early December, when the company announced the $2.7 billion Hugh Brinson Pipeline (formerly Warrior) had reached FID, ET signaled a potential market transformation.

The pipeline is being built in a Permian Basin, however, which had "solved" its egress problems after a couple of other pipeline projects were announced before Hugh Brinson, analysts said.

Building a pipeline where egress is not needed indicates that demand at the end of the line is driving production, which means that an oversupplied U.S. gas market could finally see the light at the end of a very low-priced tunnel.

The Permian

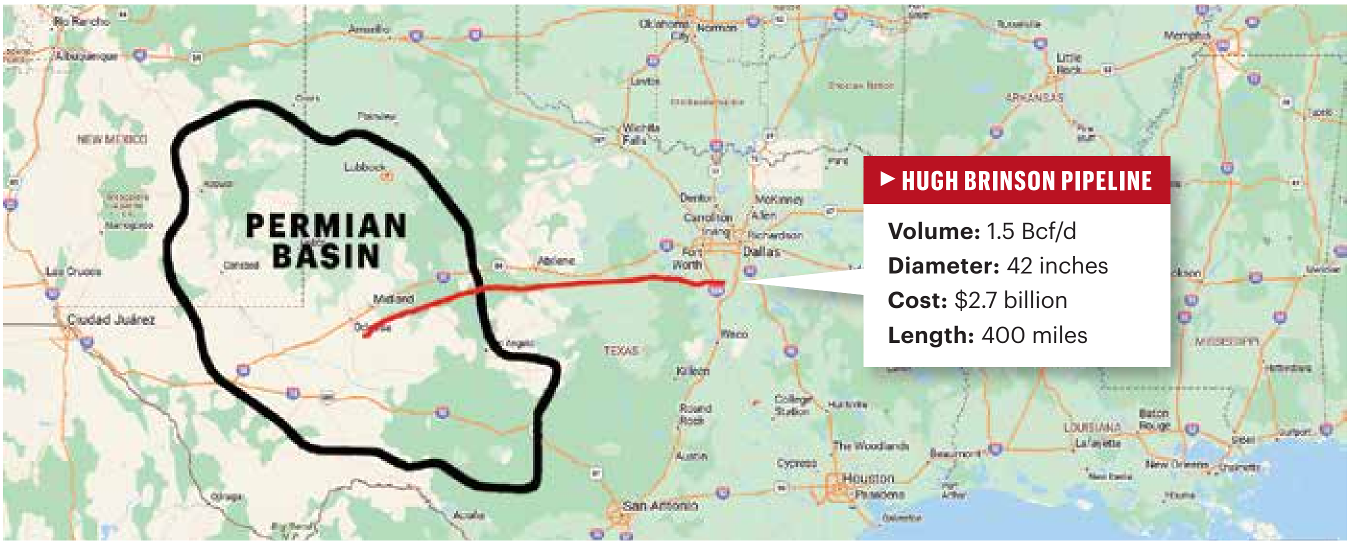
In 2023 and most of 2024, the primary problem in the Permian Basin and for producers nationwide has been too much natural gas in the system and not enough pipeline capacity to take it away.

Natural gas prices at the Waha Hub near Pecos, Texas, spent much of 2024 in negative territory. Associated gas-to-crude ratios continued to climb, and some E&Ps cut crude production as the only other option was paying the price for flaring.

The situation changed with the opening of the 2.5 Bcf/d Matterhorn Express Pipeline, which started operations at the beginning of October and delivers natural gas to the Katy, Texas, area near Houston. East Daley Analytics reported the new line ramped toward capacity faster than any other pipeline the firm had monitored before.

Before the Matterhorn had started flowing, the next natural gas pipeline slated for the Permian, the 2.5 Bcf/d Blackcomb, was announced by a JV led by WhiteWater

Hugh Brinson Pipeline



SOURCE: REXTAG

Energy Transfer's Hugh Brinson Pipeline will distribute natural gas to areas looking to grow power generation.

Midstream. WhiteWater expects the line to be operational by the second half of 2026. Blackcomb will deliver to the Agua Dulce Hub near Corpus Christi in South Texas.

A few weeks later, Kinder Morgan announced that it was moving forward on a 570 MMcf/d expansion of the Gulf Coast Express, a pipeline that also ships to South Texas ports.

Several analysts reported that the natural gas egress capacity problems for the Permian were solved, and that another pipeline would therefore not be needed for operators to ship all of the associated gas they produce.

Which was why Energy Transfer's announcement that the company would build the Hugh Brinson pointed to growing demand for natural gas—a situation for which the U.S. gas market has been waiting, analysts said.

Unlike other recent pipeline projects, both built and planned, ET's line does not head directly to the LNG and processing centers on the Gulf Coast. Instead, the line heads directly east from the Permian to North Texas.

"There is only one reason [Hugh Brinson] would still get built: demand pull from the DFW [Dallas/Fort Worth] area from data centers and electric utilities," said Ajay Bakshani, director of analytics for East Daley Analytics.

Midstream companies and gas producers spent much of 2024 discussing the upcoming increase in demand to keep up with a rapidly growing need for electricity in the U.S. market.

"In my decades of experience in the mid-term arena, I've never seen a macro environment so rich with opportunities for incremental build-out of natural gas infrastructure," Rich Kinder, executive chairman at Kinder Morgan, said during his company's third-quarter conference call.

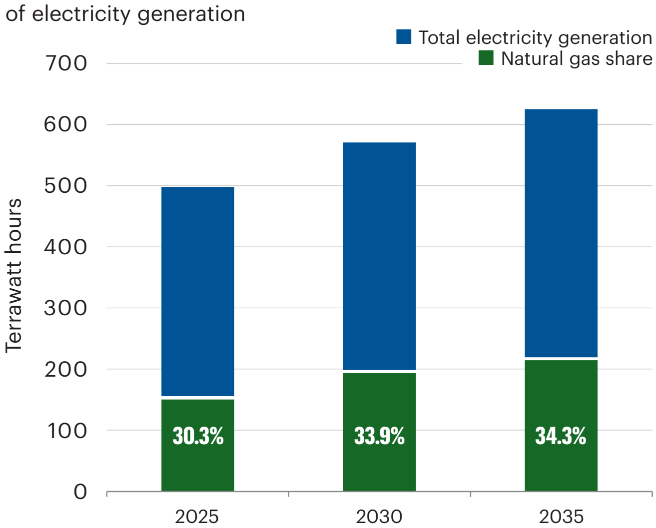
Multiple executives at other midstream and gas production companies have said similar things, but the

"In my decades of experience in the mid-term arena, I've never seen a macro environment so rich with opportunities for incremental build-out of natural gas infrastructure."

RICH KINDER, executive chairman, Kinder Morgan

Texas: Forecast for Natural Gas Share of Electricity

Electric Reliability Council of Texas's forecast natural gas share of electricity generation



SOURCE: ELECTRIC RELIABILITY COUNCIL OF TEXAS, S&P GLOBAL MARKET INTELLIGENCE POWER FORECAST AS OF JUNE 30, 2024

▸ CLOSER LOOK: A MATTER OF MEETING DEMAND

"There is only one reason [Hugh Brinson] would still get built: demand pull from the DFW [Dallas/Fort Worth] area from data centers and electric utilities."

AJAY BAKSHANI, director of analytics, East Daley Analytics

"In general, natural gas pipelines only FID when they get customer commitments to build the pipeline. So, the takeaway from the [Hugh Brinson] FID is that producers are willing to commit to takeaway capacity because it is needed to avoid bottlenecks on the horizon."

HINDS HOWARD, portfolio manager, CBRE Investment Management

details of upcoming moves were not available.

The Hugh Brinson announcement provides a fairly good tell that electrical and data center demand is solidifying.

Dallas/Fort Worth has the second-highest concentration of data centers outside of Northern Virginia and ET's management also hinted that growing demand drove the pipeline decision, saying the Hugh Brinson's contracting is "weighted a little bit heavier towards market pull than it is on producer push" during its third-quarter earnings call.

"Unlike producers, demand-pull customers like electric utilities do not care about overbuilding the basin as much as securing supply," Bakshani said. In two years, the natural gas egress out of the Permian could potentially be overbuilt.

However, at least one analyst said the usual production scenario could still be in play in the Permian, with Energy Transfer's decision coming about because producers still want more natural gas egress.

"In general, natural gas pipelines only FID when they get customer commitments to build the pipeline," said Hinds Howard of CBRE Investment Management.

"So, the takeaway from the [Hugh Brinson] FID is that producers are willing to commit to takeaway capacity because it is needed to avoid bottlenecks on the horizon."

Howard said ET did call out that project's advantageous position with power plants and data centers, but believes the bulk of the commitment for the pipeline came from producers pushing for more egress instead of the pull from downstream customers.

Analysts easily come to different conclusions about Texas production.

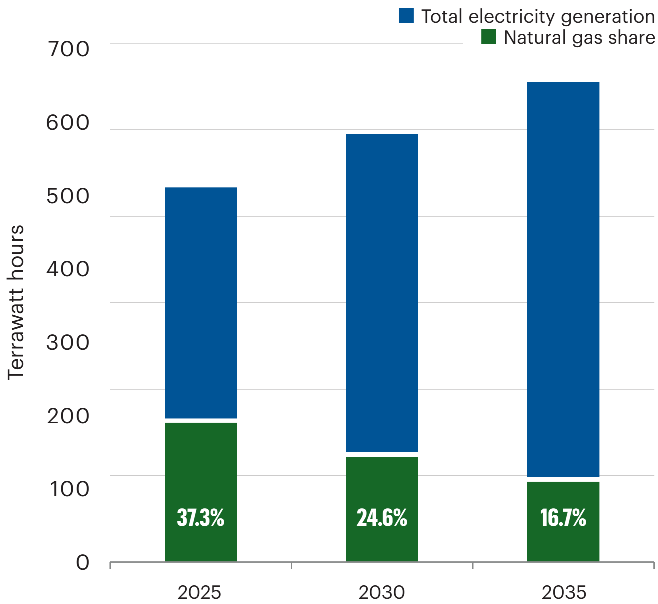
Gauging the activity levels of the Permian always takes some guesswork. Basin production numbers are a black box, thanks to the Permian being in the same state where most of its crude and natural gas are shipped for refining and processing. Pipelines do not have to register the amount of product they ship unless they cross state lines or international borders. Therefore, analysts for the Permian have to rely on secondary indicators to determine production numbers.

Appalachia

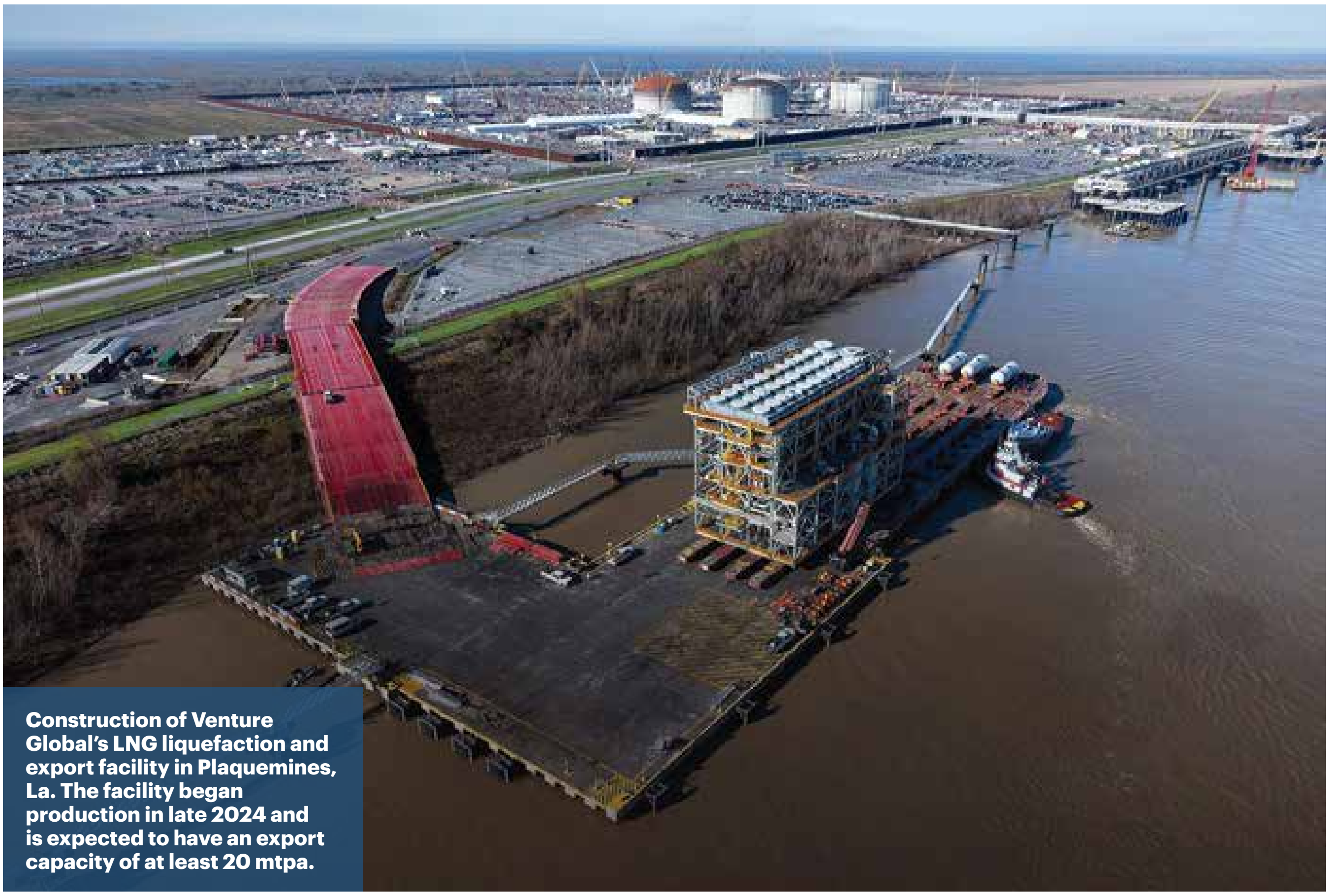
In the mid-Atlantic and Southeast, midstream power players have been building up their infrastructure to supply gas-

Appalachia: Forecast for Natural Gas Share of Electricity

PJM Interconnection forecast natural gas contribution to electricity generation



SOURCE: PJM INTERCONNECTION, S&P GLOBAL MARKET INTELLIGENCE POWER FORECAST AS OF JUNE 30, 2024



Construction of Venture Global's LNG liquefaction and export facility in Plaquemines, La. The facility began production in late 2024 and is expected to have an export capacity of at least 20 mtpa.

VENTURE GLOBAL

fired power systems. This year could find producers able to unlock a supply that's been backed up thanks to anti-development sentiment that has held sway in the region.

"A tremendous amount of demand has been building up," said Williams Cos. CEO Alan Armstrong during a broadcast interview on CNBC in November.

Large utilities are contracting with Williams now for future capacity, while new data centers developers are seeking on-site power generation. Before the end of 2024, the company signed a precedent agreement for expansion of the existing Dalton lateral line that serves northern Georgia. This expansion will support load growth from increased electric power generation driven by industrial reshoring and data center growth.

"We're seeing people contacting us directly, wanting to get natural gas off of our big systems to fuel new power generation in what they call behind the meter," Armstrong said. "So, rather than going through the utilities, they're actually wanting to install their own power generation and not have to deal with the long queues that exist in a lot of places right now to get connected to the grid."

EQT's CFO Jeremy Knop noted during his company's third-quarter earnings call that much of the new demand is coming from the eastern U.S., thanks to concentration of data centers and the reshoring industrial movement.

"This demand will be regional, with more than half likely to come from the Southeast in the PJM markets," Knop said. PJM Interconnection is the largest U.S. electrical grid operator and provides services to parts of 13 states, including Pennsylvania, Kentucky and West Virginia.

Knop forecast during the meeting that data centers, coupled with the ongoing retirement of coal plants in the region, could add up to 10 Bcf/d of natural gas demand by 2030.

Haynesville

Producers in the Haynesville Shale, located in northeastern Texas and northwest Louisiana, are also expecting to see a demand increase, but one driven primarily by the long-awaited opening of several LNG liquefication and export terminals along the Gulf Coast.

The region's proximity to the heaviest concentration of LNG production in the U.S. will enable it to play a major role as several plants start to come online.

Venture Global's Plaquemines LNG loaded its first cargo in mid-December. The plant will have an intake capacity of 2.6 Bcf/d once fully operational.

Expand Energy, the nation's largest natural gas provider, put an emphasis on Haynesville development toward the end of 2024. In November, the company reported 12 rigs in operation, with eight in the Haynesville and four in the Appalachian Basin.

Proposed Uinta Basin Railway

SOURCE: BUREAU OF LAND MANAGEMENT

Uinta

One of the smaller basins in the U.S. may also have a major role in the industry's future.

As 2024 drew to a close, the U.S. Supreme Court heard arguments in the Uinta Basin railway case.

Producers in the play have long tried to expand takeaway capacity for the basin's waxy crude, which is so thick that it can only be shipped by rail.

A proposed new railway was stymied by a lawsuit by Eagle County, Colo., and environmental group Center for Biological Diversity.

The railway builder lost the case on its appeal to the U.S. Court of Appeals for the D.C. Circuit. The panel ruled that to be approved, the railway project designers must consider not only the CO_2 produced in the direct operation of the railway, but in the follow-on effects of delivering more crude to producers.

The case was appealed to the U.S. Supreme Court, which heard arguments in early December.

Tom Sharp, director of permitting intelligence for analytical firm Arbo, said there was no clear signal of which way the court would turn.

"The justices probed two competing approaches. Industry advocates pushed for a bright-line test based on 'proximate cause,' which is a concept borrowed from tort law that limits liability to reasonably direct harms, just as a negligent driver wouldn't be liable if a delayed doctor's patient died across town," Sharp said in an email to *Oil and Gas Investor.*

"Along these lines, the industry counsel's standard would be that agencies shouldn't be faulted for not evaluating impacts that are both remote in time and place, when another agency has regulatory authority."

Attorneys for the government argued, however, that strengthening federal agencies' discretion "to determine 'reasonable' scope of the environment review could reduce litigation without creating regulatory gaps due to the extraordinary breadth of varied actions the government needs to analyze," Sharp said.

The follow-on effects of adding greenhouse gases to the atmosphere was a major issue for the LNG industry in 2024. The D.C. appeals court vacated two federal permits for developing plants in Texas, saying that more consideration needed to be given to the total CO_2 the projects would produce overall.

The Supreme Court is expected to release its decision in the spring. ■

2.6 Bcf/d
Plaquemines LNG capacity

$2.7B
Estimated cost of Energy Transfer's Hugh Brinson Pipeline

3
Number of Permian Basin natural gas pipeline projects that reached FID in 2024

88 mls
Proposed Uinta Basin Railway Length

E&Ps Making More U-Turn Laterals—and Problem-Free

Of the more than 70 horseshoe wells drilled to date, 35 were in just the first nine months of 2024 as operators find 2-mile, single-section laterals to be problem-free while more economic than two 1-mile straight holes in their isolated acreage.

NISSA DARBONNE | EXECUTIVE EDITOR-AT-LARGE

Operators across the Lower 48 are drilling U-shaped double-long laterals, finding lower-cost new-well inventory in acreage they already hold.

And they're doing it problem-free.

"When we look at the M&A landscape, there are fewer and fewer opportunities out there that will have inventory that will jump ahead of the low breakeven inventory that we've added today," Jason Pigott, Vital Energy president and CEO, told investors in a 2024 call.

"We see really similar cycle times with this design as we do with a more conventional straight-lateral steering strategy," Vital COO Katie Hill added.

Vital has converted 84 1-mile wells in its inventory to 42 2-mile horseshoe wells and added 77 horseshoe wells in locations that were not initially planned because they were considered sub-economic as short laterals, Pigott said.

Udriller.com, a website that keeps track of U-turn wells dating back to the initial horseshoe well in 2019, counted 76 of these through early October, with 35 spud in the first nine months of 2024 alone.

Among operators drilling U-turn laterals in 2024 were Matador Resources, Occidental Petroleum and EOG Resources, in addition to Vital, SilverBow Resources, Comstock Resources and GeoSouthern's GEP Haynesville.

77 More Locations

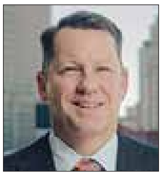
A Permian Basin pure-play E&P, Vital gained two horseshoe wells in the Delaware in its 2023 acquisition of Forge Energy and is targeting U-shaped wells for special-sized leaseholds in both the Midland and Delaware basins.

Since one 10,000-ft U-lateral costs less than two 5,000-ft straight laterals, or "sticks," Vital was able earlier this year to add 77 new long-lateral U wells out of 154 1-mile locations that Pigott said were "previously excluded due to the economics."

When Vital was drilling its first horseshoe wells in 2023 at its Allison pad in Upton County in the Midland Basin, "every single well was getting faster," Pigott told investors.

"So, the more we do it, we'll continue to get costs down and improve our breakevens."

Vital also added Delaware acres in its $1.1 billion cash acquisition in September of Point Energy Partners, which



"We targeted this technique anywhere we have short laterals.... When you come back [after the turn, toward the pad], you come back on that same spacing that you would traditionally have. So, whether you develop on six wells per section or four wells per section [spacing], we designed the return lateral on that [well] spacing."

JASON PIGOTT, president and CEO, Vital Energy

had leasehold that includes locations suitable for horseshoes.

"We're really excited about Point because it's in our backyard, it had low-breakeven wells and we're using horseshoe technology to improve economics out of that asset," Pigott said in November.

Spacing and completion recipes are the same in U laterals as two single-well laterals, he added.

"We targeted this technique anywhere we have short laterals.... When you come back [after the turn, toward the pad], you come back on that same spacing that you would traditionally have.

"So, whether you develop on six wells per section or four wells per section, we designed the return lateral on that spacing."

