Oil and Gas Investor

SPECIAL OGI REPORT

PERMIAN PLAYS

THE TAKEAWAY ON THE US' MOST PROLIFIC BASIN

Production, Infrastructure Balance Remains Elusive

THE OGInterview

COMMERCIAL BANKING

Open for Oil, Gas Business

BUILDING A BAKKEN BEAST

Chord Energy CEO Danny Brown Details How It's Easier to Get Better When You're Bigger

CANADIAN OIL SANDS

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JUNE 2024

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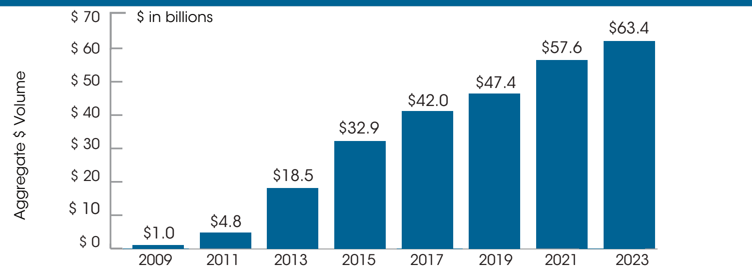

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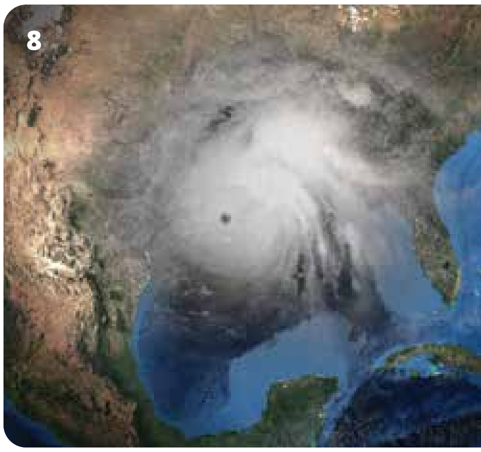

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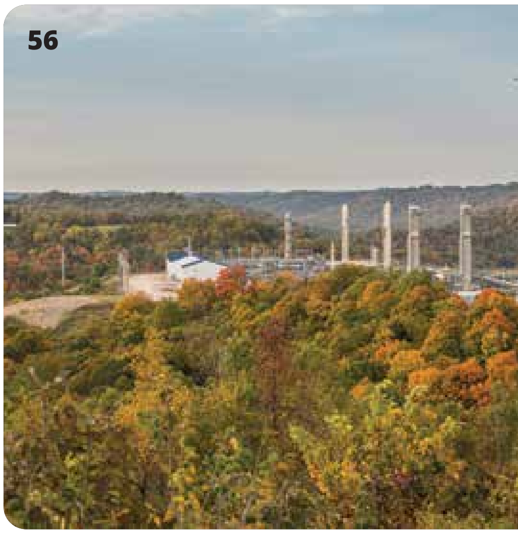

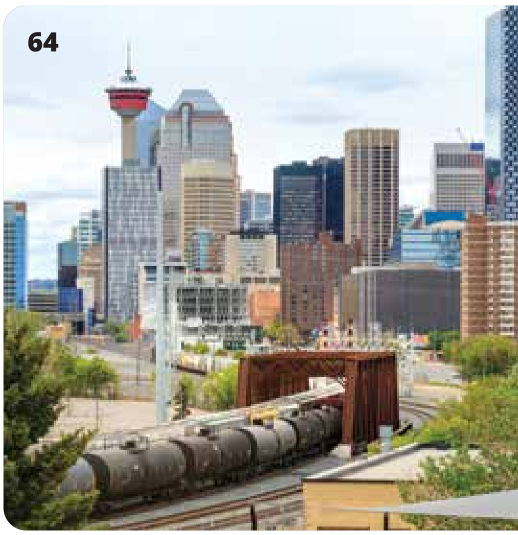

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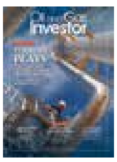
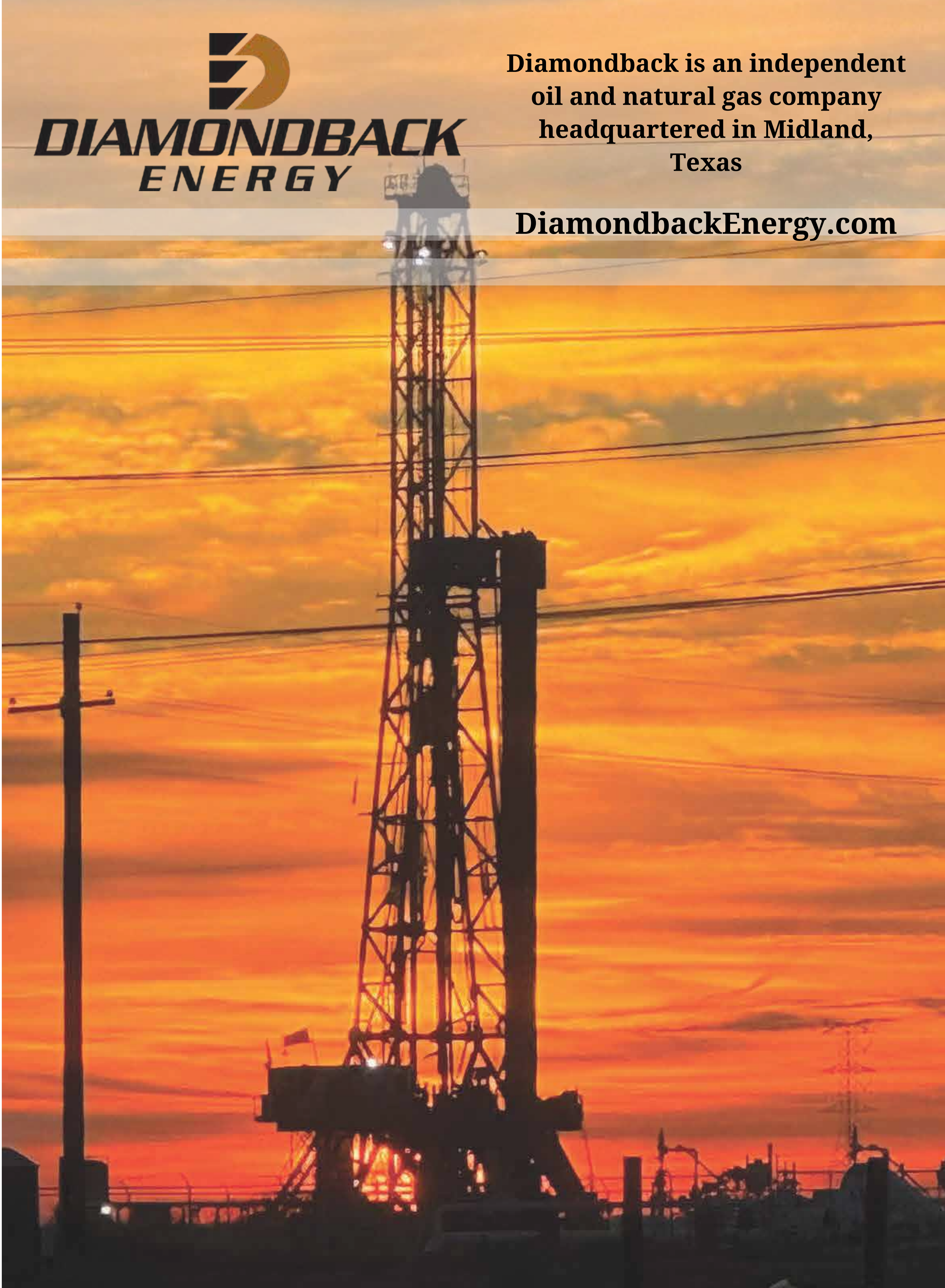
NEW ENERGIES

TECHNOLOGY



ABOUT THE COVER:
Photographer Jim Blecha captured this image of midstream operations in the Permian Basin.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The Widening Runway of US Shale

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FORT WORTH, Texas—I'm writing to you this month from the floor of the Fort Worth Convention Center during Day Two of Hart Energy's Super DUG conference, the largest such gathering of U.S. shale producers and those who work in fields that support the industry.

And if there is one thing that is abundantly clear, it's that in any utterance about U.S. policy and its necessary adherence to an "all of the above" strategy to keep the lights on and ensure energy security, U.S. shale remains at the top of the heap.

At *Oil and Gas Investor*, we've maintained our examination of what U.S. shale brings to the global supply/demand dynamic. This edition includes the third installment of our series examining the challenges and opportunities in the mighty Permian Basin: our cover story analyzing the play's infrastructure landscape and a feature that digs into best practices of differing completions strategies.

But U.S. shale is more than its most prolific basin. In The OGInterview, Chord Energy CEO Danny Brown shares his excitement about the beastly Bakken play within the Williston Basin.

It's hard to argue with his analysis that the Bakken is a force. It's the purest oil play in the country, and should be a magnet for any oil bull.

Brown also offers perhaps the clearest insight I've heard during an interview on the calculus that goes into building a company via consolidation. It will be fascinating to see what this toddler-aged company achieves, especially with the closing of its most recent buy in Enerplus, which neighbors the assets under Chord's umbrella, netted by the merger of Oasis Petroleum and Whiting Oil & Gas.

In another feature, EOG Resources executives are amplifying the company's 3-mile-lateral tack in Ohio's Utica oil play to a company-record 3.7-mile test—and finding the rock's output and costs "compete with the best plays in America." CEO Ezra Yacob told investors during a spring earnings call that understanding the resource in Ohio's Utica oil window is recognizing it's akin to where the Permian was around 2012-2013. That sounds like a clear indication that EOG—among the most successful independents standing—believes there's a lot of resource left to produce.

And despite the wariness of natural gas pricing instability, there is no doubt the resource is needed and abundant.

Chevron owns some of the hottest acreage in the Haynesville, and those 72,000 net acres, contiguous and undeveloped in the center of the play, are whetting the appetites of companies looking to capitalize on the bonanza.

"That is a position that all Haynesville operators are interested in," Mike Winsor, CEO and COO of Paloma Natural Gas, said during Hart Energy's DUG GAS+ Conference and Expo in Shreveport, La, in March.

"It's not very often you can come into an acreage position that is consolidated. You can come in with a blank slate. And whatever your well-spacing, whatever your design, there's a huge amount of running room there."

Also in this edition, we take a look at how commercial banks—a space that had contracted before it began expanding back into oil and gas—are strategizing to make the most of the U.S. shale opportunities. Consolidation has opened a window for smaller, well-managed companies with clean balance sheets to access the cash needed to capitalize on what's next.

And if you believe the dozens of presenters at Super DUG and those in the 1,600+ crowd, you ain't seen nothin' yet. OGI

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Pre-Season Jitters in the Hurricane Zone

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What if it rains?

No, not "what's Plan B for the Father's Day picnic?" What if it really rains, like a Category 4 or 5 hurricane in the Gulf of Mexico with the force to tear apart infrastructure and cripple an economy?

The answer is a big fat "it depends."

From July through September 2005, three major hurricanes tore through the Gulf. The first was Dennis in July. Katrina in August and Rita in September collided with more than 3,000 platforms and 22,000 miles of pipelines in their direct paths.

Katrina entered the outer continental shelf as a Category 5 and destroyed 46 platforms, damaging 20 others, the Minerals Management Service said in its 2006 assessment. Rita, a Category 4 when it entered the area, knocked out 69 platforms and damaged 32 others.

Prior to those three storms, Gulf of Mexico oil production averaged 1.56 MMbbl/d in June. Production would not reach that level again until July 2009.

Many of those offshore facilities were older and not as equipped for powerful storms as they are now. Still, in July 2021, Gulf oil production was 1.85 MMbbl/d. Hurricane Ida struck in August and production would not recover until January 2023.

But those figures are restricted to the U.S. Gulf of Mexico. Overall U.S. production dipped temporarily but shale fields were able to compensate. Oil prices barely sustained a scratch.

Busy season ahead?

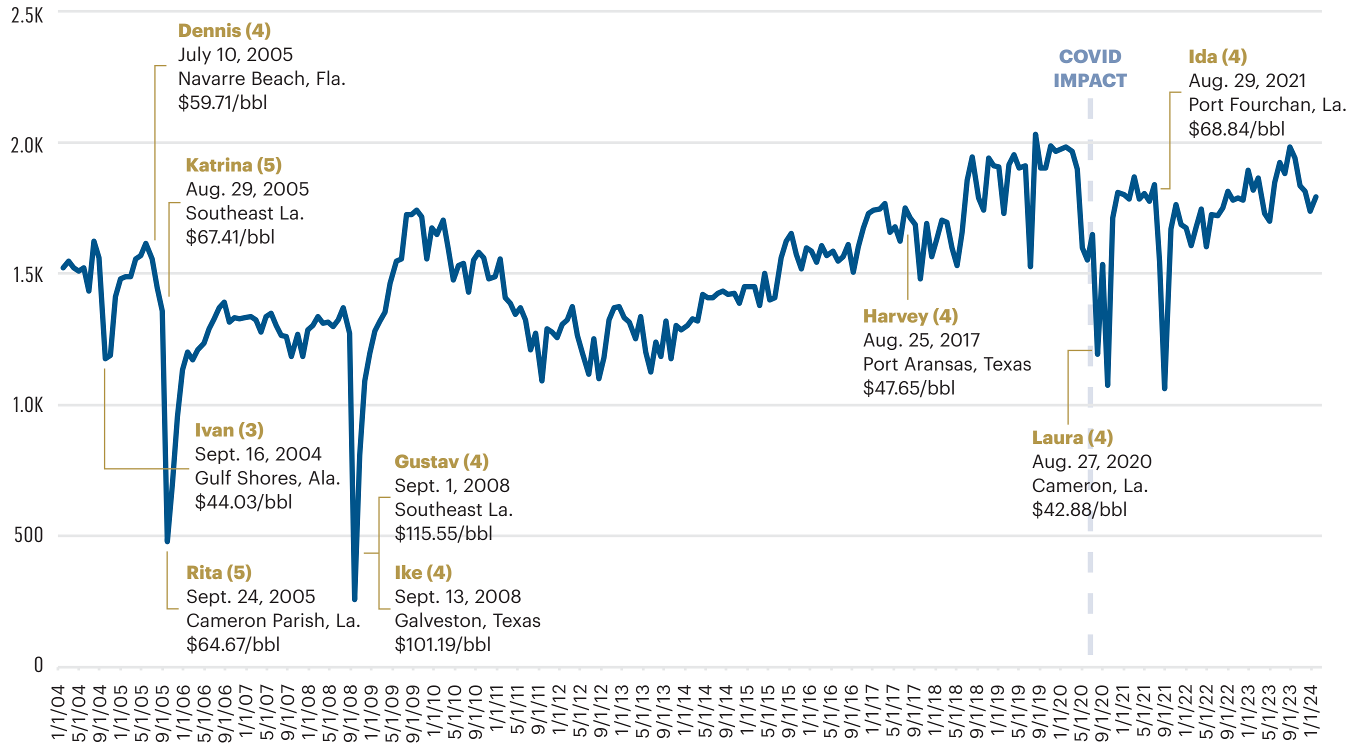
In 2023, the U.S. produced more crude oil than any other country in the world. More than one of every seven of those barrels was produced in the offshore Gulf of Mexico.

Offshore production is expected to grow, with the Bureau of Ocean Energy Management forecasting output to peak at an average of 2.06 MMbbl/d in 2027 (compared to an average of 1.8 MMbbl/d in February).

But again, what if it rains?

Researchers at Colorado State University predict 23 named storms for the 2024 Atlantic hurricane season, well above the average of

Major Hurricanes and U.S. Gulf of Mexico Oil Production (Mbbl/d)



SOURCE: OIL AND GAS INVESTOR, ENERGY INFORMATION ADMINISTRATION, NATIONAL WEATHER SERVICE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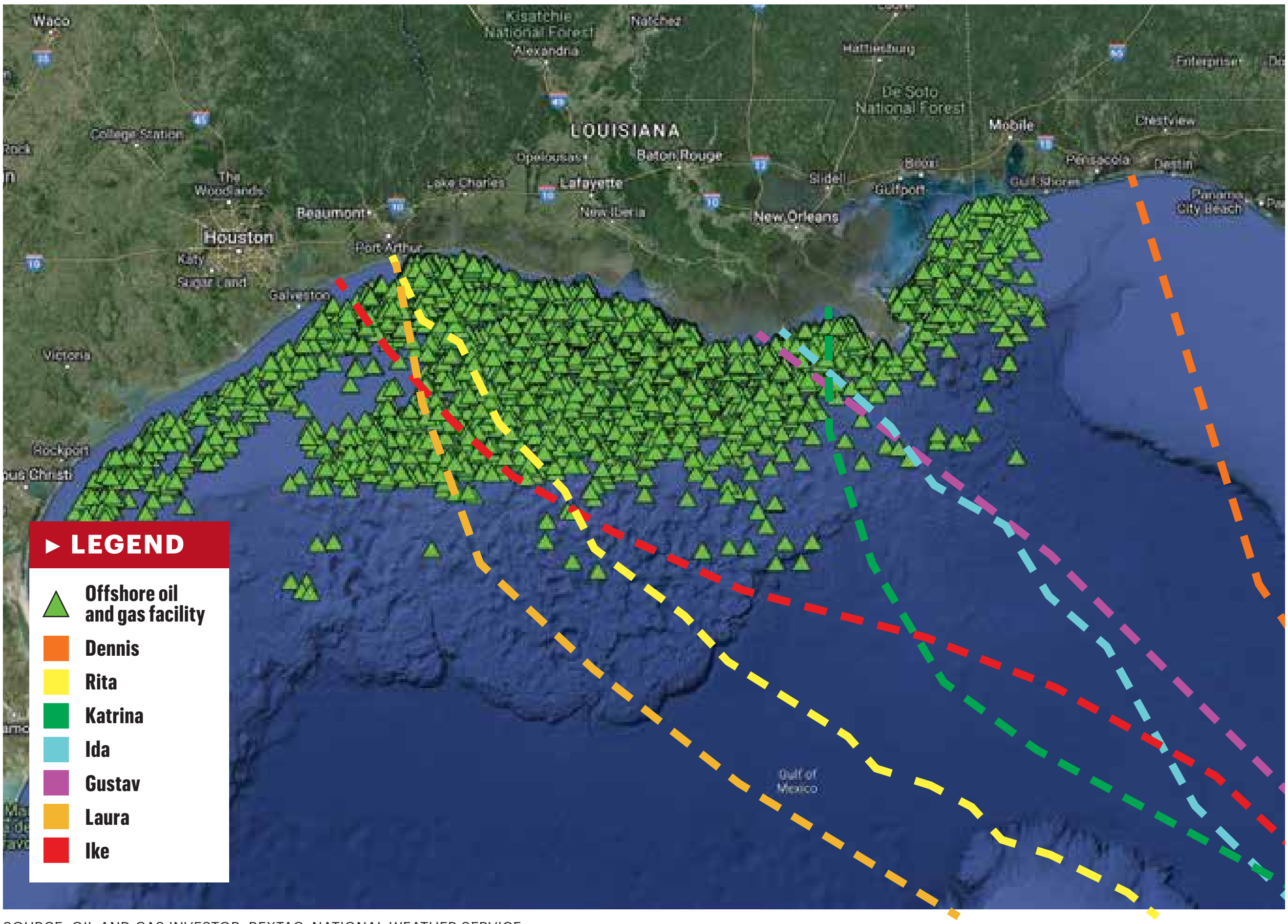
Paths of Major Hurricanes



SOURCE: OIL AND GAS INVESTOR, REXTAG, NATIONAL WEATHER SERVICE

14.4. Of those, 11 are expected to be hurricanes, with five major hurricanes. There were 19 named storms in 2023, with four coming onshore: Hurricane Idalia, and Tropical Storms Harold, Lee and Ophelia.

The European Centre for Medium-Range Weather Forecasts predicts 23 named storms for 2024, as well. AccuWeather forecasts 20-25 named storms, eight to 12 of which are hurricanes, with four to seven major hurricanes and four to six direct U.S. impacts. A team at the University of Pennsylvania forecasts an unprecedented 33 named storms.

Before dismissing these forecasts as climate change hokum designed to goose EV sales, remember that the “Great Storm” that devastated Galveston, Texas in 1900–the deadliest weather event in U.S. history–was what is now defined as a Category 4 hurricane.

It struck eight years before Ford’s first Model T rolled off the assembly line, so auto emissions were not a factor. It also happened to be a year of very high water temperatures.

In hot water

Like this year.

“This year’s sea surface temperatures in the eastern and central tropical Atlantic are much warmer than normal, also favoring an active Atlantic hurricane season via dynamic and thermodynamic conditions that are conducive to developing hurricanes,” the Colorado State researchers wrote.

They compared this year’s January-March sea surface temperatures to other years with the same conditions. In 1926, there were only 11 named storms, but eight were hurricanes and six were major hurricanes. In 2020, there were 30 named storms, 14 of which were hurricanes, with seven major hurricanes.

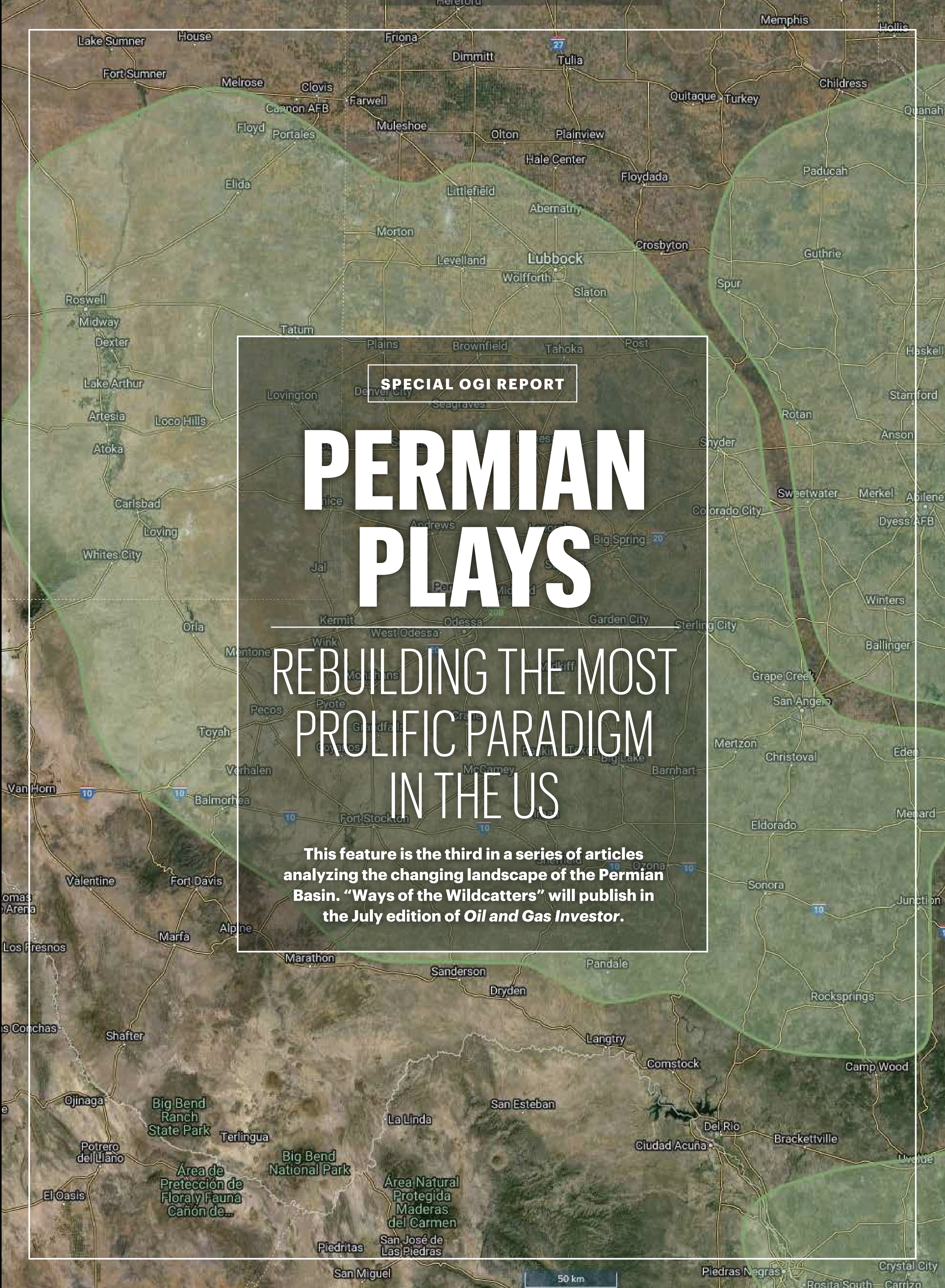
Hurricanes enter coastal lore based on relative levels of destruction. When storms begin to touch land, they start to lose energy. Rarely does a storm come ashore above Category 3, with exceptions of monsters like Camille, Andrew and Hugo. By contrast, there is no easing in the outer continental shelf. A Category 4 or 5 hurricane will smack a platform with everything it’s got.

The advantage is in people affected. Casualties are rare on offshore facilities because they are evacuated well before a storm can wreak havoc. There are no odd characters determined to ride it out at sea.

So, again, what if it rains?