Matador U-Turns

Matador's first two 2-mile U-lateral tests in the Delaware are outperforming adjacent 2-mile straight laterals in 11 months online now, according to Railroad Commission of Texas (RRC) data.

CHESAPEAKE ENERGY

HART ENERGY

ASCENT RESOURCES

1. The second known horseshoe was drilled in the Lower Eagle Ford in 2020 by Chesapeake Energy in La Salle County. Chesapeake landed seven more Eagle Ford horseshoe wells before selling its South Texas assets in 2023 in three packages to SilverBow, Ineos Energy and WildFire Energy. 2. This summer, Comstock Resources was drilling a U-shaped well in the Haynesville in its DeSoto Parish, La., where GeoSouthern's GEP Haynesville had recent success. 3. Privately held Ascent Resources spud the Echo S. ATH HR #3H horseshoe well in the Utica's wet-gas window in eastern Ohio in Belmont County in October 2022.

Both U-laterals are in a development of 11 wells to date about 4 miles north of Mentone, Texas, in Loving County.

The U-shaped JJ Wheat NW WF #2021H produced an average of 0.048 bbl/d per lateral ft through August, higher than the 0.038-0.043 bbl/d per ft averaged through August from four adjacent straight-lateral sticks.

It was landed in Wolfcamp XY, while the four sticks are in Wolfcamp A and B, according to RRC files.

Including the #2021H, the five laterals range from 10,036 ft to 10,752 ft.

Next door, Matador varied the project in three tests.

A 2-mile U-turn, JJ Wheat SE WF #2024H, averaged 0.075 bbl/d per lateral ft in its first 11 months online from a total 8,659 ft of hole in Wolfcamp XY, according to the RRC.

An adjacent 1-mile stick, JJ Wheat WF SESE #214H, averaged 0.076 bbl/d per lateral ft through August. It is also landed in Wolfcamp XY. The lateral is 4,876 ft.

In another look from the same pad, Matador made a 2-mile straight lateral, Barnett Trust WFA NWSE #223H, in Wolfcamp A. Production through August from the

10,036-ft hole averaged 0.043 bbl/d per lateral ft, according to the well file.

Five More Tests

Since turning these into sales in October 2023, Matador has made five more U laterals—the Janie Conner #120H in Eddy County, N.M., in the Lower Avalon and four Burke State wells, all in Bone Spring, in Lea County, N.M.—according to Udriller.com.

Data was not yet available on these.

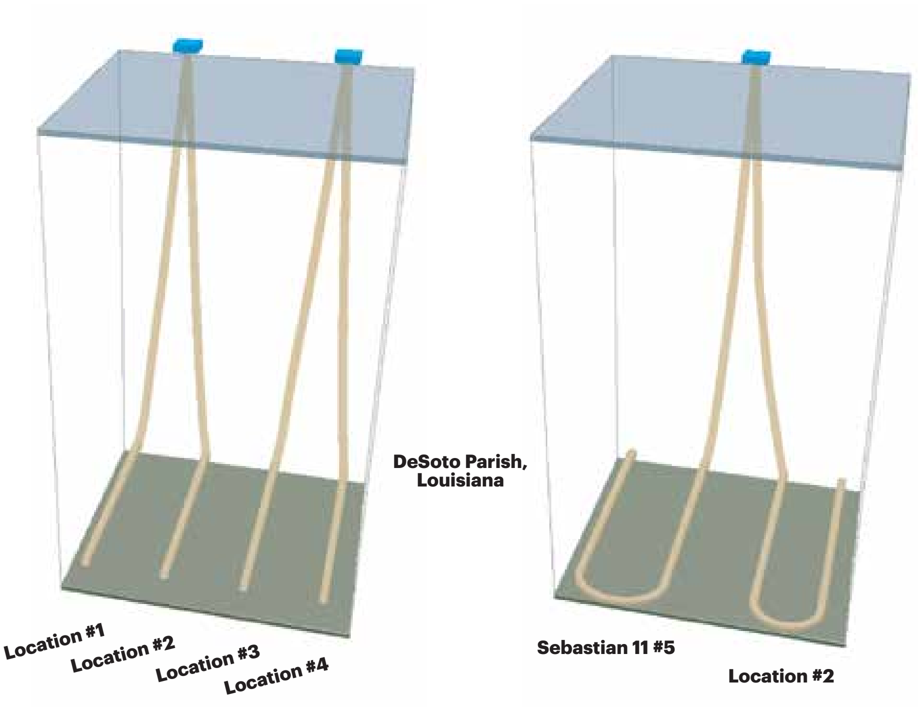
Joe Foran, Matador chairman and CEO, told investors in fall 2024 that the five new U-laterals were drilled 30% faster than the first two.

Also, it used remote, simul-frac completions on the four Burke State wells.

The four 2-mile U-lateral Burke State wells are in a 1-mile section where Matador would have needed to make eight laterals to tap the equivalent length of rock.

"The team estimated $3 million in cost savings per U-turn well when compared to the alternative of drilling eight 1-mile ... wells," Foran said, by eliminating the vertical sections of four of the eight 1-mile holes.

Comstock Haynesville Horseshoe Tests



SOURCE: COMSTOCK RESOURCES

Comstock Resources has a second U-shaped well underway in the Haynesville in DeSoto Parish, La., near one recently drilled by GeoSouthern's GEP Haynesville.

"We've done it [U-turn laterals] successfully. And you do that because of offsetting wells, lease requirements" and other reasons.

TIM BEARD, vice president of drilling, Expand Energy

U-Turn IPs

The initial JJ Wheat U-turn tests' first-24-hour IPs were also higher than their straight-lateral Wolfcamp counterparts, coming in with 1,266 bbl and 1,153 bbl, according to RRC data.

One of the 2-mile straight laterals IP'ed 1,098 bbl; the other four, fewer than 800 bbl.

"Even though they're U-turn wells, they performed just like a straight 2-mile-long lateral—very high pressures and IP rates of between 2,100 and 2,400 boe/d [including gas]," said Tom Elsener, Matador executive vice president of reservoir engineering.

At the time, the U-shaped JJ Wheat wells were online more than four months. In addition to oil, they made between 1 Bcf and 1.3 Bcf of casinghead gas in their first 11 months.

"You wouldn't know the difference if it was a U-turn or 2-mile lateral from the production results," Elsener said.

At the time, Matador estimated making up to 20 U-turn wells in the next two years.

"We're ready to do a few more of those." But, at first, "we still are kind of in the learning phase," Elsener said.

"We're going to learn about some different targets in different areas.... I still think we're kind of in the walking mode. We're not quite in the running mode yet.

"But I think we're very optimistic about it."

Haynesville, Marcellus, Utica

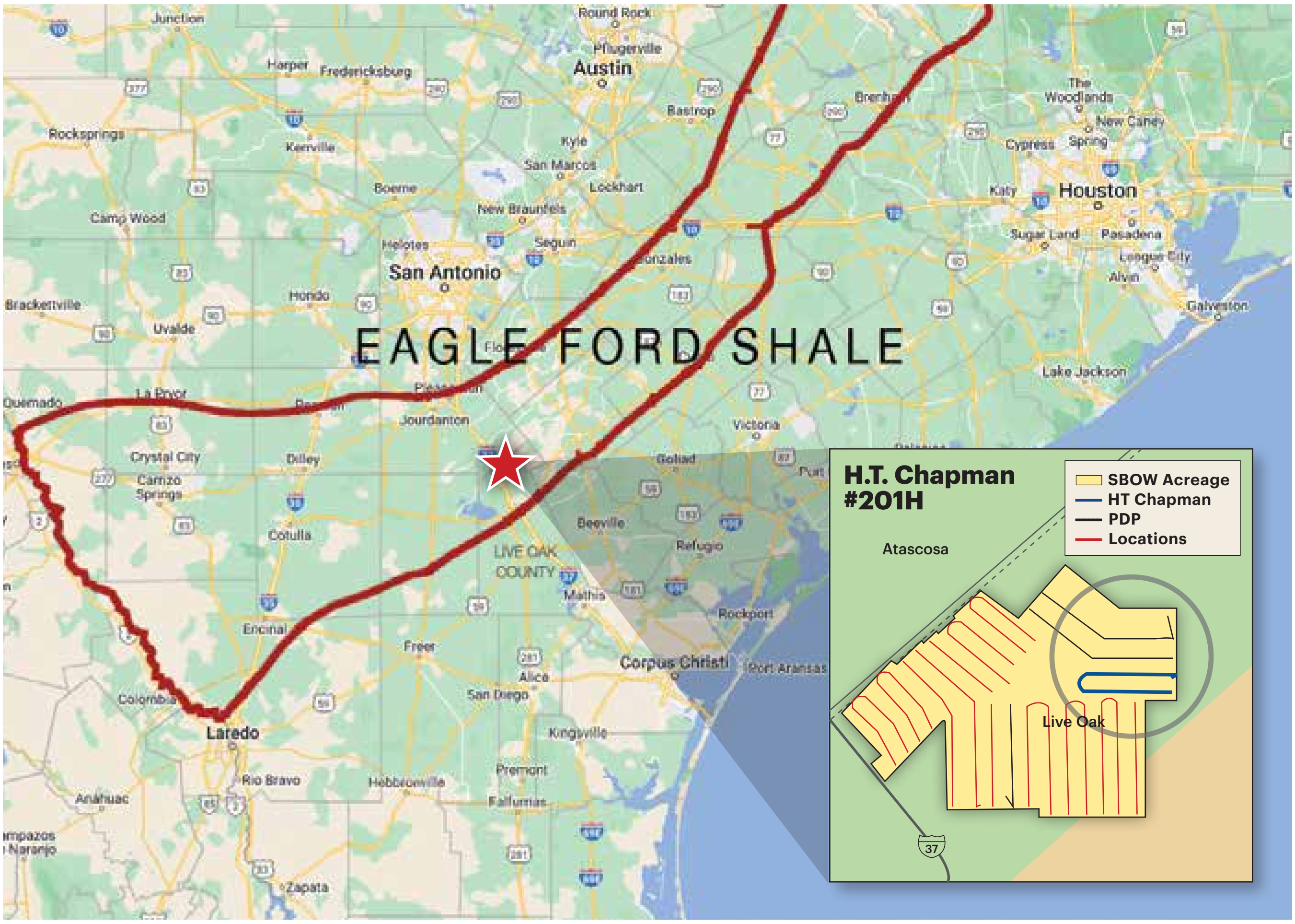
Through early October, operators had spud 76 U-turn wells across the Lower 48 since a Shell Oil pilot in 2019 in Loving County, according to a running tally at Udriller.com.

All but four have been in oil plays: Permian, Denver-Julesburg and Anadarko basins, and Bakken and Eagle Ford shales.

Chesapeake Energy was second to test U-turn laterals, landing one in La Salle County in 2020. Chesapeake merged with Southwestern Energy to form Expand Energy in 2024.

That well, Jea Unit L Las L #3H, had been producing since mid-2012, according to the RRC file, and had declined to 31 bbl/d for a total of 266,000 bbl in its first 98 months online.

SilverBow Resources' U-Turn Plans



SOURCE: REXTAG AND SILVERBOW RESOURCES

SilverBow drilled the first U-shaped wells in the Austin Chalk in spring 2024 on its odd-shaped leasehold in northern Live Oak County, Texas, and planned several more prior to merging into Crescent Energy.

It was brought back online in September 2020 with the U lateral and produced 809 bbl/d. Production in May was 103 bbl/d. The well produced 310,000 more barrels over the 45 months since it converted to a horseshoe.

Including that well, Expand made eight U laterals, all in the Eagle Ford—six full U-turn holes, a W-turn and a J-turn—before exiting South Texas in 2023.

"We've done it successfully," Tim Beard, Expand vice president, drilling, told *Oil and Gas Investor*. "And you do that because of offsetting wells, lease requirements" and other reasons.

There is potential for U-turns in Expand's Haynesville leasehold as well, Beard said.

Beard said, "Now, you have to worry about the stresses downhole to make sure that these wellbores aren't going to fall apart."

But they're doable.

The balance of Expand's portfolio is in the Marcellus. Is it interested in making U-laterals there? "Absolutely," Beard said.

Where there is stranded acreage, "it's going to enhance your economics. We're not doing it for any reason other than that."

Ascent Resources landed one, Echo S ATH HR #3H, in the Utica's gas-weighted fairway in eastern Ohio in April 2023. Through June 2024, it produced 5.9 Bcf and 10,739 bbl of oil, according to Ohio Department of Natural Resources data.

Coterra Energy spud one in the Marcellus in Susquehanna County, Pa., in September 2023, according to Udriller.com.

Beard said, "I think the Ohio and West Virginia area—being more benign from a subsurface-feature perspective—is probably where they make the most sense in [Appalachia].

"But that doesn't mean we won't do those in Northeast Pennsylvania as well."

Torque and Drag

In the Haynesville, GeoSouthern Energy's GEP Haynesville spud a U-turn in DeSoto Parish, La., in early 2024.

The results prompted Comstock Resources to put one, Sebastian 11 #5, nearby. Turned into sales in October, it had an IP of 31 MMcf/d from 9,300 ft of completed lateral.

The single-section lease had meant four 1-mile sticks that would have involved two pads and cost $40 million, Dan Harrison, Comstock COO, said in an investor call.

Making two U-turn wells instead will result in a single pad at a cost of $32 million.

If successful, "the majority of all the short wells in our inventory will convert to long laterals," Harrison said.

Making these wells is a matter of necessity, he added. "Until you kind of 'have' to do it—you're looking at your inventory improvement—a lot of people probably just don't push to go there."

In the drilling process, "it's the same tools, the same motors that we run," Harrison said. "You just make another turn and you just stay with it until it goes all the way around 180 degrees."

There is some risk in drilling a horseshoe well, though.

"You have to get casing around the curve," Harrison explained. "When you're completing and pumping your perforating guns down and plugs for all your frac stages, all of these have to get pumped around the curve."

This introduces more torque and drag. "Obviously, when you're pushing and pulling pipe around the 180-degree bend, it adds more drag, tripping in and out of the hole.

"So, a 10,000-ft horseshoe [is] maybe more like the equivalent of a 15,000-ft straight lateral when you look at the drag going in and out of the hole."

Reduced Footprint

Despite this, Harrison said the risk is small. "The industry kind of already has shown it in the Permian and I think the Eagle Ford [and] other areas....

"You just have to prove it out and ... after you do more of them, it becomes a little bit more routine and the risk is greatly diminished," he said.

Fewer wellheads are more environmentally beneficial as well, he said, as the surface footprint and emissions are reduced.

If successful, Harrison said, "the majority of all the short wells in our inventory will convert to long laterals."

The exception will be in sections where spacing allows only one more lateral. "We won't be able to convert all of them to 10,000-ft horseshoe wells, but I think a good chunk of the inventory we will be able to convert," he added.

As Comstock's new U lateral was landed problem-free, "I think this is the first of many to come," he said.

"I think the public wants to see more of them drilled. They want to see it become routine. They want to see it de-risked."

A 15k-Ft Horseshoe?

A securities analyst asked Comstock if there are 7,500-ft stick locations that can be made into 15,000-ft horseshoes.

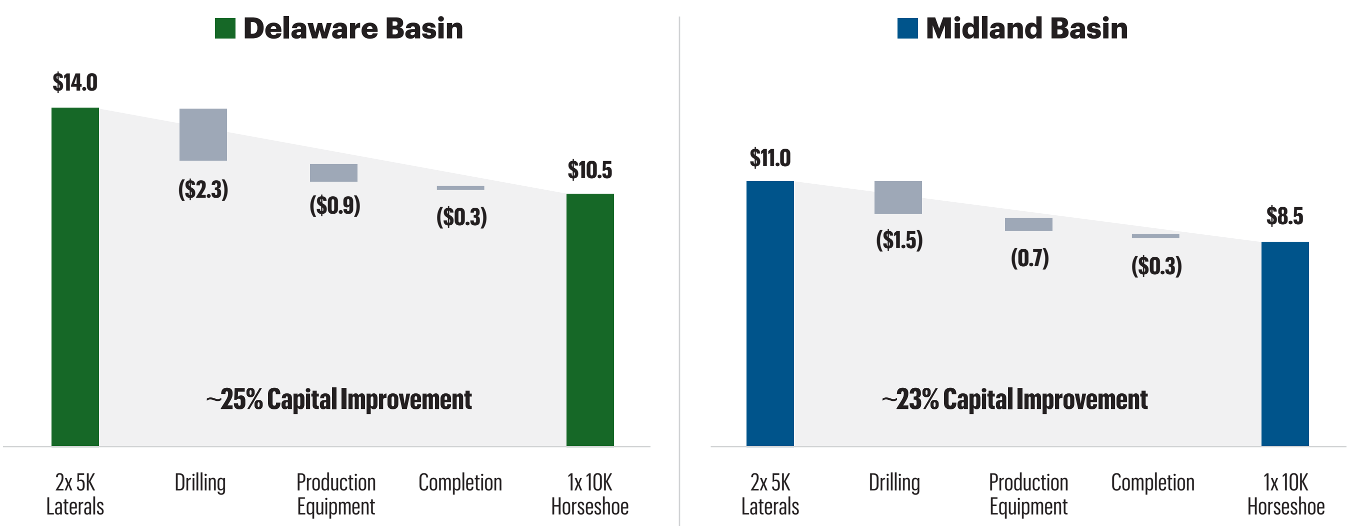
"We've already kind of had some internal discussions about that," Harrison said. "We're not ready to kind of jump out there and do that yet."

It is, however, a possibility in the future.

"The industry gets better with time," he said. "Tools get better. If you have the demand for tools and the demand for certain services, in time they show up. They get developed and they get refined."

There are economic considerations to take into account, however, and today a 7,500-ft lateral has better economics—a

Vital Energy Horseshoe Well Cost Savings ($MM)



SOURCE: VITAL ENERGY

Vital Energy reported 2-mile U-shaped laterals in both the Midland and Delaware basins cost less than two 1-mile laterals, while tests to date have been problem-free.

Matador Resources' U-Lateral Tests, Loving County, Texas

	Formation	Type	Oil (bbl)*	Months Online	IP (bbl)	Lateral (ft.)	Bbl/d/ft.
Northern Pad, 11-Well Package							
JJ Wheat NW WF #2021H	Wolfcamp XY	U-turn	172,838	11	1,266	10,752	0.048
Barnett Trust WFA NWNW #221H	Wolfcamp A	Straight	131,025	11	1,098	10,175	0.038
Barnett Trust WFA NWSE #223H	Wolfcamp A	Straight	146,000	11	481	10,036	0.043
Barnett Trust WFA SENW #22H	Wolfcamp A	Straight	139,855	11	685	10,054	0.041
Barnett Trust WFB NWNW #225H	Wolfcamp B	Straight	129,113	11	754	10,084	0.038
Barnett Trust WF B #121H	Bone Spring	Straight	285,313	31	1,370	9,639	0.031
Barnett Trust WF C #122H	Bone Spring	Straight	286,547	31	1,474	9,642	0.032
Barnett Trust WF D #123H	Bone Spring	Straight	316,413	31	1,623	9,917	0.034
Barnett Trust #115H	Permitted	—	—	—	—	—	—
Barnett Trust #226H	Permitted	—	—	—	—	—	—
Barnett Trust #136H	Permitted	—	—	—	—	—	—
Southern Pad, 4-Well Package							
JJ Wheat SE WF #2034H	Wolfcamp XY	U-turn	216,413	11	1,153	8,639**	0.075
JJ Wheat WF SESE #214H	Wolfcamp XY	Straight	125,129	11	630	4,876	0.076
Barnett Trust WFA NWSE #223H	Wolfcamp A	Straight	146,000	11	481	10,036	0.043
Barnett Trust #227H	Permitted	—	—	—	—	—	—

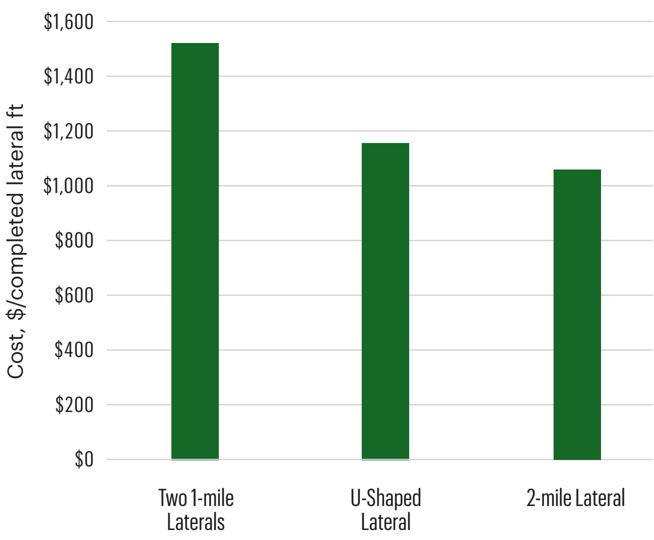
SOURCE: HART ENERGY VIA TEXAS RAILROAD COMMISSION AND U-DRILLER.COM DATA
*THROUGH AUGUST 2024. THOSE ONLINE 11 MONTHS WERE TIL'ED IN OCTOBER 2023; 31 MONTHS, FEBRUARY 2022. **TOTAL FROM TWO OPEN INTERVALS OF 4,124 FT AND 4,515 FT.

better breakeven—than a 1-mile lateral when factoring for all-in cost to drill versus production and reserves, Harrison said.

For that reason, there would be less incentive to convert 1.5-mile sticks into 3-mile U wells.

"If you have two sections or three sections, typically we'll just drill a 15,000-ft straight lateral," Harrison said. "We're not going to do a bunch of [15,000-ft] horseshoe laterals."

Total Cost per Completable Foot



SOURCE: UDRILLER.COM

Although a 2-mile U-shaped lateral costs more than a 2-mile straight lateral, it costs less than two 1-mile straight laterals.

While Comstock is not likely to drill longer U-shaped wells at present, "there will probably be some people that will try to push the horseshoe lengths a little bit farther," Harrison said.

The Shell Well, 2019

The first known horseshoe lateral was the Neelie #4H well drilled by Shell Oil in the Delaware Basin in 2019.

According to Udriller.com, the 2-mile lateral, now owned by ConocoPhillips, was landed in Wolfcamp in Loving County with 1,300-ft spacing. It was brought online in June 2019 and produced 727 bbl/d of condensate its first full month.

According to RRC data published in mid-August, production totaled 273,791 bbl of condensate through May 2024. Solution gas through May totaled 1.6 Bcf.

A look at Shell's request for an RRC permit to drill the U-shaped lateral demonstrates the Texas oil and gas reviewer's own surprise.

The file includes a pre-emptive note by Shell in the request, explaining that the plan is for a horseshoe well. The motivation was a workaround on a subsurface issue rather than a surface, acreage-related issue, it added.

"Due to loss-circulation issues in the Neelie 1-85 LOV #2H well, this permit is being amended to drill the original #4H lateral and the previously permitted #2H lateral," Shell reported to the RRC.

The #2H would now include the #3H well. The exception required a waiver by the offset operator, but since Shell operated both wells, it told the RRC that it "grants itself a waiver." ■

Lenders to Thrifty E&Ps: We're Back

Haynes Boone survey reveals an unusual reduction in hedging, indicating that banks are rewarding producers for reining in their shale spending.

DEON DAUGHERTY
EDITOR-IN-CHIEF
ddaugherty@hartenergy.com

Domestic oil and gas producers are exercising newfound freedom to roll the dice on price after years of diligent spending restraint, measured growth and debt reduction.

"For the first time in a while, we're actually seeing reductions in hedging percentages," said Kraig Grahmann, partner at Haynes and Boone and lead author of the firm's Fall 2024 Borrowing Base Redeterminations Survey (BBR).

Hedging on a minimum percentage of production is a common criterion of reserved-based lending. But in the absence of bank or board dictates, producers can run the table on price if they'd rather take a longer view. It includes some risk, but lenders and other investors appear increasingly willing to take their chances on U.S. producers again.

Mired in debt and investor ire over reckless spending during the first half of the shale revolution, the backlash reached an inflection point in 2017, and E&Ps in need of cash "were kind of forced to hedge"—even if the market wasn't good for it—to appease banks' strict minimum requirements for capital access, Grahmann told *Oil and Gas Investor*.

But quarter after quarter, public E&Ps have paid down billions of dollars' worth of debt. Increasingly, their leverage is dropping below minimum thresholds. Changing the corporate spending dynamic made E&Ps an investable business again, Grahmann said. That's inserted flexibility into their credit agreement negotiations, which includes a holiday from hedging.

Indeed, most reserve-based loan (RBL) borrowers operate at low leverage, Grahmann said. On the unsecured debt side, many companies have cut back the use of sizable borrowing bases to access cash.

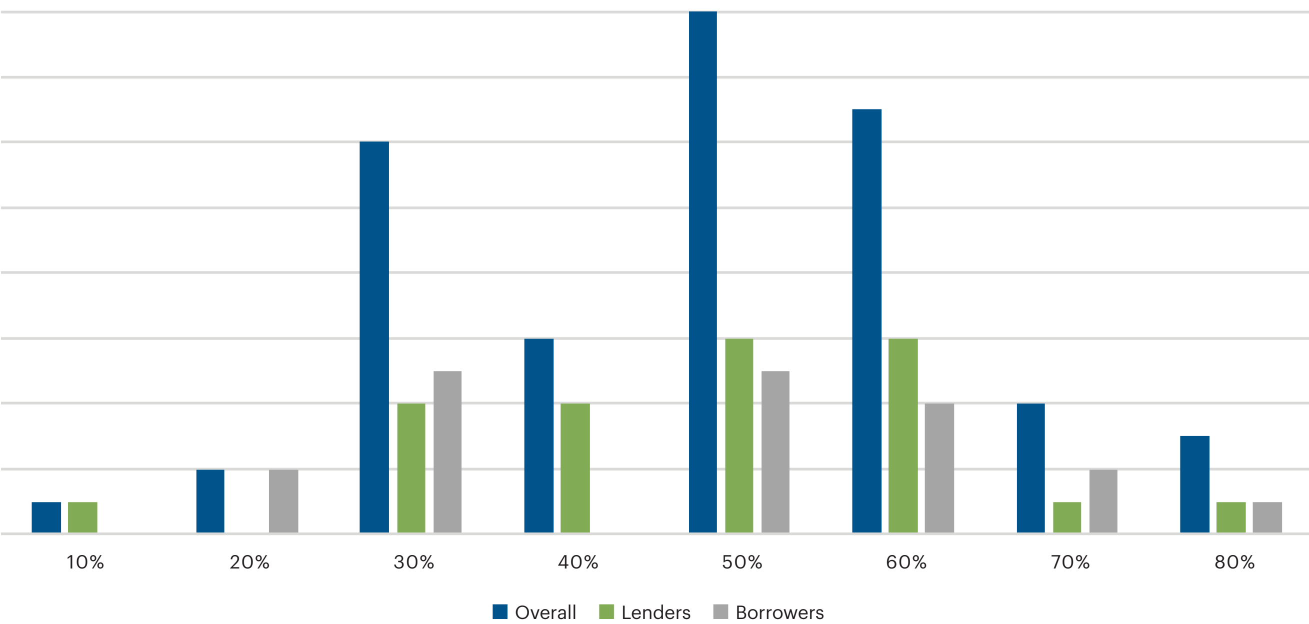
"[Producers] don't have whole lot of money actually on that line of credit, and so that's also what's getting the bank comfortable giving them these hedging holidays." Grahmann said. "If something goes really bad, chances are some of these companies only have 20% to 30% or 40% of their borrowing base even drawn right now. There's a lot of room to work with."

Steady as She Goes

There's also evidence that oil-weighted

Haynes Boone Hedging Responses

On average, what percentage of anticipated future production have reserve-based credit facility borrowers hedged for the next 12 months?



producers' conservatism is shaping corporate strategy wholesale. Hayne Boone found that amid market uncertainty, most of those firms are implementing flat–in some cases, reduced–budgets in 2025.

The semi-annual polling of industry lenders and operators took place between Oct. 10 and Nov. 19, accounting for sentiment on Russia's lingering war on Ukraine, violence in the Middle East, politics in the U.S. and economic concerns around the world. Those concerns likely shaped survey participants' caution and hold-steady stance, Grahmann said.

"The outlook is one where there could be a lot of opportunities, but there also could be a lot of volatility, and so survey participants aren't really moving one way

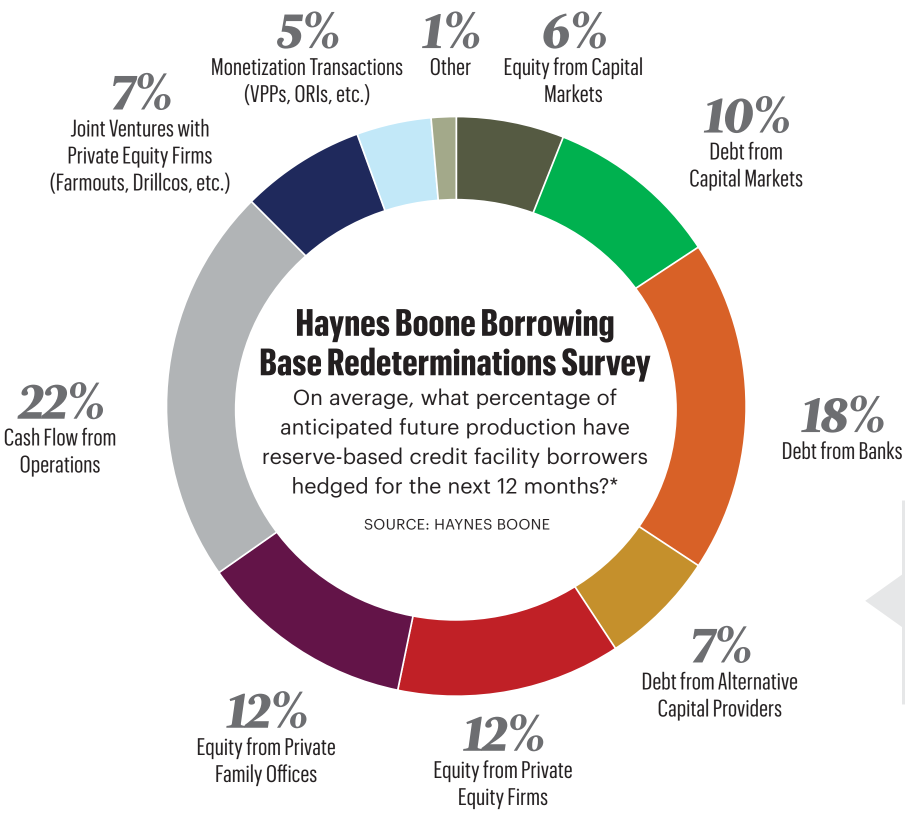
Haynes Boone Energy Bank Price Deck Survey Gas Base Case

Fall 2024

Haynes Boone Energy Bank Price Deck Survey Oil Base Case

Fall 2024

SOURCE: HAYNES BOONE



*Respondents could select more than one option. Haynes Boone collected 216 responses. The figures in the chart above indicate the percent of total responses for each option.

or the other," he said.

Bankers aren't jumping to conclusions, either.

"They're not cutting back or trying to get money off the table. [Bankers are] still continuing to extend credit to lend, but they're not getting overly aggressive either as far as making too much capital available," he said. "Producers are not trying to get too far ahead of the curve by putting in big drilling budgets for next year. People are being cautious."

Most of the survey's 57 respondents checked the steady box for near-term borrowing bases, too. And, respondents showed just a smidge of shift in capital access sources from their plans recorded six months ago.

The December survey showed a 2% increase in E&Ps' belief they will access capital during the next year via monetization transactions, debt from capital markets or debt from alternative capital providers.

Faith in family offices slipped 1% during the last six months, according to participant responses.

Price Prognostications

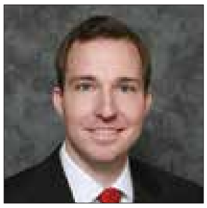
Lenders and producers are generally holding a cautious view that's closing in on optimism for crude oil prices.

In conjunction with the BBR survey, Haynes Boone produced a semi-annual Energy Price Deck Survey. The spring report showed expectations of base case oil prices falling through 2027 and then flattening through 2033. Fast-forward six months and now those polled expect prices to pick up in the short term through 2027, continue on that trajectory longer term through 2033, and remain higher than spring estimates.

"Prices have remained steady because there is still a large global demand for oil, with consumption projected to continue to grow well into the next decade—even as wind and solar generation continue to grow as an alternative source of energy," said the report's lead author, Kim Mai, an attorney in the Houston office of Haynes Boone.

Base case predictions for gas prices in the fall report maintained an upward trajectory long-term, but the price range declined from spring reporting. The previous survey anticipated gas prices would remain at \$3.30-\$3.45/MMBTU in 2026 through 2033. That compares to the fall range between \$3.19 and \$3.23/MMBTU.

Haynes Boone said that while forecasts show global gas demand increasing based on population growth, infrastructure electrification and data center demand, other factors are at play. Price would be influenced by production increases and a decision by the Trump administration to expedite permitting for LNG export facilities. OGI



"They're not cutting back or trying to get money off the table. [Bankers are] still continuing to extend credit to lend, but they're not getting overly aggressive either as far as making too much capital available. Producers are not trying to get too far ahead of the curve by putting in big drilling budgets for next year. People are being cautious."

KRAIG GRAHMANN, partner, Haynes Boone

Kim Mai

Kissler, Wyett: Trump Tariffs and the Energy Markets

U.S. production and prices may increase; global cooperation may decrease.

DENNIS KISSLER
STEVE WYETT
BOK FINANCIAL

Dennis Kissler is senior vice president of trading for BOK Financial Services. Steve Wyett is chief investment strategist for BOK Financial Services.

The question on many people's minds starting 2024 was how soon the U.S. Federal Reserve and other central banks would start cutting rates and whether they would move in lockstep. Now, kicking off 2025, a significant focus is on the nature and magnitude of proposed U.S. tariffs and how the U.S. economy—and the world—will react.

Through the U.S. presidential campaigns, election and now transition, many of the details surrounding tariffs remained unknown. When Donald Trump takes office, however, experts are expecting more clarity. While we wait for new tariffs to be announced and new details to be shared, experts and economists can help paint a picture of what the road ahead may look like.

Inflation? Growth?

Big picture, it's not the use of tariffs in general that has had some economists concerned, but rather how broad or large the tariffs might be.

During his campaign, Trump's proposals included imposing a blanket tariff of 10% to 20% on all imports, with additional tariffs of 60% to 100% on goods imported from China, and a 25% to 100% tariff on goods from Mexico if the Mexican government doesn't take steps on its end to close the U.S.-Mexico border. However, in late November, he proposed a 25% tariff on goods imported from Mexico and Canada, and a 10% tariff on imports from China.

Targeted tariffs can help keep China from dumping steel on the global market, for example, or something of that nature, but the broad use of tariffs probably damages the economy as much as it helps it.

If you're using tariffs to protect domestic producers, inevitably, what you're saying is, "I'm going to raise the price of this foreign good that can be imported cheaper, so it can be made here." However, that means consumers are now going to be asked to pay a higher price for the good either by paying the tariff on what's imported or by paying a little bit higher price for a domestic producer to produce the good. The domestic producer is going to price it as close to the tariff price as possible.

But proponents of broad tariffs argue the opposite. For instance, the Washington International Trade Association (WITA)—a nonprofit, nonpartisan organization that includes the president and CEO of the American Apparel & Footwear Association as president of its board—publicized a trade model that predicts broad tariffs would benefit U.S. consumers and businesses in multiple ways.

Specifically, the 2022 model looks at the impact of a 15% revenue tariff increase on all imported goods, and a 35% tariff increase on some imports that are significant for economic reasons or for "national resilience," such as imports from Non-Free Trade Agreement (NFTA) countries. With those in place, the model predicted a 7% boost to the U.S. economy, 10 million new jobs, a 10% rise in inflation-adjusted household income and $603 billion generated in federal revenue.

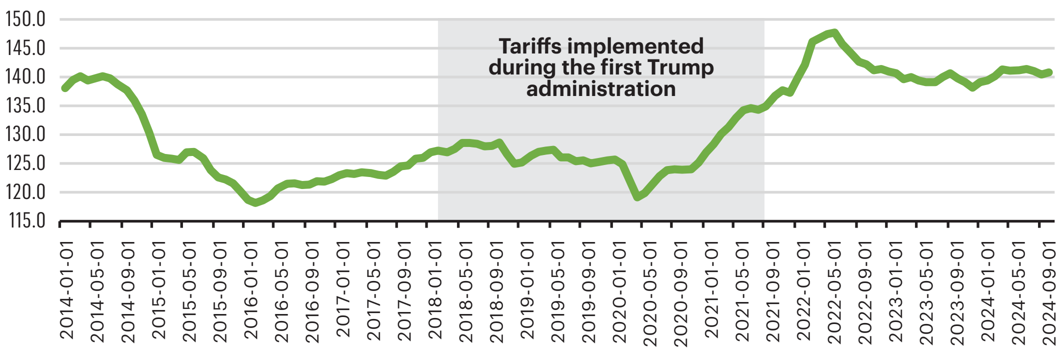
Also, keep in mind that during the first Trump administration, tariffs were implemented on imports from China and overall inflation remained subdued. The real question this round will be the amount or percentage that will be imposed.

The model from the Federal Reserve Bank of

Import Price Index

All imports excluding petroleum.

Trump's previous tariffs had less of an impact on import prices than the COVID pandemic.



SOURCE: FEDERAL RESERVE BANK OF ST. LOUIS

St. Louis uses tariff figures that differ significantly from the ones Trump suggested during his campaign. To put all of these numbers into perspective, you have to go back nearly 200 years to 1830, when the highest tariff in U.S. history, a near-62% tax on all dutiable imports, was imposed and received strong political opposition within the U.S.

The second-highest tariff was the 1930 Smoot-Hawley Tariff Act, which raised around 900 import tariffs by an average of 40% to 60%. This act is believed to have been a driver of the Great Depression, but it's unlikely the U.S. is in the same position now.

How Will Other Countries React?

One reason the Smoot-Hawley Tariff Act is believed to have helped cause the Great Depression is because of its significant reduction in global trade. In response to the act, around two dozen countries enacted high tariffs of their own within two years of its passage, causing a 65% drop in international trade between 1929 and 1934.

Experts are saying that Trump's proposed tariffs on China and Mexico, in particular, could have serious effects on those countries—on top of the struggles they are already having—and no one knows how they and other countries would react.

As our colleague, Pete Tibbles, senior vice president of foreign exchange trading at BOK Financial, told us: if Trump does come in and put those tariffs into place, then that's obviously going to have a detrimental effect on China because that country has been trying to grow its economy but it's been a struggle.

China has a lot of housing problems. There is a middle class now in China, which is great, but it's gotten to the stage where housing is a little saturated and they have all these zombie towns where they can't sell the property, so many of the massive property conglomerates are in a lot of trouble.

In turn, China's reaction to high U.S. tariffs could also impact the energy market. In retaliation, the Chinese government could come against U.S. crude imports into their country. It also would weaken their economy. Remember that they're the largest crude importer, so if we weaken their economy, the biggest demand puller is going to be coming down and that could be a problem for U.S. crude exports in general.

Another question is how Chinese exporters themselves will react. People say, "It's going to hurt Chinese exporters." Well, if that's true, then do they slow down their exports? Do they export to other places in the world where there are no tariffs? Until we know more details from Trump on how it's going to look, it's very difficult to come up with good answers.

Mexico, meanwhile, is dealing with controversial judicial reforms which could impact the United States-Mexico-Canada Agreement (USMCA). It's not just a U.S. story; it's a Mexico story as well.

However, until more is known about Trump's tariff policy, it's hard to know what that story is, experts stressed time and time again. Obviously, it's going to affect trade, but how it affects trade can be very different, depending on the specific policies. Does it move the needle a lot for oil and natural gas prices? It will have an effect, but past history of a Trump administration (pre-COVID) actually points to more price stability.

Paisie: With Oil Prices, It's All About the Economy

One of the keys to pricing is whether global conflicts curtail the flow of oil. They have not.

JOHN PAISIE
STRATAS ADVISORS

John Paisie is president of Stratas Advisors, a global research and consulting firm that provides analysis across the oil and gas value chain. He is based in Houston.

We are considering a range of factors that will affect the oil market at the beginning of 2025. Macro-level factors (geopolitics, economics and government policies) will establish a broader context for the oil markets.

In assessing the oil markets, it is always a requirement to consider geopolitics, but while the conflicts in Ukraine and the Middle East continue (along with the recent fall of the Assad regime in Syria), oil prices do not reflect the potential level of risk. Instead, the market has been calmed by the uninterrupted flow of oil. We expect this to continue during 2025.

From an optimistic viewpoint, a negotiated settlement could bring the Russia-Ukraine conflict to a close. It is also possible that the Middle East could be entering a period in which there is respite in the tit-for-tat between Israel and Iran (and proxies), while the situation in Syria could proceed without devolving into sectarian violence and clashes fostered by outside parties. While there is plenty of potential for chaos—especially with respect to the Middle East—the optimistic view reflects our base-case expectations, which translates into geopolitics not being a major driver of oil prices during 2025.

In contrast to geopolitics, we think that economics will be a major driver for oil prices. We are expecting that the U.S. economy will continue to exhibit strength, which will be supported by easing monetary policy, while the EU economies will continue to struggle with downside risks stemming from the possibility of increased tariffs imposed by the incoming Trump administration.

Especially vulnerable is the European manufacturing sector, which has contracted by 6% since January 2022, in part, from the higher energy costs associated with the beginning of the Russia-Ukraine conflict.

The biggest source of economic uncertainty is associated with China's economy. China's economic growth is under pressure from the threat of additional tariffs from the U.S. In November, the congressionally chartered U.S.-China Economic and Security Review Commission recommended that the U.S. remove the "most favored nation" status for China. The removal of the status would result in all of China's exports to the U.S. ($427 billion in 2023) being exposed to tariffs ranging from 35% to 100%. Trump has indicated that he will impose tariffs of 60% on Chinese imports.

Government policies in recent years have been supportive of alternative fuels and the electrification of the vehicle fleet. With political gains being made by the right-wing parties, some of the momentum will be stifled this year, both in Europe and, most notably, in the U.S. where the policies and incentives enshrined under the Inflation Reduction Act (IRA) of 2022 are at risk.

The Trump administration could scrap tax incentives aimed at fostering investment in clean technologies, including electric vehicles (EVs), low-carbon hydrogen and renewable fuels. Although part of the IRA package is expected to be downsized, it will be complex for the next administration to completely repeal the scheme, as it is estimated that in the EV and battery sector only, it has attracted around $110 billion in investments in U.S. territory—with much of the investments placed in states that expressed a Republican majority.

Delay from OPEC+

Within the context of the macro-level factors, supply and demand fundamentals will underpin oil prices.

In alignment with our expectations for economic growth, growth in oil demand will be heavily dependent on the extent of demand growth in Asia with the growth stemming from China, India and other developing Asian countries.

As we have been highlighting and expecting, OPEC+ announced at its December meeting that its members will continue to delay the unwinding of supply cuts. Given the level of oil prices and the supply/demand dynamics, OPEC+ had plenty of incentive and supporting rationale to delay any change to its supply until the beginning of the second quarter.

The delay will provide time for OPEC+ to learn more about the intentions of President Donald Trump, who has discussed policies that are positive and negative for oil prices. With the latest delay, the unwinding of production cuts will take until Dec. 31, 2026.