Those of us who have lived on the Gulf Coast for a while have vivid memories of Allison, Ike, Katrina, Harvey and other storms. My neighborhood in Houston is far better prepared for flooding after improvements to the nearby bayou following Harvey’s deluge. Out in the Gulf, platforms are now able to withstand waves higher than Katrina’s 82 feet and winds up to 144 mph.

Past hurricane performance is not a guarantee of future gales, of course, but given how the offshore oil industry specifically and the Gulf Coast in general have been clobbered previously, it’s best to be prepared. And we are prepared as we can be … for the last storm, at least. OGI



SPECIAL OGI REPORT

PERMIAN PLAYS

REBUILDING THE MOST PROLIFIC PARADIGM IN THE US

This feature is the third in a series of articles analyzing the changing landscape of the Permian Basin. "Ways of the Wildcatters" will publish in the July edition of *Oil and Gas Investor*.

THE TAKEAWAY ON THE PERMIAN

Midstream companies and E&Ps may have different priorities, but continued pipeline development is crucial for the basin's future.

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Harold Hamm remembers a point in the 2000s when the pipelines out of the Permian Basin were practically dry.

The shale revolution was getting underway, and the new volumes from West Texas could not yet match the infrastructure already in place.

"We had pipes in place that could handle the volume. Basically, at that time, they were mostly empty," said Hamm, who owns the private E&P Continental Resources.

The situation would change. Before the end of the 2010s, crude pipelines were so full that alternative means of transport had to be found.

Now, Hamm and his team see the same problem arising with natural gas. Producers in the area have long known that, as shale plays age, they produce more gas and less crude.

The gas-to-oil ratio at primary sites in the Permian tripled between 2018 and 2023, according to an analysis by the U.S. Energy Information Administration (EIA). However, as price of crude has remained strong—above $70/bbl for more than two years—producers have continued to increase crude production.

The resulting gas oversupply in the Permian has dropped the region's natural gas price into negative territory and forced some companies to seek permission to flare excess methane.

A new major gas pipeline is expected to open this year and will bring some relief.

However, analysts have forecast gas takeaway capacity will fill in only a couple of years. Another major natural gas pipeline project would therefore be needed in the 2026-2027 timeframe. Several projects are in development, but none have reached the final investment decision stage of the process. Construction for a major greenfield pipeline usually takes at least two years.

Meanwhile, the federal government is implementing new rules restricting flaring and monitoring gas emissions. Producers may face a problem, Hamm said. If crude production produces more gas than can be moved, crude production may be trapped.

Midstream companies have built a crude network that is expected to handle the increasing flows into the next decade. The picture for natural gas is less clear. Industry watchers say new pipeline capacity will be needed sooner rather than later.

"What we're trying to prevent, as the rules change and time goes on, is the ordeal of building out volume before building out the pipes," Hamm said. "That has to change and should have already changed."

New plumbing

Midstream companies, meanwhile, are dealing with a changing region and an industry.

Since the 1920s, people have been exploring the Permian Basin for oil, each generation trying out new tools and technologies—and always having to re-do the plumbing.

"The Midland Basin's been drilled for 100 years," said Stephen Luskey, executive vice president and chief commercial officer of Brazos Midstream, one of the larger

"What we're trying to prevent, as the rules change and time goes on, is the ordeal of building out volume before building out the pipes. That has to change and should have already changed."

HAROLD HAMM, founder and executive chairman, Continental Resources

Brazos Midstream is constructing the Sundance Plant, a new cryogenic processing facility capable of handling 200MMcfpd located in Martin County, Texas, and approximately 200 plus miles of associated gathering pipeline, expected to be commissioned Q4 2024.

BRAZOS MIDSTREAM

Brazos completed its Comanche III processing plant in early 2019.

BRAZOS MIDSTREAM

privately owned midstream companies operating in the Permian. "There's been infrastructure on both sides of the basin for that long."

The gathering and processing part of the job means that companies have to handle new, complicated setups at the production site.

"When we first started, you were talking about one or two horizontal wells per pad. Today, we've got folks drilling eight to 12 per pad," Luskey said. The infrastructure required has scaled up accordingly. Large pipes, more compression, more gas plant expansions are all needed to handle the new output.

"Fortunately for us, unfortunately for the operators, (shale-quality infrastructure) hasn't existed," he said. "What you're seeing, in essence, is folks like Brazos are having to re-plumb the basin, basically."

Room for crude

The plumbing for the Permian has often been difficult to time.

Permian crude production outpaced the midstream network's ability to take it away near the end of 2018. As production surged, crude pipelines were at capacity, and producers sometimes had to rely on more expensive rails and trucks to haul crude away, according to an analysis at the time by S&P Global.

Pipeline builders quickly caught up. By the time the Permian hit a 2020 pre-COVID peak crude production at a little under 5 MMbbl/d, takeaway capacity had already surpassed 6 MMbbl/d as the Exxon Mobil-operated Wink-to-Webster line came online, with a capacity of 1.5 MMbbl/d.

By 2023, total egress capacity for the Permian was about 8 MMbbl/d, well ahead of production levels. There was enough excess capacity that Enterprise Products Partners decided to convert its Seminole Pipeline into an NGL transport conduit in October 2023, subtracting 210,000 bbl/d from crude capacity.

In May 2024, the U.S. Energy Information Administration reported that Permian crude production had hit 6.16 MMbbl/d. While overall egress capacity is not a problem, there are some issues that major midstream companies are trying to address.

One is in Corpus Christi, Texas. The port, with recently enlarged shipping channels and growing export facilities, is the most attractive destination for crude in the state, according to an analysis by RBN published in early May. As a result, the four pipelines serving crude to the South Texas City averaged over 90% capacity in 2023.

Two pipeline expansion projects serving Corpus Christi are in the works. On May 9, Enbridge called a binding open season for its Gray Oak Pipeline, with a proposed capacity expansion of 120,000 bbl/d and a project completion in 2026. Enbridge may adjust the proposed added capacity, depending on the demand from the open season. According to RBN, private EPIC Midstream is considering a similar expansion on its EPIC Crude system, though the company has not determined a definite time to more forward.

Either way, the overall Permian crude capacity situation should be able to handle the region's production growth, as noted at the 2024 Enverus Evolve conference in Houston. The region's production output is expected to grow about 2 MMbbl/d by the end of the decade, after growing

"What used to take us 10–12 months in building a processing plant takes probably 18–20 months. Compression now is a 52-week lead time to purchase. I mean, we used to be able to call and just get it off the shelf."

WILLIAM BUTLER, CFO, Brazos Midstream

5 MMbbl/d over the last decade.

"What we have now is a very healthy midstream system. They're doing very good in the oil patch," Hamm said. "Whether it's the Kinder Morgans, the Energy Transfers, Enterprise, whoever it is, they're moving a hell of a lot of volume."

Gas light

With that volume comes a whole lot of natural gas, which is what Brazos planned for, said company CFO William Butler.

When Brazos Midstream formed, its founders knew they wanted to focus on the development of gas pipelines and facilities. At the time, natural gas was in a bear market, thanks to the development of gas-rich shale basins in Appalachia, Texas and Louisiana.

That left the group with a choice, Butler said.

"We needed to either go into the most economic, lowest-cost gas basin, or we needed to go into a basin where they produce a lot of gas, and they don't care what the price is," he said. "So, we wanted to go to an area where the wellhead economics were driven by oil prices, not by gas prices."

Since its start, the company has also seen changes in the field and boardroom.

M&A was a hot subject for the Permian E&Ps last year. In early May, Kinetik Holdings announced a $1.3 billion midstream deal to acquire Durango Permian. However, Butler said the same level of merger activity has not been seen overall by midstream companies.

"We kind of think the writing's on the wall," he said. "But we've got a lot to do out here. We're building a lot and have a lot of work to do before we think about something like that."

Permian Basin Natural Gas Production

SOURCE: ENERGY INFORMATION ADMINISTRATION

Brazos Midstream chose the Permian Basin because it was the most economic, lowest-cost gas play.

BRAZOS MIDSTREAM

The company has focused on building up its lines and processing facilities and is currently working on about 200 miles of high-pressure pipe and a processing plant in the Midland Basin.

Butler said that for the typical Permian E&P, methane gas will make up less than 5% of a typical horizontal well's revenue, making the price irrelevant to the producer. Midstream companies, however, remain focused on the volume going into their lines and plants.

"The volume is going to come by virtue of the oil price in the economics of the Permian Basin. Both the Midland and the Delaware have sub-$40 breakeven oil prices," he said. "There's no better place to be."

The place can still throw up some obstacles. Brazos leaders said they have seen a sea change in the supply chains in the basin, ever since the beginning of the COVID pandemic in 2020, especially in the processing to make NGLs.

The company's plants have avoided becoming a production bottleneck, Butler said, but the company has to plan well in advance for supplies.

"What used to take us 10-12 months in building a processing plant takes probably 18-20 months," he said. "Compression now is a 52-week lead time to purchase. I mean, we used to be able to call and just get it off the shelf."

Luskey said the company is often bidding for braised aluminum heat exchangers against corporations building LNG terminals. Utility companies are overloaded with requests.

"In typical oil and gas business fashion, everybody tries to ramp up at the same time," he said.

Two NGL pipelines are under construction in the Permian. Targa Resources aims to place the 400,000 bbl/d Daytona line in service by the end of the year.

Enterprise is targeting a first half of 2025 in-service date for the 600,000 bbl/d Bahia project and has temporarily converted its Seminole crude pipeline to transport NGLs in response to high demand in an area where E&Ps are focused on crude.

"The growth is going to continue to happen," Luskey said.

Coincidentally huge

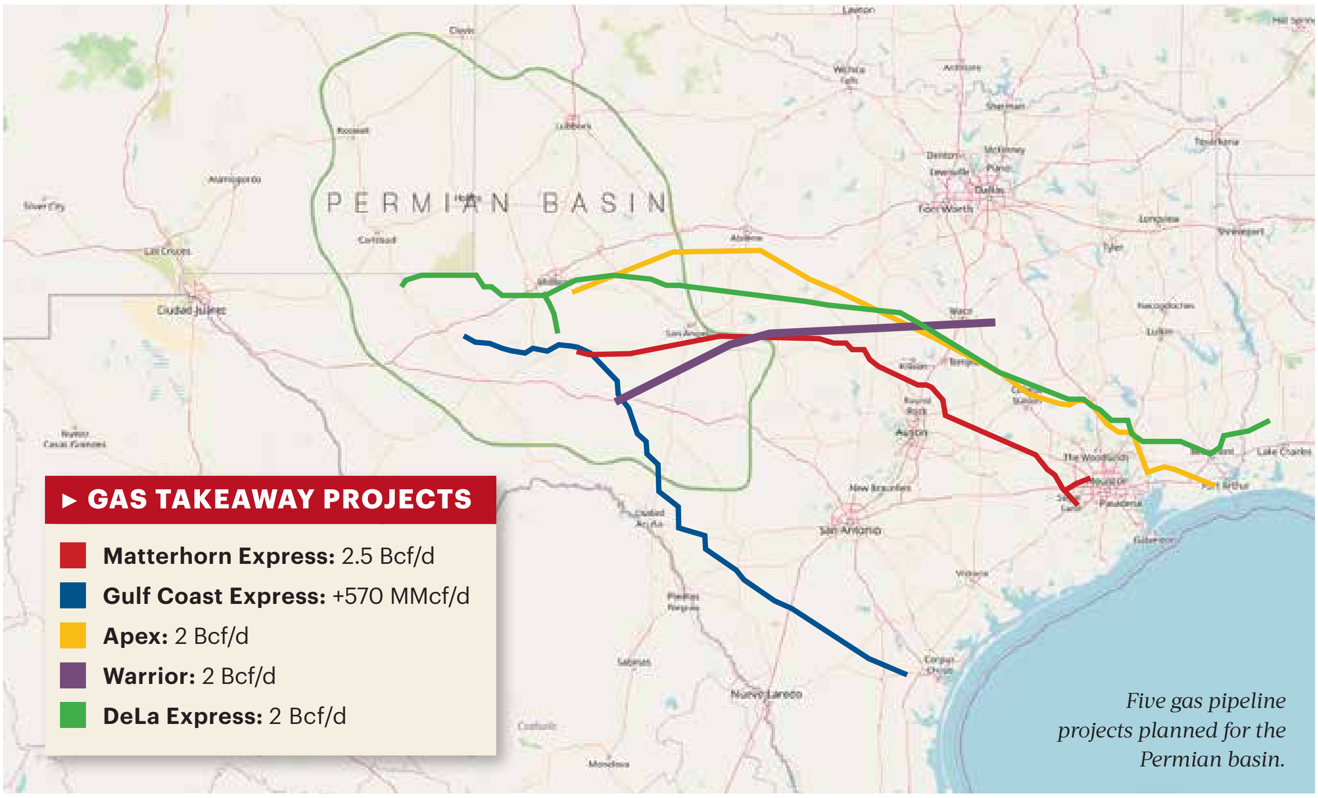
According to the EIA, the Permian was the country's second-most productive natural gas basin at 17.2 Bcf/d for March. The gas-focused Marcellus Basin averaged 25.315 Bcf/d.

The price of natural gas has been in the doldrums for most of 2024, dropping below $2/MMBtu at the Henry Hub futures market at the beginning of February and not climbing above the mark for three months. By mid-May, the price had climbed to a still-anemic $2.25/MMBtu.

Low prices and high volume can cause some problems, however.

The overall low demand for natural gas, coupled with spring maintenance work on several area gas pipelines, drove the spot price at the Waha Hub near Pecos, Texas, into negative territory. Producers now had to spend more than $1/MMbtu for a transport company to take the gas off their hands.

According to a Reuters, the resulting traffic jam on the West Texas gas network led some companies to resort to flaring. During the last week of April, the Texas Railroad Commission approved 21 flaring requests from operators, primarily in the Permian and the Eagle Ford Shale, more than four times the requests that had been approved



Five gas pipeline projects planned for the Permian basin.

SOURCE: OIL AND GAS INVESTOR, CORPORATE REPORTS

during the same time in 2023.

Luskey said that flaring is typically due to older infrastructure that can't handle more recent and efficient drilling technology. As an independent, the company prefers to build reinforced networks that can handle a higher load.

"What's going to make or break Brazos is our success. It's not where we did or didn't set an additional unit at a compressor station, so let's have the excess capacity to manage the spikes in growth as it comes," he said.

Flaring often happens when the pipelines or processing plants are unable to handle the excess load when gas continues to be pumped on the line even when it's not flowing fast enough. Flaring will generally first appear on some of the older pipeline networks with older pipes or aging compression units. Some companies in the area often have to deal with older material stretched out over millions of acres.

As a relative newcomer to the Permian, Brazos has the advantage of building its networks with large-diameter steel pipe pipe and new units. It's one of the company's selling points to potential customers.

"You're not going to see a 20% to 30% line loss on our system, you're not going to flare multiple times a week," Luskey said.

For the basin as a whole, producers hope a new pipeline will allow them to lower the line pressure completely.

Lines of egress

There are five major pipeline projects slated to take natural gas out of the Permian and onto different destinations on the Gulf Coast.

The Matterhorn Express, a JV of by EnLink, WhiteWater, Marathon Petroleum and Devon Energy reached FID in 2022 and is currently the only project under construction. The 580-mile pipeline was designed to handle 2.5 Bcf/d of natural gas and terminates close to Houston. The line is expected to be in service before the fourth quarter.

The arrival of the Matterhorn will give Permian producers some breathing room, but not much, and not for long. The pipeline is expected to be at full capacity before the end of 2025, as natural gas production in the Midland and Delaware continues to increase with time and with increased exploitation of the area.

The other projects publicly proposed are:

- The Gulf Coast Express expansion, proposed by Kinder Morgan, would add 570 MMcf/d to an already existing pipeline that terminates in South Texas. Kinder Morgan called an open season on the project in May 2022 in hopes of implementing the expansion by December 2023. However, no FID on the project has been announced. In January, Kinder Morgan CEO Kim Dang said the company was still interested in the project.
- The Apex Pipeline is a proposed 563-mile, 2 Bcf/d capacity greenfield project that would terminate near Port Arthur, Texas. In March 2023, Targa received Texas Railroad Commission approval for the line. Company executives have publicly stated that they are still deciding if the project will move forward.
- Warrior Pipeline would run from the Permian to other Energy Transfer pipeline connections southwest of Forth Worth, Texas. The plan has the advantage of utilizing underused pipeline capacity in the Dallas/ Fort Worth area and would have between 1.5 Bcf/d

Brazos Midstream pipeline construction stretching Reagan, Glasscock, Midland, Martin, Howard, Andrews, and Ector counties in the Midland Basin. Pipeline construction is an imperative in the Permian Basin as output is rapidly reaching capacity.

BRAZOS MIDSTREAM

and 2 Bcf/d capacity. Energy Transfer says the pipeline could be completed within two years of FID, which it has not yet reached. Company co-CEO Tom Long said during the company's first-quarter earnings call that the company continued to work on the project and would reach a decision about whether or not to go forward "pretty quick."

- The DeLa Express project became public in April when private company Moss Lake Partners filed preliminary paperwork with the Federal Energy Regulatory Commission. The proposed 690-mile pipeline would have a capacity of 2 Bcf/d. It's the only pipeline that would cross state lines, as the terminal point is slated for Cameron Parish, La. The pipeline is also the only one designed to haul liquids-rich gas, meaning that shippers could bypass processing in West Texas before shipping. According to its filing with FERC, Moss Lake has projected a 2028 start date.

Ready to move?

Continental Resources President and CEO Robert Lawler said there will be a definite need regardless of whether the other proposed projects go forward.

"With the continued investment in oil in this basin, that need for additional capacity is going to continue to grow," Lawler said. "And without the additional capacity, we are going to limit not only the gas for production but the oil production that the United States and the world need."

Inside and outside of the Permian, much of the industry has been waiting for a natural gas boom.

In the next two years, North American LNG exports are expected to more than double from their present capacity of 11.4 Bcf/d to 24.3 Bcf/d, according to the EIA. Along the Gulf Coast, companies are constructing multiple LNG export terminals, which the Permian is expected to feed.

More recently, the connection between artificial intelligence (AI) and gas-fired generation has become known throughout the energy industry. TC Energy's COO Stanley Chapman said during an earnings call that data center power demands could call for an 8 Bcf/d increase in natural gas production, equal to 21% of current natural gas demand in the U.S. for electrical production.

Data centers housing AI servers require far more electricity than typical servers, as AI chips use much more energy in their functions than normal chips.

Others in the gas industry have reported a surge in energy demand from "reshoring," or when a manufacturing company moves its operations back to the U.S. after moving them offshore. Forbes reported in January that 69% of U.S. manufacturers are reshoring their operations.

Lawler said the growth projections are strong enough that some companies have become more aggressive in their project decisions. The trend could potentially encourage a midstream company pondering a major pipeline project.

Historically, companies have looked at a base of about 75% before announcing FID. With the long, steady growth in the Permian, that may no longer be necessary, he said.

"What's interesting about this production path and the certainty that we have around it, is that, recently on some project FIDs, folks have leaned into a lower commitment base," he said. "With this certainty, we see it where we think the midstream company should have a better line of sight to those pipes being full and that FID should occur sooner." OGI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COMPLETING THE CYCLE

Vital Energy's 20-well unit in southwestern Glasscock County is producing some 18,000 bbl/d from some 300,000 feet of horizontal hole.

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Four formations, 20 wells, four pads.

It took more than half a year, but Vital Energy made a mega-well-count drilling spacing unit (DSU) in the Midland Basin's Glasscock County, completing some 57 miles of lateral hole.

In addition to the time involved in drilling, completions took three months alone, said Katie Hill, Vital Energy COO.

Beginning to come online in February, production had not yet peaked by mid-May. In early May, the DSU was making more than 18,000 bbl/d—15% more than Vital's expectations.

And the total output was still growing, Hill told investors at that time.

Each well's lateral is some 15,000 feet—kicked off at up to 8,200 feet of total vertical depth—for a total of 90 miles of hole southeast of the city of Midland, Texas.

On the four pads, one hosts six wellheads; two host five each; one hosts four. Ten of the wells were made in the Camp F 21 lease; 10 in the Halfmann 21 lease.

In wine-rack fashion, five wells were landed in Lower Spraberry, eight in Wolfcamp A, two in Wolfcamp C and five in Wolfcamp D.

"This is the largest package Vital has ever developed," Hill said. "And our team did an incredible job, safely executing [the package] ahead of schedule."

The job employed two completion crews. The wells were online 19 days ahead of schedule.

Wolfcamp C appraisals

The two Wolfcamp C wells are appraisal tests. "Our current public inventory does not include Wolfcamp C," Hill said. So far, "we're particularly encouraged by the performance."

If they work, it "could significantly extend our inventory life."

Jason Pigott, Vital's president and CEO, said, "We're really working through 'How do we co-develop these new zones?'"

More production data will give light to a go-forward plan. "It's the first test with this kind of new higher-intensity design, but very, very promising," he said.

"And those C zones are one of the contributors to our outperformance of that western Glasscock package. … [We] are getting more out of these wells via the new completion techniques."

The seven Wolfcamp C and D wells "had a lot of pressure during drill-out and, in fact, free-flowed to 5.5-inch casing at start for a number of weeks before we ultimately put them on ESP [artificial lift]," said Kyle Coldiron, Vital vice president for new well delivery.

"So strong bottomhole pressure [and] strong results so far. We're encouraged with what we see."

Drilling began in mid-2023 and completions were underway beginning in the fourth quarter.

Midland, Delaware frac trends

Arun Jayaram, an analyst for J.P. Morgan Securities, reported earlier this year that a look into current completion techniques in the Midland Basin showed productivity is up for some operators.

Posting higher first-six-month oil output were Chevron (12.2 bbl per lateral foot), SM Energy (11.8), ConocoPhillips (10.9), Diamondback Energy (10.7) and Vital (10.2).

"Average proppant loads were up 6% on a year-over-year basis at 2,147 pounds per lateral foot," he added.

Pumping the most intense completions were SM Energy, Ovintiv, APA Corp., Pioneer Natural Resources and Chevron, he added.

In a look at Delaware Basin completions, Jayaram found leaders in first-six-month oil productivity were EOG Resources (17.6 bbl per lateral foot), ConocoPhillips (17.3), Oxy (17.1), Marathon Oil (14.8) and Coterra Energy (14.2).

"Average proppant loads [in the Delaware] were down 1% on a year-over-year basis at 2,416 pounds per lateral foot," he added. "The most intense completion designs

Delaware Basin Completions, Year-Over-Year Change*

	Lateral Length	First six Months boe/ft	Proppant/ ft	Fluid/ft
APA Corp.	-30%	86%	-2%	8%
Occidental Petroleum	9%	15%	8%	17%
Chevron	-1%	12%	5%	26%
Tap Rock Resources	-18%	12%	4%	5%
Continental Resources	3%	10%	-9%	-13%
Diamondback Energy	-6%	4%	17%	23%
Franklin Mountain Energy	-4%	3%	7%	4%
EOG Resources	5%	2%	-2%	3%
ConocoPhillips	-4%	2%	10%	18%
Permian Resources	4%	-2%	8%	11%
Matador Resources	2%	-3%	0%	-3%
Callon Petroleum	5%	-5%	8%	-5%
Exxon Mobil	7%	-7%	7%	10%
Spur Energy Partners	12%	-8%	-6%	-6%
Mewbourne Oil	-1%	-9%	-2%	-1%
Coterra Energy	14%	-9%	-2%	-4%
Marathon Oil	8%	-13%	6%	28%
Vital Energy	10%	-14%	-13%	-2%
Devon Energy	7%	-23%	0%	-3%
BTA Oil Producers	7%	-41%	-13%	-6%

*TWELVE MONTHS ENDING MARCH 2023 VS. 12 MONTHS ENDING MARCH 2022.
SOURCE: J.P. MORGAN SECURITIES ESTIMATES, CITING ENVERUS DATA

Midland Basin Completions, Year-Over-Year Change*

	Lateral Length	First six Months boe/ft	Proppant/ ft	Fluid/ft
Occidental Petroleum	-2%	38%	15%	15%
Birch Operations	-16%	13%	-8%	-3%
Exxon Mobil	11%	3%	3%	5%
Permian Resources	20%	3%	-1%	2%
Ovintiv	-11%	2%	6%	-7%
Vital Energy	1%	1%	-1%	-5%
CrownQuest Operating	0%	-1%	2%	-3%
Summit Petroleum	-3%	-1%	2%	1%
SM Energy	1%	-1%	2%	25%
Endeavor Energy	5%	-2%	3%	6%
Fasken Oil & Ranch	0%	-3%	10%	-7%
Pioneer Natural Resources	13%	-4%	31%	1%
Hibernia Resources III	-9%	-5%	-11%	-9%
Chevron	0%	-5%	20%	96%
Surge Operating	16%	-6%	4%	1%
Diamondback Energy	9%	-9%	-4%	9%
ConocoPhillips	2%	-9%	-1%	-6%
APA Corp.	8%	-9%	12%	12%
HighPeak Energy	0%	-12%	0%	-1%
Callon Petroleum	-1%	-16%	-16%	-2%

*TWELVE MONTHS ENDING MARCH 2023 VS. 12 MONTHS ENDING MARCH 2022.
SOURCE: J.P. MORGAN SECURITIES ESTIMATES, CITING ENVERUS DATA

"The rock doesn't know it's being trimul-fracked. … The reservoir feels the exact same frac it would otherwise.… The wells would produce exactly the same because the completion downhole is exactly the same."

BRENDAN MCCRAKEN, president and CEO, Ovintiv

were utilized by Tap Rock Resources—now a part of Civitas Resources—and ConocoPhillips."