With OPEC+'s delay in unwinding its supply cuts and our outlook for non-OPEC supply, we are expecting that oil demand will outpace oil supply through much of 2025. While this deficit will be supportive of crude prices, the extent of spare capacity of around 6 MMbbl/d will put downward pressure on oil prices. OGI

As Upstream M&A Eases, Oilfield Services Gears Up

In the first nine months of 2024, OFS dealmaking hit $19.7 billion—the highest since 2018.

DARREN BARBEE
SENIOR MANAGING EDITOR, DIGITAL
dbarbee@hartenergy.com

As early as April, the wave of E&P consolidation in the Lower 48, led by the Permian Basin, had clearly set off aftershocks in the oilfield services (OFS) sector.

Within the first nine months of 2024, OFS dealmaking hit $19.7 billion—the highest since 2018, according to Deloitte's 2025 Oil and Gas Industry Outlook.

The OFS sector has seen dramatic periods of instability in the past 10 years—suffering through the pandemic and the reverberations of an OPEC-U.S. shale producer price war along with the rest of the industry.

But while profitability returned to many E&Ps set on capital discipline—upstream net income rose 7% from 2014 to 2023 despite an 18% drop in oil prices—OFS companies fared far worse. Between 2015 and 2021, the OFS sector was saddled with $155 billion in losses.

And while E&Ps reaped the benefits of increased efficiencies and productivity gains from OFS companies, that sector lagged behind the rest of the oil and gas industry.

Shale players reduced the business and margins of the sector, Deloitte said in its report. "Simply put, the sector became a victim of its own technological success for its customers."

But Deloitte sees signs that the OFS sector is "emerging from the shadows."

Over the past three years, the sector's net income has cumulatively exceeded $50 billion, Deloitte said. OFS capex is at the highest level—and net debt at one of its lowest points—since 2016.

"In fact, oilfield services companies seem to be repeating what their upstream shale customers did years ago—growing profitably without a commensurate increase in capex," Deloitte said.

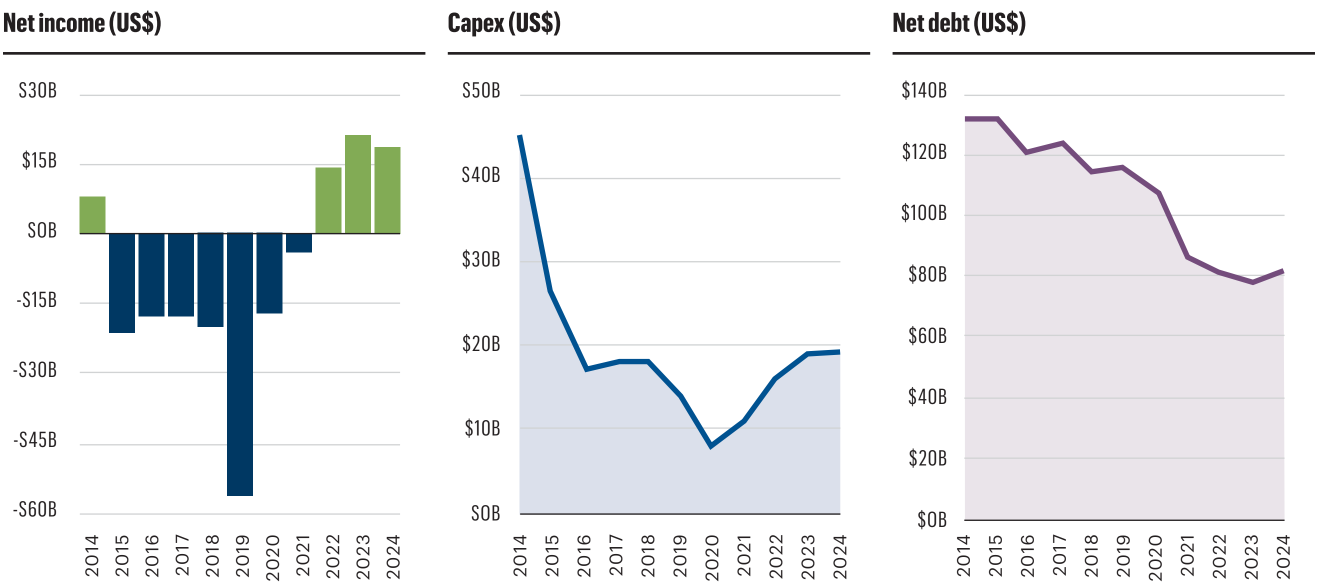
Upstream deals since 2023 have flourished, with nearly $136 billion spent on major M&A consolidation, largely in the Permian Basin, Deloitte said. With a rash of deals done, acquirers have started the process of integrating their new assets.

Next year's M&A for upstream and oilfield services companies will unfold in a markedly different manner, likely with less emphasis on the Permian and more on service and supply company combinations.

Extra-Permian M&A

Permian M&A is by no means done. In November, Coterra Energy added acreage in the Delaware Basin with $3.95 billion worth of deals from private E&Ps Franklin Mountain

A Turnaround in the Oilfield Services Sector



NOTE: FINANCIAL DATA FOR 2024 IS ON LTM BASIS AS OF NOVEMBER 20, 2024.
SOURCE: DELOITTE ANALYSIS OF DATA FROM S&P CAPITAL 1Q.

The OFS sector has seen dramatic periods of instability in the past 10 years—suffering through the pandemic and the reverberations of an OPEC-shale price war along with the rest of the industry.

SHUTTERSTOCK

"In fact, oilfield services companies seem to be repeating what their upstream shale customers did years ago–growing profitably without a commensurate increase in capex."

DELOITTE'S 2025 OIL AND GAS INDUSTRY OUTLOOK

Energy and Avant Natural Resources. Other E&Ps, such as Surge Energy, have $1.3 billion in liquidity ready to deploy for the right acquisition target.

The Permian's main challenge is everyone wants in and the pickings are getting slimmer. That has led to higher acreage prices and limited high-quality acquisition targets in the basin, Deloitte said.

Ultimately, that may lead to increased drilling and buying activities in other basins, primarily the Eagle Ford Shale and Bakken Shale. In early December, Crescent Energy followed that playbook with an agreement to buy Eagle Ford E&P Ridgemar Energy for $905 million.

In the first three quarters of 2024, the two plays saw about $7.7 billion in announced deals.

Deloitte's take: The Eagle Ford and Bakken offer additional acquisition targets and refracturing opportunities without the natural gas infrastructure constraints the Permian is facing.

"Consolidating acquired assets and leveraging investments in new technologies, while benefiting from strengthening natural gas prices due to new pipelines, will likely support the profitable growth strategy of shale majors in 2025," Deloitte said.

But the bigger prize could be how shale majors rethink their Tier 2 and Tier 3 acreage across shale basins. Recompletions, EOR and innovative completion techniques have the potential to enhance their capital returns and well productivity.

In the Bakken, Tier 1 acreage development is growing by 5% to 10% annually, while Tier 2 acreage is growing by 20% annually.

The Eagle Ford and Bakken can also take some of the concentration risk off of the Permian. In 2024, the Permian contributed 46% of U.S. crude oil production, 20% of gross natural gas production and 51% of rig count activity.

The basin's outsized oil production is growing at an annual average of 485,000 bbl/d, which is equivalent to Colombia's annual average consumption, Deloitte said.

E&Ps looking for inventory in the Eagle Ford and Bakken can also bridge the valuation gap across the shale basins, keep the overall production profile of U.S. shale basins stable and help bring back private equity or venture capital players, Deloitte said.

"This is especially true in the U.S. upstream sector, where public company consolidations offer more favorable valuations for undeveloped inventory compared to private equity buyouts, with premiums remaining modest at 10% to 15%," Deloitte said.

In the Permian, E&Ps will likely have to adapt to address low oil prices and peaking productivity gains. In the Midland Basin, rigs drilled an average of 47 miles of horizontal wells through June 2024.

The Permian also faces an all-time low inventory of drilled but uncompleted wells at 4,500, and the forecasted resurgence in global liquids consumption is expected to increase by 1.5 MMbbl/d in 2025, Deloitte said.

"Against the backdrop of major acquisitions, eyes will be on U.S. shale majors to share and execute their 'what's next?' strategy for the Permian Basin," Deloitte said.

OFS M&A, Cycle-Proofing

With E&P efficiencies and consolidations setting the stage, the time for even more service company consolidation may be nearing.

"A period of financial strength amid an easing macroeconomic environment and a highly fragmented sector is generally followed by consolidation," Deloitte said.

The firm pointed to SLB's pending acquisition of ChampionX in an all-stock transaction valued at $7.7 billion. The transaction was the largest service company deal announced in 2024. Deloitte noted that SLB's deal focuses on expanding its presence within the "less cyclical and growing production and recovery space that covers the asset life cycle from completion through decommissioning."

Similar dynamics were at play with Nabors Industries' agreement to acquire Parker Wellbore in a deal valued at $372 million. Parker's casing-running business complements Nabors' tubular services, Deloitte noted.

Coming next may be a rollup of service companies now that E&Ps have consolidated.

"Considering their large upstream customers have completed megamergers in the Permian region in 2023 and 2024 and will require scalable and tech-powered oilfield services, many small-sized companies could seek exits at favorable valuations, spurring consolidation across the sector," Deloitte said.

The firm added that buyer interest for drilling rigs increased in 2024 with deal value reaching $3.8 billion–the second-highest level since 2018.

And, during the past four years, the industry's capital expenditures have increased by 53%, while its net profit has risen by nearly 16%. Regardless of M&A, oilfield services are on a roll. The sector reported its best performance for the 2023-2024 period in the past 34 years, Deloitte said.

And some companies are engaging in increased investments in low-carbon technology projects to help balance the risks associated with the traditional oil and gas market.

"These investments will likely help companies position themselves as key players in the future energy landscape," Deloitte said.

Oilfield companies such as SLB are leveraging their digital capabilities to deliver high-margin, lower-carbon solutions to their customers, Deloitte said. SLB is developing an all-electric subsea infrastructure aimed at reducing costs, improving efficiency and lowering carbon emissions.

OFS companies are also implementing cost-reduction measures, including restructuring operations, exiting unprofitable business lines, implementing variable cost management programs and streamlining corporate structures.

"These initiatives have yielded substantial financial benefits–for instance, NOV Inc. reported US$75 million in annualized cost savings and Weatherford reported a 160-basis-point increase in gross margin," Deloitte said. "By recalibrating its strategies, the sector has navigated the challenges posed by reduced demand for certain services, while continuing to drive efficiency and maintain capital discipline."

Some OFS companies are also transitioning into "energy technology companies" by diversifying their portfolios to include low-carbon ventures such as carbon capture and hydrogen generation, Deloitte said.

Baker Hughes is developing supercritical CO_2 turboexpanders to support NET Power's low-cost, emission-free, carbon-capturing power system. And SLB is developing an integrated direct lithium-extraction solution that could be significantly faster than traditional methods, while lowering resource usage, thereby possibly reducing operational costs.

Deloitte said new technology solutions are expected to drive the long-term growth of OFS companies, "with companies like Baker Hughes targeting approximately US$6 billion to US$7 billion in new orders by 2030." OGI

Notable OFS Deals, 2024

Announced/ Closed	Acquirer	Seller	$MM
4/2/24	SLB	ChampionX	$7,740
7/25/24	Helmerich & Payne	KCA Deutag	$1,970
7/31/24	Apollo	U.S. Silica Holdings	$1,850
9/5/24	Noble Corp.	Diamond Offshore Drilling	$1,590
3/27/24	SLB	Aker Carbon Capture	$380
10/15/24	Nabors Industries	Parker Wellbore	$380
10/15/24	Flowserve	MOGAS Industries	$290
7/9/24	ChampionX	RMSpuptools	$110
12/3/24	Innovex International	Downhole Well Solutions	$104

SOURCE: HART ENERGY

"A period of financial strength amid an easing macroeconomic environment and a highly fragmented sector is generally followed by consolidation."

DELOITTE'S 2025 OIL AND GAS INDUSTRY OUTLOOK

PCC

PRIVATE CAPITAL CONFERENCE

– A Premier IPAA Event –

January 23, 2025

THE POST OAK AT UPTOWN
HOUSTON

Our 31st Annual Event!

CAPITAL MARKETS COMMITTEE CHAIR | JOAQUIN ANDERSON
MANAGING DIRECTOR - STRUCTURED PRODUCTS, BP ENERGY COMPANY

Private Capital Conference

This event seeks to help U.S. oil and natural gas operators determine how they can approach different providers to meet their needs. We will examine who has capital to invest, how the rules have changed for companies seeking capital and discuss evolving industry trends that affect capital providers and capital seekers alike.

Featured Sessions Include:

- **Driving Success: Companies Effectively Raising Capital and Executing Exits in the Current Energy Environment**
- **The State of Traditional Private Equity**
- **A Banker's Perspective on How to Get Deals Done in Today's Market**
- **Private Credit - The Alternative Debt Providers**
- **Family Offices and International Equity: The Hottest Trends in Energy Investing**
- **Keynote Luncheon Speaker - Carolyn Hansard**

CONFERENCE CHAIR

CALLIE HAMILTON, CFA
Managing Director
Real Assets Energy
Prudential Private Capital

REGISTER BY VISITING
ipaa.org/events

SPONSORSHIPS ARE AVAILABLE AND SELL QUICKLY!

Contact Beth Stockner
bstockner@ipaa.org
276-608-8224

IPAA
INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

THANK YOU 2025 Premier Sponsors

bp
KIRKLAND & ELLIS
OPPORTUNE
Akin
BAKER BOTTS
HAYNES BOONE
LATHAM
LATHAM & WATKINS
SIDLEY

EY: Three Themes Will Drive Transformational M&A in 2025

Prices, consolidation and financial firepower will push deals forward.

REGINA BALDERAS
HEITH ROTHMAN
SEAN HEINROTH
EY

Regina Balderas is the EY Americas Oil & Gas and Chemicals Strategy and Transactions Leader. Heith Rothman is a principal at EY-Parthenon in the Strategy and Transactions Practice. Sean Heinroth is a principal at EY-Parthenon in the Strategy and Transactions Practice.

With a change in administrations, it is natural for dealmaking activity to take a pause as the industry assesses both the economic and political climate. For oil and gas companies, however, transactions could pick up quickly owing to three factors which have underpinned the strong M&A market over the past two years.

Pricing Outlooks Pave Path for M&A

While headlines may continue to add volatility in day-to-day trading, the sector enters 2025 with a relatively positive outlook for medium-term oil and international gas prices. This consensus on longer-term price expectations—which have more of an impact on strategic decision-making around acquisitions—creates a positive outlook for M&A as bid and ask valuations should stay roughly synchronized. This alignment will allow deal flow to continue.

Inorganic Growth Fuels Cost Advantages in Core Business

As detailed in this year's annual study of U.S. oil and gas production and reserves, focusing on building out core areas of growth enables companies to expand production, add reserves and keep cost increases at or below the levels of prevailing general inflation.

Consolidation is critical and is likely to continue to deliver improvements, efficiency and value throughout 2025.

Although many of the deals announced in recent years are complex and involve global portfolios of assets, each transaction included a core value driver around consolidation in the unconventional space. This consolidation offers the opportunity to optimize operations and implement technology.

Additionally, the scale of these enterprise deals will spur further M&A activity as the evaluation of the new portfolio unveils assets that are no longer core to the future business. Inorganic growth will continue to be a go-to-method for oil and gas companies to capture cost advantages and deliver returns.

Sector Firepower Available for Investment

The oil and gas sector has built up firepower, meaning the ability of companies in the sector to fund transactions from their balance sheet.

The EY Strategy and Transactions practice measures firepower by examining a company's cash position, market capitalization and debt positioning. For oil and gas companies, rising oil prices have helped increase revenues and valuations, driving up their firepower. The sector experienced a wave of megadeals in 2023 and 2024, with only a recent slowing, which was expected as dealmakers awaited both the U.S. election outcome and signals from the new administration concerning its appetite for further consolidation.

It is likely that deal activity will resume relatively quickly—further spurred by a perception of fewer regulatory hurdles to getting deals approved, encouraging a broader range of participants. Recent and expected interest rate cuts add to this expectation, but the opportunities are not the same for all players.

Firepower represents the ability to execute deals, but recent growth trends also underscore the need for more activity. The intersection of these two trends defines four zones.

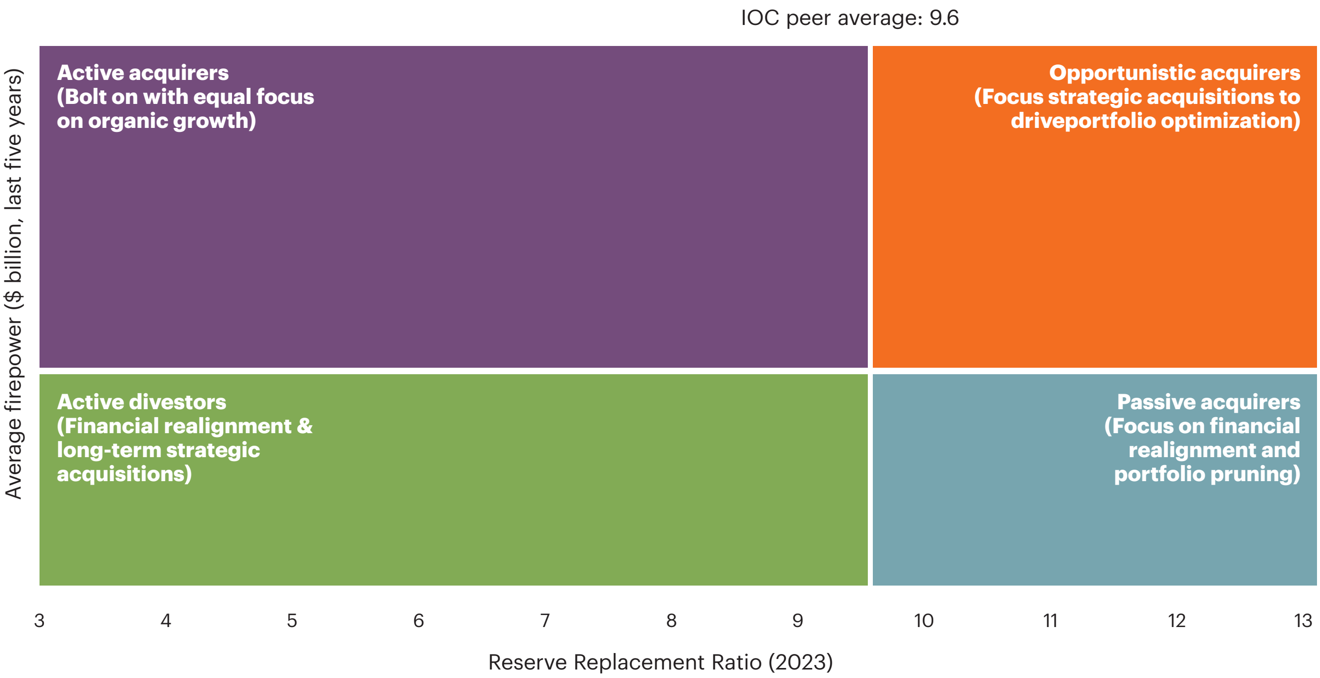
Companies that have seen relatively weaker recent performance and have low firepower are in a zone where active divestments should be part of their strategic thinking. These companies need to undertake financial realignment to increase their ability to undertake longer-term strategic acquisitions.

Companies with higher firepower but lagging their peers in terms of performance populate the active acquisition zone, where companies should be equally focused on organic growth and bolt-on acquisitions. They have the firepower but need growth opportunities.

The passive zone is defined by companies with good performance, but weaker firepower. The balance sheet needs to be addressed, but acquisitions able to enhance cash flow in particular will be targeted.

Companies with both strong recent performance and a high level of firepower define the zone of opportunity, where companies can take advantage of strategic

Strategy Matrix: Firepower vs. Reserve Replacement Ratio



SOURCE: CAPITAL IQ, SECONDARY RESEARCH, EY ANALYSIS

acquisitions that may appear.

There are situations in which, despite having low firepower, some firms need to execute large deals. This doesn't mean those companies are incapable of making strategic acquisitions, but they will be challenged to do it from the balance sheet, requiring different deal structures, or more complex transactions.

Subsector Outlook

For 2025, the subsectors of oil and gas will see different M&A activity levels and motivations:

▶ **Upstream companies**–Strategic acquisitions in this subsector have been motivated by a desire to boost competitiveness, access reserves, focus on operational efficiency and stakeholder benefits. While dealmaking in the prolific Permian Basin is making this the domain of deep-pocketed, large producers, independents are also driving a push to increased activity beyond the Permian. U.S. natural gas assets remain attractive due to the potential for LNG exports to meet Europe's demand.

Notably, international oil companies (IOCs) account for more than 50% of the industry firepower, so there is an expectation these players will continue to target both traditional assets and new green technologies such as carbon capture and hydrogen. On the other hand, pure-play independents, particularly those with large U.S. shale acreages, are attractive targets for their ability to enhance competitiveness and gain access to reserves.

▶ **Midstream companies** have historically accounted for about a quarter of oil and gas sector deals despite already being consolidated. Looking ahead, the subsector will be impacted by continued upstream integrating into downstream operations to secure offtake and may see further consolidation within its own as midsized players combine to achieve scaled economies.

> *"Consolidation is critical and is likely to continue to deliver improvements, efficiency and value throughout 2025."*

▶ **Downstream companies** have trended toward consolidation to enhance operational efficiencies, but current pressure on refining margins and economics is having a dampening effect on firepower. Deals in 2025 will likely be prompted by moves to adapt to shifting consumption patterns, efficiency and sustainability.

▶ **Oilfield services companies** have been tremendously impacted by the consolidation in the U.S. upstream subsector, but this has been somewhat offset by stronger performances in offshore and international business. Overall oil and gas capex in 2025 is expected to rise 4%, further bolstering oilfield equipment and services firepower, and M&A will be driven by the need for scale, competitive cost structures and access to capital.