Ovintiv trimul-fracs

While Vital was trying a 20-well DSU in southern Midland Basin, Ovintiv was doing trimul-fracs—that is, completing three pads simultaneously—in its leasehold.

Ovintiv brought 35 Midland Basin wells online this year through early May.

The company's tri-fracs jobs are 30% faster this year than in 2023.

"At an industry leading 4,200 feet per day, we expect to utilize trimul-fracs on more than half of our program this year," Greg Givens, Ovintiv COO, told investors in a May call.

"This approach yields a 15% savings in completions cost per foot and essentially doubles the completed feet per day versus a traditional [one pad] zipper frac."

To date, Ovintiv has applied the trimul-frac to some 70 wells in the Midland Basin. It began the program in 2022. Frac stages to date are more than 3,400.

Wells perform just as well after a trimul-frac than those completed one at a time, Givens said. "We're seeing no degradation to well performance really at all.

"… The performance from these wells is very much in line with the other wells in the field."

The tri-job is showing "lower treating pressures and the ability to pump these jobs faster, which generates cost savings, which will flow straight to the bottom line," he added.

One-third of Ovintiv's 2023 completions were trimul-fracs. "This year, it will be a little over half and we see no reason why we couldn't continue to push that up even higher in the future as we continue to use the

Current completion techniques in the Midland Basin show productivity is up for some operators.

PATTERSON-UTI

“(W)e’re getting to a point where the fixed cost of the wells is a significantly larger portion of the cost of the well.”

DANNY WESSON, COO, Diamondback Energy

technology,” Givens said.

Brendan McCraken, president and CEO, said, “The rock doesn’t know it’s being trimul-fracked.

“So, the way we design these completions—the rate of slurry, sand and water that’s going through each cluster—is exactly the same in either a zipper, a [two-pad] simul-frac or a trimul-frac.”

Thus, the gains are all in dollars in above-ground efficiency. “The reservoir feels the exact same frac it would otherwise.… The wells would produce exactly the same because the completion downhole is exactly the same.”

Devon, Delaware

In its Delaware Basin position, Devon Energy is using simul-fracs, particularly on its 13-well Van Doo Dah project in Lea County, N.M., in its Cotton Draw project area straddling the Eddy-Lea counties’ border.

Van Doo Dah came online two weeks ahead of schedule. IPs averaged 4,000 boe/d, 52% oil, from each of the 10,000-foot Upper Wolfcamp laterals in their first 30 days.

“The massive scale of this project was showcased by the peak flow rates that reached nearly 30,000 gross bbl/d,” Clay Gaspar, Devon COO, told investors in May.

“This success further reinforces why I believed the stacked-pay potential in Cotton Draw to be one of the best tranches of acreage in all of North America.”

He added that simul-fracs have “been a key driver of compressed cycle times.”

Diamondback, Midland

Back in the Midland Basin, Diamondback Energy is shedding days in lateral feet completed, Travis Stice, chairman and CEO, told investors in May.

The company is working on lowering costs by getting its pressure-pumping operations onto power lines.

“A lot of that’s going to come in the way of getting these e-fleets off of generated power and onto some form of grid power where we can recognize a lower energy-source cost,” said Danny Wesson, Diamondback COO.

Diamondback has between three and four simul-frac crews working continuously in the Midland, said Kaes Van’t Hof, Diamondback president and CFO.

Costs have been squeezed so much by now, though, Wesson said, that “we’re getting to a point where the fixed cost of the wells is a significantly larger portion of the cost of the well,” Wesson said.

The variable costs are affecting “pennies and nickels and not as much dollars anymore.” To drive costs yet lower, “we’re going to have to think about doing things differently.” OGI

FOUND IN MITCHELL COUNTY, PERMIAN BASIN: 2.5-MILE WOLFCAMP STEPOUTS

Bayswater Exploration & Production has taken its Midland Basin oil play far east into Mitchell County where a high carbonate content "gives us a chance to really compete with the big guys."

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In Mitchell County, Texas, where the Midland Basin transitions into the Eastern Shelf, the number of horizontal wells can be counted by hand.

If far eastern Howard County, to the west of Mitchell, seemed a reach for tight-rock wildcatters in the past decade, jumping the border now into Mitchell is a newer frontier. After all, county seat Colorado City hews closer to Abilene than the unofficial Permian capital of Midland.

The straight lines in the Railroad Commission of Texas' GIS viewer in Mitchell County are county roads and section lines—typically, the same thing.

The rare horizontal well darts like an exclamation mark across the map, making a visual placeholder in Mitchell's 916 square miles—particularly in the county's northwestern corner.

There, privately held Bayswater Exploration & Production has taken a hunch and some subsurface clues—logs and old cores of the ancient stratigraphy—that suggest the Wolfcamp A works in Mitchell, too.

Oil, water

The Wolfcamp A is some 250 feet thick at the Howard-Mitchell border, where surface elevation sinks a bit into a mostly imperceptible valley.

There, the "A" is at about 5,500 feet vertical depth compared with some 9,500 feet in the Midland Basin core.

And Denver-based Bayswater's pilot laterals to date are vouching for prospecting.

Its Luxor #H4W lateral's first nine full months online has surfaced 140,467 bbl of oil, according to Railroad Commission data through February 2024. Casinghead gas was 140.5 MMcf.

A second pilot, Oasis #H4W, made 173,271 bbl of oil in its first 10 full months online with casinghead gas at 81.3 MMcf.

Drilled from the same pad 12 miles northwest of the city of Westbrook, Luxor was taken 2.5 miles north, crossing under Texas Highway 350. The first-24-hour IP in July 2023 tested 805 bbl of oil and 515 Mcf of solution gas, peaking at 977 bbl/d in November.

The Oasis well—taken some 2.5 miles south to make a toe under a pasture just west of the silty Lake Gregory—IP'ed in May 2023 with 621 bbl of oil and 347 Mcf of gas. It peaked a couple of months later at 1,025 bbl/d.

Initial water came on strong, like in early Wolfcamp A horizontals in the Midland core when operators began pilots there more than a decade ago. The initial test of a combined 9,100 bbl from Luxor and Oasis had been anticipated, though: Bayswater included a water-injection well in the pad.

Shale-sourced

Wolfcamp A is what operators in the Midland's core southwest in Midland and Martin counties have successfully targeted. So, what's different here?

The "A" in Mitchell doesn't resemble the traditional Wolfcamp model, said John Dyer, Bayswater senior vice president for the Permian.

"It's very different. We're drilling in a high-percentage carbonate reservoir compared with what other companies are developing to the west," Dyer said. "The lithology is remarkably different on the eastern edge of the play."

In the early Permian period in western Mitchell about 300 million years ago, a shallow shelf was along the edge of an ocean that covered the Midland Basin.

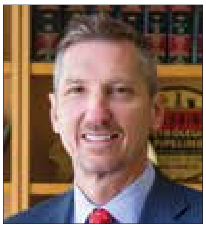
The Wolfcamp was deposited at that time. Some 50 million years later, the Permian period came to an end with a third mass extinction in a series of five to date.

"As our drilling program approaches the shelf edge from the west, we're encountering detrital carbonate sediments, which have mixed with the shalier Wolfcamp," Dyer said.

Carbonate content increases in the Wolfcamp, just as it does approaching the Central Basin Platform (CBP) that flanks the far western edge of the Midland.

Bayswater has produced 1 MMbbl from the 44 Magnum lease in the Sprayberry Trend Area of Howard County, Texas.

BAYSWATER EXPLORATION & PRODUCTION



"In the early mapping days of the Permian shale targets, operators typically wrote this [eastern] area off as not being prospective due to the high-carbonate lithology observed on the vertical control wells. There's so much carbonate in this section it's really not a shale play anymore."

JOHN DYER, senior vice president for the Permian, Bayswater Exploration & Production

"In the early mapping days of the Permian shale targets, operators typically wrote this [eastern] area off as not being prospective due to the high-carbonate lithology observed on the vertical control wells," Dyer said.

"There's so much carbonate in this section it's really not a shale play anymore."

In Howard County initially, adjacent to Mitchell's western border, Bayswater and other operators got to work where the Wolfcamp A is generally shale, but carbonate content is greater than in the Midland core.

"The organic richness from the shale is critical for sourcing the hydrocarbons," Dyer said. "But the oil-storage capability and deliverability of the reservoir may be more determined by the interbedded carbonates."

As Bayswater continued to step out farther east, "We found the carbonates becoming more and more porous."

Porosity is up to 12%. "They are getting sourced locally from the intermixed shale section, resulting in high hydrocarbon saturation."

The reservoir

The carbonates are limestone and dolomite. "Shale can be deposited closely with other sediments—sandstones, siltstones, carbonates. We're producing all of those together

Bayswater has produced 1.5 MMbbl from its Fortress of Solitude.

BAYSWATER EXPLORATION & PRODUCTION

"The carbonate-rich wells are better than the traditional shale wells in our neighborhood. You have the porosity, and it's a little more brittle. It fracs better."

STEVE STRUNA, founder, president and CEO, Bayswater Exploration & Production

in one package," Dyer said.

The rock is up to 75% carbonate.

"I remember watching the gamma-ray logs while drilling the first of the eastern-asset wells," Dyer said. It made for some insomnia, "lying awake at night thinking, 'We're drilling just all carbonate in these wells. Is this going to work?'"

But as cuttings and gas shows were coming in, "I was thinking, 'Wow, we're still in a very hydrocarbon-rich environment.' Both the shales and carbonates fluoresce with oil."

Without a reason to plug and pack up, Bayswater completed the well: Far East 1-12 #H3W in Howard County near the Mitchell County line.

It IP'ed 1,298 bbl/d of oil in 2021.

"I thought 'Wow, this is not my father's shale model!'"

Cumulative production is more than 430,000 bbl.

Going to Mitchell

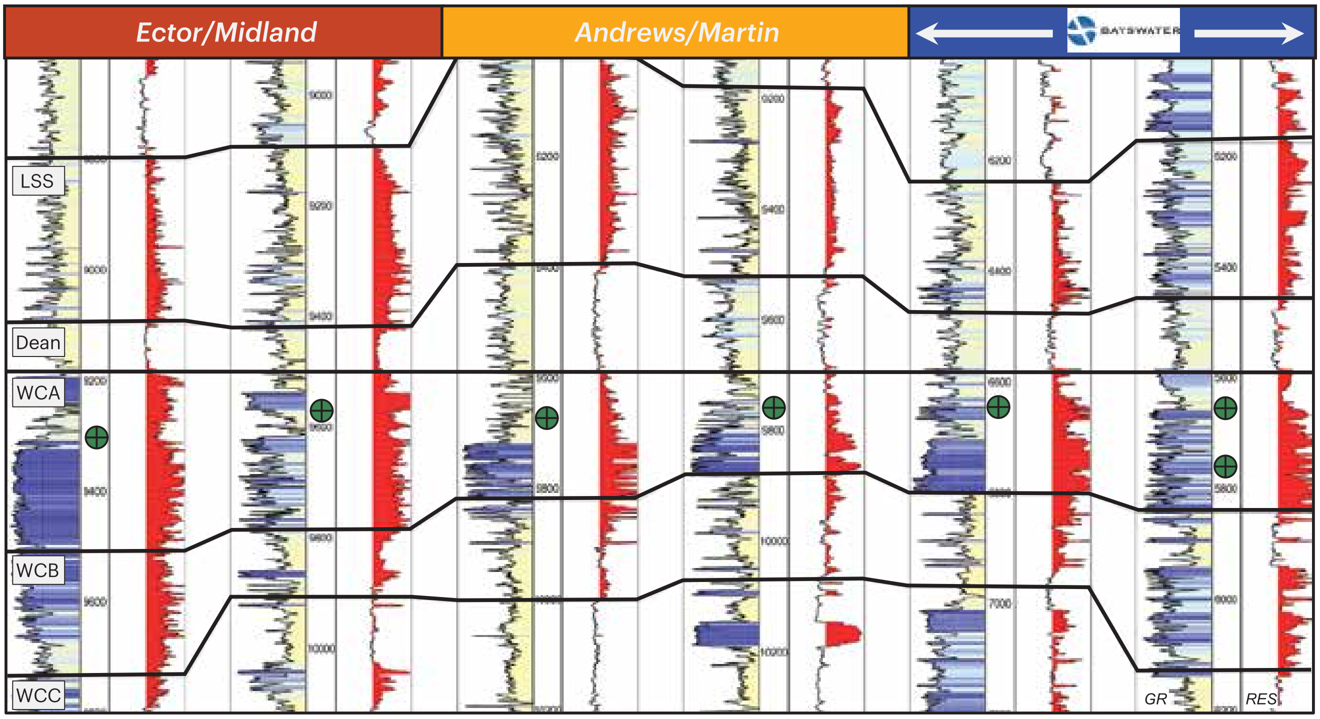
Farther east than the Far East well, the Luxor and Oasis wells are further outperforming their older Howard wells that were landed in the Lower Spraberry and Wolfcamp A, B, and D, said Steve Struna, Bayswater founder, president and CEO.

In addition to Far East and continuing the Asian theme, the eastern Howard pads are the Orient, Rising Sun, Samurai, Morning Calm and Kamikaze, totaling 16 wells inside Howard at the Mitchell border.

"The carbonate-rich wells are better than the traditional shale wells in our neighborhood," Struna said. "You have the porosity, and it's a little more brittle. It fracs better."

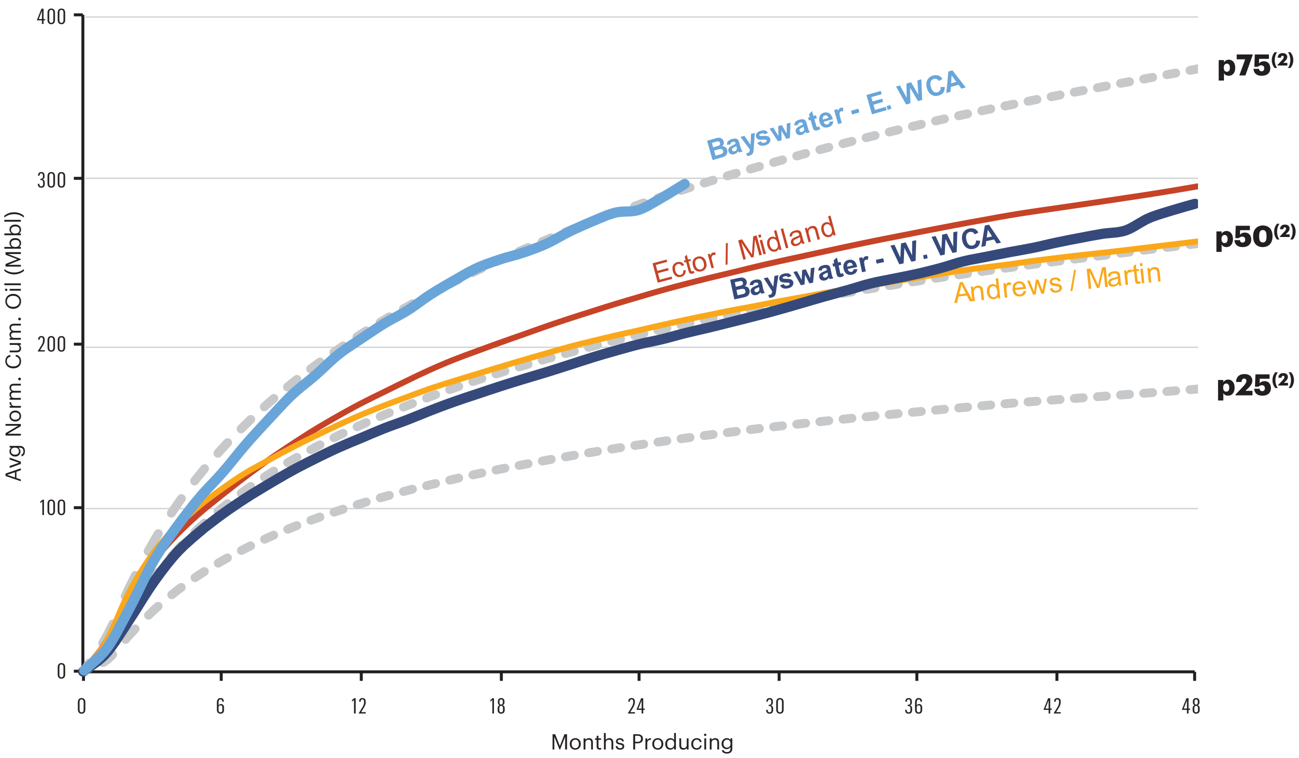
The Howard wells "are all really attractive, economic wells," he added. "But our best ones are out here on this

Midland Basin Facies, East to West[1]



SOURCE: APPROX. WCA LANDING. (1) LOG DATA SOURCED FROM TGS AND BAYSWATER.

Bayswater Eastern Wolfcamp A Well Performance[1]



WCA WELLS SINCE 2019. PRODUCTION NORMALIZED TO 10,000-FT. LATERAL LENGTH.
NOTE: ALL PRODUCTION NORMALIZED TO 10,000' LATERAL LENGTH.
SOURCE: BAYSWATER, CITING ENVERUS AND TPH & CO.

Morning Calm is one of five pads totaling 16 wells in eastern Howard County near the Mitchell County border.

BAYSWATER EXPLORATION & PRODUCTION

[farther] eastern edge where you have more carbonates."

Some 1.75 miles east of the Oasis/Luxor pad, Bayswater has landed two additional 2.5-mile laterals—the Xerxes #H3W and Moses #H3W.

This spring, the operator began drilling six more 2.5-mile laterals, including a four-well pad, between the first two pads. Completion is expected this summer.

Spraberry Trend

Bayswater's initial Permian package—in Howard County—was leased in 2016. Its first production was in 2018.

Northeastern Howard and northwestern Mitchell are semicircled on the east by vintage Clear Fork vertical oil fields—overlying Wolfcamp, such as Westbrook and Coleman Ranch, that have made more than 240 MMbbl.

"It's a very robust petroleum system we're drilling in," Dyer said.

Bayswater's total Mitchell County production through February is 300,000 bbl, all from the Spraberry Trend Area Field.

From Howard, where it's operated longer, Bayswater has produced 12 MMbbl, also from the Spraberry Trend Area, primarily from leases 44 Magnum (1 MMbbl), Formula One (1 MMbbl) and Fortress of Solitude (1.5 MMbbl).

Bayswater's leasehold is mostly HBP. It has one rig drilling it currently. "So, if it's not HBP, it will be shortly," Struna said.

Vertical control

While the venture into Mitchell was in frontier rock for lateral taps, well control was plentiful from all the legacy verticals punctuating the landscape from the past century.

Bayswater also found core that had been pulled from the old wells.

"The vertical well control gave us confidence that this mixed-lithology, carbonate/shale reservoir was capable of producing all the way into Mitchell County," Dyer said.

As for also landing in Spraberry and in Wolfcamp B, C, and D, as well as in any other formations in Mitchell, "We are evaluating those as we go," Dyer said.

But Wolfcamp A "will be our primary focus."

The "B" is thin and it's "fairly clay-rich in the eastern-asset area. It doesn't seem to be a primary target for us right now."

Generally, though, all of the Wolfcamp sections are more carbonate easterly, approaching the Eastern Shelf.

Eight days, spud to release

At some 5,500 feet, Wolfcamp A in the area "is some of the shallowest in the basin, which gives us a chance to really compete with the big guys on our drilling cost to total depth," Dyer said.

D&C for the 2.5-milers is less than $7.5 million. "These should be some of the lowest D&C wells in the basin."

The 2.5-mile lateral is looking like "our sweet spot," he added.

The wells are drilling in eight days from spud to release for the total of nearly four miles of hole–5,500 feet vertically and 2.5 miles from heel to toe.

"Over the years, the bit technology, the oil-based mud, everything out there [in the industry] has made us able to drill these wells in about the same time as you would drill a shale well," Dyer said.

Three-mile laterals are possible. "We can do three [miles]. We've done some three-milers [farther west]." But the completion becomes more complicated, he added.

The higher carbonate content does result in a better frac though.

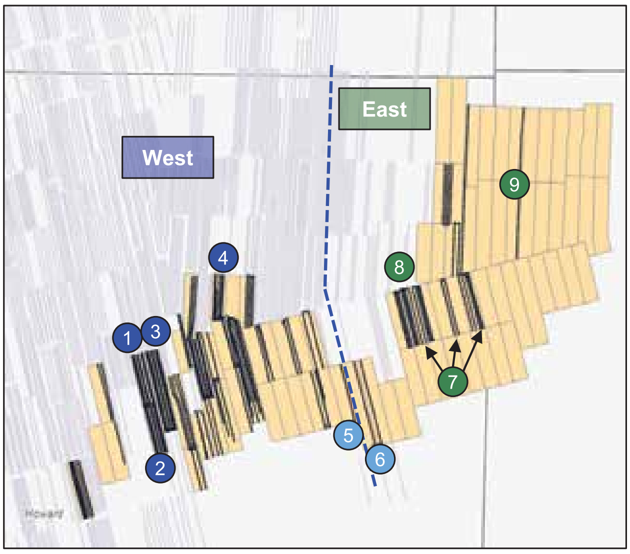
"We think we're getting better frac complexity in this carbonate system, so it helps us there," Struna said.

EUR from the far eastern Wolfcamp A is 73 bbl of oil per foot and 88 boe. It adds up to about 900,000 boe for a two-mile lateral.

The results are greater than Bayswater's western A wells (58 bbl and 79 boe), as well as the western Lower Spraberry (43 bbl and 56 boe), Wolfcamp B (34 bbl and 58 boe) and Wolfcamp D (38 bbl and 58 boe).

Bayswater calculates its eastern Wolfcamp A gross location inventory at 163 wells and breakeven at $40 WTI. "On a lateral-foot basis, this is probably some of the best in the basin," Struna said. OGI

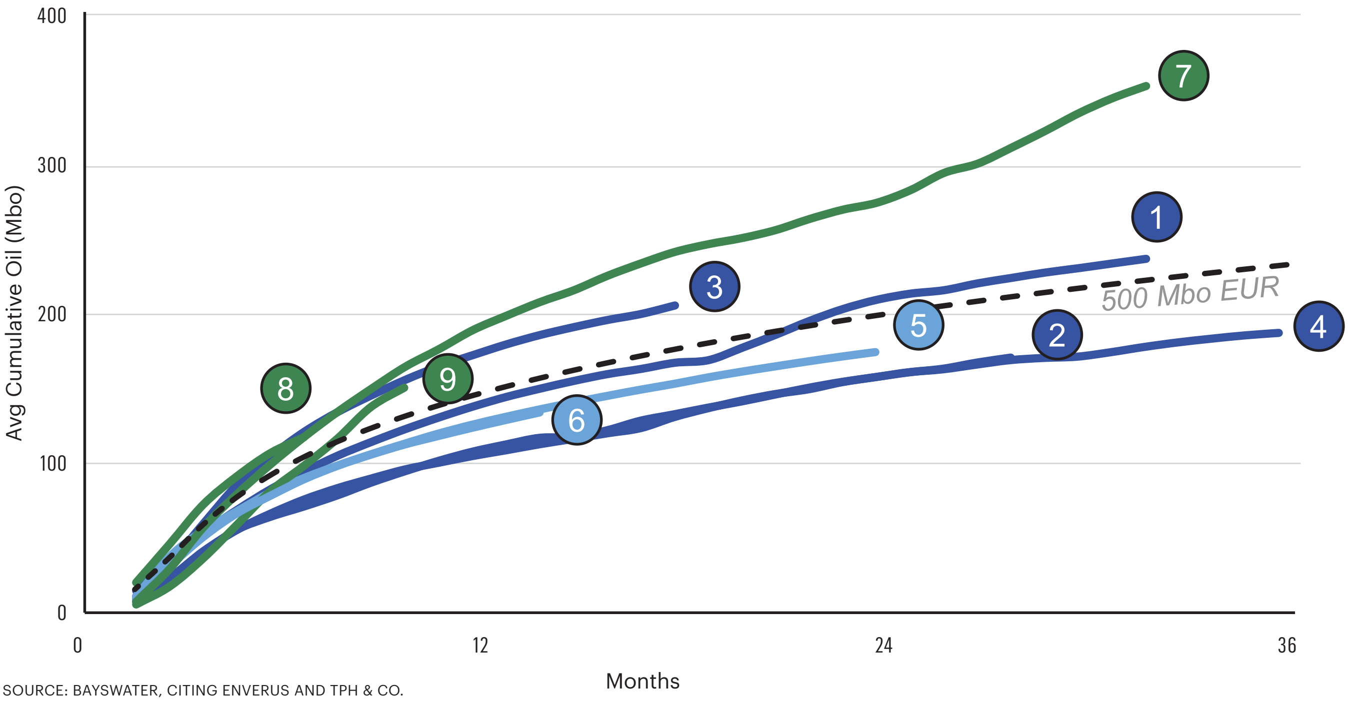
Bayswater Recent Wells



#	Dev. Name	# of Wells	Zones Drilled
1	44 Magnum	6	LSS, WCA, WCB
2	Formula 1	8	LSS, WCA, WCB
3	Fortress of Solitude	8	LSS, WCA, WCB
4	Jackpot	5	LSS, WCA
5	B-Side	1	WCD
6	Sidekick/Hustle	2	WCD
7	Original East Parents	4	WCA
8	Far East Infills	7	WCA
9	Oasis/Luxor	2	WCA

SOURCE: BAYSWATER EXPLORATION & PRODUCTION

Bayswater Cumulative Oil by Pad



SOURCE: BAYSWATER, CITING ENVERUS AND TPH & CO.

Commercial Banks Open for Oil, Gas Business

Regional banks are picking up market share and rallying the U.S. upstream sector.

DEON DAUGHERTY
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Regional banks across the U.S. are swooping in and grabbing market share in oil and gas lending as large European banks' climate fears have made them squeamish toward the space.

In the most recent example of Euro flight, UBS' acquisition of Credit Suisse, the merger of Switzerland's two largest lenders, showed what can happen when two big banks combine during the net-zero trend. Both have committed to phase out carbon emissions from their portfolios by 2050.

What's more, big U.S. money center banks are focused on high-grading their portfolios with a focus on publicly listed companies that offer capital markets opportunities, said Marc Graham, managing director and head of energy at Texas Capital.

Marc Graham

"Into the space vacated by these lenders, we have seen regional banks become more active," he told *Oil and Gas Investor (OGI)*.

And, as states like Texas have withdrawn their money management responsibilities from investment groups likes Blackstone, which are perceived as pivoting away from fossil fuels, red state-lenders have another opening.

Bryan Chapman

Bryan Chapman, market president for energy lending at First Horizon Bank, noted the Fort Worth, Texas-based bank has pledged to support Texas leaders' divestment.

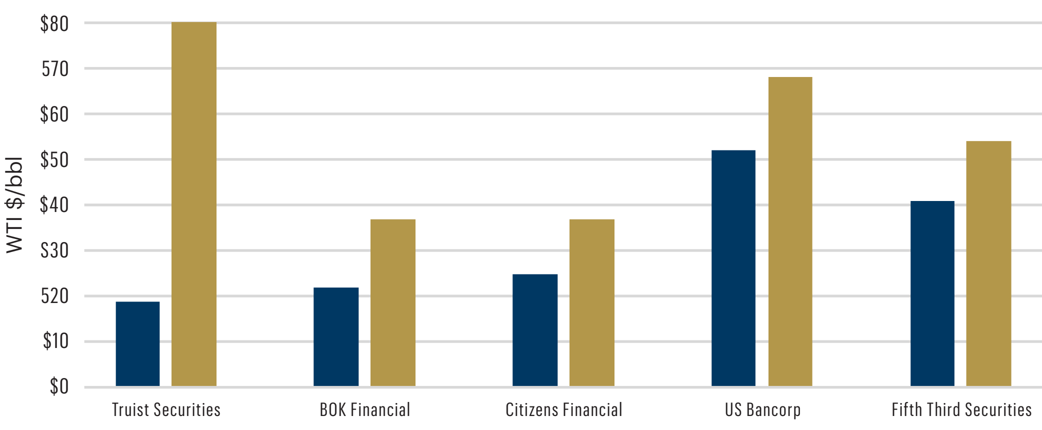
"I think a lot of people just thought there was going to be this big switch that was going to get flipped. And so, you saw oil prices crashing, and then you ended up seeing this clean energy kind of skyrocketing," Chapman told *OGI*. "Over the last couple of years, you've really seen a complete reversal. The margins in those clean energy deals are very, very low. When interest rates went up, there's just not enough margin in those deals to sustain that kind of increase in the cost of debt capital."

Upstream companies are running their businesses with less debt and stabilizing growth with a focus on generating free cash flow to pay dividends, repurchase shares or fund distributions to private equity sponsors, Chapman said.

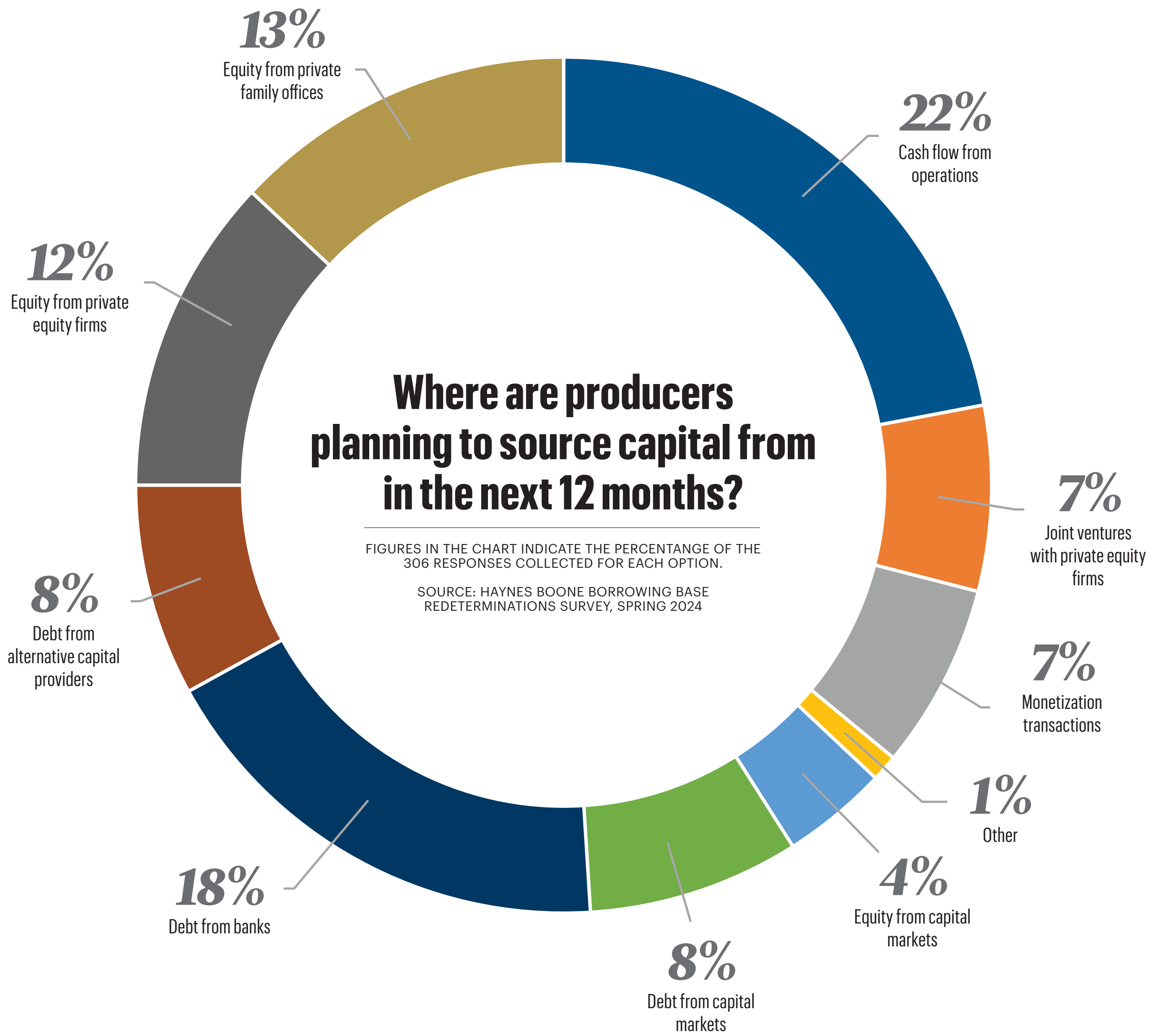
"They've just structurally shifted to a more

Regional Banks Rediscover Oil and Gas

Average loans to oil and gas companies, $ billions, 2016-2021 vs. 2022-2024 (first quarter)



SOURCE: BLOOMBERG



conservative capital structure because no one's going to bail you out of a bad balance sheet. If you want to have some leverage and negotiations, you have to have low debt," he said. "So, if someone's going to pay cash, you'll have the ability to pay off your debt."

Bulls on parade

The majority of E&P lenders are open for business, said Marisol Salazar, senior vice president and manager for energy financial services at BOK Financial.

Marisol Salazar

Entering 2024, the firm says millions of dollars in payoffs have been a result of consolidation.

"When you look at a huge portion of your book having paid off by selling those companies at the end of 2023 [and during the first part of this year], you see banks that are pretty hungry," she told *OGI*. "Couple that with a lot of discipline amongst both bankers and companies, and that leverage has been pretty low."

U.S. energy lenders' confidence in oil is growing in contrast to sentiment on the near-term slump in natural gas markets, according to findings in the Spring 2024 Haynes and Boone surveys on borrowing base and price decks released in mid-May.

Of the 92 participating lenders and borrowers in the firm's Borrowing Base Redeterminations Survey, 35% expect no change in borrowing bases during the spring round. About 20% anticipate an increase and 7% expect a 20% increase.

The tempered optimism is also reflected in results of the firm's Energy Bank Price Deck Survey in which 26 energy banks participated. Oil price projections among the group revealed stable to slightly higher projections on long-term oil prices. The base case of those surveyed is $57.09/bbl by 2033; in the fall 2023 survey, the base case for oil was $55.59/bbl.

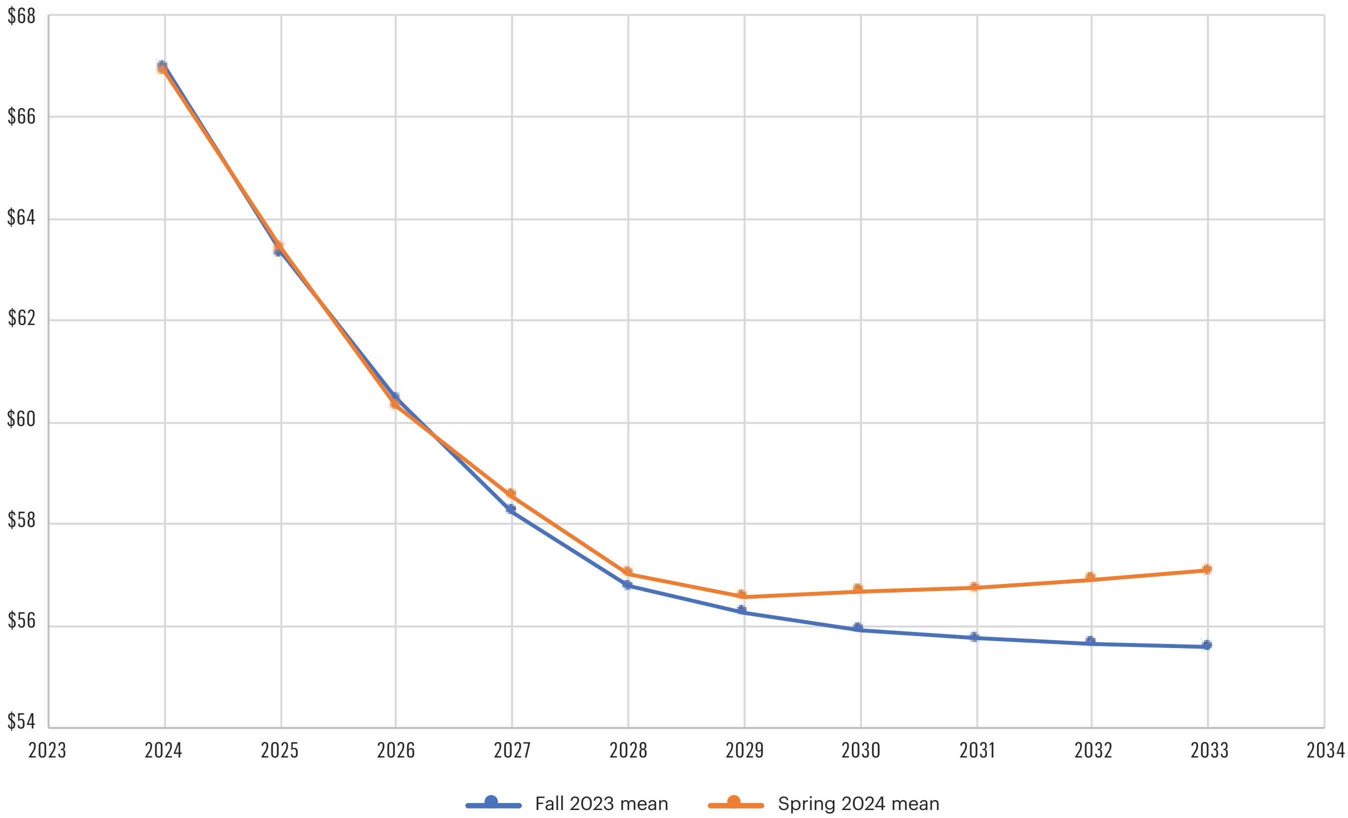
Kraig Grahmann

On the natural gas side, historically low prices based on oversupply and a warm winter, have raised some concerns about gas-weighted redeterminations. But, the survey showed expectations for a natural gas price bounce to $3/MMBtu by 2025.

"The oil market has newfound positivity, with borrowing base increases possible for some producers," said Kraig Grahmann, a partner in Haynes and Boone's energy practice

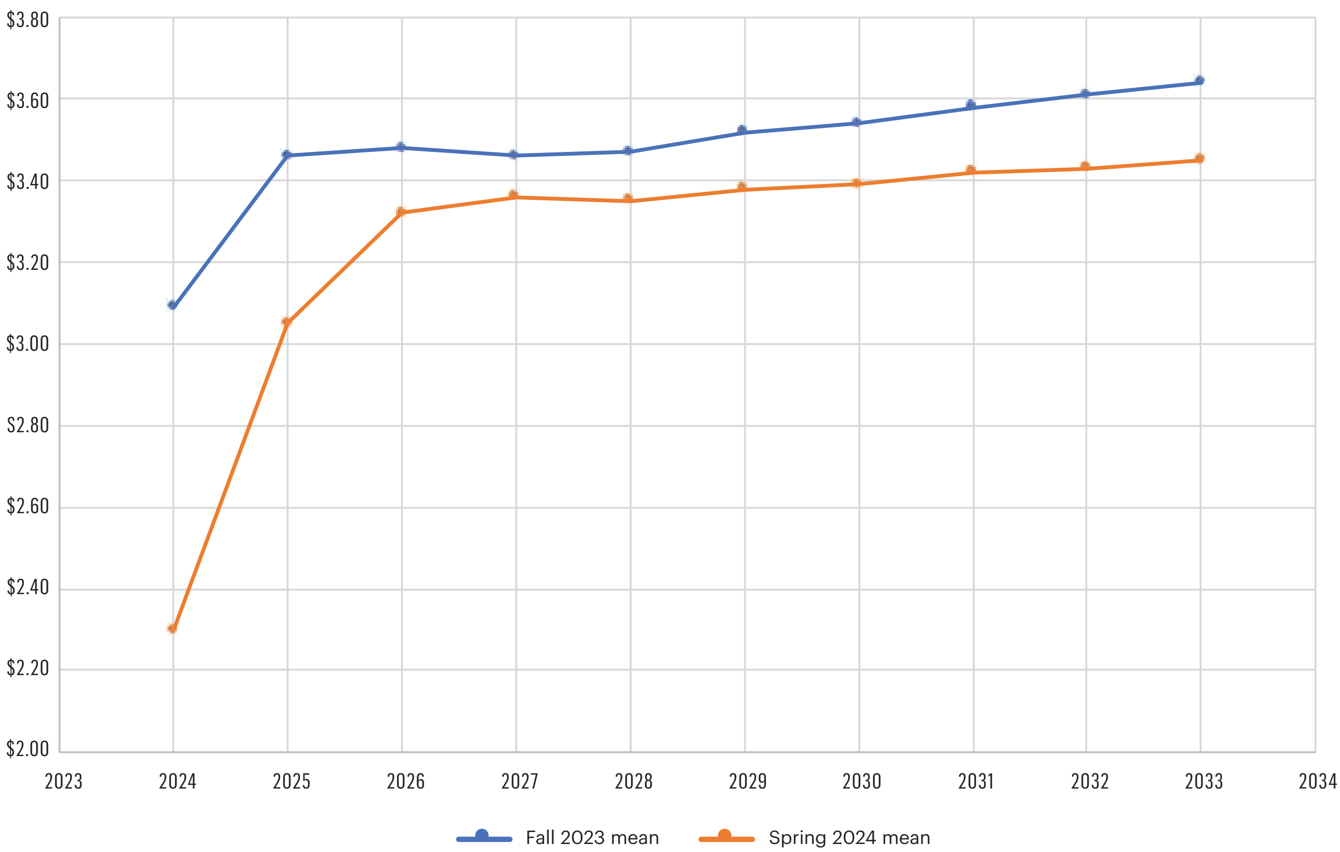
Oil Base Case

Fall 2023 vs. Spring 2024 ($/bbl)



Gas Base Case

Fall 2023 vs. Spring 2024, ($/MMBtu)



SOURCE: HAYNES BOONE ENERGY BANK PRICE DECK SURVEY

Oil and Gas Deal Numbers Since January 2022

Companies	Deals
Wells Fargo	318
BofA Securities	315
JP Morgan	282
RBC Capital Markets	267
Mitsubishi UFJ Financial	259
Citi	258
Mizuho	237
Sumitomo Mitsui	221
Scotiabank	219
CIBC	193
TD Securities	185
Truist Securities	180
Barclays	168
BMO Capital	152
HSBC	152
US Bancorp	152
PNC Financial	149
ATB Capital	147
Goldman Sachs	134
National Bank	129
Credit Agricole	123
Fifth Third Securities	121
ING Groep	116
Bank of China	113
Societe Generale	110
Morgan Stanley	108
Capital One	99
KeyBanc	86
BOK Financial	83
Citizens Financial	83
Industrial & Comm Bank of China	81
BNP Paribas	80
Comerica	77
Natixis	77

Average Annual Oil and Gas Loans

Regional U.S. banks are increasing their lending to oil and gas

	2016-2021	2022-2024 [1Q]
Truist Securities	19	80
BOK Financial	22	37
Citizens Financial	25	37
US Bancorp	52	68
Fifth Third Securities	41	54

SOURCE: BLOOMBERG

group. "But we have a 'best of times, worst of times' split, with distress in natural gas markets countering the oil boom."

Among those surveyed, a meaningful drop is expected in equity capital markets. The survey showed that any shortfall will likely be balanced by an increase in equity from family offices and private equity firms. Based on the fall 2023 sentiment, bank debt and using debt from capital markets are generally expected to remain stable.

The consolidation trend that has reshaped the upstream sector during the last six months—and in the midstream space to a lesser degree—indicates an upcoming surge of divestment activity of non-core assets once those deals close. But it's unlikely to manifest until 2025, according to overall sentiment of those surveyed.

Graham said consolidation has returned capital to providers, who are looking for ways to deploy it. The small producers will likely see a new bloom in their relationships with lenders that were "highly selective" during the fall redeterminations.

"Lenders are now seeking to commit to new relationships in order to build those portfolios back up again," he told *OGI*. "Given that the number of E&P companies is declining via consolidation, it is only logical that capital providers are going to seek opportunities to deploy capital with relatively smaller producers."

Capital access

Capital remains available to the upstream space, but Graham said companies must recognize that the sources have changed. Diversified New York City-based private equity funds, pensions and European banks are being replaced by family offices, private credit term loan providers and regional banks, all of which are significantly more active today than just a few years ago, Graham said.

"If a company recognizes this shift and develops relationships with the new players, they will improve their odds of attracting capital," he said.

This year is also opening a window for E&Ps to access the credit and debt markets. Companies are adding new lenders to their revolving credit facilities and others have successfully accessed the capital markets.

"The strong credit profile of the industry is drawing investors back into the sector. Consolidation of operating companies has resulted in the return of capital to lenders and investors alike," Graham said. "That capital is being put back to work."

But climate concerns remain a hurdle for some lenders that have opted to lessen their exposure to fossil fuels. Across the board of regional lenders, the opportunity set—and access to capital for disciplined borrowers—is growing.

"For us, [oil and gas] is a major focus and so we continue to take advantage of where … some banks initially when they pulled out of energy or some that just have a cap on how much they do in energy," Salazar said. "Whether it's because they want to keep a cap or because of ESG, we continue to have that focus and continue to add market share."

It's not that commercial lenders are immune to ESG concerns; it's only one part of calculus that goes into whether financing is profitable.

"Texas Capital recognizes that our borrowers should be good stewards of the environment, be good social citizens and have appropriate governance practices in place," Graham said.

Moreover, as a Texas state-registered bank, Texas Capital exists to "support the breadth of the Texas economy and all of the industries that contribute to it.

"We are unapologetic supporters of the oil and gas industry because of its contribution to the Texas and U.S. economy," he said. "We take a pragmatic approach to how the nation sources its energy." OGI

Building a Bakken BEAST

Chord Energy CEO Danny Brown breaks down the M&A strategy that is hitting all the right notes.

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Chord Energy could be the quintessential example of what other E&Ps are trying to achieve in the recent lightning round of upstream M&A. Poised to become the Williston's largest producer upon completion of its acquisition of Enerplus—expected at the end of May—leadership gears to take the best of every practice it absorbs. Shareholders have taken notice and the firm's stock price is soaring, with expectations of more upside by year end.

How did a company that didn't exist in 2021 do it? CEO Danny Brown tells Deon Daugherty, Oil and Gas Investor *editor-in-chief, how it all came together and what's next for the emerging behemoth in the Bakken.*

Deon Daugherty: Walk us through the genesis of Chord Energy.

Danny Brown: You've got to go back into the legacy organizations. I came into Oasis [Petroleum] in April of 2021. We were through the depths of COVID, through the Saudi-Russia oil price wars, but still in the midst of a very, very heavy investor focus on ESG and certainly a lot of questions about the durability of the industry and the durability of our product.

Like many E&P companies at the time, we were somewhat struggling for relevance. We were a very small-cap company in a basin that was [given] as much attention as those companies within the Permian Basin.

Both Whiting and Oasis had entered restructuring into 2020. After the COVID demand loss and the Saudi-Russia price wars, it was a terrible time with negative oil prices and high debt. So many companies couldn't make it through. They both went into bankruptcy and both got new boards and hired new CEOs. I was hired on the Oasis side, and I think both of us—the CEO of Whiting Oil & Gas and myself over at Oasis, as well as our boards—realized that we were subscale at our current size. I think it was my second day on the job that I called the CEO of Whiting.

DD: What was that conversation like?

DB: Well, there was just a recognition that we

CHORD ENERGY

"As we went through the integration, we said, well, that's great. We're twice the size that we were before. We're a new company. We really did try to do something new, not have this be Oasis 2.0 or Whiting 2.0—let's be something new as we move forward."

DANNY BROWN, CEO, Chord Energy

were two small companies fighting for investor relevance. We had assets that were beside one another within the basin, and we discussed the strategic merit in investigating whether or not a combination would make sense. And we both agreed that it would, but we also both agreed that we had a lot of work to do for ourselves before we could really seriously pursue something.

So, we both went on a "journey of self-help" for ourselves. (Oasis) had an asset in the Permian Basin, which was acreage that we liked, but it had some drilling commitments associated with it and it really distracted us from where we wanted to focus our attention, which was in the Bakken. We divested the Permian position [and] we picked up a position in the Bakken from QEP.

1,029,263
net acres

1,024,771
net acres held by production

Diamondback previously had bought QEP really for their West Texas acreage. They also picked up their Bakken acreage. It didn't fit that fantastically within Diamondback's portfolio. And so they ended up selling that asset. We picked that up.

We announced these within a few days of one another. We had sold our Permian position, but we increased our Bakken position by 50%. That was a big part of our portfolio cleanup to position us to do the next big thing.

DD: The next big thing?
DB: Well, Oasis Petroleum had an affiliated midstream, separately traded company called Oasis Midstream Partners, OMP. And we recognized that we were not seeing the full value

of that midstream company within our company. Generally, a midstream company will trade at 7x-8x EBITDA, whereas an oil and gas company at the time was trading, let's call it between 3x-4X EBITDA.

The risk of the cash flows is less for the midstream company because you've got contracts guaranteeing those cash flows, and generally those cash flows command to higher multiple. Well, here we had this huge midstream company that Oasis owned outright, but we were trading as if we were only an E&P company and we didn't have these other cash flows in it, so we weren't realizing the full value.

It would be hard for someone to do a merger with us because we would say, "Hey, you need to recognize the value there." And they'd say, "Well, the value's not in your stock price." We needed to do something about that. The second big thing we did after we did the portfolio repositioning from an asset standpoint is we merged our OMP holdings into Crestwood Equity Partners, which was a pure-play midstream company.

DD: That's a lot of work within a fairly short amount of time.

DB: We didn't want to sit on our hands. Another thing we were really active about was a really progressive and forward-leaning return of capital program back to our shareholders. There's a lot of companies that have done that now, but when we did it, I think we were one of the first ones to come out to the degree that we did. And we got a lot of good attention from shareholders along the way.

4
operated rigs

The combination of making these other strategic moves was largely applauded by investors. They loved the focus for us back in the Bakken, they recognized the trap value we had with OMP. Combining the two organizations made us more resilient. It was an all-equity deal. And so, both sets of shareholders participated in the upside in the pro forma organization. And we were able to wring out synergies from the deal, which we thought would be around $65 million when we announced between Whiting and Oasis, but turned out to be $100 million of synergy annual savings. Both sets of shareholders benefited from that. And because we were larger, more investors were noticing us.

58%
oil

Slowly, our share price went up. And as we went through the integration, we said, well, that's great. We're twice the size that we were before. We're a new company. We really did try to do something new, not have this be Oasis 2.0 or Whiting 2.0–let's be something new as we move forward.

As we went through the integration, we made sure that all of our systems, all of our processes, would be scalable so that if we potentially double in size again, we would be able to do that fairly easily. And I think that's paying dividends now for our transaction with Enerplus.