In oil and gas, discipline has differentiated this current wave of consolidation from previous merger activity. This trend is expected to continue as companies determine what to retain and what to spin-off as non-core, which is allowing other players in turn to consolidate their own positions in those "non-core" areas. OGI

Midwesterners to CCUS: Not in My Corn Field

Midstream firms in the Midwest are running into brick walls of local opposition against carbon capture projects.

SANDY SEGRIST
SENIOR EDITOR, GAS AND MIDSTREAM
ssegrist@hartenergy.com

Carbon capture and underground storage projects have been on the drawing board for decades.

And over the same period, Americans have mostly backed the idea.

Poll after poll find that most Americans do not put climate change at the top of their threat list, but they generally support the removal of greenhouse gases from the atmosphere.

A series of Massachusetts Institute of Technology surveys found general support for carbon capture projects dating to the 2010s. The Pew Research Center found support for efforts to curb climate change in 2023.

The first major projects were pitched at the beginning of the 2020s. Since then, midstream companies and their investors have discovered that, while the general public is fine with the idea, many of the locals are much less predisposed to it and have passionate opinions.

Four projects have been attempted in the Midwest since 2021. All but one has encountered staunch opposition from some of the landowners along the proposed routes and the state legislators that represent them.

The projects have also received support from some residents and related industries, but the opponents have been able to claim at least one victory. One project has been canceled, and another was being reconsidered at the end of 2024.

Opponents claim the projects will not help the environment, are dangerous and violate their land rights.

"It's pretty exciting to be here making property rights one of the most important topics in our state," Mike Klipfel, a South Dakota farmer, told the Tri-State Livestock News following a court victory against a project in August.

Supporters say the projects are necessary to meet emission standards that keep going up, and to improve the viability of industries such as ethanol production.

"I think this is really a turning point in our industry," said James Broghammer, CEO of Pine Lake Corn Processors, in a streaming video supporting a carbon capture and storage (CCS) project. "We can either decide to support these plants and get behind CO_2 sequestration, or this is the beginning of the end."

Land Battle

The fights over carbon capture, utilization and storage (CCUS) pipeline projects have a different flavor than typical midstream sector battles. The decisions surrounding the Keystone XL or the Mountain Valley Pipeline projects boiled down to competing lobbying efforts and court battles between the environmental and energy sectors.

CCUS projects are different because the pipelines don't carry hydrocarbons to market, but greenhouse gases to isolated areas for disposal. Courts are still determining the legal definitions governing the projects on a state-by-state basis.

The state fights over CCUS don't follow political affiliation and tend to be more regional in nature, with rural landowners battling businesses interested in lowering their carbon output.

In February, Iowa opponents of the use of eminent domain to build Summit Carbon Solutions' CO_2 pipelines staged a die-in at the state capital in Des Moines. The look was far less "urban" than similar city protests–participants mostly middle-aged or older, flattened on the floor wearing red, button-up, collared shirts along with blue jeans and work shoes.

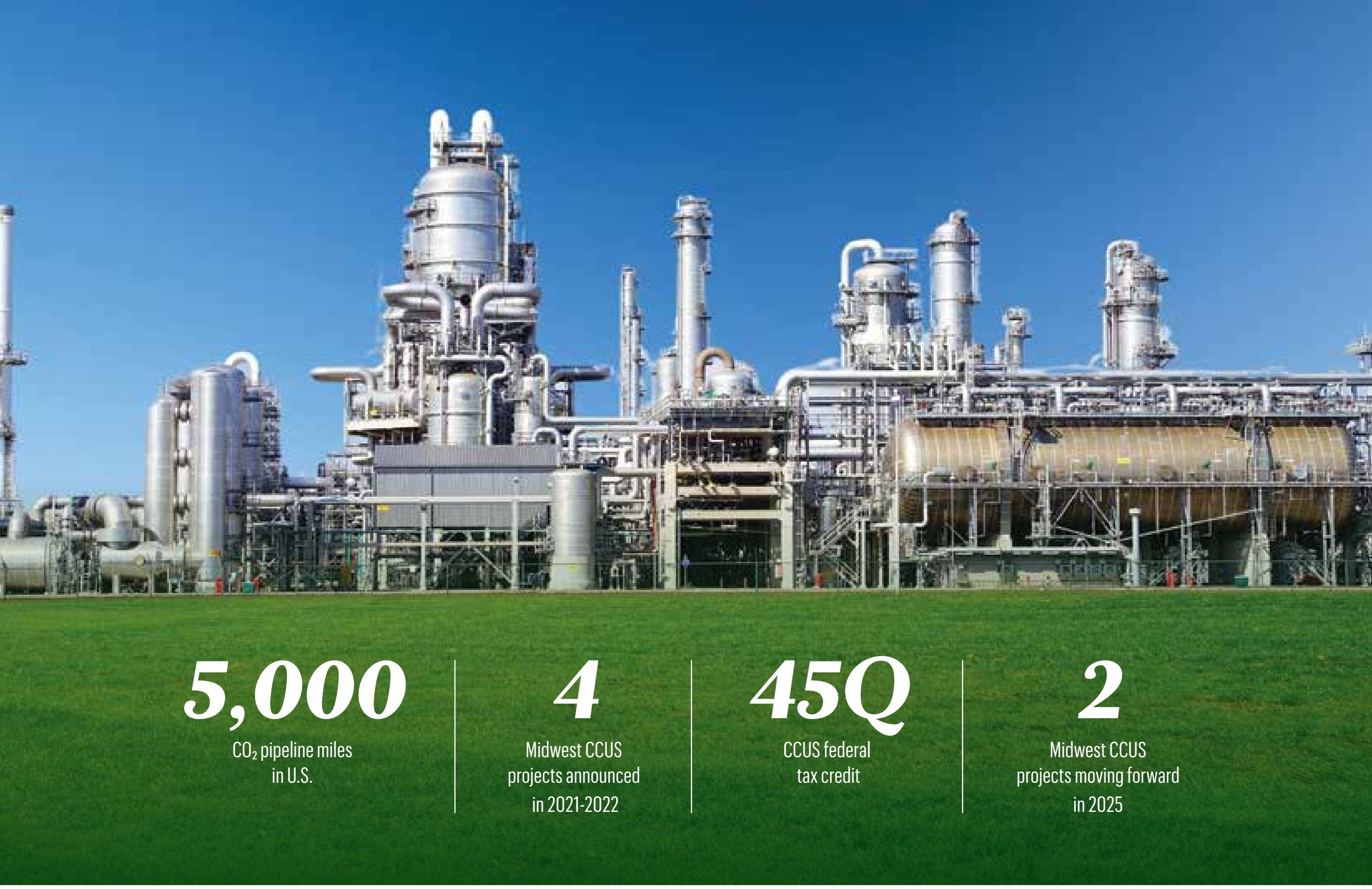
Continental Resources Executive Chairman Harold Hamm has watched the battle unfold on the $4.5 billion Summit Carbon Solutions project, in which his company invested $250 million in 2022.

After hearing an appeal of a lower court decision, the Supreme Court of South Dakota remanded the case back to the lower courts, saying that too many issues remain unresolved.

"There's a lot of misunderstanding, because some of that stuff is so hard to explain," Hamm said in an interview with *Oil and Gas Investor*.

A big part of the fight in South Dakota, and in other states within Summit's proposed network, is the issue of eminent domain. Companies building crude, gas and NGL pipelines generally have eminent domain authority because the products on the line are all defined as commodities.

Some states have declared CO_2 to be a commodity and have therefore granted eminent domain authority. The South Dakota High Court found that "the existing record suggested that CO_2 is being shipped and sequestered



SHUTTERSTOCK

CO_2 is useful in many fracking operations, and for years producers in Texas and Louisiana have been shipping it and storing it underground for later use.

underground with no apparent productive use and therefore would not qualify as a commodity." It's a line of reasoning Hamm did not agree with.

"Really? Well, how about your corn? Do you sell every grain of that, or do you store some of it?" he said. "It is just nonsensical. It made no sense at all."

The court, however, did not make a final ruling on eminent domain when it remanded it back to the lower court, and the Summit project continues to move forward.

Of the four Midwestern CCUS projects announced in 2021, Summit is the most ambitious. The company has partnered with 57 ethanol plants in Iowa, Minnesota, North Dakota, South Dakota and Nebraska. After gathering up to 18 MM tons/year of CO_2 along its 2,500-mile network, the greenhouse gas will be moved to disposal wells in North Dakota.

The ethanol industry has backed the development of CCUS as a way to expand its business base. Like all other industrial companies, ethanol producers are required to keep a close eye on their emissions.

Ethanol producers also have to deal with the rising carbon intensity requirements of some U.S. states, especially California, said Sen. Mike Jacobsen (R-Neb.), in a letter for the American Carbon Alliance, an organization that promotes carbon capture.

"Carbon sequestration can make sure Nebraska ethanol continues to have a role in the U.S. economy," Jacobsen said.

Tough Business

The economics of building and running a CCUS operation are still being figured out, giving the start-up firms another hurdle outside of the political barriers.

The CO_2 headed for permanent storage can't be sold. The start-ups instead rely on CO_2 producers to pay for takeaway and have otherwise depended on government subsidies and the 45Q tax credit.

"It takes a lot of money to build these pipes, build these projects, build these injections," Hamm said, referring to the need for federal subsidies.

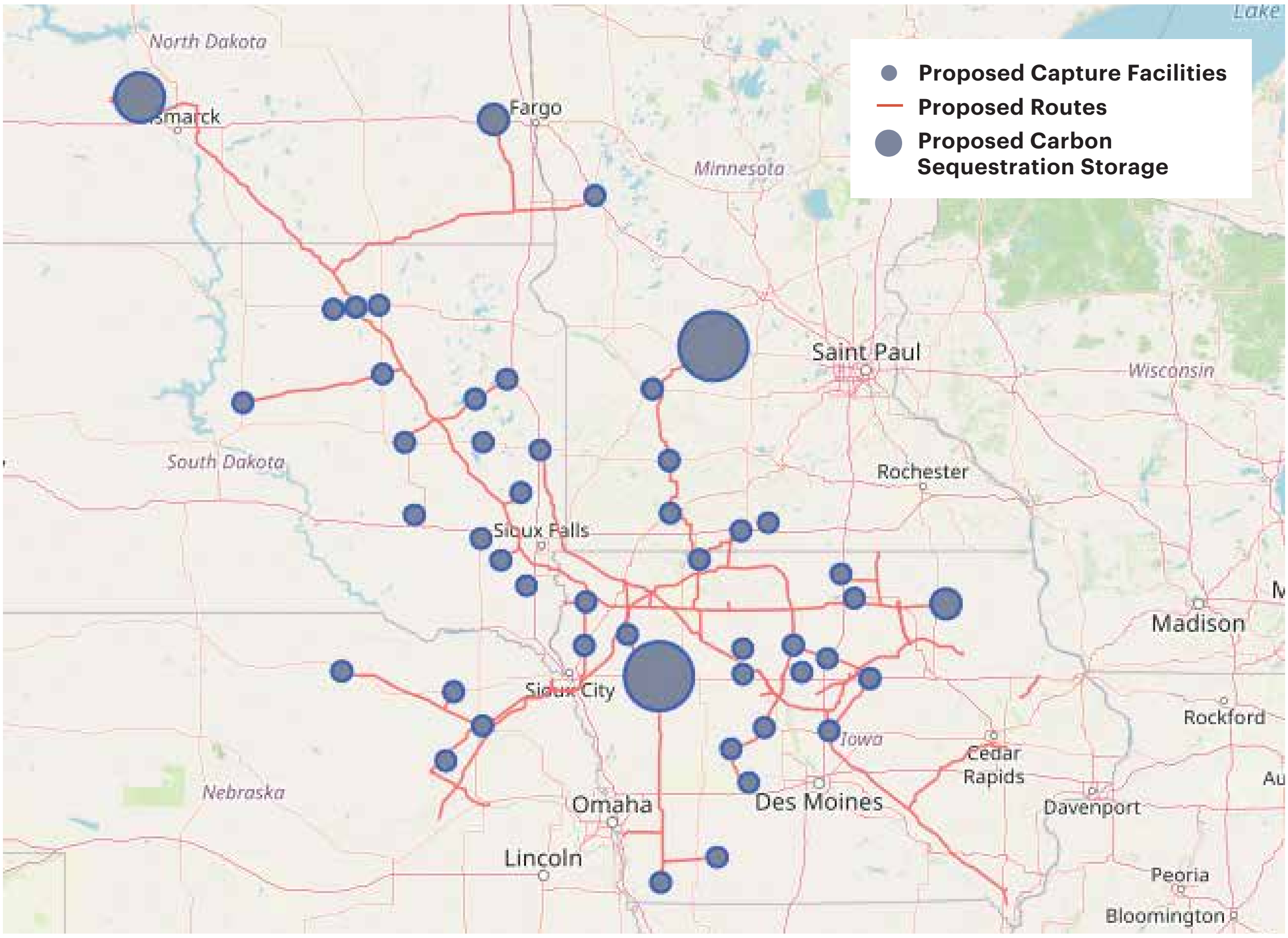
The federal government gave $5.3 billion in support for CCUS research and projects from 2011 to 2023, according to the General Accounting Office. The government predicts that the 45Q credit will allow participating businesses to keep an extra $5 billion from 2023 to 2027.

Financial challenges still exist for midstreamers wanting to enter the market. Projects generally need to be large-scale to move enough volume to collect enough fees, potentially limiting the size of entrants into the sector.

Moving CO_2 also presents several problems when compared to moving methane. CO_2's liquefication temperature is far higher than methane's, meaning that the typical pressure fluctuations that would not cause a problem with methane could cause damage with CO_2. It also becomes acidic when mixed with water, corroding pipelines much faster than methane.

The challenges have taken a toll on the original start-ups.

Summit Carbon Solutions' Proposed System



SOURCE: REXTAG, SUMMIT CARBON SOLUTIONS

Navigator CO_2 Ventures started business in March 2021. The company's Heartland Gateway would have operated on a 1,300-mile network providing the same service to ethanol producers as Summit. The South Dakota government rejected the company's siting approval in September 2023. Navigator canceled the project the next month.

Wolf Carbon Solutions launched in January 2022. The company limited its scope to a 280-mile pipeline from electric generators and ethanol plants in Iowa to a disposal sites in Illinois. In December 2024, the company withdrew its petition to build in Iowa after it had difficulty obtaining easements for the project. In a statement, the company said it was still determining whether it will continue on the project.

Tallgrass Energy has attracted the least amount of opposition for its plan, the Trailblazer Conversion Project. The CCUS is also the only brownfield project of the four. In 2023, Tallgrass received permission from the Federal Energy Regulatory Commission to convert an interstate natural gas pipeline to a CO_2 pipeline. The project will transport CO_2 from ethanol facilities in Nebraska to a disposal site in Wyoming. Tallgrass held an open season for capacity on the project in May 2024. Tallgrass filed for permits to build compression facilities at an ethanol plant in Aurora, Neb., in September, the Aurora News-Register reported.

Proven Elsewhere

While the major projects in the Midwest are new, storing CO_2 underground is old hat for much of the energy sector.

CO_2 is useful in many fracking operations, and for years producers in Texas and Louisiana have been shipping it and storing it underground for later use.

About 5,000 miles of CO_2 pipeline already exist in the U.S., primarily for enhanced oil recovery, according to the Congressional Research Service.

As of 2023, a small number of carbon capture and storage facilities were operating in the U.S., most of them co-located with gas processing or ethanol plants, according to the Congressional Budget Office (CBO). Almost all of the facilities send the captured CO_2 to E&Ps for enhanced oil recovery.

"The main reason CCS is used to such a limited extent is that the cost to implement CCS technology exceeds its value in most potential settings," the CBO said in a report on the technology.

However, some operators see potential.

Louisiana is attempting to join the Midwest in developing permanent underground storage for CO_2 on a major scale. The state recently received permission from the federal government to dig the deep wells needed for permanent storage and currently has 10 projects vying for permits.

In the Midwest, many in the ethanol industry see it as the natural next step in growth.

Speaking in a Summit informational video, Dave VanderGriend, CEO of biorefiner ICM, said "If this does not happen, you're going to stagnate this industry at the point it's at today." OGI

Segrist: The Keystone for Trump?

The president-elect talks about reviving the famously controversial pipeline project while threatening tariffs on the nation where it originates.

SANDY SEGRIST
SENIOR EDITOR, GAS AND MIDSTREAM
ssegrist@hartenergy.com

Protesters in front of the White House display a banner opposing construction of the Keystone XL. More than 1,200 people were arrested for civil disobedience during the prolonged protest in 2011.

SHUTTERSTOCK

>1,200 Number of protesters arrested

4 Number of presidents involved

875 mi Length of proposed Keystone XL

$15B Amount TC Energy claimed in arbitration

It's like clockwork.

The party that controls the White House changes and the otherwise left-for-dead Keystone XL Pipeline re-enters the national news cycle.

"The Trump team's plan to resuscitate a dead oil project," read a Politico headline in November, detailing anonymously sourced plans of the president-elect to resurrect the Keystone XL.

Even though President-Elect Donald Trump had already threatened Canada with tariffs.

Even though no midstream company is waiting in the wings to build it.

"(The Keystone project is) on the list of things they want to do first day," one source told Politico.

Though, it would be hard to approve a pipeline project on Day One if there's no pipeline project available to approve. On the other hand, some analysts chalked the issue up to Trump being Trump. They said that whatever action the White House takes will be unpredictable, but the president-elect is unlikely to shoot himself in the foot.

The U.S. accounted for 97% of Canada's crude exports in 2023, according to the Canada Energy Regulator. The percentage may change with the opening of the Trans Mountain Pipeline, but the U.S. imports 50% of the crude shipped from the new pipeline as well.

That amount of trade is as important to the U.S. as Canada.

"Our futures are undeniably linked, as they always have been," said Kevin Birn, Canadian oil markets chief analyst for S&P Global Commodity Insights, in an interview with the Calgary Herald.

A Decade of Back and Forth

The Keystone pipeline has become undeniably linked with American politics. Each of the last

Keystone Pipeline and Terminated Keystone XL Project

SOURCE: REXTAG

four presidents have weighed in on the project in one form or the other.

"Build the damn thing," President George W. Bush told the crowd in Pittsburgh at Hart Energy's DUG East conference in 2013.

The 2,689-mile Keystone Pipeline System delivers crude from Hardisty, Alberta, to refineries and hubs in Illinois and southeast Texas. TC Energy (TRP) and ConocoPhillips (COP) built the line. TRP bought COP's interest in 2009 and started operations in 2010. The pipe has delivered around 4 Bbbl of crude since.

Before the line was completed, TC Energy was already planning for an extension.

In 2008, TRP proposed the Keystone XL, an 875-mile addition that took a more direct route than its predecessor from Alberta to hubs in Illinois and Oklahoma. The project would have increased the network's capacity from 591,000 bbl/d to 830,000 bbl/d.

The pipeline ultimately failed after enduring a process that made the Mountain Valley Pipeline seem like a cakewalk by comparison. Opposition to the project became a rallying cry for environmental groups, and the Keystone XL bounced around in on-again, off-again status for more than a decade.

In 2010, the U.S. State Department drafted an approval, then extended its environmental review, then announced its approval in 2011, and then demanded a route change three months later.

Protests ramped up and the Keystone XL became part of the national debate. In 2011, more than 1,200 people were arrested for civil disobedience during a prolonged demonstration at the White House. The issue became the tennis ball in the ongoing back-and-forth between a Republican Congress and President Barack Obama's White House.

"For years, the Keystone Pipeline has occupied what I, frankly, consider an overinflated role in our political discourse," Obama said in his final decision to reject the project in 2015. "It became a symbol too often used as a campaign cudgel by both parties rather than a serious policy matter."

It then became an issue in the 2016 election, with Donald Trump offering support. One of his first acts in office was to reverse the State Department's stance on Keystone XL in 2017. However, Trump wanted certain elements of the deal reworked and demanded that U.S. line segments be built with American steel.

By the time work started in 2020, another election season was underway. This time Trump lost, and new President Joe Biden made cancellation of the project one of his first priorities.

Almost Dead

Before Trump brought it up during his 2024 campaign, the Keystone XL seemed to be put to rest for good.

TC Energy was still attempting to recover some of the losses of the failed project six months ago.

In July, a tribunal rejected TRP's arbitration claim of $15 billion against the U.S. government. The midstream company submitted an arbitration request under the North American Free Trade Agreement (NAFTA) in 2021.

The reason for the rejection? The changing of minds regarding political policy. The Trump administration canceled NAFTA in 2020 and replaced it with the USMCA agreement. Biden canceled Keystone XL's permit the year after that decision.

The tribunal hearing the arguments told TC Energy they could not decide if they had the authority to determine which set of rules was in place.

"This ruling does not align with our expectations and views of the plain interpretation of the protections NAFTA and the USMCA were designed to offer," said Patrick Keys, executive vice-president and general counsel for TC Energy, following the decision. "TC Energy was treated unfairly and inequitably in the revocation of the permit, which was driven by political considerations."

Three months later, a stung TC Energy spun off its liquids pipeline business into South Bow. The new company is focused primarily on paying off debts and has not indicated an interest in bringing back the project.

After the federal permits were canceled, opponents of the line in Nebraska ensured that land easements were returned to the property owners, meaning any further project would have to be started from a blank slate.

Still, the pipeline, or a substitute, does have its supporters. Fewer than 10 crude transport pipelines cross the U.S.-Canadian border. The Keystone's primary competitor, Enbridge's Mainline, is considering an expansion, even with the TMP's startup, Bloomberg reported in November.

The Mainline reported that uncontracted demand for pipeline space was greater than capacity in July, August and November. Several Canadian market players said high demand for crude pipeline space is expected for the foreseeable future.

"I think Keystone XL might be back on the table," Bob Geddes, president of Calgary-based Ensign Energy Services, told the Calgary Herald. "It's all about providing cost-effective energy."

On the other side of the border, it'll be about whether Trump decides to revive a political fight for the next go-round. OGI

East Daley: New Pipelines Could Open Floodgates

Led by the opening of the Matterhorn Express, a slew of projects is set to battle bottlenecks in the Permian Basin region.

AJAY BAKSHANI
MARIA PAZ URDANETA

Ajay Bakshani is director of midstream equity and Maria Paz Urdaneta is a Lead Data Analyst at East Daley Analytics.

Midstream is back in the Permian Basin. Following the start of Matterhorn Express, investors have pulled the trigger on several new greenfield pipelines to move natural gas away from West Texas. The investments stand to solve a longstanding bottleneck for operators and open the door to more energy production.

In early December, Energy Transfer (ET) announced a final investment decision (FID) on the Warrior Pipeline, renamed as the Hugh Brinson Pipeline. The 42-inch pipeline will span 400 miles from the Waha Hub in West Texas to Maypearl, south of Dallas/Fort Worth, where it will connect to other ET pipelines and storage infrastructure.

In Phase 1, ET will also build a 36-inch lateral for 42 miles in Martin and Midland counties to connect the mainline to third-party processing plants. Including a Phase 2 compression expansion, ET estimates a total project cost of about $2.7 billion.

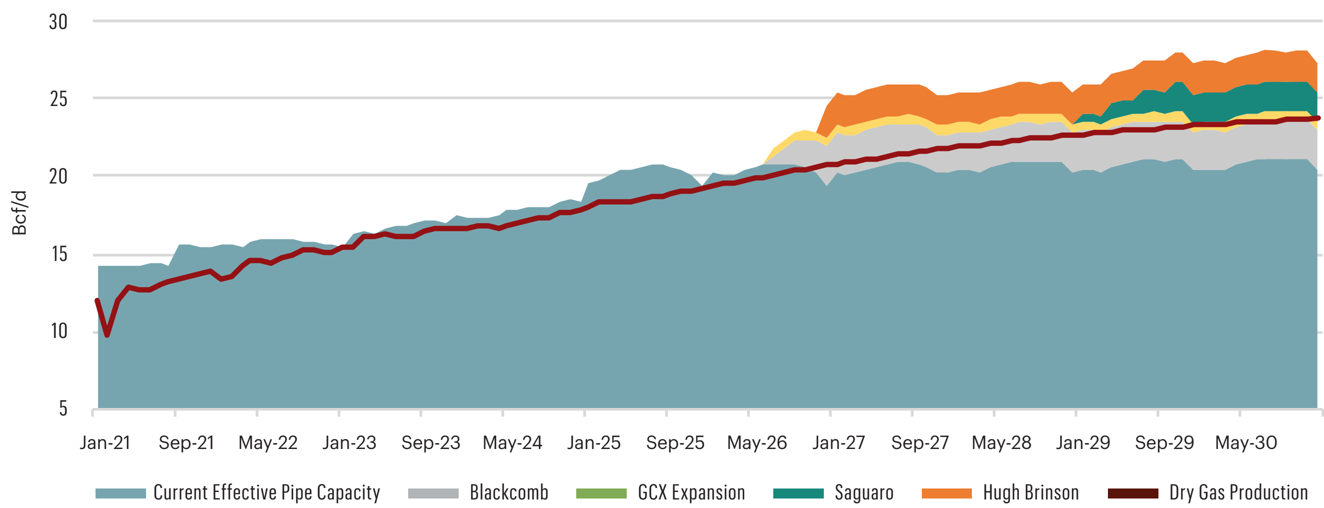
ET executives had suggested a final project decision was close on the company's third-quarter earnings call in early November. Including compression, the Hugh Brinson Pipeline will be able to transport up to 2.2 Bcf/d at an estimated $2.7 billion cost. ET plans to start Phase 1 of the project (1.5 Bcf/d capacity) by the end of 2026.

The go-ahead by ET follows the FID in July of another 42-inch greenfield project, the Blackcomb Pipeline. Led by WhiteWater Midstream, the Blackcomb group includes the Whistler Pipeline joint venture (50.6% WhiteWater, 30.4% MPLX, 19% Enbridge) and Targa Resources. Blackcomb will be able to transport up to 2.5 Bcf/d from the Permian Basin to the Agua Dulce hub in South Texas, sourcing supply from processing plants in the Midland and connections to the Agua Blanca Pipeline. Start-up is planned in the second half of 2026.

Adding to the midstream momentum, Kinder Morgan (KMI) is moving forward with an expansion of the Gulf Coast Express Pipeline (GCX). KMI will add compression to the 500-mile line to South Texas, taking its total capacity from the Permian to 2.57 Bcf/d. The GCX partners (KMI, ArcLight Capital Partners and Phillips 66 (PSX)) reached FID after obtaining binding long-term agreements, KMI said in its third-quarter earnings update.

These announcements follow the widely anticipated start of the Matterhorn Express Pipeline from the Permian. Led by WhiteWater Midstream, the 42-inch Matterhorn began delivering gas on Oct. 1 to the Katy Hub west of Houston. Volumes have ramped quickly on Matterhorn, climbing up to 1.4 Bcf/d in early November, thanks to multiple pipeline interconnects. In early December, Matterhorn was delivering about 1.3 Bcf/d to Katy on six interstate systems monitored by East Daley Analytics.

Permian Gas Production and Pipeline Egress



SOURCE: EAST DALEY ANALYTICS

Long Runway for Permian Growth

The new pipelines are great news for producers in the Permian Basin. Including Matterhorn and ET's decision on the Hugh Brinson line, Permian operators could see over 7.7 Bcf/d of new takeaway capacity added by the end of 2026.

Operators for years have contended with limited takeaway for their associated natural gas, slowing development and pressuring gas prices lower in the basin. During periods of pipeline maintenance, spot prices at the Waha hub can trade for negative prices. But with the latest decision by ET, East Daley expects ample gas pipeline capacity out of the Permian to accommodate growth.

The chart on the opposite page compares East Daley's latest Permian Basin gas production forecast with our outlook for pipeline egress through 2030, including ET's Hugh Brinson pipeline. If Mexico Pacific LNG reaches FID (expected early this year), and thus ONEOK moves ahead with its Saguaro pipeline, the basin will have plenty of capacity through 2030.

East Daley expects a near-term boost in Permian oil and gas output thanks to Matterhorn as operators start more wells. We model average dry gas production to grow 1.5 Bcf/d to 18.6 Bcf/d in 2025.

Oil production also grows in our 2025 forecast. Permian oil production passed 6 MMbbl/d at the end of 2023 and was on pace to average 6.1 MMbbl/d in 2024. We forecast 300,000 bbl/d of growth in 2025. By the time Blackcomb and the ET line start at year-end 2026, Permian oil production reaches over 6.7 MMbbl/d in our outlook.

Expanding Texas Demand

While great for producers, the overbuild of gas pipelines is likely to significantly narrow spreads from the Waha hub, a source of profit for many midstream and marketing companies. Firms with marketing affiliates (including ET) can sell cheap gas bought in the Permian to higher-priced markets.

So, why would ET still build Hugh Brinson? One answer is data centers and increasing power demand in the Dallas-Fort Worth area, where Hugh Brinson terminates. ET's management hinted as much in the third-quarter call, saying contracting is "weighted a little bit heavier towards market pool than it is on producer push." Unlike producers, demand-pull customers like electric utilities do not care about overbuilding so much as securing supply.

With ever-increasing demand estimates from data centers and general population growth, Texas will need a lot of generation capacity, and natural gas plants will be a part of the solution.

The Electric Reliability Council of Texas (ERCOT) expects peak generation capacity will need to grow 72% by 2030 to meet demand, from 86 megawatts (MW) in 2024 to 148 MW. Those estimates are significantly higher than other independent system operator forecasts, and we would not be surprised if a more conservative outlook materializes. Nonetheless, we expect a large increase in power (and thus natural gas) demand ahead.

The theme of higher power demand is starting to crystalize into real investments, and ET looks to be an early winner with the Hugh Brinson project. It, along with the Matterhorn start, is one more reason to be bullish on the long-term outlook for the Permian Basin. With the Blackcomb and KMI expansions still ahead, the future is certainly bright.

Belcher: Heed the Lessons from Europe's Net-Zero Perils

The EU's aggressive climate stance is wreaking economic havoc.

JACK BELCHER
CORNERSTONE GOVERNMENT AFFAIRS
jbelcher@cgagroup.com

Jack Belcher is a principal at Cornerstone Government Affairs, where he focuses on regulatory affairs, risk management and ESG matters within the energy and transportation sectors.

The ongoing economic decline in Europe is well-documented. There has been a slew of bad economic news from across the continent.

German automaker Volkswagen announced the closing of three of its 10 plants, the shedding of tens of thousands of jobs and across-the-board pay cuts of 10%. Volkswagen's woes are the result of poor sales in China and other markets, but they are also emblematic of a broader problem for manufacturing in Germany and most of Europe—they are not competitive because their energy costs are too high and, thus, their products are too expensive.

Europe is undergoing a process of deindustrialization. Germany was a manufacturing marvel for over a century. It was a world leader in steel production, machinery, electronics, automobiles, chemicals and pharmaceuticals. Much of its success came from its highly educated workforce, well-managed and efficient infrastructure, and state support and finance. But even with all of that history and its built-in advantages, German manufacturing, and manufacturing throughout Europe, cannot overcome the competitive disadvantage it faces due to high energy costs and energy scarcity.

While Europe has long had its challenges regarding energy supply, its current energy and manufacturing crisis was preventable and self-inflicted. The EU has taken a very aggressive approach to climate change through punitive measures to reduce greenhouse gas (GHG) emissions.

In 2005, the EU established the European Emissions Trading System (ETS) which had success in reducing GHG emissions, including CO_2, nitrous oxide and perfluorocarbons, through a cap-and-trade market that targets emissions from electricity and heat generation, industrial manufacturing (including petroleum refining and chemicals manufacturing), aviation and maritime transport. These targeted sources amount to about 40% of the EU's GHG emissions.

The result of the EU ETS program has been a significant reduction in GHG emissions, but it has also damaged the European economy, especially its manufacturing sector. Its ETS program makes the cost of electricity more expensive, thus making manufacturing more costly and uncompetitive with the rest of the world. It has resulted in significant closures in manufacturing facilities across Europe, including steel, aluminum, ferro and magnesium production, all of which are critical to manufacturing. It has caused factory closures, massive layoffs and economic uncertainty. But the EU didn't stop there. In 2010, it launched the European Green Deal with a promise of no net emissions of GHG by 2050 and climate, energy, transport and taxation policies to reduce net GHG emissions by at least 55% by 2030.

Regulations Aplenty

More recently, following the lead that the U.S. took with the clean energy incentives in the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA), the EU launched a series of less punitive, more incentive-based measures. The Net-Zero Industry Act (NZIA) is an EU initiative designed to increase the manufacturing of clean technologies in the EU. The Critical Raw Material Act (CRMA) is designed to strengthen the European critical raw materials value chain. REPowerEU is a plan for the EU to phase-out Russian fossil fuel imports by conserving energy, diversifying energy supplies and producing clean energy. Finally, the Carbon Border Adjustment Mechanism (CBAM) places carbon intensity limits on imports into the EU and provides import fees for products that miss those targets.

The EU is also enacting the EU Methane Regulation, which requires the European natural gas, oil and coal industries to measure, monitor, report and verify their emissions to the highest global standards and take steps to reduce emissions.

This regulation is especially important to the U.S. LNG industry and to U.S. gas producers whose gas is delivered to Europe as LNG. If successfully enacted, it would require U.S. producers to rigorously monitor and reduce their methane emissions.

U.S. natural gas and LNG producers are not happy with this new layer or regulation and compliance. When Europe was cut off from Russian gas, the U.S. jumped in to help supply its needs. But in the future, Europe's regulations might push U.S. LNG producers to send more supply to Asia.

SHUTTERSTOCK

Volkswagen has announced plans to close three of its plants, including this one in Wolfsburg, Germany.

Europe's energy options are limited. The continent has very little oil and gas production, outside of the declining North Sea, despite having promising prospects both onshore and offshore. U.S. LNG imports have become increasingly critical to Europe's energy situation with the reduction in Russian gas imports following Russia's invasion of Ukraine, and the destruction of the Nord Stream 2 pipeline.

Germany has banned nuclear energy production, closing its last three nuclear facilities in April 2023. The European grid is facing issues similar to that of the U.S. During periods of extreme cold or heat, reliable sources of generation are challenged, and prices are through the roof.

The combination of self-inflicted higher electricity prices, increased reliance on LNG imports and limited reliable energy production is destroying Europe's manufacturing sector, its economy and its security. The world can no longer afford its products. In short, Europe has gone from being one of the world's leading manufacturers of goods to being the world's largest producer of regulations.

Bad News for U.S.

Europe's malaise is bad news for the U.S. for a number of reasons. A strong Europe helps the U.S. because transatlantic trade is critically important to the overall economy. As a strategic security partner, a weakened Europe emboldens Russia, China and other adversaries of the West. A weakened Europe strengthens the position of the BRICS nations in their efforts to move the world away from the U.S. dollar as the reserve currency.

For the past seven decades, the relationship between the U.S. and Europe has been critical to building a democratic, peaceful and secure world. Starting with the Bretton Woods agreement in 1944, it has been essential to establishing global peace and order through multilateral agreements such as the General Agreement on Tariffs and Trade (GATT), the World Trade Organization (WTO), the International Monetary Fund (IMF), the World Bank Group, the International Court of Justice (World Court) and other global institutions and agreements that promote the rule of law, free and fair trade, human rights, environmental protection and sustainability, and prosperity. Without a strong European economy, buoyed by a manufacturing sector, these global pursuits and tenets will be under threat.

Europe's manufacturing and economic crisis is not just a threat to global institutions and prosperity but also a potential harbinger of things to come to the U.S. It is a reminder of the damage that can be done when noble pursuits pursued with the best intentions aren't properly weighed against the potential outcomes.

Europe's climate goals were not meant to wreck its manufacturing economy, but they have made energy prices too expensive and European manufacturing uncompetitive. Europe can still turn things around, perhaps through a populist wave that reverses policies, but it would have to move fast as it is hemorrhaging factories and industries.

The U.S. is blessed with abundant energy supplies, but it could still wreck its manufacturing sector if it moves too fast and takes a similar course to that of Europe. OGI

Bracewell: Many Await Updates to Existing CO_2 Pipeline Safety Regulations

Lack of clarity over federal rules puts projects in limbo.

CATHERINE LITTLE
ANNE COOK

Catherine Little and Anne Cook are partners in the Washington, D.C., office of the Bracewell law firm, where they advise oil and gas pipeline, associated storage and LNG clients across the U.S. on traditional and renewable energy, transportation and safety-related legal matters at federal, state and local levels.

CO_2 pipelines are expected to play a key role in reducing greenhouse gas emissions and achieving net-zero emissions by 2050 in the U.S.

Carbon capture and storage system (CCS) projects, many of which involved transportation by pipeline, are intended to capture and remove CO_2 from the atmosphere and transport it to permanent underground storage or conversion sites. Certain of these projects are eligible for grants from the Department of Energy (DOE), which is tasked with providing "future growth grants" to fund CO_2 projects such as CCS.

A critical path for success of CO_2 projects depends, in part, on regulation by the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration, referred to as PHMSA. While pipelines are considered the most efficient and safest mode to transport CO_2, the sufficiency of existing CO_2 pipeline safety regulations has come under scrutiny in light of a 2020 CO_2 pipeline incident in Satartia, Miss.

As CCS projects progress, third parties have called for updated CO_2 regulations. Meanwhile, states and local governments have considered—and some have passed—moratoriums on CO_2 pipeline projects until updated regulations are in place or local regulations are enacted to address what they see as gaps in the federal regulatory scheme.

It is a common misconception, however, that PHMSA does not regulate any CO_2 pipelines, or that those regulations are not comprehensive. PHMSA has long exercised statutory and regulatory authority over the design, construction and operation of thousands of miles of CO_2 pipelines. Further, PHMSA announced a rulemaking in 2022 to both update CO_2 regulations and establish regulations for gaseous CO_2 pipelines.

The agency has been slow, however, to rebut public misconceptions about regulation of CO_2 pipelines and to issue a proposed rule. Such delays potentially hinder CCS projects and the ability of the U.S. to meet its climate goals.

~5.2K
miles of regulated CO_2 pipelines in U.S.

Existing PHMSA Regulations

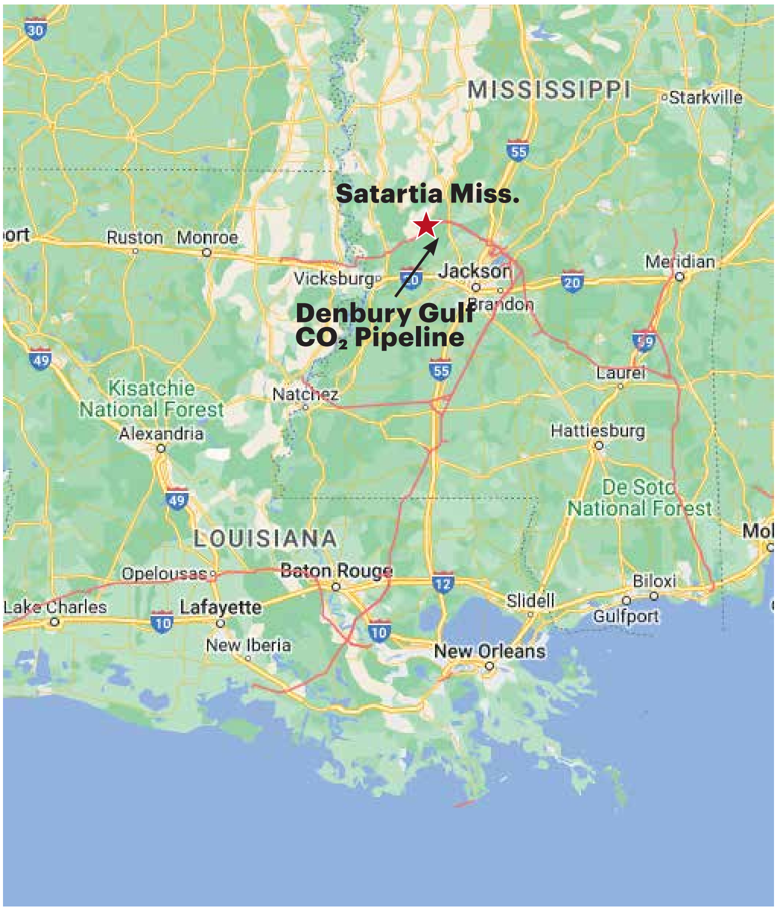
Congress authorizes PHMSA to regulate the transportation of gas and liquid by pipeline, including both gaseous and liquid CO_2, to protect against risks to life and property. Approximately 5,200 miles of regulated pipelines currently transport liquid (supercritical) CO_2 in the U.S., which have been regulated since 1991. Current regulations for supercritical CO_2 pipelines govern design, construction, operation, maintenance and emergency response planning, and many establish supplemental or different design, construction, operations and maintenance obligations specific to the unique risk profile presented by CO_2, which is colorless, odorless, heavier than air and non-flammable.

PHMSA regularly monitors compliance of CO_2 pipeline operators through routine inspections of pipeline facilities and construction projects, as well as accident response and investigations. Through enforcement, PHMSA requires remedial actions and assesses civil penalties, including a record proposed civil penalty associated with the Satartia incident.

As it relates to gaseous CO_2, PHMSA has asserted that it maintains "safety authority" with the ability to investigate and address "any" safety issue through safety orders, even though the agency has not yet established regulations for gaseous CO_2. PHMSA's authority to regulate pipelines does not, however, extend to pipeline siting, routing or permanent storage.

Pending CO_2 Pipeline Rulemaking and State Laws

PHMSA has been working on its "priority" CO_2 rulemaking to regulate gaseous CO_2 and revise existing supercritical CO_2



SOURCE: REXTAG

MISSISSIPPI EMERGENCY MANAGEMENT AGENCY/PHMSA

Vehicle is Parked on HWY 433 outside of Satartia, Miss., where a CO_2 transport pipeline carrying liquefied CO_2 ruptured in 2020, leading to the evacuation of over 200 residents and hospitalization of over 40. The white is ice generated by the release of pressurized CO_2.

regulations specific to emergency response, conversion of service, dispersion modeling, and leak detection and reporting. Based on public comments, other topics which may be addressed by PHMSA could include, among others, standards for impurities and odorization.

The Office of Management and Budget is currently reviewing PHMSA's proposed rule, a review initiated in February 2024. As of this writing, the proposed rule was likely to be published at the end of 2024 or early 2025, although the change in administrations may impact the timeline for the proposed rule and, ultimately, the content as well.

Multiple states have considered issuing moratoriums on CO_2 pipeline projects, and California and Illinois passed laws establishing such moratoriums until PHMSA finalizes its rule. California allows for the state to pass its own regulations and the Illinois moratorium expires after a certain time has passed.

In addition, Congress is reauthorizing the Pipeline Safety Act in 2025 and current proposals floated by the House and Senate have addressed CO_2 pipeline regulation in varying degrees. Industry trade groups have tried to fill the gap left by PHMSA's slow march to updated regulations, such as the development of the "Carbon Dioxide Emergency Response Tactical Guidance" by API and the Liquid Energy Petroleum Association, to provide best practices for preparedness and initial response to a release of CO_2. Meanwhile, some local governments have responded by attempting to put ordinances in place to establish their own moratoriums or to limit development, such as in Iowa and Illinois.

Challenges for CO_2 Project Proponents

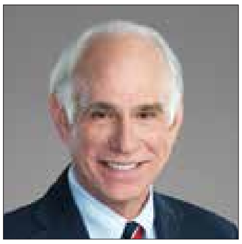
In 2021-2022, several large CO_2 pipelines were proposed in the Midwest as part of larger CCS projects, aiming to reduce CO_2 emissions. Opposition to those projects and/or the development of CO_2 pipelines more generally has worked at federal, state and local levels to leverage the Satartia incident and the fact that the PHMSA has not yet issued updated regulations for CO_2 pipelines.