DD: So, you doubled in size, and then Enerplus is another big add.

DB: [Enerplus is] about half our size currently. When I came into this role in April of 2021, there were three, not quite pure-play, but three almost pure-play Bakken companies that were all about the same size: Enerplus, Whiting and Oasis. And from an outsider's perspective, it made so much sense to me at the time that they should all be part of the same company.

DD: What have been the challenges along the way?

DB: No integration is easy. We tried to take a "best of" approach as we build core. And one of the nice things about being a new CEO to Oasis is that some of the legacy practices, the legacy processes and the legacy way of doing things, candidly, I didn't have an emotional attachment to them because they weren't a product of something that I'd come up with. I probably had an opportunity to be a little more unbiased around those things and no need to defend my previous way of thinking.

And the CEO on the Whiting side was in the same boat. It really unshackled us as we put the two organizations together.

If there's a great process that Oasis is implementing, let's keep that. And if there's a great process that Whiting is implementing, let's use that. And if we find out in this process that really neither one of them is a best practice, well let's ditch them both and go to option C and we'll move forward. Those were the marching orders given to everyone.

I think that's the harder way of doing something as opposed to saying, "Well, we're just going to adopt company A's or company B's practice and we're going to jam everything together." That's the easier way to do it. It's probably a less risky way of doing it, but I don't think you have as strong as the potential value that you can get out of a deal. I wanted to get every bit of value out of the deal as we could. It wasn't just the assets that I was looking for, but also the processes and then maybe catalyzing some new thinking within the organization.

DD: How did Enerplus become part of the equation?

DB: Well, bigger doesn't necessarily mean better, but there's more ways to be better if you're bigger. I think my counterpart at Enerplus had some similar feelings.

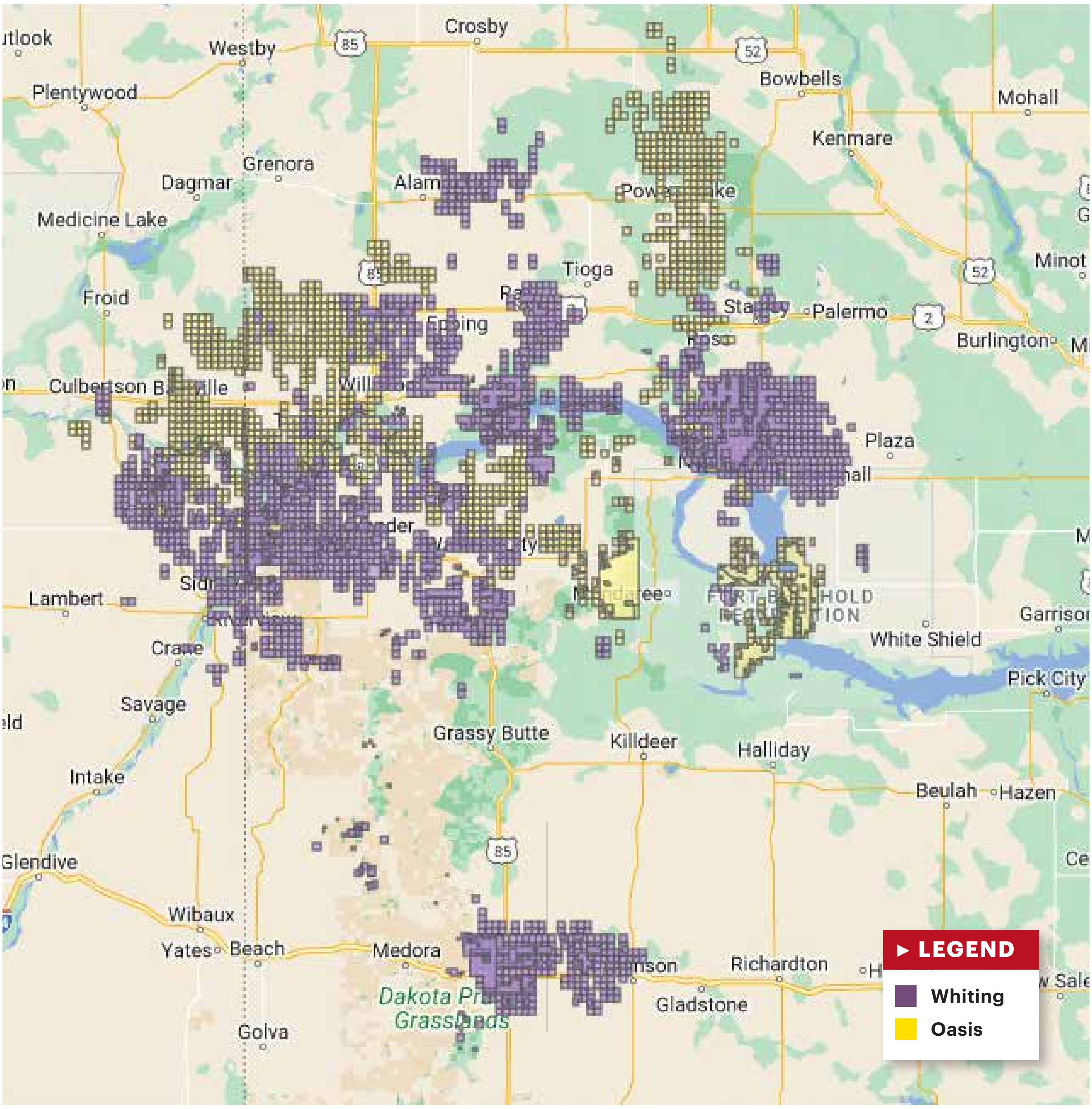
On occasion, I would speak with the Enerplus CEO, and we would have discussions about that. Was there strategic merit to putting our two organizations together? And I'll say, ultimately, both sides saw that there was, and we were able to put something together that I think really made sense for all parties. I think the most telling thing is that it's a 90% equity deal, which means that their side really believed in the future of the company because they're betting their equity stake on the future performance of the company.

DD: What makes the Williston special in your view? You divested your Permian assets, but the Permian gets the industry excited. Why do you want to be the behemoth in the Bakken?

DB: I am an oil bull. I like oil. Not to say I don't like natural gas and other forms of energy. I'm a hydrocarbons guy, but I think oil is a great commodity to be involved in. And the Bakken really is the oiliest basin of the major unconventional basins around. The proportion of oil we produce is higher than any other basin.

As a comparison, the Permian is a much larger basin

Whiting, Oasis Acreage in the Bakken



SOURCE: REXTAG

and it produces about five times the oil that's produced in the Bakken. But it also produces about seven times the gas that's in the Bakken. And so, it's a gassier basin than we've got within Williston.

We're only really going after one zone. We're a middle block and development player generally. And so you can imagine all the stack pay zones that are in the Permian, which are fantastic from a resource potential standpoint. But it also leads to some uncertainty on what the deliverability is going to be. And then there are all of the things that have been talking about certainly increasing conversations over the past, say three or four years on parent-child relationships offset drainage both vertically and horizontally. We just don't deal with as much of that here. We're not developing as densely as it's developed within Permian, and we're only really developing in one zone.

DD: What are the challenges of operating in the Bakken? When you talk about ensuring that your processes are scalable, to what end?

DB: When we put Oasis and Whiting Petroleum together, at the time we were both a little under $3 billion in market cap. We put these together, we made a company that was over $5 billion in market cap that still struggled for relevance, to get attention.

As you mentioned, there is much more focus on the Permian. I like many things about the Bakken, but there's not as many investor eyes on Bakken as there is in the Permian, despite some of the advantages. When we

While Chord Energy keeps their eyes open for strategic M&A outside of the Bakken, with nearly a million acres stretching across the basin and existing operational synergies, the bar for further consolidation within the Bakken is lower, according to CEO Danny Brown.

went into this, we said, "Well, we need to be bigger, and so we need to be on the lookout." We're the product of consolidation. By putting Oasis and Whiting together, we need to continue to look at that as we move forward.

What we didn't want to do is create a solution that worked great for Chord, but was limited in its applicability. Say you've got an accounting system that can only handle so much data and now you're running it ragged. Maybe it was working fine for Chord, but if we were 50% bigger or a 100% bigger, it just wouldn't have the bandwidth in order to be able to accomplish that. So, let's not lock ourselves into that. Let's recognize that if we can grow sensibly, we should look to do that. Let's make sure that the systems are scalable in order for us to do that.

DD: I've read that Chord has something like $586 million allocated toward M&A if the opportunity arises. Is that accurate?

DB: We don't really have a slush fund set aside for M&A, but what we do have is a balance sheet that's very strong. We are sitting right now essentially unlevered. We've got debt, but we've got an equal amount of cash to offset that debt. We're sitting essentially unlevered as an organization, but we have capacity to put a significant amount of debt on the organization if we think it's the right thing. So, one of the first things they'll teach you, one of the first things I learned when I went to business school was, leverage isn't necessarily a bad thing, so long as it allows the organization to enhance returns while maintaining a comfortable margin of safety from a risk standpoint.

73%
working interest

DD: Would the intent be to remain a pure play in the Williston or Bakken?

DB: It's a sensible question. I think the bar for us to consolidate within the Bakken is low relative to the bar for us to go outside the basin. And it's for all the reasons you think: We know the basin really well. We've got over a million acres in the basin, so we stretch from east to west, from north to south; we kind of touch every part of the basin. Anything that we would acquire in the basin we're probably going to be adjacent to or very close to, which means not only will we know the subsurface there, and so we will know what we're getting into, but there's probably true operational synergies that we can wring out of it too.

There's a lot of operational synergies we would have within the Bakken. We know that regulatory environment well, we've got field offices up there, we've got all of our supply chain put in place and so we can get services. If you go out of a basin, you don't have all of those same things.

It's important to clarify that we look at opportunities out of the basin, but we're pretty clear-eyed about the risk of going out of basin.

DD: Have generalist investors decided that perhaps oil and gas isn't going away?

DB: It's certainly so much more encouraging than it was two years ago. We couldn't get a meeting with the generalist investor two years ago. We're getting more meetings now. We're seeing certainly more what I would

CHORD ENERGY

say larger names and more passive investments within our stocks certainly. Larger organizations seeing more and more interest as you get bigger. I think it's not what it was 10 years ago, but it's a far cry from where we were two or three years ago.

And so I do think generalist investors have some interest in the space. Now, regaining some interest in the space doesn't necessarily mean investing as heavily as they did before. We're certainly not back to that spot.

DD: What else should we know about the Chord story?

DB: One thing that I'm really excited about is we have been able to–not only streamline our operations position ourselves to do some of these big strategic transactions–we've also done a lot of work internally.

I've talked about "self-help" in the context of getting ourselves prepared to do a big deal, but I didn't talk as much about the most important self-help that we've done to focus on how to generate high returns within the assets that we have.

So, forget doing a deal with Whiting, forget doing a deal with Enerplus. How do we ensure that the capital efficiencies and margins of our existing asset base are as high as they can possibly be? And we've seen tremendous success with that.

DD: What excites you about Chord's future?

DB: We have widened the spacing of our development. One of the things we recognized is that in the early time of the basin, we were likely developing too closely together with our different wells. And as we were developing too closely together, we were overcapitalizing. And so, just by definition, for a given amount of oil, we were spending too much capital.

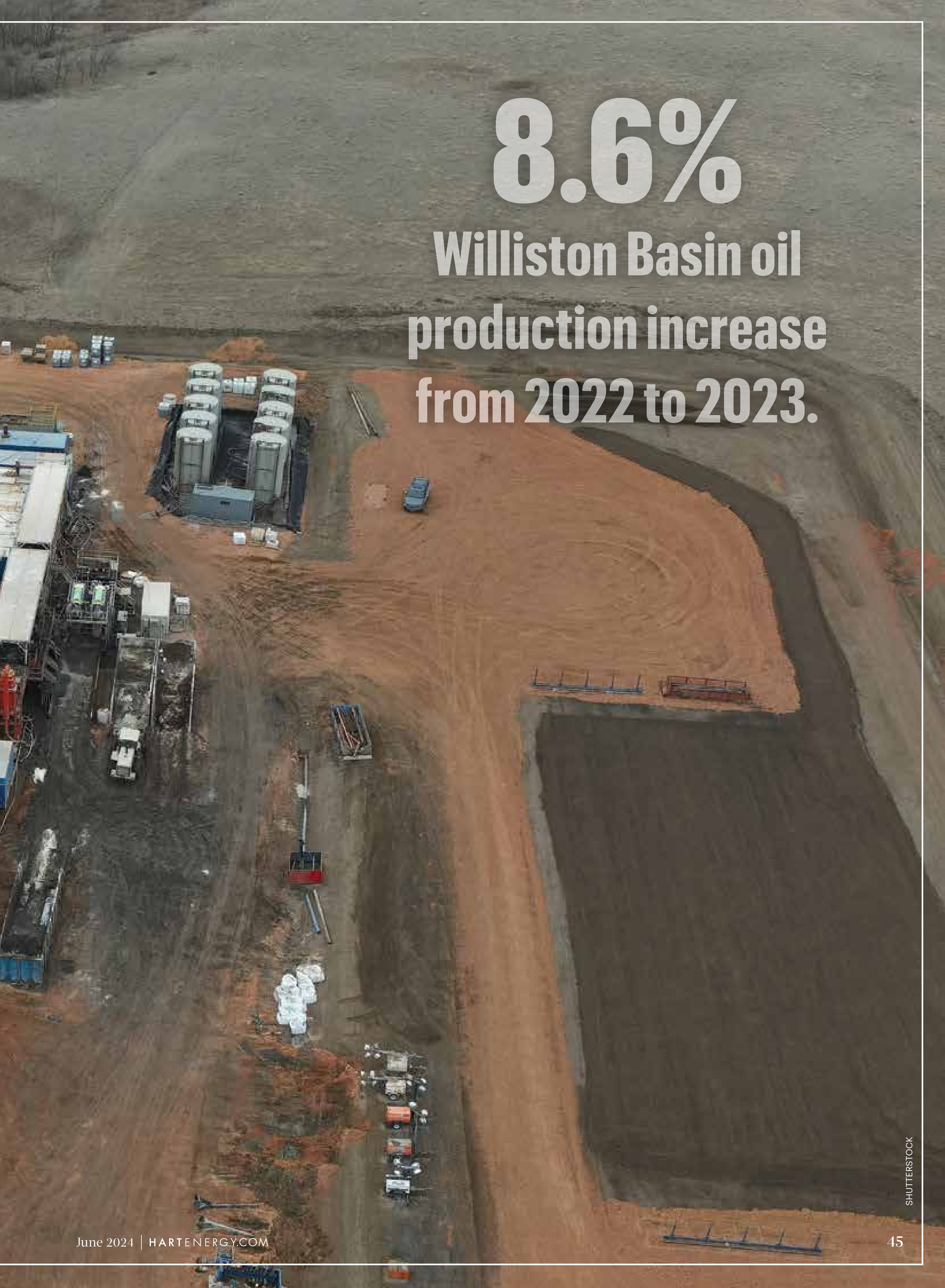
On a per-section basis, we were generally drilling our wells, call it between eight and 12 wells per section. And we're probably between four and six wells per section now. Almost half the number of wells that we would've done previously and still getting essentially the same amount of oil out of the ground. And so you can imagine how much more capitally efficient that program is.

Now you can accelerate some value by putting more sticks in because you get it quicker, but over the long term, the rate of return you're going to get is far superior if you do it by widening out. We've combined widening out our well spacing with drilling longer laterals.

636.3 MMBoe
net acres

DD: How does this translate to your shareholders?

DB: It's a combination of our base dividend and the variable dividend that we declare every quarter and then share repurchases. And so, 75% of the free cash flow that we generate every quarter will go back to shareholders in a combination of those three methods. But you can't have good return of capital unless you have good return on capital in the first place. You've got to make money in the first place. Return on capital is the foundation of everything. OGI



8.6%

Williston Basin oil production increase from 2022 to 2023.

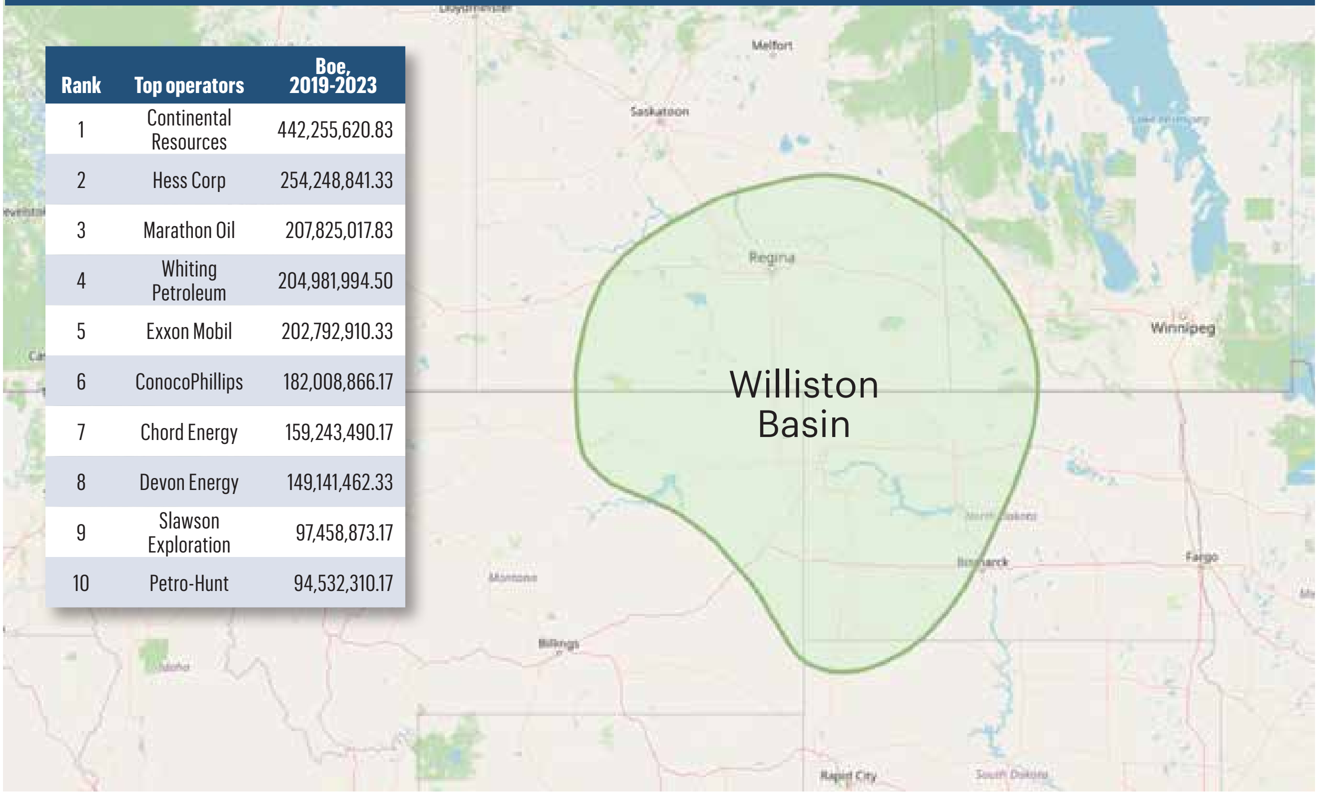
SHUTTERSTOCK

BASIN FOCUS: WILLISTON BASIN

Oil production has rallied in the Williston since mid-2023, while natural gas production rose sharply throughout the year.

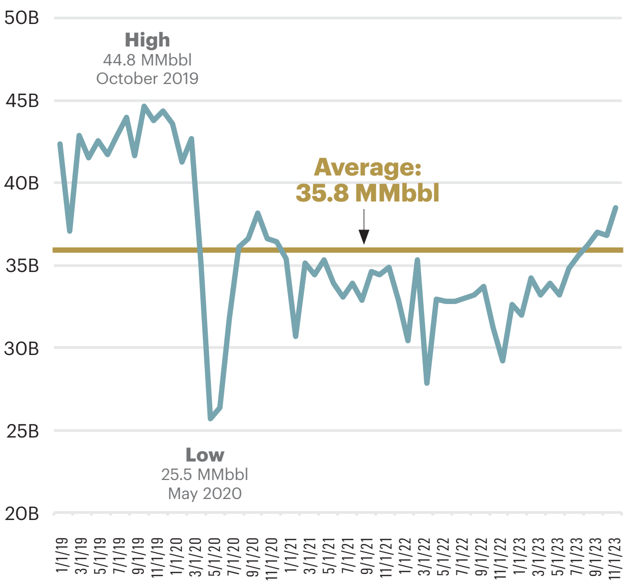
Williston Basin Top Operators

Rank	Top operators	Boe, 2019-2023
1	Continental Resources	442,255,620.83
2	Hess Corp	254,248,841.33
3	Marathon Oil	207,825,017.83
4	Whiting Petroleum	204,981,994.50
5	Exxon Mobil	202,792,910.33
6	ConocoPhillips	182,008,866.17
7	Chord Energy	159,243,490.17
8	Devon Energy	149,141,462.33
9	Slawson Exploration	97,458,873.17
10	Petro-Hunt	94,532,310.17



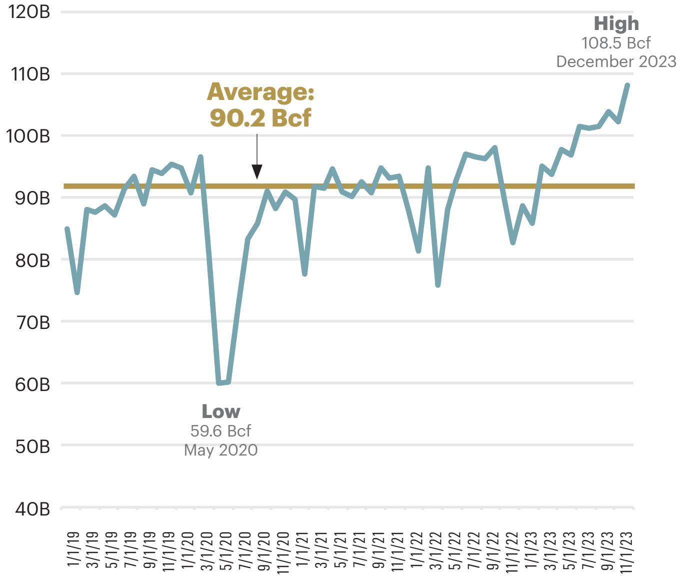
Williston Basin Oil Production

2019-2023, monthly, bbl



Williston Basin Gas Production

2019-2023, monthly, Mcf



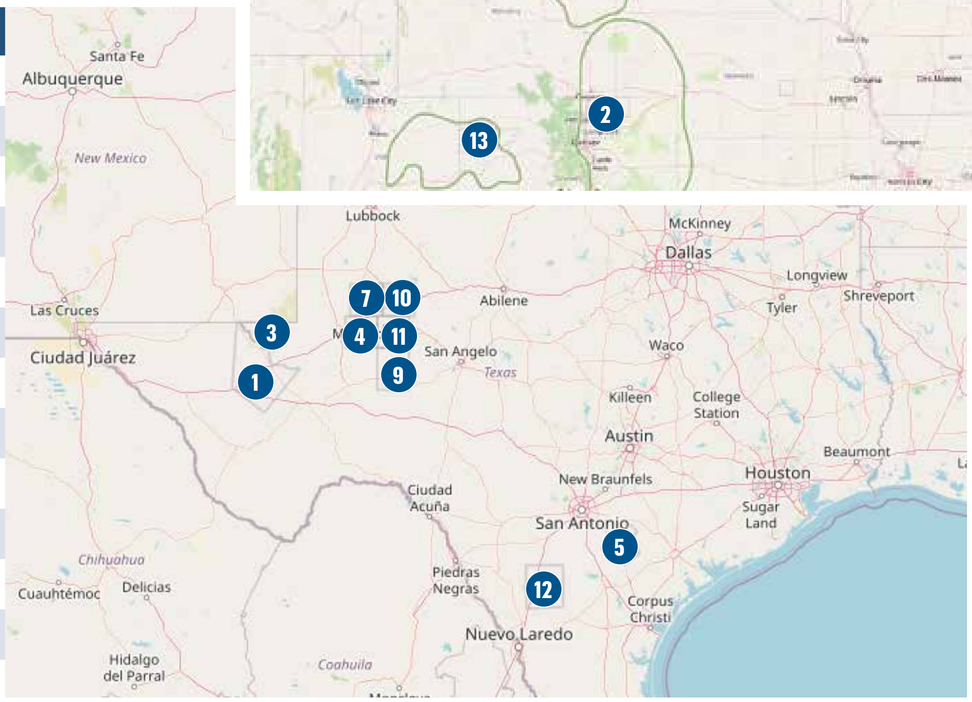
SOURCE FOR CHARTS AND MAPS: REXTAG.COM

PERMITS

Reeves County, Texas, regained the top spot for well permits issued last month.

Permitted Wells by County

Rank	County	Well Count
1	Reeves, Texas	53
2	Weld, Colo.	52
3	Loving, Texas	46
4	Midland, Texas	43
5	Karnes, Texas	39
6	Campbell, Wyo.	34
7	Martin, Texas	30
8	Dunn, N.D.	28
9	Reagan, Texas	24
10	Howard, Texas	23
11	Glasscock, Texas	21
12	La Salle, Texas	20
13	Rio Blanco, Colo.	16



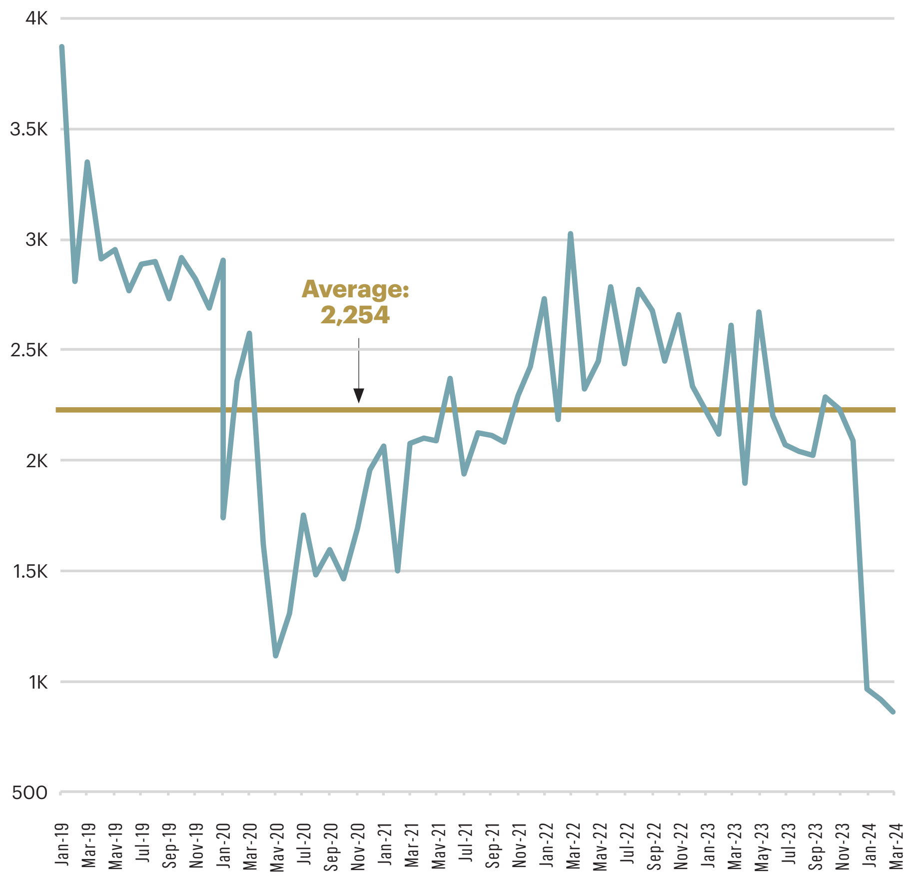
Permitted Wells by Operator

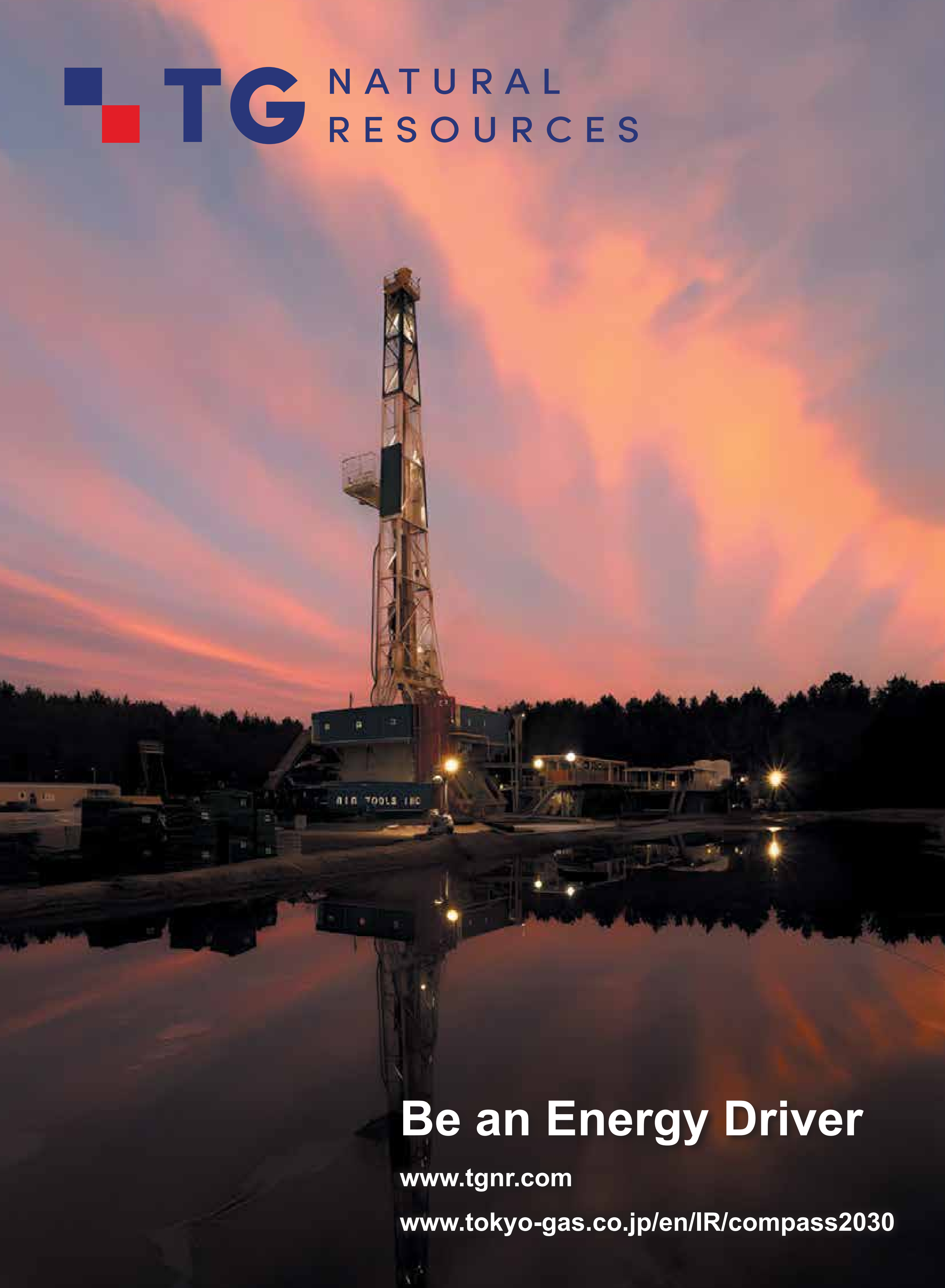
Operator	Well Count
EOG Resources	39
Anshutz Exploration	36
Pioneer Natural Resources	34
Chevron	24
Nickel Road Operating	24
Occidental Petroleum	21
BPX Operating	21
CrownQuest Operating	21
Verdad Resources	20

Permitted Wells by State

State	Well Count
Texas	542
Colorado	129
North Dakota	66
Oklahoma	53
Wyoming	51
Louisiana	17

U.S. Permits Issued Monthly

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Done Deal: Exxon Plans Longer Laterals

The acquisition of Pioneer Natural Resources will allow the supermajor to introduce its system of capital-efficient wells into the Midland Basin.

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Exxon Mobil plans to apply decades of shale research and drilling experience to some of the Permian Basin's best acreage after acquiring Pioneer Natural Resources.

The supermajor closed a $60 billion acquisition of Pioneer on May 3 after regulatory scrutiny by the U.S. Federal Trade Commission. Approval came with the condition that Pioneer founder and chairman Scott Sheffield won't be allowed to sit on the Exxon board.

The deal delivers to Exxon what experts call among the best acreage and inventory in the Permian Basin, the nation's top oil-producing region.

Pioneer owns a large, contiguous acreage position in the core of the Midland Basin, where the company leads in oil production among peers, including ConocoPhillips and Diamondback Energy.

Before closing the Pioneer deal, Exxon was much larger on the Delaware Basin side of the Permian, stretching from far West Texas into southeastern New Mexico.

Exxon gained a blocky acreage footprint in the core of the New Mexico Delaware Basin in 2017 through a $6.6 billion acquisition from the Bass family of Fort Worth, Texas.

Exxon and XTO Energy, the unconventional shale gas leader Exxon acquired for $36 billion in 2010, also have a smaller Midland Basin position.

The company also holds interests in acreage and legacy vertical wells along the Permian's Central Basin Platform, an area that developed decades before advances in horizontal drilling and fracking technologies.

The combination boosts Exxon's Permian production up to 1.3 MMboe/d.

Bart Cahir, senior vice president in Exxon Mobil's unconventional shale business, told Hart Energy that Exxon is confident it can ramp production up to 2 MMboe/d in 2027 after the Pioneer deal.

"They have deep operating expertise and excellence, as do we," Cahir said. "We probably bring a little bit more of a technology and research orientation."

"As we put that alchemy together, it's really exciting," he said.

Go long

Exxon and XTO have worked to perfect drilling and completion designs in the Permian Basin for several years.

Cahir said Exxon was among the first operators to commit to so-called "cube" development in the Permian, in which multiple wells are drilled targeting multiple benches from a single well pad.

Pioneer has also deployed a cube development strategy in the Midland Basin. But Exxon is excited to deploy the strategy at scale across Pioneer's massive asset.

Exxon has focused on optimizing the spacing and stacking of wells across various target intervals, designing completions, understanding rock mechanics and studying how fractures grow over time, he said.

"As we think about a unified development plan, we're going to spend a lot of time leveraging that technical know-how we have in that space," Cahir said.

Cube development has helped operators scale and optimize projects, reduce drilling costs and grow production. E&Ps are also using fewer rigs to drill longer horizontal laterals underground to optimize drilling programs.

Exxon is among the producers going long in the Permian: Cahir said the company has

Exxon Mobil became one of the largest operators of the Midland Basin oil field through a $60 billion acquisition of Pioneer Natural Resources.

SHUTTERSTOCK

drilled wells with 4-mile laterals in the Permian Basin.

Data from Enverus Intelligence Research shows that Exxon is a leading operator drilling longer laterals on both the Midland and Delaware sides of the basin.

"We do anticipate expanding our use of more 4-mile laterals as we continue to develop," Cahir said.

Exxon drilled three 4-mile lateral wells at its production facilities at Poker Lake, N.M, according to Enverus data.

Also in the Delaware Basin, Exxon drilled a 3.6-mile lateral at its Big Eddy unit in New Mexico.

In the Midland Basin, XTO Energy drilled a 3.5-mile lateral on a John Braun A Unit 4 lease in Midland County, Texas.

"We're going to be able to extend lateral lengths out even further across this contiguous acreage, which drives you a level of capital efficiency," Cahir said, "and we're doing that still seeing our recoveries enhanced through time."

Exxon is working in other areas to improve its effectiveness in fracturing the shale rock and improving resource recovery.

"It's an exciting time to be able to lean into that technology and begin to deploy it," he said.

Basin allocation

Exxon now has a much bigger inventory portfolio to choose from when it comes to allocating drilling capital.

Generally, the Midland Basin has lower drilling costs—and wells drilled there can sustain lower oil prices while still generating a profit.

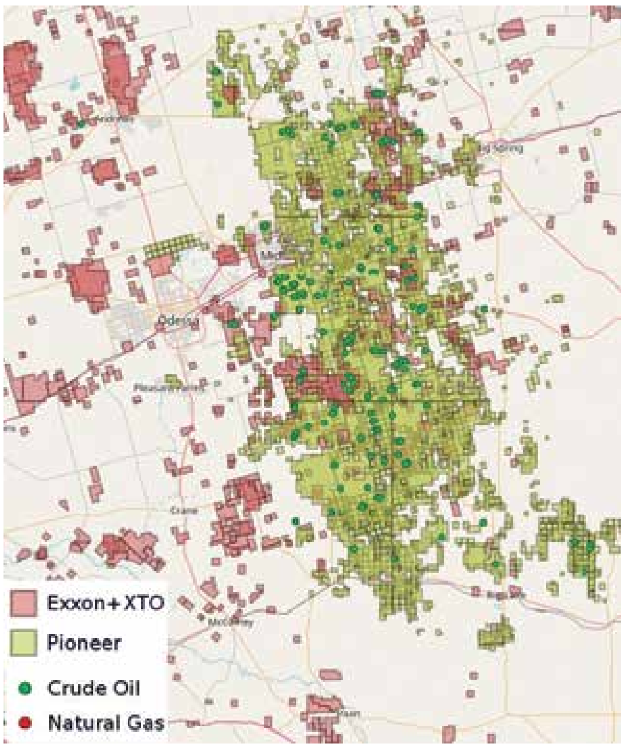
Wells drilled on Pioneer's acreage have some of the best economics in the Midland Basin: When the Pioneer acquisition was announced in October 2023, Exxon said it anticipated a cost of supply of less than $35/bbl from Pioneer's assets.

Meanwhile, the most recent Dallas Fed Energy Survey found that Permian operators require an average oil price of $62/bbl just to break even when drilling a Midland Basin well.

Breakeven prices are higher in the Delaware Basin ($64/bbl WTI average, per the Dallas Fed), where drilling targets are deeper, pressures are higher, geology is more complex and infrastructure bottlenecks frustrate operators.

But as Exxon works to grow Permian production up by about 700,000 boe/d to 2 MMboe/d in around three years,

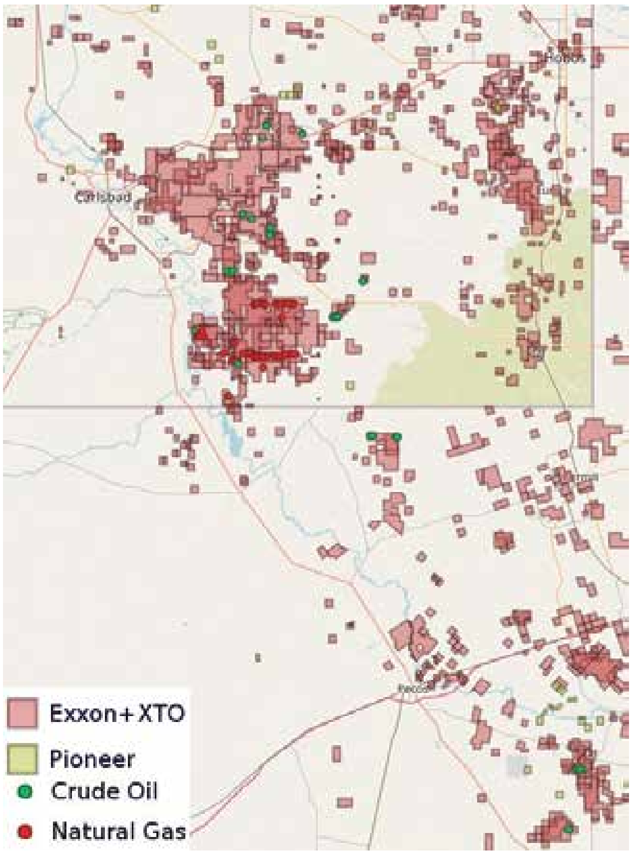
Exxon, Pioneer Delaware Basin



SOURCE: REXTAG

The combination of Exxon Mobil and Pioneer Natural Resources brings together two of the Permian Basin's largest landowners and producers. NOTE: Wells displayed began production on or after Jan. 1, 2022; Acreage displayed may include non-operated interests, per available Rextag data.

Exxon, Pioneer Midland Basin



SOURCE: REXTAG

Exxon Mobil's core Delaware development happens on the New Mexico side of the basin, where the company has grown through large-scale M&A. NOTE: Wells displayed began production on or after Jan. 1, 2022; Acreage displayed may include non-operated interests, per available Rextag data.

drilling capital will continue flowing into the Delaware, Cahir said.

It's unclear how the development cadence on Pioneer's Midland asset might change following closing and integration.

But adding Pioneer's existing production will give Exxon a massive lift: Pioneer produced around 15.6 MMbbl of crude oil, or 503,000 bbl/d, from the Midland Basin in January, according to the most updated figures from the Texas Railroad Commission (RRC).

Pioneer has actively been filing data with the RRC on new well completions targeting the Spraberry trend area across its Midland footprint, records show.

The go-forward plans should materialize through the integration process, which is already underway, Cahir said.

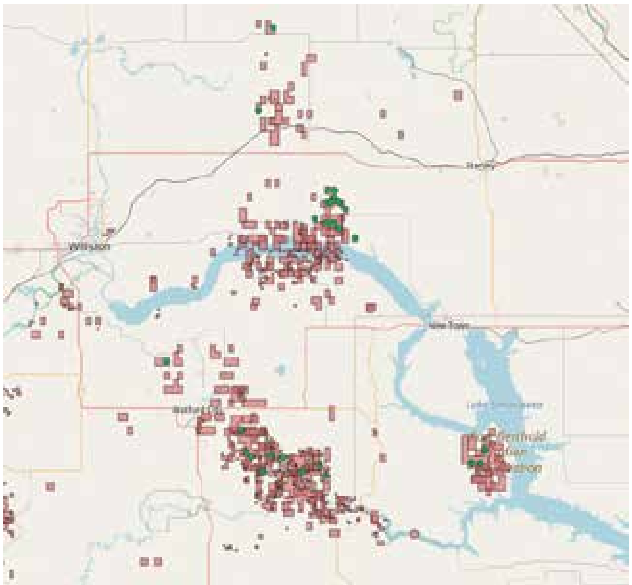
"We have a period of time here now where we have to make job offers to the team at Pioneer," he said. "We're excited to get them together."

The Permian Basin obviously stands out among Exxon and XTO's unconventional portfolio. Exxon has positioned the Permian and its key position offshore Guyana as the company's two major drivers of future crude oil production.

But Cahir said Exxon is committed to continue developing its other unconventional assets around the Lower 48.

Exxon has drilled new wells on its Bakken Shale asset base in North Dakota in recent years, according to data from

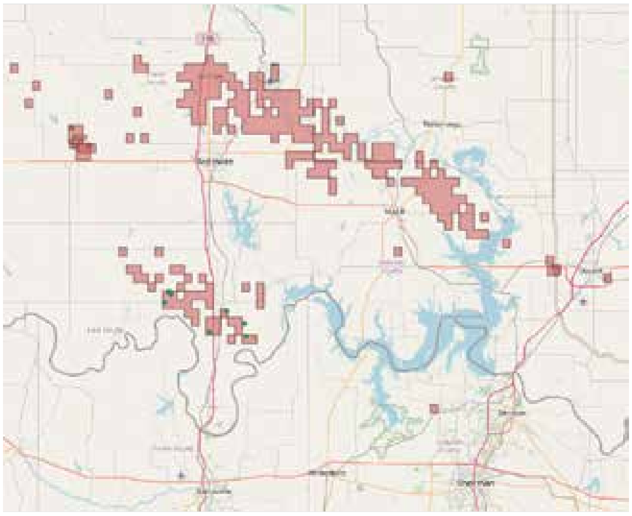
Exxon Bakken



SOURCE: REXTAG

Exxon continues to bring online new Bakken oil wells from its North Dakota acreage. NOTE: Wells displayed began production on or after Jan. 1, 2022; Acreage displayed may include non-operated interests, per available Rextag data.

Exxon Midcon



SOURCE: REXTAG

XTO owns acreage in the Midcontinent, where the company has drilled targeting the Woodford formation. NOTE: Wells displayed began production on or after Jan. 1, 2022; Acreage displayed may include non-operated interests, per available Rextag data.

the North Dakota Department of Mineral Resources.

XTO has also submitted data on well completions targeting the Woodford formation in Love County, Okla., in recent years, according to Oklahoma state data.

Exxon owns interests in gassier unconventional basins, including the Haynesville Shale in East Texas and northern Louisiana.

XTO also owns natural gas-rich acreage in West Virginia, where the company brought online new gas wells as recently as 2020 and 2021, data show. OGI

Diamondback Seeks to Keep Small Company Culture During Growth Spurt

CEO Travis Stice says the company's nimble nature is among its top qualities and key to the successful integration of Endeavor Energy this year.

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The folks who run Diamondback Energy apparently take the company's name seriously.

Seizing opportunities to expand across the Permian Basin with rattlesnake aim–even as other E&Ps bowed to shareholder demands for little-to-no growth–Diamondback in the last decade or so has become a Permian pure-play juggernaut.

And the company will integrate its latest target to swallow whole, a $26 billion deal for Endeavor Energy Resources, by applying a "small company dynamic culture with a large asset base" that is growing ever larger.

That culture is Diamondback's biggest benefit, CEO Travis Stice said during a first-quarter earnings call with analysts.

"We are going to have to make sure we maintain that gritty, quick, fast-moving adaptive culture to a larger asset base," he said. "There's a lot of capital being put in the ground before 'first oil'–sometimes upward of $250 [million], $300 million–but as long as you have the ability to move crews and rigs within a quarter, within a year, and keep hitting numbers, we're going to keep doing that at a larger scale."

A flat, unsiloed organizational structure has been present at Diamondback since its inception, Stice said.

"The only way that you can grow an organization and maintain that effectively is to have an unreasonable level of trust. And as we encourage the Endeavor employees to come over, we're going to be demonstrating this high level of trust," he said. "It's going to be a very important part of our evolving culture as a much larger company."

In February, Diamondback announced the $26 billion cash-and-stock agreement with Endeavor to create a combined company valued at more than $52 billion. The transaction consideration was to consist of approximately 117.3 million shares of Diamondback common stock and $8 billion of cash, subject to customary adjustments.

Stice was questioned about the 11th-hour action of the U.S. Federal Trade Commission (FTC), which issued a "second request" form regarding the Endeavor deal.

The agency made the notification on April 29, the final day it could do so statutorily, and extended its review period on the transaction.

"Our research indicates that most of the larger transactions have received that," said Derek Whitfield at Stifel. "Is that consistent with how you're thinking about it?"

Stice acknowledged the issue, but didn't elaborate.

"Yeah, that's consistent," Stice said.

Dealmakers involved in the largest transactions announced during a historic E&P consolidation trend, which revved up last fall, have received the same FTC notice.

In April, Chesapeake Energy's $7.4 billion merger with Southwestern Energy was delayed by such a request. The agency also filed second request notifications with Chevron and Hess Corp. related to their $53 billion merger, as well as Exxon Mobil and Pioneer Natural Resources regarding their $60 billion deal, which closed in early May. OGI

"We are going to have to make sure we maintain that gritty, quick, fast-moving adaptive culture to a larger asset base."

TRAVIS STICE, CEO, Diamondback Energy

Diamondback Energy CEO Travis Stice says his company will demonstrate a high level of trust as it integrates Endeavor Energy's people and assets into its operations.

ENDEAVOR ENERGY

FINANCE & INVESTMENT

Producers Trim 2024 Hedges Amid Bullish Oil Prices, M&A

Meanwhile, gas-weighted players are benefitting from solid hedge books planned ahead of price uncertainty.

ANDREW PRATT
CONTRIBUTING EDITOR

Fiscally fit and price optimistic, many E&Ps reduced their hedging programs entering 2024 and are staying the course even as conflict inflames the Middle East, Russia's protracted war in Ukraine lingers and a U.S. oversupply of natural gas threatens to upend energy markets.

Three years of capital discipline and deleveraging have fortified balance sheets, boosting producers' confidence that they can weather 2024 profitably with a smaller hedge portfolio or with no hedges at all, analysts say.

"Corporate debt is very low historically. Oil demand is growing," Daniel Michalik, a Chicago-based associate director with Fitch Ratings, told *Oil and Gas Investor* (OGI). "Most producers are fairly comfortable with the relatively favorable macro environment."

Hedging declined amid oil producers, which are seeing prices that generate steady profits, and gas-weighted operators, which saw U.S. prices weaken—and then collapse—during the first four months of 2024. A historic wave of E&P consolidation that began late last year remains on-trend. In many cases, M&A has reduced the risk that prompted previous hedges: The incumbent synergies of the pro forma companies boost those balance sheets, giving management confidence that they have the internal resources to cope with downturns.

A January report from BloombergNEF indicates that shale producers have reduced 2024 hedge coverage on oil production to 13%, and natural gas to 31%. These levels are among the lowest recorded during the seven years that the data service has monitored shale hedging.

In February, Fitch analysts reported that, among its covered producers, oil-weighted companies hedged 39% of production and gas-weighted operators covered 48% of their production with hedges. Both represent significant decline across multiple years.

Producers are hesitant to switch up the strategy so far this year. Insiders say prudently priced natural gas coverage will remain out of reach unless prices rise significantly from sub-$2/Mcf levels, a movement that many analysts view skeptically.

Oil producers say that prices have a long way to drop before an expanded hedge portfolio would be worth the risk of missing out on the profits generated by reductions in supply or increased demand. Both WTI and Brent futures contracts have traded above $70/bbl since January 2022. While the April 30 WTI price of $82.70/bbl is down substantially from the 2022 average of $94.90/bbl, it remains well within the range needed to assure profitability across the industry, CEOs and analysts told *OGI*.

"Maybe a (sustained) environment of oil at sub-$50 a barrel" would prompt producers to expand their hedging activities, Michalik said. But market indicators suggest no one is anticipating such a dramatic slide in oil's fortunes.

Geopolitical impact

The World Bank said in its April Commodity Market Outlook that it expects oil prices to

A natural gas fracking pad near Moundsville, W.Va.

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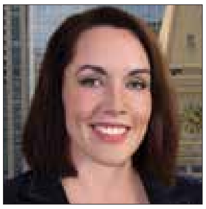

> *"I think it's well known that Aethon is a hedger. We like to lock in our returns as far out in the future as we possibly can [but] we're really trying to figure out more what's going on out there before we fully lock in those hedges."*
>
> **ANDREA PASSMAN,** COO, Aethon Energy

increase this year because of rising geopolitical tensions and a tight balance between supply and demand. It projects the Brent crude price will average $84/bbl, up from its forecast of $83/bbl last year, with lots of upside potential if conflict intensifies in the Mideast or Europe.