On the other hand, pipeline proponents are facing challenges and have been hampered by the lack of clarity regarding CO_2 pipeline safety regulation and the failure of PHMSA to expeditiously update its regulations, despite climate goals and DOE funding to incentivize such projects.

Existing and proposed projects face challenges with respect to permitting, other necessary regulatory approvals and possibly funding unless or until PHMSA issues a final rule. The "one government" approach should support these projects to meet the nation's climate goals as well as provide additional jobs and other economic benefits. OGI

Energy (and Politics) for 2025

The incoming administration's policies on sanctions, tariffs, regulations and deportations will impact the oil and gas industry.



ED HIRS
DEPARTMENT OF ECONOMICS, UNIVERSITY OF HOUSTON
edhirs@edhirs.com

Ed Hirs lectures on energy economics at the University of Houston, where he is an Energy Fellow in the College of Liberal Arts and Social Sciences.

Elected leaders will be ushering in expansive energy policies for 2025 and other policies that will impact energy markets. U.S. leadership in the energy transition may stall even with Tesla's owner holding a Cabinet-level position in the new Trump administration.

The conflicting policy pronouncements of the incoming Trump administration deserve a quick look. His promise to lower gasoline prices to $1.87/gal will not come via "drill, baby, drill." His team has already made entreaties to Saudi Arabia to lower the price of crude to accommodate the pledge. If OPEC+ delivers, then U.S. producers will feel pain once again.

The new Trump administration may well try to tighten sanctions on Iranian access to the oil markets, but we can expect price caps and restrictions on Russian oil and gas. Neither change in policy will have an impact on global prices. Iranian and Russian oil is reaching the global market in quantity via circuitous routes in the Middle East and Asia, but reaching the market, nonetheless. Following the release of sanctions on Iran during the Obama administration, the global oil price rose because Iran no longer had to sell into the shadow market at a discount. Azerbaijan's "production" dropped by 500,000 bbl/d.

The specter of the U.S. increasing tariffs may have a more positive impact for domestic oil and gas producers at the expense of consumers in the short run.

Tariffs by themselves do not necessarily lead to recessions, but a trade war with Canada and Mexico will have a far-reaching impact across the U.S. economy. The Canada-Mexico-U.S. trade and investment flows are $1.8 trillion annually. But if the Trump administration follows through with 25% tariffs on all Canadian and Mexican goods and services, the inbound price on 4 MMbbl/d of U.S. crude oil imports will increase by $7 to $15/bbl. Domestic producers will enjoy the ability to match the price increase on the imports. Consumers will cry foul.

The Trump administration will certainly roll back the Biden administration's methane rules and regulations. While this will not impact the major oil companies that are now moving toward smaller environmental footprints, the independents will enjoy the delay—for however long it lasts.

Produced water, always a problem for producers, will be an even greater problem for 2025.

The Permian Basin produces approximately 21 MMbbl/d, with that number forecast to continue to increase. With disposal and remediation costs at least $1/bbl, water disposal has become an $8 billion industry annually.

As Permian subsidence continues due to oil and gas production, and the prevalence of earthquakes and blowouts of abandoned wells increases, the reinjection of water becomes more problematic. Of course, a higher oil price would more than offset the increased costs of remediating the water for agriculture.

One Trump policy initiative will undoubtedly cause havoc in the oil patch. Mass deportations will disrupt work crews and their families across the Permian and other basins in the U.S. Apart from losing workers directly, the diminished workforce will demand higher wages. Again, these could be offset by higher oil prices.

President-elect Donald Trump has pledged to lower the costs of electricity to Americans. This policy promise is unattainable.

Historically low natural gas prices have kept wholesale electricity prices historically low. The other components of the consumer's electricity bill are driving the higher prices. These include initiatives to update long-neglected transmission and distribution infrastructure, add transmission lines to bring electricity from rural wind and solar farms to consumers, and to harden local infrastructure against weather events.

There is no federal remedy that can save the U.S. consumers from increasing electricity prices.

Expected electricity demand growth from AI data centers will practically double U.S. electricity consumption in the next decade. Grid operators are not allowing the data centers to remove power plants from their current portfolios—mainly because supply growth has not kept pace with demand growth, and especially so in deregulated grids in California, Texas and the Midwest.

New data centers will be forced to build their own power plants, providing a boon for natural gas consumption. Small modular nuclear power plants will benefit also.

2025 for energy will be challenging for undercapitalized players and a buying opportunity for those with capital. By their nature, transitions are unsettling, and while the transition to cleaner fuels is clearly underway, 2025 will be marked by a return to state-led initiatives. OGI

Uncertainty Abounds: IRA Clean Energy Incentives Await Fate

Policy experts weigh in on possible next steps for President Joe Biden's signature climate law, the Inflation Reduction Act, following the Trump-led Republican trifecta.

VELDA ADDISON
SENIOR EDITOR,
ENERGY TRANSITION
vaddison@hartenergy.com

With U.S. President-Elect Donald Trump set to return to the White House and a Republican-controlled Congress in place, the fate of President Joe Biden's signature climate law is uncertain.

Political pundits do not expect a complete repeal of the Inflation Reduction Act (IRA). Rather, scalpels will likely be taken to the law which ushered in nearly $370 billion in funding for clean and lower-carbon energy projects and initiatives. Several provisions in the law could be impacted, but no one knows what the future will bring.

As investment trends shift amid growing energy needs, energy companies are still working to provide reliable and affordable energy while minimizing environmental impacts. However, developers reliant on incentives such as tax credits, grants and loans to sweeten project economics are concerned about which parts of the IRA the new Congress and Trump administration will attempt to roll back.

Trump has already pledged to rescind unspent IRA funds. While the IRA didn't have bipartisan support before its passage, the benefits–including jobs–that the Democrat-backed law has brought to Republican-led states may have altered some viewpoints.

"The only way to change the IRA, the law, is to pass a new law."

TIM URBAN,
senior principal,
Bracewell

It's a challenging period for taxpayers, said Tim Urban, the Washington D.C.-based senior principal who leads the tax policy practice at Bracewell.

"We are at a weird intersection of the implementation of IRA, [which] is not complete, and some of the very, very significant tax policy questions and tax legal questions haven't yet been answered," Urban said. "The [Biden] administration is on a mission now to try to publish as much guidance as possible before the end of the year and barring that, before the end of the presidential term."

At the same time, taxpayers who are considering building facilities, buying equipment or producing lower carbon energy resources like hydrogen or renewable methanol face a conundrum, he added.

"They're trying to get the best deal they can … in the waning days of the Biden-Harris administration" and Treasury regulations are needed to implement credits. But an incoming president with a congressional majority made up of Republicans who voted against the IRA want "another sort of bite of the apple."

Taking the IRA to bits won't be easy, and

Keeping Tabs on Public Dollars

Several online trackers are following the flow of Inflation Reduction Act money.

When the Inflation Reduction Act was signed into law on Aug. 16, 2022, by President Joe Biden, $370 billion in the legislation represented the largest investment in clean energy and climate-related programs.

Funding has been steadily doled out by federal agencies to states and taxpayers, ranging from those seeking energy efficiency home improvements and residential clean energy tax credits, to companies seeking billions of dollars to pursue large manufacturing facilities, utility-scale renewable energy projects or to advance technologies.

Tracking how much of the appropriated funds has been obligated is a monumental task with numbers frequently changing as awards, loans and tax credits are granted by the various agencies responsible for distributing the money. However, several trackers manned by public policy groups, analysts and others have surfaced to help keep tabs on the public dollars. Plus, some federal agencies regularly share what they've done with the money and what remains.

The U.S. Department of Energy's Loan Programs Office (LPO), for example, issues a monthly application activity report on statutory and estimated available loan and loan guarantee authority across its programs. This includes the Title 17 Energy Infrastructure Reinvestment (EIR) program created by the IRA to provide loan guarantees for projects that reinvest in old energy infrastructure to reduce

SHUTTERSTOCK

President-Elect Donald Trump has pledged to rescind unspent funds from the Inflation Reduction Act.

"It's really hard to make big economic outlays when part of the economics of making a project work are dependent on tax incentives that are now in question."

HANNAH HAWKINS, principal, KPMG's Washington National Tax, Tax Incentivized Transactions, Leasing and Energy Group

as history has shown with other big pieces of legislation signed into law, unlikely, experts say.

Risks, Opportunities

There was a lot of campaign rhetoric about blowing up the IRA, said Ken Irvin, co-leader of Sidley's global Energy and Infrastructure practice. Realistically, however, some lawmakers are recognizing that money has been spent on projects funded in part by the IRA—and the investments are good ones.

A group of Republican congressmen even urged House Speaker Mike Johnson in a letter prior to the November 2024 election not to repeal clean energy credits in the IRA.

"IRA provisions for clean hydrogen, carbon sequestration, advanced manufacturing, biofuels, those all seem consonant with Trump 2.0 and the philosophy there," Irvin said. "The EV [electric vehicle] tax credit… Mr. [Elon] Musk doesn't seem bothered by getting rid of that, and Mr. Trump wants to roll back the EV mandate. So, that one may be in jeopardy" along with some clean energy incentives.

The Biden administration had set a target for 50% of

emissions and support clean energy development.

The IRA appropriated $5 billion to carry out EIR through Sept. 30, 2026, with a total cap on loans of up to $250 billion. As of Oct. 31, the EIR program had about $244.8 billion in estimated loan authority available, according to the LPO.

In all, the LPO said it was appropriated $11.7 billion to support issuing new loans.

The U.S. Department of Agriculture (USDA) reported in November that it had invested more than $2.7 billion through its Rural Energy for America Program (REAP) for more than 9,900 renewable energy and energy efficiency improvements. Nearly 7,000 of the projects were funded by more than $1 billion provided by the IRA, the USDA said.

Several nongovernmental groups have been tracking spending. Atlas Public Policy's Climate Program Portal is among the online resources available to public officials, advocates and 501(c)(3) nonprofit organizations to track federal investments in climate initiatives. It focuses on investments from the IRA and the Infrastructure Investment and Jobs Act.

Other trackers include the Rhodium Group's Clean Investment Monitor, a joint project with MIT's Center for Energy and Environmental Policy Research, and the Inflation Reduction Act Tracker, a joint project of Columbia Law School's Sabin Center for Climate Change Law and the Environmental Defense Fund.

Some efforts feature trackable databases while others have focused on how much investment the IRA has generated in certain states. But some lack information, such as loans and tax credits, that would paint a more accurate picture. Another challenge is that information is quickly outdated as awards and loan

SHUTTERSTOCK

The Trump administration and Republican-controlled Congress could present opportunities for hydrogen that use natural gas as feedstock, experts say.

SHUTTERSTOCK

President-Elect Donald Trump's platform includes a promise to "cancel the electric vehicle mandate and cut costly and burdensome regulations."

all new vehicle sales to be electric by 2030 and rolled out regulations to help it get there. In March, the U.S. Environmental Protection Agency (EPA) released strict car emissions standards for light-duty and medium-duty vehicles with model years 2027 and later. But the rule prompted opposition and litigation. The House voted in September to repeal the rule as some called it an "EV mandate."

Trump's platform included a promise to "cancel the electric vehicle mandate and cut costly and burdensome regulations."

Another sector already battling headwinds in the U.S. could also be at risk.

"You can't open a newspaper without seeing some utterance by the president-elect about offshore wind, for instance. That's not a state secret," Urban said. Also, "At various times there has been an overall concern by Republicans about trying to ensure that the credit value of these credits is sort of right-sized and matched up against the value provided to taxpayers generally, forgoing this tax benefit."

Listening to industry players and Washington, D.C., chatter, so are time frames of so-called tech neutral electric generating production and investment tax credits that kick in for projects placed in service starting in 2025. Those credits are at risk, according to Hannah Hawkins, principal for KPMG's Washington National Tax, Tax Incentivized Transactions, Leasing and Energy Group.

The safest way to approach the situation is to "expect that everything is on the table, even if some things don't seem to be realistically on the table," Hawkins said.

Joe Brazauskas, senior counsel for Bracewell who helps clients navigate federal legislative and regulatory processes, said the entire breadth of the IRA provisions will be scrutinized with Republicans in the majority.

"There are what we call certain provisions that have a Republican DNA in them, things that in previous Congresses that Republicans have been supportive of," he said. "Those are the ones that are more focused on traditional fuels or a traditional fuel nexus."

There are, however, potential opportunities for some lower-carbon energy technologies incentives. Hydrogen provisions came to mind for Brazauskas, who said there may be opportunity for champions of low-carbon hydrogen to explain the hydrogen value chain's connection to natural gas production and reducing methane emissions.

The changing of the guard also provides a chance for backers of provisions that didn't make the final cut of the IRA, for some reason, to get back into play. These include hydropower and biogas provisions, Urban said, adding some may want legacy credits set to expire to instead be extended.

Some taxpayers and trade associations have been "circling the Congress like hungry falcons waiting for an opportunity to get back into the mix," Urban said.

However, "the administration hasn't been able to get guidance out quickly enough. So, you've got taxpayers going into 2025 with a new credit that they don't understand how to live within."

guarantees are approved.

"It's really hard to find this information," Joe Brazauskas, senior counsel for Bracewell, told *Oil and Gas Investor* when asked about how much IRA money is left. He cited Politico, saying the Environmental Protection Agency has obligated roughly 80% of its funds and the Interior Department maybe about 25%, with just under $50 billion left in terms of obligations.

"The Biden administration is certainly attempting to obligate as many funds as possible to buttress against a potential for Trump to try to claw back some of this money," said Brazauskas. "When the funds have already been obligated, when there's contractual agreements that are already signed ... is an example of funds that will, interestingly enough, have to be administered by the next administration."

For agencies like the Environmental Protection Agency or the Department of Energy that still have massive pots of money available, "the next administration is going to come in and examine those programs," he said.

After some analysis, the new administration may consider repurposing unobligated dollars.

"It's quite possible that certain programs that bolster things like carbon capture and sequestration or utilization are ones that potentially a Trump administration will want and may want to continue with," Brazauskas said, "although I haven't really seen a signal to say we ought to preserve some of that functionality. But I do think that there will be a lot of scrutiny on these programs and ... how that money might be used in other places."

SHUTTERSTOCK

U.S. Rep. Andy Kim (D-N.J.) speaks to climate activists outside the Capitol during the vote for the Inflation Reduction Act on Aug. 12, 2022.

SHUTTERSTOCK

A vessel lays cable for a wind farm.

Unfinished Business

Nearly a year after the U.S. Treasury Department and Internal Revenue Service released proposed rules for the 45V hydrogen production tax credit offered in the IRA, final guidance had not been issued as of mid-December as regulators weigh tens of thousands of comments.

Final guidance was also yet to come for the new clean fuel production tax credit. The wait for final guidance to access tax credits adds to uncertainty for developers deciding whether to move forward with projects.

The Biden administration is making a good faith attempt to offer as much guidance as possible to provide security for taxpayers contemplating investment decisions before the new administration arrives, Urban said.

If the final 45V rule is published before Biden leaves office Jan. 20 and it addresses concerns taxpayers have to help hydrogen hubs prosper, "that scenario might sort of defuse some of the taxpayer anxiety about the regulations," Urban said. If final rules are released and are not well received, taxpayers may take their concerns to their legislators and the incoming Trump administration.

One aspect that makes the tax guidance process different when a new administration looks at final guidance is that it doesn't necessarily have to undergo a similar process that, for example, an EPA regulation would in terms of the notice and comment, Brazauskas said. "It's potentially possible for, say, a new administration, Treasury, to just say, 'we're pulling these back and we're going to sort of rethink how that guidance ought to work.'"

Legislative Levers

When it comes to changing parts of the IRA, the Congressional Review Act (CRA) is among the levers that legislators may pull. It requires a joint resolution of disapproval, which must be approved by both houses of Congress and signed by the president to prevent the rule from being effective, according to the Congressional Review Service (CRS). It only applies to final rules, not to presidential actions or to non-rule agency actions such as orders.

As of August 2024, the CRA has been used to overturn 20 rules, CRS said in a report.

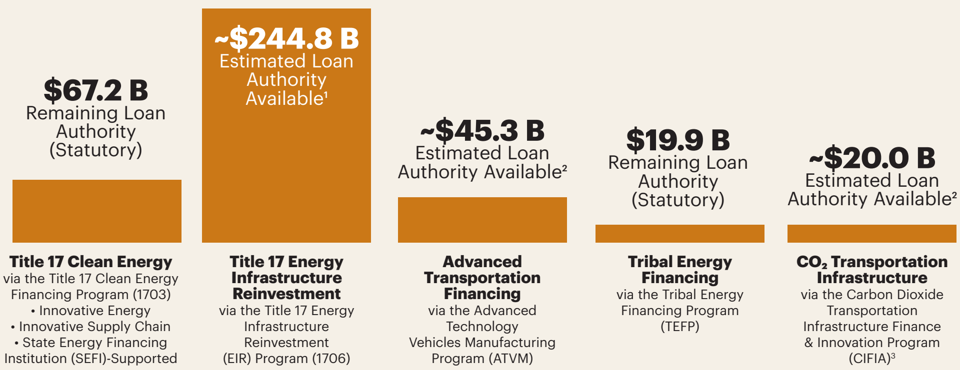
"I think the important thing that sometimes gets lost in the media reports about this is that there are laws and there are regulations that implement the laws," Urban said. "And the administration has the ability to tinker with regulations. The Congressional Review Act allows Congress an opportunity to participate in tinkering with regulations, but neither of those two avenues change the law. The only way to change the IRA, the law, is to pass a new law."

Brazauskas cited, for example, the EPA's finalized methane fees for emitters in the oil and gas industry.

The final rule, announced Nov. 12 by the Biden administration, was part of a directive in the IRA aimed at curbing methane emissions. The Waste Emissions charge starts at \$900 per metric ton of methane emitted in 2024. That rises to \$1,200 in 2025, and \$1,500 for 2026 and beyond. The rule applies to oil and gas facilities that report emissions of more than 25,000 metric tons per year of CO_2 equivalent. Companies violating the rules will start paying penalties next year based on methane emissions

Estimated Remaining Loan Authority

SOURCE: U.S. DEPARTMENT OF ENERGY'S LOAN PROGRAMS OFFICE



Notes

All program lending authority amounts—estimated and statutory— are updated as of Oct. 31, 2024. These figures are updated annually.

1) EIR has a statutory limitation on loan guarantee authority of up to \$250 billion. The figure listed here for EIR as "approximate loan authority available" is the best estimate based on current credit subsidy available.

2) Neither ATVM nor CIFIA have a statutory limitation on the direct loan authority (ATVM) and direct loan and loan guarantee authority (CIFIA) amounts. Figures listed here for ATVM and CIFIA as "approximate loan authority available" are best estimates based on current credit subsidy available.

3) CIFIA is administered in support of DOE's Office of Fossil Energy & Carbon Management.

reported in calendar year 2024.

"This regulation now is finalized and it has to be reported to Congress. The Congressional Review Act says that Congress needs to have 60 legislative days to review a rule and so here we are. It's Nov. 12. So, there is no way that there are 60 legislative days left in this Congress."

The next Congress can essentially reset the clock for review.

"It is a privileged bill. That means that it has to be taken up," he said. If the disapproval starts in the House, passes there and moves to the Senate, where it is passed, the president can sign the disapproval into law. "This is why it's [the CRA] powerful when there's a new administration that takes over" to rescind rules. "And it says that the federal agency cannot promulgate a substantially similar rule."

The CRA was used when the Trump administration followed President Barack Obama's administration. It was also used during the Biden administration after Trump's first term as president. CRS data show the CRA was used once during the 107th Congress (2001-2002), 16 times in the 115th Congress (2017-2018) and three times in the 117th Congress (2021-2022).

"I think they [legislators] will certainly figure out which rules are vulnerable and utilize this process," Brazauskas said. "But in the tax context, I think it's important to note there's not a lot of precedent for utilizing the CRA to pull back a tax guidance.… If they want to do wholesale or even pull back parts of the IRA, they will need to write a new bill."

Urban said he anticipates vigorous debate on how Republican legislators will grapple with the IRA. "This is not a binary equation like the next Congress and administration must either maintain the IRA exactly as it is now in every way, or repeal the IRA root and branch completely."

Some legislators may have fallen in love with various pieces of the IRA, he said.

In reality, there are too many unknowns to make a clear assessment at this point with outstanding guidance and potential defectors as Trump's cabinet picks near completion.

Obligated Dollars

The IRA's clean energy funding is being delivered via grants, loan guarantees and tax incentives. Incentives essentially fall into two buckets: tax credits and appropriated dollars, according to Irvin.

"A lot of the appropriated dollars have been obligated. For a new administration to try and pull that back implicates serious legal issues.… To the extent that it hasn't yet been allocated but it was appropriated by Congress, there is an issue with Mr. Trump," Irvin said. "He thinks he can use impoundment. He thinks he can choose not to spend money appropriated by Congress. This was actually a thing in the Nixon administration. There's an anti-impoundment act of 1974. So, we'll have that constitutional issue come up."

The Impoundment Control Act of 1974 (ICA) restricts the president's ability to impound, or not spend, funds Congress has provided. It was passed in response to President Richard Nixon's administration's refusal to release funds appropriated by Congress for some programs he opposed, according to a House Committee on the Budget impoundment explainer.

"Put simply, if the president wants to spend less money than Congress provided for a particular purpose, he or she must first secure a law providing Congressional approval to rescind the funding in question," the committee explained.

"The ICA requires that the president send a special message to Congress identifying the amount of the proposed rescission; the reasons for it; and the budgetary, economic and programmatic effects of the rescission," the explainer continued. "Upon transmission of such special message, the president may withhold certain funding in the affected accounts for up to 45 legislative session days. If a law approving the rescission is not enacted within the 45 days, any withheld funds must be made available for obligation."