"Further conflict escalation involving one or more key oil producers could result in extraction and exports . . . being curtailed, rapidly lessening global oil supply," according to the World Bank report.

A recent Goldman Sachs survey of clients found most believe global politics pose the biggest risk to world economies—which generally results in upside for commodity prices.

After three years of oil prices averaging above $68/bbl, the value of the S&P Oil & Gas Exploration & Production Select Industry Index has more than doubled since August 2021, despite the sector's struggle to recapture general investors. High-margin petroleum sales have left some investment-grade oil producers well-capitalized and secure enough to forgo the price security of hedging.

Large, integrated producers historically eschew hedging. They have the diversity to cover the downside and want exposure to upside pricing. Among oil producers with the strongest balance sheets, the sentiment resonates.

"If I hedge, I'm locking in what dollars we can receive, but I've also taken away exposure" to profits when oil prices rise, Chord Energy CEO Danny Brown told *OGI* during an exclusive interview.

Brown said he views hedging as a tool to either protect an expanded capital program or meet other goals such as keeping current on debt obligations. Echoing comments on strategy by other CEOs in recent weeks, Brown said Chord is spending to maintain current production while sending money back to shareholders rather than investing in new drilling or borrowing to expand.

"As a result of that, I don't need to protect my capital program. Our capital program is resilient down to much lower prices than it is right now," he said.

Nor is paying down debt an issue at Chord, Brown said. "It's not like we're making a lot of interest payments to a bank."

Chord's balance sheet—and its ability to weather market vacillations—is based, at least in part, on its M&A strategy. The firm was expected to close on the $11 billion acquisition of Williston peer Enerplus by the end of May.

Analysts say multibillion-dollar mergers like Chord-Enerplus are expected to contribute to further declines in oil hedge volume. Larger, fiscally stronger companies are more likely to shoulder the commodity price risk without hedging, which has the potential of locking out future upside.

Keeping the cash flowing

In the current environment, investors have pushed

"It's just murder. We're holding back our production to stay within as close as we can to hedge volumes" because "it's just $1.70 gas."

CHRIS WIDELL, CEO, Sponte Operating

producers to avoid hedges and take the full benefits when prices rise. Investors want producers to generate maximum free cash flow to pay dividends and buy back stock, and producers are responding in kind, said Vincent Piazza, North American oil and gas equity analyst for Bloomberg Intelligence, an investment analyst group.

"You have started to hear more about cash flow yields and dividend payouts on (investor) conference calls than production growth," Piazza said. "You don't necessarily get better cash flow from putting more money into the ground. It can be a self-defeating strategy because the more you produce, the more the price goes down."

Oil-focused executives increasingly express confidence they can continue to divert free cash flow to stockholders and pay off or avoid debt while maintaining prudent production levels that don't weaken oil prices.

Brown said Chord has the resources to finance its current capital program and pay cash to investors while leaving most of its production unhedged. The firm has hedged 13.8% of its crude oil production at a weighted average of $65.65/bbl for 2024, according to analysis by Siebert Williams Shank.

There is little room for hedging among the supermajors. Chevron has agreed to buy Hess Corp. for $53 billion and plans to eliminate Hess' price hedges when it completes the acquisition. Pioneer Natural Resources closed out its hedges ahead of closing its $60 billion merger with Exxon Mobil, which, though it is cautiously expanding into energy trading, has not historically relied on oil price hedging to boost its bottom line.

The reduction in oil price hedging comes as natural gas producers who locked in prices for 2024 are expected to benefit greatly from hedges in 2024. A warm winter and steady production have left U.S. storage facilities full, depressing prices nationwide.

"Gas storage is roughly 36% above the five-year average nationally, so we will have ample supply going into the spring and summer lull," Piazza told *OGI*.

At the end of April, prices at the Waha Hub fell to negative numbers, making Permian Basin natural gas a costly byproduct of some oil producers' efforts to maintain or expand oil output. Prices on the NYMEX for the June futures contract of natural gas hovered just under $2/Mcf at the end of April.

Depressed gas prices have made hedges prohibitively risky and expensive four months into 2024. "It makes no sense to hedge when gas is $2," Piazza said.

Natural gas prices, which can be volatile because of their regional delivery limits and close links to electricity production, prompt gas producers to maintain more hedging even if that puts them at risk of missing out on price spikes.

That includes industry leaders such as Chesapeake Energy, EQT and Southwestern Energy. According to Siebert Williams Shank, Chesapeake hedged 59.9% of 2024 production at a price of $3.66/Mcf. EQT has 63.3% hedged at $3.96/Mcf and Southwestern has 52.8% hedged at $3.46/Mcf.

With prices under $2, gas-focused producers are using the prices contracted in hedges when they target cost-cutting and output goals.

Sabine Oil & Gas, a subsidiary of Osaka Gas USA, has hedged 80% of its production for the last three years, CEO Carl Isaac said.

"Our sales volumes today are equivalent to our hedge volumes today," Isaac told a crowd gathered for Hart Energy's DUG Gas+ conference this spring.

Publicly Traded E&P Companies With High Percentage of Gas Production Hedged in 2024

SOURCES: FITCH RATINGS AND SIEBERT WILLIAMS SHANK ESTIMATES

Publicly Traded E&P companies With High Percentage of Oil Hedged in 2024

SOURCE: FITCH RATINGS

Gas-weighted companies' hedging outweighs the strategy of oil producers this year.

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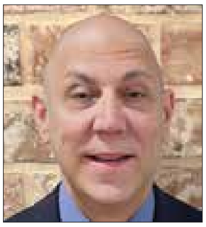

> *"Our sales volumes today are equivalent to our hedge volumes today."*
>
> **CARL ISAAC,** CEO, Sabine Oil & Gas

At current gas prices, some producers say unhedged volumes aren't economic to produce.

"It's just murder," said Chris Widell, CEO of Sponte Operating. "We're holding back our production to stay within as close as we can to hedge volumes" because "it's just $1.70 gas."

Matching expenses to hedging returns is critical because his company is still working to counter the surge in production costs that began after the COVID epidemic, Widell said.

Sponte is "drilling only when we have to," and Widell estimates the company has cut costs by 20% during the last 18 months.

If they lack sufficient hedges going, natural gas producers can only wait for hoped-for developments such as significant increases in LNG exports and a surge in BTUs needed for electricity production this summer.

Andrea Passman, COO for Aethon Energy, said the company considers its hedge book a key tool in its strategy of increasing cash distributions to investors and maintaining a strong free cash flow.

Aethon, one of the largest private natural gas producers, is looking at hedges strategically after three years of acquisitions and 30% year-over-year growth. The company is now in "maintenance mode," Passman said.

"Hopefully, we see some future price increases," Passman said. "But I think '24 and '25 will probably look kind of similar, with 2025 showing a little more volatility, especially as volumes start to come up from" expected expanded LNG production. Aethon plans to adjust its hedges to reflect the effects of that volatility, once they become evident, she said.

"I think it's well known that Aethon is a hedger," Passman said. "We like to lock in our returns as far out in the future as we possibly can [but] we're really trying to figure out more what's going on out there before we fully lock in those hedges."

While the largest companies may be able to go light on hedging, many small and medium-sized companies rely on debt to grow and build out projects, said Michael Corley, founder and managing director of Mercatus Energy, an advisory group that helps producers with their hedging strategies.

Companies with debt obligations "can't just wait for prices to go up" to meet their commitments, Corley said. Hedging a portion of production can ensure that banks get paid while still letting exploration and development companies benefit substantially from price increases.

Swaps and other hedging tools can reduce the risks of regional transportation problems like those that led to negative prices for Permian gas, Corley said.

"Producers need price protection, especially if they are weighted toward natural gas," Corley said. "You only have to go back to four years ago to where hedging was beneficial" to most producers. OGI

Paisie: Oil in the $86–$88 Range for Second Half

Supply/demand dynamics overtake geopolitics in influencing prices.

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.

Last month, we put forward the view that the situation in the Middle East would not result in any meaningful disruption to the volumes of crude exports. So far, this view has aligned with reality, even though the conflict in the Middle East (as well as the conflict between Russia and Ukraine) remains unresolved.

Consequently, the risk premium associated with geopolitics has decreased and the supply/demand fundamentals are taking a more prominent role in shaping market sentiment. This shift has resulting in oil prices falling back to levels consistent with our forecast that the price of Brent crude will be between $86/bbl and $88/bbl during the second half of this year.

Recent economic data is consistent with oil demand growth during 2024 being moderate (we are currently forecasting that oil demand will increase this year by 1.41 MMbbl/d in comparison to 2024).

The U.S. economy grew by only 1.6% on an annual basis for the first quarter, which is significantly less than during the fourth quarter of last year when the U.S. economy grew at an annual rate of 3.4%. It is also the lowest quarterly growth since second-quarter 2022. While consumer spending held up reasonably well (2.5% growth in the quarter in comparison to 3.3% in fourth-quarter 2023), the position of consumers is weakening.

According to the U.S. Bureau of Economic Analysis, the personal savings rate decreased to 3.2% in March and is heading to the lowest levels since 2007. In comparison, during the period from 2010 through 2019, the personal savings rate averaged above 5%. Concurrently, credit card debt is at all-time highs and continuing to increase (by $143 billion in the fourth quarter) at the same time that consumer delinquencies are increasing.

While the headline unemployment number is still low, a better indication of current state of the labor market is the underemployment rate (includes discouraged workers and part-time workers who desire to have full-time jobs) which increased to 7.4%, the highest level since November 2021.

In contrast to geopolitics and oil demand, we are forecasting that oil supply will help stabilize oil prices during the second half of the year with the expectation that OPEC+ will maintain its production cuts, while non-OPEC supply will increase by only 1.19 MMbbl/d.

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Looking beyond this year

While the oil industry is dealing with volatility in the short term, it will need to deal with structural changes in the coming years. In our reference scenario, we are forecasting that global oil demand will continue to increase through 2035, but demand will be lower in 2050 than in 2035.

While global oil demand is forecasted to increase through 2035, there will be a substantial shift from mature OECD economies to developing non-OECD economies.

While product demand in OECD countries is forecasted to decrease during the period of 2023 through 2035, product demand in non-OECD countries is forecasted to increase by more than 9 MMbbl/d. Asia will represent the bulk of the demand growth, but there will also be growth in Latin America, Africa and the Middle East.

The increasing importance of non-OECD countries with respect to demand for oil products is driven, in part, by the forecasted growth of the vehicle fleet in non-OECD countries. During the period between 2023 and 2035, the size of the vehicle fleet in non-OECD countries will exceed the size of the vehicle fleet in OECD countries.

While there are uncertainties about the forecasts, there is little uncertainty about the general direction of the forecasted shifts. The shifts will result in changing trade flows—with respect to crude oil, as well as oil products—which will require exporters and importers to address their supply chains. Additionally, the shifts will result in the expansion of linkages between geographic regions, including linkages of North America with the rest of the world. OGI

Kissler: Wild Price Moves Unlikely Through Rest of 2024

DENNIS KISSLER
BOK FINANCIAL SECURITIES

Dennis Kissler is senior vice president of Trading for BOK Financial Securities. He is based in Oklahoma City.

It's been a wild, geopolitical-tension-fueled ride for crude oil since the beginning of the year. With WTI prices ranging from $70/bbl in January to as high as near $87/bbl in mid-April, you wouldn't be alone in wondering if this ride will continue through the remainder of 2024. The answer, as always, is: it depends. Nevertheless, most signs point to calmer waters ahead.

For one, most of the risks have been more bark than bite, so far—at least as it pertains to oil. The Houthi attacks in the Red Sea shipping areas and Ukraine targeting and actually hitting Russian interior refineries received a lot of press and, of course, have drastic implications for those involved, as well as for the level of geopolitical tension.

However, the actual number of barrels taken off the global market due to these events has been minimal. The real trade, as is often the case, was to "sell the rumor and buy the fact." Looking forward, while major supply disruptions caused by these conflicts remain a possibility, the energy market's nervousness is easing.

OPEC+ production cuts

Still, there are other wild cards. For example, one factor that has been taking barrels off the global stage is OPEC+. In March, OPEC+ members agreed to extend their voluntary output cuts of 2.2 MMbbl/d until the end of June. Then, in early April, OPEC+ released a statement supporting member countries' efforts to more fully conform with the cuts. Namely, Iraq and Kazakhstan pledged to achieve full conformity and compensate for overproduction, and Russia announced that its voluntary adjustments in second-quarter 2024 will be based on production instead of exports.

OPEC's compliance with production cuts will most likely last through the remainder of the year. And so, that takes one wild card off the table—that is, unless OPEC+ ministers change their oil supply policy for the second half of the year or if the voluntary production cuts continue and there is less compliance.

Global economic growth

Another wild card is the strength of the global economy, which impacts oil demand. As I've written about previously, slower economic growth in Asia is a potential headwind for oil prices because of the volume of manufacturing in the region. That's particularly the case regarding China, known as "the world's factory."

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The Eurasia Group has estimated that China's oil demand growth in 2024 will drop substantially from what it was in 2019, prior to COVID. Moreover, the consultancy group anticipates that China will forego its model of oil-intensive economic growth, so we won't see its demand return to the levels seen previously (1 MMbbl/d between 2015 and 2020). Meanwhile, the International Monetary Fund (IMF) expects that China's economic growth will fall from 5.2% in 2023 to 4.6% in 2024, with a further drop to 4.1% in 2025. However, the IMF projects that the broader world economy will continue growing at 3.2% this year and in 2025, which is the same pace as global growth in 2023.

So, what does all this mean for oil prices? Unless we see a weakening of the global economy or OPEC+ overproducing past their production quotas, crude prices should be in equilibrium at around the mid-$70s/bbl area (Nymex WTI). That said, the U.S. Dollar Index is also a wild card for crude exports. The stronger the dollar remains, the more exports could struggle, which could add more to storage.

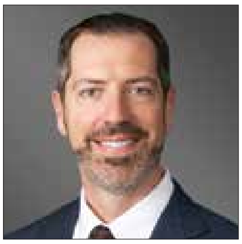
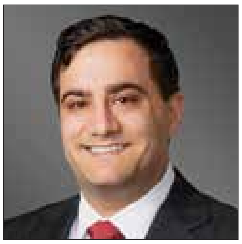
A natural gas renaissance?

Lastly, natural gas seems to have found a floor in the $1.70-$1.80/MMBtu range, as prices that cheap are not normally sustainable, even with storage pushing more than 30% above the five-year average.

Natural gas will be the most prominent producing power source. This begs the question: We have seen prices bottom, but is the upside capped? I think so, until at least fall, and even then, only if temperatures for this summer average above normal. It would take some abnormal deviation of temperatures for us to see a major move up in prices before year-end. Nevertheless, the demand for natural gas is out there in a big way and the longer-term odds favor the upside as time passes. OGI

Long, Bartz, Besser: A Slippery Mess

The overlap between securities laws and oil and gas interests.

ROBERT LONG
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Robert Long and Steven Bartz are shareholders, and Michael Besser is an associate in the Dallas office of Greenberg Traurig.

A surprising number of businesspeople and lawyers, including securities lawyers, fail to recognize that interests in oil, gas and mineral rights could be considered securities under U.S. federal and state securities laws. Accordingly, if you participate in oil and gas-related investments, you should attempt to determine whether the investment constitutes a security.

As the price of oil climbs from its lows in 2020 and the U.S. Securities and Exchange Commission (SEC) adopts new rules that impose new reporting requirements and restrictions on certain activities of investment advisers to private funds, the question of whether investments in certain oil, gas and mineral rights constitute securities is becoming increasingly important.

The U.S. regulatory regime for private funds has grown considerably since the 1930s and 1940s when Congress adopted the main U.S. securities laws defining a "security" and the U.S. Supreme Court decided the landmark case SEC v. W.J. Howey Co., which provided the touchstone analysis for determining when an investable asset is a security. More than 75 years later, too many businesspeople and their lawyers overlook the fact that interests in oil, gas and mineral rights can be securities under U.S. federal and state securities laws.

And while the consequences of noncompliance with U.S. securities laws have become more acute during that intervening period, courts and the SEC have not provided enough clarity concerning this issue and, instead, have left us with a patchwork of opinions and interpretations that do not fit together precisely like a jigsaw puzzle. The inherent uncertainty of any ex ante analysis, when coupled with the increasingly severe consequences for an incorrect conclusion, begs for new analytical clarification by legislators or regulators, including the SEC.

Definitions

The definition of a "security" under federal securities laws, as outlined in the Securities Act of 1933 (Securities Act), the Securities Exchange Act of 1934 (Exchange Act), the Investment Advisers Act of 1940 (IAA), and the Investment Company Act of 1940 (ICA) (together the IAA and the ICA are the 1940s Acts), and whose definitions are virtually identical, is broad and encompasses a wide range of financial instruments.

In addition to traditional instruments, such as stocks and stock options, the Securities Act and 1940s Acts expressly include a "fractional undivided interest in an oil, gas, or other mineral rights" in their definitions of a security, and the Exchange Act expressly includes a "certificate of interest in an oil, gas, or mining title or lease" in its definition of a security.

These definitions clearly contemplate encompassing certain rights in oil, gas, other minerals and mining as "securities"; however, these enumerated concepts are unhelpful in delineating which types of rights in oil, gas, other minerals and mining constitute securities and which do not. Accordingly, additional analysis is necessary, and most courts employ a functional approach by analyzing the "economic realities" of the instrument, investment, or other interest in question.

Thanks to the Howey decision and the line of decisions that followed it, the analysis of the economic realities is typically explored by determining whether the particular oil, gas, other mineral or mining interest in question constitutes another specifically listed type of security under the Securities Act, Exchange Act, and 1940s Acts: an "investment contract."

An investment contract is identified by an investment of money in a common enterprise with profits expected to come primarily from the efforts of others, a principle known as the Howey test. Thanks to the Howey test, the definition of a "security" can be applied to various schemes designed by those seeking the use of others' money on the expectation of profits.

Court tests

Courts have applied different approaches to divining whether rights concerning oil, gas, mineral interests or mining are securities. Some rely solely on whether the right in question is expressly enumerated in the definition of a security (a "Plain-Language Analysis"), whereas others are willing to find that such rights properly fall within another category of enumerated security, such as an "investment contract" or "any interest or instrument commonly known as a 'security'" (an "Economic-Realities Analysis"). Further complicating the analysis, the SEC has recognized four principal types of oil, gas, and mineral interests owned by private parties: (1) the mineral rights, (2) the landowner's royalty, (3) the overriding royalty, and (4) the leasehold interest.

The U.S. Securities and Exchange Commission in Washington, D.C.

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Many courts and regulators have taken the position that (A) each type of oil and gas interest, i.e., each of the four types listed, is to be considered in its entirety as a separate interest and (B) fractional undivided interests are involved only when they are created in one of those four particular types of interests.

If the entirety of a specific mineral interest, the entire landowner's royalty, the entire override, or the entire lease is sold—as distinguished from a fractional interest in a specified mineral interest, the landowner's royalty, the overriding royalty, or the lease—then no sale of a fractional undivided interest is involved.

Accordingly, if an entire mineral interest, an entire landowner's royalty, the entire overriding royalty, or an entire leasehold interest is sold, then the sale would not constitute the sale of a "security" under the Plain-Language Analysis. Note, however, that this conclusion under the Plain-Language Analysis is arguably inconsistent with the actual plain language of the statutes because each "type" of oil and gas interest is not deemed to be an undivided portion of the interest. Instead, some courts and regulators have effectively redefined an "interest" in oil, gas, minerals and mining as a specific category of associated rights so as to avoid subdividing those newly separate rights into fractions, which would create a security.

Even so, the sale of an entire mineral interest, an entire landowner's royalty, the entire overriding royalty, or an entire leasehold interest might, nevertheless, constitute the sale of a "security" under the Economic-Realities Analysis if all of the elements of the Howey test are satisfied.

The problem, in a nutshell, is that sometimes an expressly identified security is interpreted to constitute a security, yet other times an expressly identified security is interpreted definitionally in a manner so as to avoid finding a security, and sometimes an expressly identified item is interpreted to not constitute a security under the Economic-Realities Analysis. This produces precious little ex ante predictability. It would be helpful to oil and gas professionals, investors and financial intermediaries if the SEC would provide clarification through the rulemaking process.

Material ramifications

In the meantime, a securities regulator's ex post determination that any particular oil, gas or mineral interest constitutes a security can have material ramifications. Federal and state securities regulators and courts have constructed complex regulatory and reporting frameworks that govern securities and the actions and duties of brokers, dealers, investment advisers, and investment companies. A determination by any regulator or court of competent jurisdiction that applicable oil, gas or mineral interests are securities can subject individuals and companies to those regulatory and reporting requirements.

For example, disgruntled clients may turn to securities regulators for assistance when they believe they have been wronged. And individuals and companies who find themselves on the wrong side of a securities-related investigation may find their lives and livelihoods turned upside down. Consequences for failure to comply with securities laws range from recission rights to penalties, to professional suspensions and restrictions. Some civil violations of federal and state securities laws may also constitute criminal offenses, and, in extreme cases, the SEC may refer cases to the DOJ or the FBI for criminal investigation and prosecution.

Accordingly, it is prudent for people who engage in financial activities related to oil, gas and mineral investments to engage knowledgeable lawyers to conduct a careful, nuanced analysis of whether their investment-related activities involve "securities" that are subject to state and federal regulation. While such an analysis cannot provide certainty in today's unsettled regulatory environment, anyone found on the wrong side of the law after conducting such an analysis in earnest will likely find themselves in a substantially better legal position. OGI

Grow Canada! Increased Production Boosts Energy Security

U.S. refineries drink in heavy crude, but domestic politics are always a hurdle.

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When feeling insecure, it's good to have a friend to count on. And when it comes to energy insecurity, it's really good when that friend has 168 Bbbl of proved crude oil reserves and other energy riches it is more than willing to share.

But in the case of the U.S. and Canada, domestic politics can strain that friendship.

"Any legislation or executive orders that could impact our market access such as domestic content requirements, those are what are worrisome for Canadians," said Jennifer Jabs, the Government of Alberta's assistant deputy minister of jobs, economy and trade, at the Offshore Technology Conference (OTC) in Houston. "For example, [with] 'buy American' and pool legislation, which is the country-of-origin labeling, we need to ensure that there are carve-outs for Canada. Our trade relationship is built on longstanding binational supply chains, and cross-border economic integration is a win-win for both countries."

Economic security, Jabs stressed, is impossible without energy security. "By energy security, I mean security of affordable supply that also maintains a high level of national security."

Case in point: Enbridge's Line 5 NGL pipeline

"It's a 1,038-kilometer, 30-inch diameter pipeline that travels through Michigan's upper and lower peninsulas, originating in Wisconsin and terminating in Sarnia, Ontario," she said. "If it were to be shut down, the region of Michigan, Ohio, Pennsylvania, Ontario and Quebec would see a 14.7 million U.S. gallons a day supply shortage of gas, diesel and jet fuel. It would cut more than half of the jet fuel supplies for the Detroit Metro Airport."

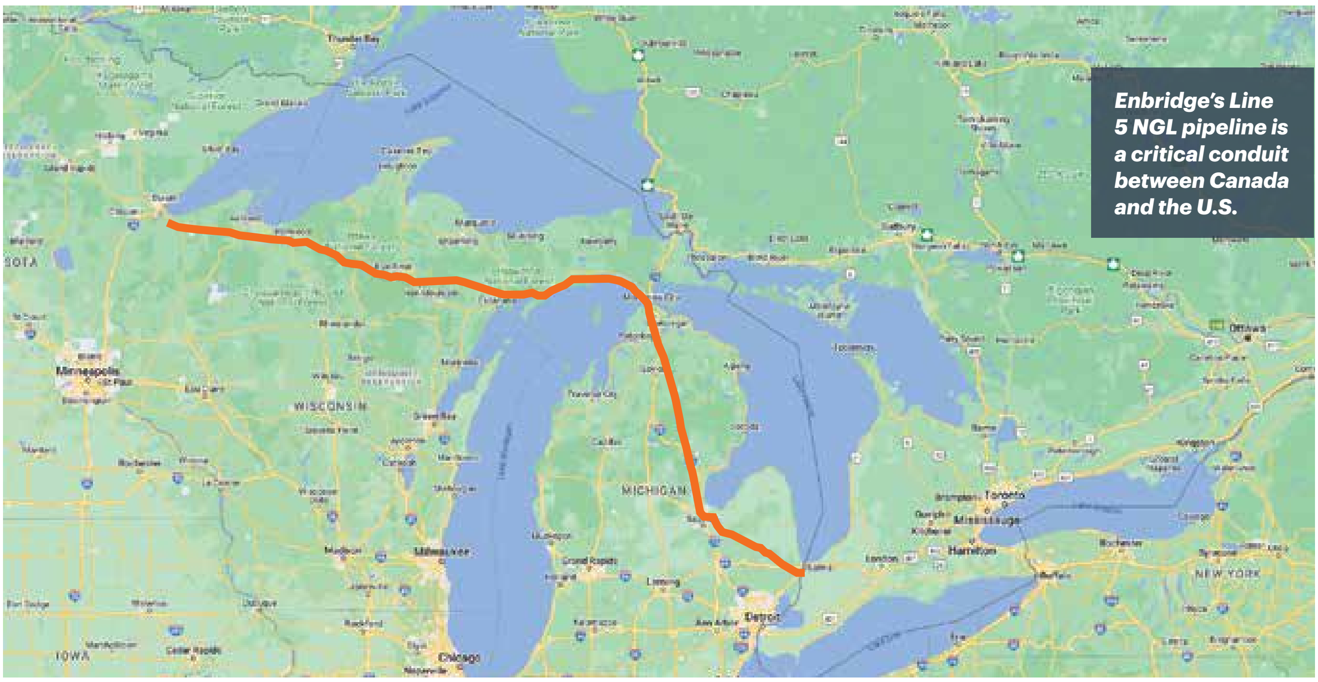
A shutdown of the pipeline would not just reduce the energy supply in both Canada and the U.S., but lead to job losses and increased energy prices impacting roughly 85 million people on both sides of the border, Jabs said.