Seeking Safeguards

Companies can help safeguard themselves against unforeseen regulative or legislative moves that put certain tax credits for projects at risk by utilizing what is known as a safe harbor clause, experts say. The move allows developers of projects to lock in incentives such as investment and production tax credits.

"The best course that you'll hear people like me tell their clients is try to begin construction on your project," Hawkins said. Referring to precedents, she added any repeal would be coupled with a transition rule and would not be retroactive. "In the space of energy credits, we've typically seen transition rules anchored on a begin construction concept, and begin construction can mean actually [putting] shovels in the ground or it can mean 5% of capex of a project incurred."

Hawkins cautioned that the mechanics of various incentives work differently.

The IRA includes multiple safe harbor provisions. In May 2024, the IRS issued a notice providing a new safe harbor that taxpayers could use to classify applicable project components and to calculate the domestic cost percentage to qualify for the domestic content bonus credit.

Bracewell advises clients to understand risks and opportunities. "We need to derisk our investments, but we also need to look for the opportunities that are there," Brazauskas said.

Urban added that popular cable TV shows have painted an inaccurate picture of federal government affairs and lobbying.

"I, for one, have never ever smoked a cigar with a congressman or senator in a wooden-paneled room [talking] about getting a special legislative deal," he said. "In reality, lobbying is really all about education. What we find is that our clients generally get the best outcomes when they find a way to meet with and educate members and senators, congressional staff and administration officials with regard to the specifics and the realities and the benefits of their various energy technologies."

Still, planning for the unknown is difficult.

"It's really hard to make big economic outlays when part of the economics of making a project work are dependent on tax incentives that are now in question," Hawkins said, adding KPMG talks to its clients about identifying risks.

She added that it can also be helpful in periods of uncertainty to look at precedents such as what prior Congresses and Treasury departments have done when faced with possible repeals of incentives and guidance modification.

"For instance, there isn't a lot of precedent of retroactive legislative repeals of tax benefits. There just isn't," she said. "That's something that we try to point out. Of course, you have to be prepared for anything." OGI

Bioenergy

Vision RNG Inks Landfill Gas Agreement in South Carolina

Vision RNG plans to transform Greenwood County, S.C., landfill gas into renewable natural gas (RNG) or power after sealing a long-term gas rights agreement with the county.

The Pennsylvania-based landfill gas and RNG developer said the agreement to purchase raw landfill gas could last up to 25 years. Plans are to spend the next 12 months working with county and landfill personnel to optimize the existing gas collection and control system to determine the amount of gas available, Vision RNG said in a news release.

The evaluation will determine whether the landfill could support RNG production or a power project. If the developer produces RNG, the gas will be used as transportation fuel and for other sustainable purchases across the U.S., the company said. If power is produced from the landfill gas, Vision RNG said it will be sold to the local grid operator.

Supermajors Ramp Up Biofuel Investments, Rystad Says

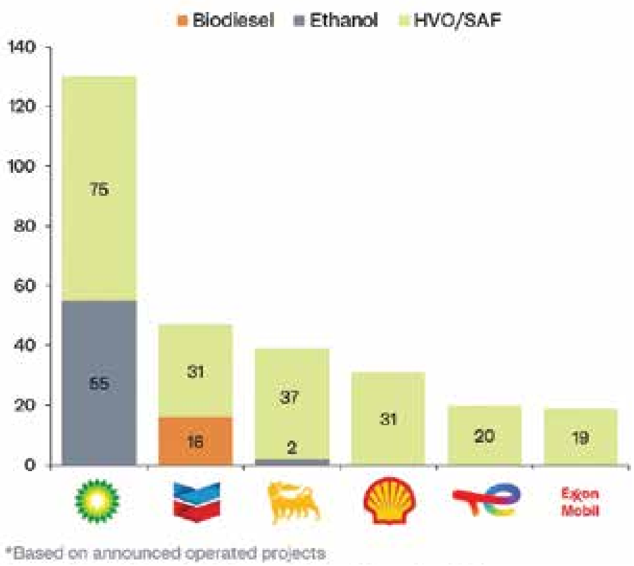
Six of the world's major oil and gas companies are boosting their biofuels investments, with 43 projects already running or targeted to start by 2030, Rystad Energy said in a report.

Among BP, Chevron, Shell, TotalEnergies, Exxon Mobil and Eni, the projects could add 286,000 bbl/d of production capacity, according to Rystad analysts Lars Klesse and Kartik Selvaraju.

Of the 43 projects, 31 are greenfield developments and six are conversions of refineries to produce biofuels exclusively. Six more projects involve co-processing, in which refineries blend bio feedstock and fossil fuel feedstock. BP announced plans for 130,000 bbl/d of biofuels production capacity.

Announced Biofuel Capacity of Oil Majors, by End-Product*

Thousand barrels per day



SOURCE: RYSTAD ENERGY

Chevron is second with 47,000 bbl/d.

Almost 90% of the projected output is hydrotreated vegetable oil and sustainable aviation fuel. Biofuels are attractive to operators because they can run in existing engines with lower emissions than fossil fuels.

Carbon Management

SLB Capturi Completes First Industrial-Scale CCS Facility for Cement Sector

SLB CAPTURI

Next steps for the Brevik CCS plant include commissioning. Operations are expected to begin in 2025.

SLB Capturi, a joint venture of SLB and Aker Carbon Capture, marked a milestone toward efforts to decarbonize the hard-to-abate cement sector with the mechanical completion of the carbon capture plant at a cement facility in Norway.

The company said it completed construction of the carbon capture plant at Heidelberg Materials' cement facility in Brevik, Norway, and is ready to test and commission the facility. In addition to the carbon capture system, the plant includes a compression system, heat integration system, intermediate storage and loadout facilities.

Heidelberg Materials' Brevik CCS plant is described as the world's first CO_2 capture facility in the cement industry. Designed to capture up to 400,000 metric tons (mt) of CO_2 annually, the plant is part of the company's plans to lower emissions and produce what it calls net-zero concrete, specifically its evoZero cement products.

"The Brevik CCS plant sets a precedent for future carbon capture initiatives, where learnings and insights from this groundbreaking project enable others to follow," SLB Capturi CEO Egil Fagerland said in a statement.

Next steps for the Brevik plant include commissioning. Operations are expected to begin in 2025.

Energy Storage

Exxon Mobil, LG Chem Ink Deal for Lithium Carbonate

Exxon Mobil inked a multi-year, non-binding offtake deal to supply South Korean chemical company LG Chem with up to 100,000 mt of lithium carbonate, an ingredient for lithium-ion batteries.

The company plans to produce lithium utilizing direct lithium extraction technology as it aims to become a leading domestic supplier. Leaning on its conventional oil and gas drilling, subsurface and exploration expertise, Exxon Mobil has said it plans to drill thousands of feet belowground to access brine from which lithium will be extracted and converted into battery-grade material.

Southern Arkansas' Smackover Formation was the site of Exxon's first lithium drilling campaign.

As part of the nonbinding agreement, Exxon will supply lithium from its planned project to LG Chem's cathode plant in Clarksville, Tenn. With an expected annual production capacity of 60,000 tons, the $1.6 billion cathode manufacturing facility will be the largest of its kind in the U.S. when its first phase begins operations in 2026. The facility, located on a 1.7 million-sq m site, will produce enough cathode materials for about 600,000 electric vehicles (EVs) with a range of 500 km annually, the company has said.

LG Chem has already lined up long-term supply agreements for cathode materials with General Motors and Toyota.

Hydrogen

Air Liquide, TotalEnergies Partner to Produce Hydrogen

SOURCE: TOTALENERGIES

TotalEnergies and Air Liquide have partnered to produce green hydrogen at the La Mède biorefinery.

Industrial gases company Air Liquide and TotalEnergies will jointly invest €150 million (US$158 million) and work together to produce renewable hydrogen at the La Mède biorefinery in southeast France, the energy company said.

The partnership took shape as TotalEnergies strived to decarbonize its European refineries. Plans are for Air Liquide to build and operate a hydrogen production unit using steam methane reforming at La Mède with an annual capacity of 25,000 tons, according to a news release. The hydrogen will be used at the biorefinery to produce biodiesel and sustainable aviation fuel.

The new unit is expected to start production in 2028, TotalEnergies said.

The company's efforts also include the Masshyli green hydrogen project with Engie. The companies aim to have an annual capacity of 10,000 tons per year. If subsidies are secured and the project is approved by European and French regulators, plans are to start the first 20-megawatt electrolyzer in 2029.

Gulf Coast, Midwest Hydrogen Hubs Land DOE Funding

SHUTTERSTOCK

Hydrogen storage hub concept.

Two hydrogen hubs in the Gulf Coast and Midwest have joined three other hubs across the U.S. in securing federal funding as the nation works to establish a clean hydrogen network to help decarbonize high-polluting sectors.

The U.S. Department of Energy (DOE) said it is committing up to $1.2 billion of federal cost share for the HyVelocity-led Gulf Coast Hydrogen Hub and up to $1 billion of federal cost share for the Midwest Hydrogen Hub, which is led by the Midwest Alliance for Clean Hydrogen (MachH2). The funding is part of up to $7 billion the U.S. allocated to establish hydrogen hubs across the country. The hubs, which position hydrogen producers and consumers together with infrastructure, are part of ongoing efforts to reduce greenhouse-gas emissions.

Located along the Texas Gulf Coast, HyVelocity's partners include AES Corp., Air Liquide, Chevron, Exxon Mobil, MHI Hydrogen Infrastructure and Ørsted, with GTI Energy serving as the administrator. Other collaborating organizations include the University of Texas at Austin, the Center for Houston's Future and Houston Advanced Research Center.

The HyVelocity hub plans to produce hydrogen through electrolysis and from natural gas with carbon capture and storage.

Of the up to $1.2 billion federal commitment, the Office of Clean Energy Demonstrations (OCED) awarded the hub $22 million to begin Phase 1. Expected to last about 18 months, Phase 1 entails planning, design and community and labor engagement activities, OCED said.

MACH2's Midwest Hydrogen Hub has proposed projects spread across Illinois, Indiana, Iowa and Michigan. It plans to use natural gas, renewable energy and nuclear energy as feedstocks. Of the up to $1 billion federal commitment, OCED has awarded the hub $22.2 million to begin Phase 1.

The Biden-Harris administration aimed to produce 10 million metric tons of hydrogen annually by 2030. The public investments in the regional hubs are expected to generate more than $40 billion in private investments and create thousands of jobs, according to the DOE.

The three other hubs that have secured federal funding include the Appalachian Hydrogen Hub known as ARCH2, the California Hydrogen Hub called ARCHES and the Pacific Northwest Hydrogen Hub PNWH2. OGI

EVENTS CALENDAR

Investment and networking opportunities for industry executives and financiers.

Scan me

EVENT	DATE	CITY	VENUE	CONTACT
2025				
Floating Wind Solutions 2025	Jan. 15-17	Houston	The Marriott Marquis	floatingwindsolutions.com
Mexico Infrastructure Projects Forum	Jan. 22-23	Monterrey, Mexico	Hotel Camino Real Monterrey	mexicoinfrastructure.com
SPE Hydraulic Fracturing Tech Conference and Exhibition	Feb. 4-6	The Woodlands, Texas	The Woodlands Waterway Marriott Hotel & Convention Center	spe-events.org
NAPE	Feb. 5-7	Houston	George R. Brown Conv. Ctr.	napeexpo.com
6th American LNG Forum	Feb. 10-11	Houston	Westin Galleria	americanlngforum.com
Oil & Gas Automation and Technology Week	Feb. 11-12	Houston	Hyatt Regency Intercontinental Airport Hotel	oilandgasautomationand technology.com
Influential Women in Energy Luncheon	**Feb. 27**	**Houston**	**Hilton Americas-Houston**	**hartenergy.com/events**
SGA 2025 Spring Gas Conference	March 2-5	Charlotte, N.C.	Charlotte Convention Center	southerngas.org
SPE/IADC International Drilling Conference and Exhibition	March 4-6	Stavanger, Norway	Stavenger Forum	drillingconference.org
CERAWeek	March 10-14	Houston	Hilton Americas-Houston	ceraweek.com
DUG Gas Conference & Expo	**March 19-20**	**Shreveport, La.**	**Shreveport Convention Center**	**hartenergy.com/events**
SPE/ICoTA Well Intervention Conference & Exhibition	March 25-26	The Woodlands, Texas	The Woodlands Waterway Marriott Hotel & Convention Center	spe-events.org
AI in Oil & Gas Conference	April 8-9	Houston	Hyatt Regency Houston West	aioilandgas. energyconferencenetwork.com
Energy Workforce & Technology Council Annual Meeting	April 9-10	Frisco, Texas	The Westin Dallas Stonebriar Golf Resort	energyworkforce.org
World Oilman's Mineral & Royalty Conference	April 14-15	Houston	Post Oak Hotel	mineralconference.com
SPE Improved Oil Recovery Conference	April 23-25	Tulsa, Okla.	River Spirit Casino and Resort	speior.org
Offshore Technology Conference	May 5-8	Houston	NRG Park	2025.otcnet.org
Canada Gas Exhibition & Conference	May 6-8	Vancouver, Canada	Vancouver Convention Center	canadagalng.com
SUPER DUG Conference & Expo	**May 14-15**	**Fort Worth, Texas**	**Fort Worth Convention Center**	**hartenergy.com/events**
World Hydrogen 2025 Summit & Exhibition	May 20-22	Rotterdam, Netherlands	Rotterdam Ahoy	world-hydrogen-summit.com
SGA Energy Symposium	May 22	Houston	TBD	southerngas.org
URTeC	June 9-11	Houston	George R. Brown Conv. Ctr.	urtec.org/2025
IADC World Drilling Conference & Exhibition	June 10-11	Amsterdam	Beurs van Berlage	iadc.org
Global Energy Show Canada	June 10-12	Calgary, Canada	BMO Centre at Stampede Park	globalenergyshow.com
Reuters Data Driven Oil & Gas 2025	June 24-25	Houston	TBD	events.reutersevents.com
2025 Operations Conference	July 22-25	Austin, Texas	TBD	southerngas.org
IMAGE 2025	Aug. 25-28	Houston	George R. Brown Conv. Ctr.	imageevent.org
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Tuesday, odd mos.	Fort Worth, Texas	Petroleum Club of Fort Worth	adamenergyfortworth.org
ADAM-Greater East Texas	First Wed., odd mos.	Tyler, Texas	Willow Brook Country Club	etxadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.org
ADAM-Permian	Bi-monthly	Midland, Texas	Petroleum Club of Midland	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.org
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin, Texas	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Petroleum Club of Houston	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	hefg.net
Houston Producers' Forum	Third Tuesday	Houston	Petroleum Club of Houston	houstonproducersforum.org
IPAA-Tipro Speaker Series	Third Tuesday	Houston	Petroleum Club of Houston	ipaa.org

Email details of your event to Jennifer Martinez at jmartinez@hartenergy.com.
For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com/events.

The Power Grid in Gridlock

Greater power demand is coming but, while there isn't enough power generation to answer the call, the transmission isn't there either, industry members and analysts report.

NISSA DARBONNE
EXECUTIVE EDITOR-AT-LARGE
@NissaDarbonne
ndarbonne@hartenergy.com
@NissaDarbonne

A deep dive in this issue of *Oil and Gas Investor* explores the power generation that new Lower 48 data centers and other imminent growth in demand will require. Besides compelling investment in generating the electrons, industry members and analysts report investment is needed in power-transmission infrastructure itself.

Estimates of new power demand for data centers alone in the coming few years is as much as 80 gigawatts (GW), which is the equivalent of 96 new nuclear reactors like Unit 1 at Three Mile Island.

Whatever the numbers turn out to be by 2030 or 2035, though, "I don't think we have the infrastructure planned to meet all this," said Rob Gramlich, president of Washington, D.C.-based consulting firm Grid Strategies.

Gramlich was among the speakers at a joint Dallas Fed and Kansas City Fed energy forum in November.

Ten years ago, some 4,000 miles of 345-kilovolt-and-greater transmission was built in the U.S., he said. "This has really trickled down to barely anything now."

While oil and gas producers have sounded the alarm over federal, state and other permitting gridlock for decades, power companies have been finding in the past decade that this hurdle is impeding transmission growth, too.

Rick Muncrief, Devon Energy president and CEO, said reform is needed "irrespective of what part of the energy sector you're in."

And urgently, he added. "With energy, you can only kick a can down the road so far and you're going to wake up one day and have a hell of a crisis on your hands.

"… When the power's out, the power's out and that's when meltdowns occur."

Further, once clearing permitting and other impasses, when new power is ready to come online "the regional interconnection queues are all backed up," said Kristina Lund, president of wind, solar, transmission and energy-storage developer Pattern Energy Group.

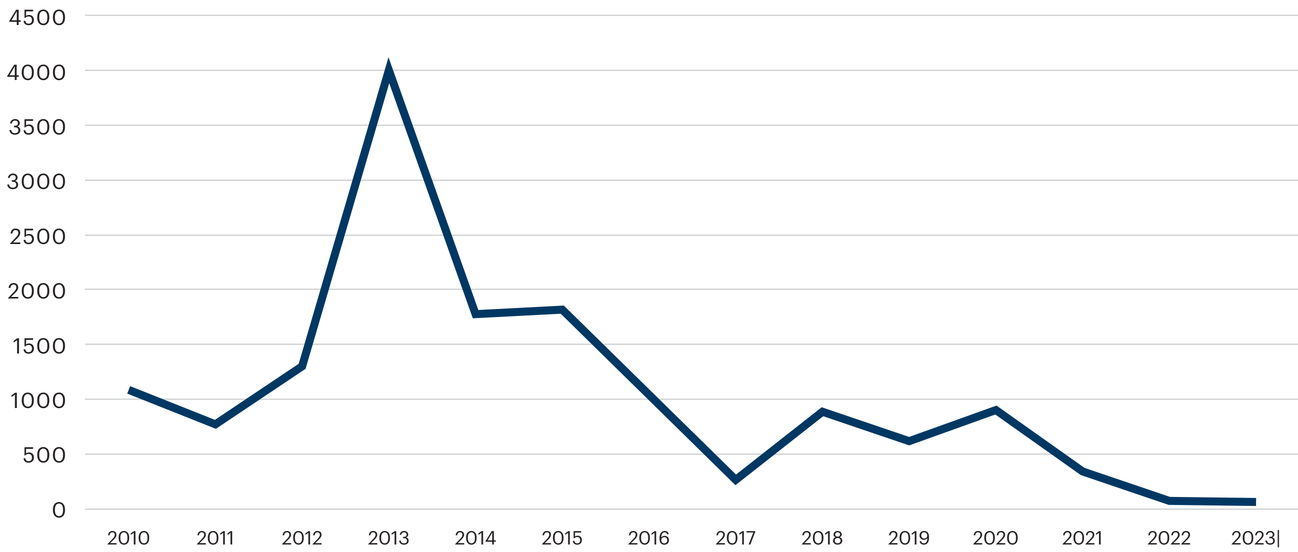
U.S. power infrastructure doubled between 1950 and 1980 as demand doubled. And it doubled again between 1980 and 2010, noted Stacey Dore, power producer Vistra Corp.'s chief strategy and sustainability officer.

Vistra projects another doubling between 2020 and 2050.

This is while also needing to replace many existing power plants, said Javier Fernandez, president and CEO of power generator Omaha Public Power District.

In Nebraska alone, "50% of the generators are 40 years old or older and 25% of them are 50 years old," Fernandez said.

Miles of 345 kV + Transmission Lines Added Each Year



SOURCE: GRID STRATEGIES

Ten years ago, some 4,000 miles of 345-kV-plus transmission was built in the U.S., but "this has really trickled down to barely anything now," said Rob Gramlich, president of consulting firm Grid Strategies.

SHUTTERSTOCK AI

Overcoming state, tribal, federal and other permitting hurdles has slowed power-transmission growth.

In a report in September, Evercore ISI energy analyst James West wrote that "the breadth and severity of issues facing the power sector are more likely to get larger before they get smaller."

He estimates some $630 billion of large-power-load consumers–data centers, manufacturing plants and industrial facilities–will come online by 2035.

"Time is of the essence to address the capability and reliability of the grid to address demand growth," he wrote.

Peak power demand will be some 38 GW greater in the next five years and peak winter demand will be some 78 GW greater in the next 10 years, he estimates.

And "the current grid infrastructure is not currently equipped to handle" this, he added.

Meanwhile, "most state public utility commissioners have little experience of regulating in a growth environment," Chris Seiple, vice chairman of power and renewables for Wood Mackenzie, reported in October.

Tech executives who are accustomed to moving at light speed "are shocked" when they "learn about the pace at which electric utilities move," Seiple added.

Woodmac counted 51 GW of new data-center announcements since year-end 2022. Should this grow 15% per year during the next five years, another 25 GW is needed, Seiple wrote.

Demand from manufacturers could be 15 GW for building batteries, solar wafers and cells, and semiconductors.

"Lastly, the wider electrification of the economy will drive demand, with electric vehicle use continuing to grow and electrolyzers connecting to the grid potentially adding another 7 GW of demand through 2030," Seiple reported.

Renewables alone won't answer the call, he added. "If renewables are only able to barely match the pace of demand growth, it means we won't be decarbonizing the power sector."

At Evercore, West also sees more power demand coming than can be answered by alternative energy.

He concluded: It is "The Age of Natural Gas." OGI

Oil and Gas Investor

COMPANIES IN THIS ISSUE

This index refers to the pages of the story or news item in which the company is first mentioned. Advertisers are in boldface.

Inspiring the Next Generation of Game Changers




THE FUTURE of our country and our world depends on game changing thinkers – technologists, engineers, geologists – who are determined to discover what's next, with the understanding that hydrocarbons will be essential and irreplaceable for decades to come. Continental Resources will lead the way by producing clean, reliable, affordable, abundant American energy.
We are America's Energy Champion.

Continental
RESOURCES