A good match

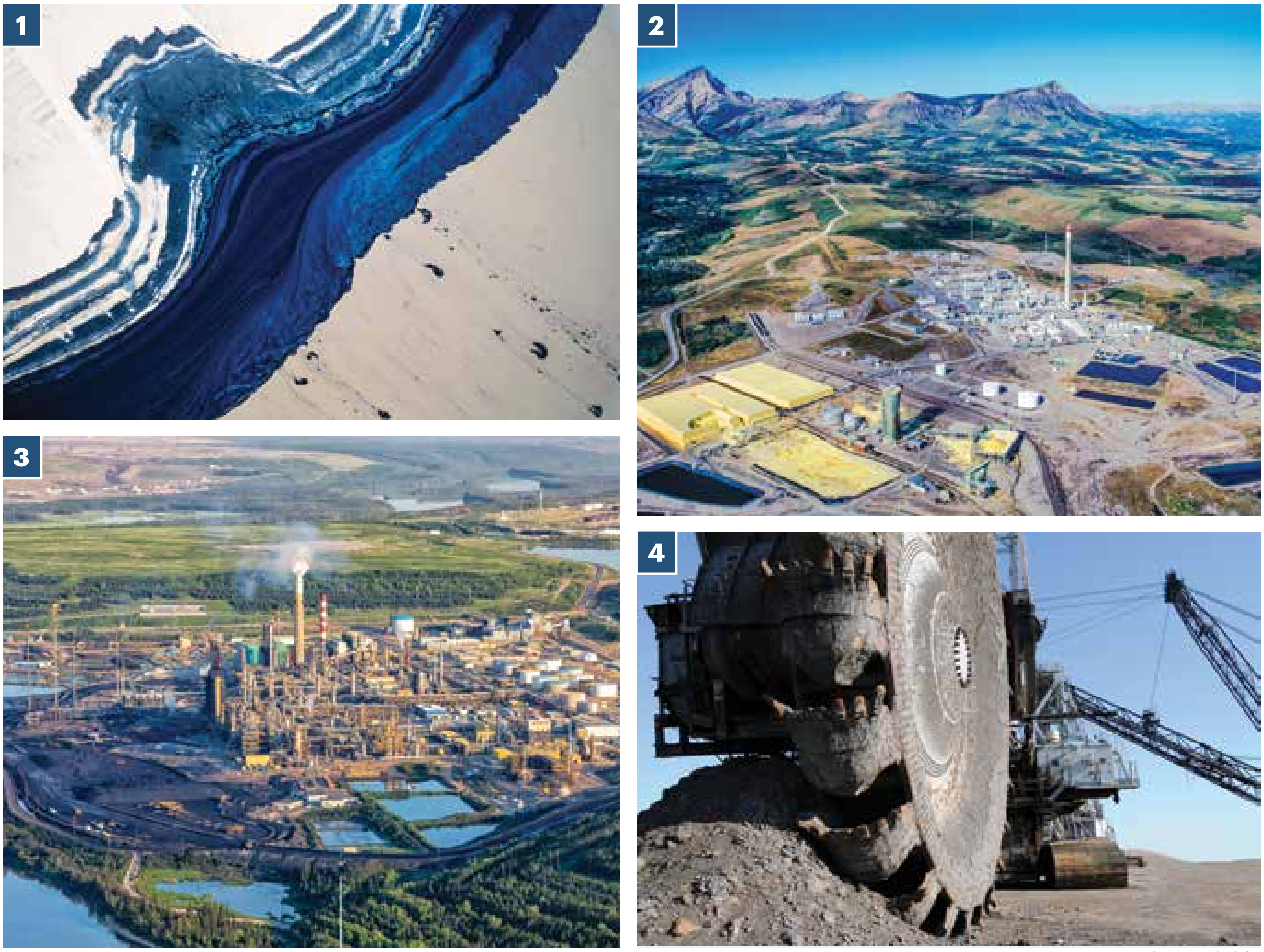
Energy-rich Canada is the largest supplier of crude oil and refined products to the U.S. The province of Alberta alone accounts for 90% of the energy products exported to the U.S. to feed American refineries.

"Canadian production has historically and continues to be a critical piece of U.S. oil

Enbridge's Line 5 NGL Pipeline



SOURCE: REXTAG



SHUTTERSTOCK

1. Aerial image of Alberta oil sands in Alberta, Canada. 2. Aerial image of oil sands refinery, Alberta, Canada. 3. Aerial view of an oil refinery build along the Athabasca river close to the Oilsands Industrial surface mining area travel in Alberta, Canada. 4. Mining equipment; close up of a bucketwheel reclaimer, used at oil sands mines in Alberta, Canada.

supply. In the last year, Canadian Western Sedimentary Basin (WCSB) exceeded record production levels of 4.6 MMbbl/d," East Daley Director of Energy Analytics Kristine Marie Oleszek told *Oil and Gas Investor (OGI)* in May. "In tandem, the U.S. imported a record amount of oil from Canada in January 2024 at 4.184 MMbbl/d. However, Canadian producers have hit a ceiling on production growth due to egress limitations and Canadian net-zero policies."

The U.S. Midwest, specifically, is heavily reliant on Canadian flows, Mark Oberstoetter, Wood Mackenzie's head of Americas (non-Lower 48) upstream research Canada, told *OGI*.

"Heavy barrels also flow to the large U.S. Gulf Coast (USGC) refining sector," he said. "That particular market is more dynamic as heavy imports can come from the Middle East or elsewhere."

"With Venezuela declining and diverting to China, Canada has filled a hole in the USGC refining sector, but other heavy producing regions can always step in at a higher price. Of the heavy oil producing regions, Canada does stand out for its friendly above-ground relationship with the U.S. and carbon pricing and regulations," Oberstoetter said.

Canada's proved oil reserves trail only Venezuela (303.8 Bbbl) and Saudi Arabia (297.5 Bbbl), according to the

"The U.S. imported a record amount of oil from Canada in January, 2024. ... However, Canadian producers have hit a ceiling on production growth due to egress limitations and Canadian net-zero policies."

KRISTINE MARIE OLESZEK, director of energy analytics, East Daley

Statistical Review of World Energy. Canada ranks as the world's fourth-largest producer of oil, trailing the U.S., Russia and Saudi Arabia. Alberta is responsible for the bulk of Canada's crude oil production, but additional significant volumes also come from Saskatchewan and offshore Newfoundland and Labrador, according to Natural Resources Canada.

Canada has 16 refineries with a total combined crude oil processing capacity of 1.85 MMbbl/d as of 2021, according to the U.S. Energy Information Administration (EIA). Eastern Canada has seven refineries with 1.07 MMbbl/d of capacity (58% of total capacity), while Western Canada has nine refineries with 784,000 bbl/d of capacity (42% of total capacity).

Canada's crude oil production exceeds its domestic refining capacity. Even though Canada imports some crude oil and products, it's a net exporter of both, mainly to the U.S. American refineries that are designed to process heavy oils such as oil sands. In recent years, the U.S. has replaced heavy oil imports from Venezuela with those from Canada owing to U.S. oil sanctions placed on Venezuela beginning in 2019.

And Canada doesn't just produce crude oil. The country is also the fourth-largest producer of natural gas, according to Natural Resources Canada. Nearly all of Canada's gas production is from the Alberta and British Columbia (BC) provinces. Saskatchewan is Canada's third-largest gas-producing province, and uranium from the province is used to generate electricity for about one in 20 U.S. homes.

"Canadian production is an effective match for the USGC refining slate and since [Enverus Intelligence Research] doesn't anticipate a peak in demand anytime soon, every barrel is important in keeping markets somewhat balanced to 2030," Enverus Intelligence Research Director Al Salazar told *OGI*.

Trade buddies Alberta and Texas

While Alberta and Texas are at opposite ends of the weather extreme, they do share something in common by way of significant energy resources and the economic benefits that come from their commercialization. Alberta is a major trade partner with Texas, which was lifted into the ranks of hydrocarbon exporter as a result of the shale revolution.

"Alberta has a major interest in Texas. We have bilateral trade of $16 billion per year between Alberta and Texas, and Texas is Alberta's second-largest U.S. trading partner," Jabs said.

Russia's invasion of Ukraine in 2022 led to a drastic decline in Russian energy exports to Europe and the U.K., and prompted a major energy crunch that was felt around the world.

"With geopolitical instability and risk of inward-facing policies, we may see a decreased appetite for energy imports from the U.S. [But] Alberta's a trusted, reliable partner in bolstering energy security while maintaining high environmental standards," Jabs said. "And Alberta can help reduce North American dependence on foreign energy and critical mineral supply chains while supporting the global energy transition."

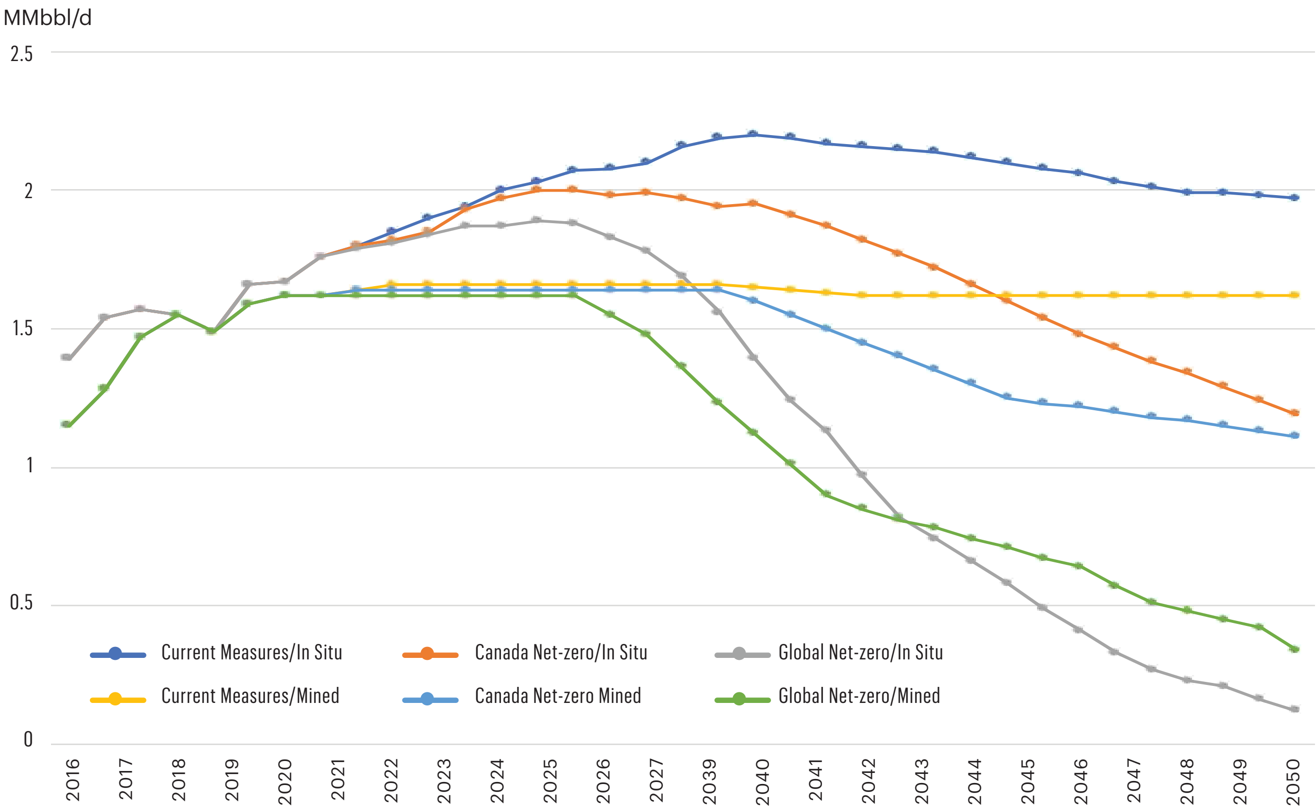
Such a downward move in oil production would expose the Alberta government, which received Cdn$16.9 billion in oil sands royalties alone in its last fiscal year. The funds cover a large portion of their provincial budget spanning healthcare to education, according to Wood Mackenzie's Oberstoetter.

If anything, the Ukraine war has shifted the attention of world leaders to securing energy supply and the energy trilemma—a framework of three objectives including security, sustainability and affordability.

Canada's energy security and that of the U.S. are arguably one and the same. U.S. refiners are in a good place most of the time, but not without concerns as they have also come to rely on the oil sands-heavy blends to run the more complex coking refineries and provide optimized products, Oberstoetter said.

"The landlocked refineries in the U.S. Midwest no longer have pipelines flowing north to access international crudes," Oberstoetter said. "So, in a scenario where oil sands production

Oil Sands Production Scenarios



SOURCE: CANADA ENERGY REGULATOR

goes completely away, those refineries would be challenged to source other heavy blends and would need to shut down certain components of a refinery or even the entire facility."

Canada's oil sands make up over 95% of the country's total oil reserves, and are concentrated in three areas: Athabasca, Peace River and Cold Lake in the provinces of Alberta and Saskatchewan, according to the U.S. based-Energy Information Administration (EIA).

Saskatchewan is Canada's second-largest oil producing province behind Alberta, and is the sixth-largest onshore producer in Canada and the U.S., according to the Canada Energy Regulator.

In recent years, Canadian crude oil production has steadily grown. Production rose 87% from 2005 to 2019 before declining 5% to average 4.66 MMbbl/d in 2020, largely due to the COVID-19 pandemic, according to the Canada Energy Regulator. Since, oil production has been on an upward trajectory. Production averaged 4.93 MMbbl/d in 2021, 5.15 MMbbl/d in 2022, and reached its highest level ever at 5.46 MMbbl/d in 2023.

Canada's oil sands production, which primarily comes from bitumen deposits in Alberta, made up 62% (32% in-situ and 30% mined) of Canada's crude oil production in 2023, according to the Canada Energy Regulator. Canada's bitumen is either mined in surface pits or produced using wells and steam (called in-situ production), according to the entity.

In-situ extraction recovers bitumen that's too deep beneath the surface for mining (greater than 75 m underground), according to Natural Resources Canada. And the lion's share of Canada's bitumen is extracted using the in-situ methods, such as steam assisted gravity drainage. In contrast, open-pit mining is similar to traditional mineral mining operations and largely employed where oil sands reserves are closer to the surface (less than 75 m underground).

Under current measures, Canada's crude oil production is expected to peak at 6.5 MMbbl/d in 2035 and plateau at that level until 2040. Thereafter production is expected to start its decline. In 2035, oil sands production is expected to average 3.85 MMbbl/d, representing 59% of Canada's total crude oil production in that year.

While operating costs have moved lower, and production has continued even with low prices during the pandemic, Wood Mackenzie doesn't envision Canada's production declining, nor does it forecast production above the ceiling set by the Canada Energy Regulator in its current measures scenario, Oberstoetter said.

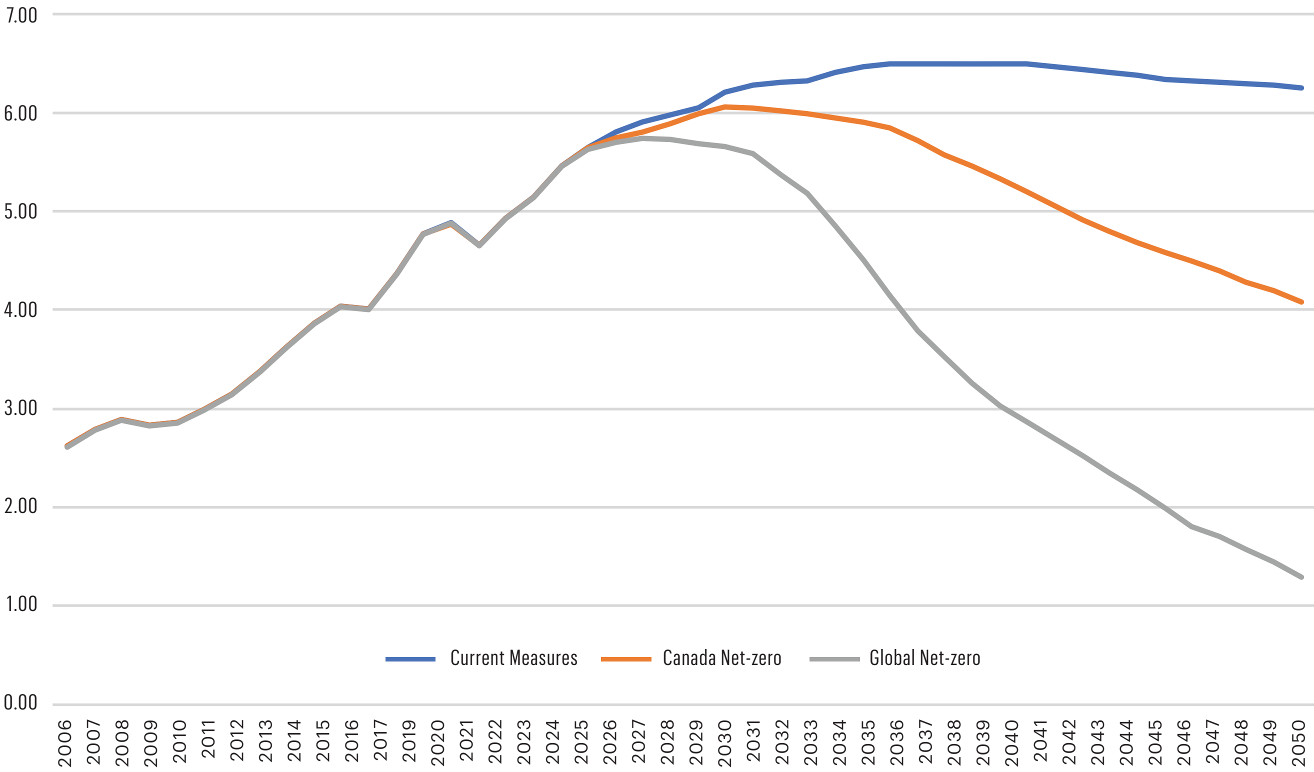
"The appetite for large-scale greenfield expansion has dimmed with the consolidation and operational focus of the past decade," Oberstoetter said. "Corporate capital discipline, takeaway and rail constraints and uncertain regulatory policy will all contribute to any ceiling view, besides oil price and project economics (greenfield projects tend to be challenged when oil prices are below US$60/bbl)."

The Canada Energy Regulator has established three scenarios to create its Canadian crude oil production forecasts. The scenarios differ depending on the pace of Canada's and the rest of the world's climate actions. The "current measures scenario" doesn't assume additional action to reduce greenhouse gas (GHG) emissions beyond those in place today. The Canada and global net-zero scenarios share the premise that the future pace of climate action in Canada is consistent with Canada reaching net-zero GHG emissions by 2050.

Under Canada's net-zero and the global net-zero scenarios, the country's crude oil production is expected to

Canadian Crude Oil Production in Three Scenarios

MMbbl/d, includes condensate and pentanes plus



SOURCE: CANADA ENERGY REGULATOR

peak and start declining much earlier than 2035, which is the case in the regulator's current measures scenario.

Under the Canada net-zero scenario, crude oil production is expected to peak at 6.07 MMbbl/d in 2029 with oil sands representing 60% of the total crude oil production. Under the global net-zero scenario Canada's crude oil production will peak at 5.75 MMbbl/d in 2026 with oil sands representing 60% of the total crude oil production.

Company interest and funding headwinds

While Canada's crude oil production will vary under different scenarios—trending down in the net-zero scenarios—heightened interest in the sector remains among companies considering consolidation options, and especially for five producers that account for around 81% of the total oil sands production, Oberstoetter told OGI.

"For Cenovus Energy, Suncor Energy, Canadian Natural Resources, Imperial Oil and MEG Energy, this is their essential resource theme and they will rely on oil sands as the primary pieces of their portfolios for the next two decades," Oberstoetter said. "Some do have other production regions or downstream assets, but most of their value and shareholder distributions is locked into the oil sands."

But for Enverus Principal Analyst Trevor Rix and Enverus Director Al Salazar, capital is an issue.

"Within Alberta, there have been challenges with Pathways Alliance CCUS proceeding due to the federal government's lack of willingness to backstop a carbon price which creates elevated political risk that further impairs the ability and/or willingness to invest in additional greenfield projects," Rix said.

"Again—under the assumption that global liquids demand does not peak and under a backdrop of limited OPEC global supply growth outside of Brazil and Guyana-Suriname, higher prices should be a green light to increase oil sands production," Salazar said. "Unfortunately, capital to fund such long-lead expansions will be tough to come by, especially with the heightened attention to environmental and energy transition themes.

"European banks and some funds refuse to fund Canadian oil sands projects. In short, the need will be there for more barrels. However, finding capital that is willing to stomach the long-lead times and payout periods and perhaps another round of midstream constraints could be tough to find. Likewise, it is extremely difficult to license new export pipelines through BC."

Canada's pipeline and takeaway headwinds

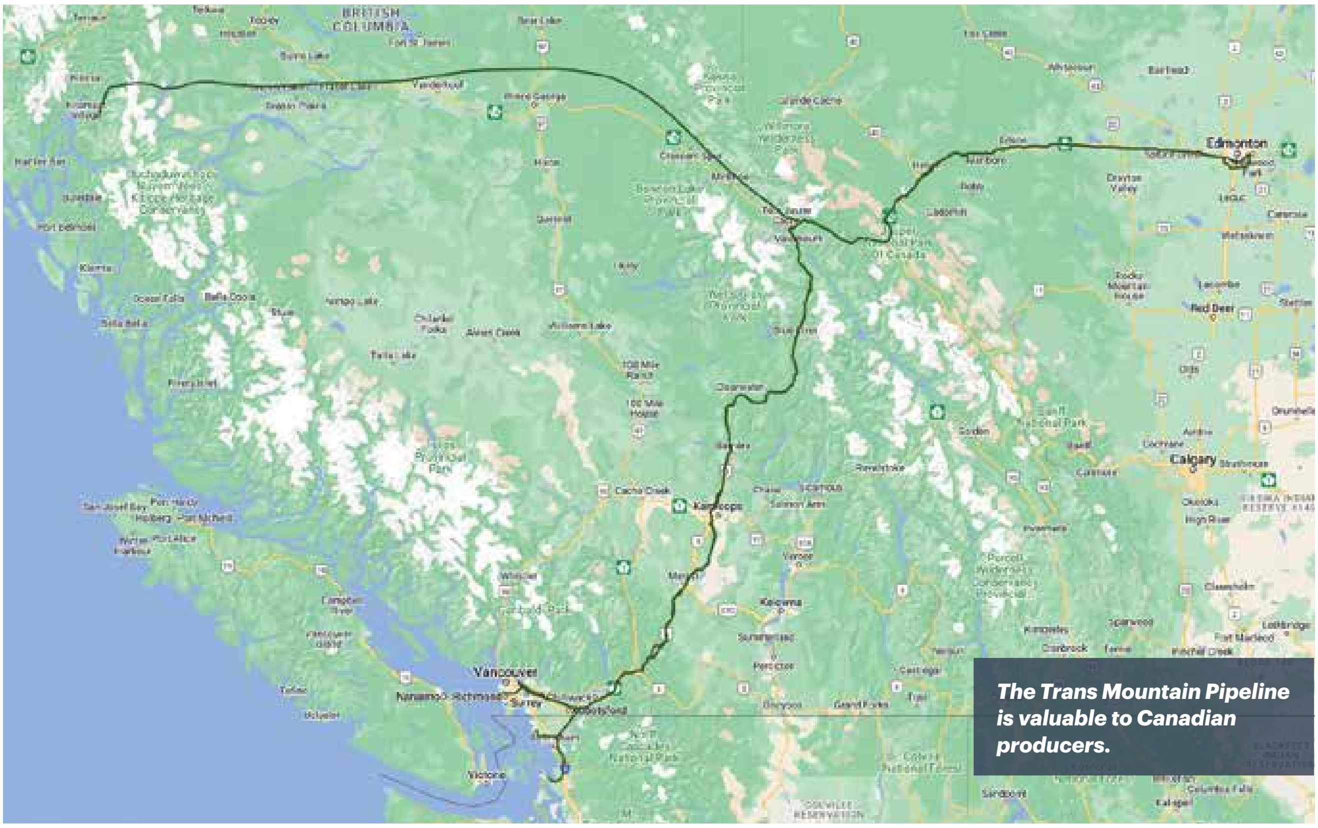
The upward trend in Canada's crude oil production in recent years is in great part due to several factors: the Alberta government rescinded mandatory production curtailments established in 2019, and the addition of export pipeline capacity. The latter point is arguably the main focus of the current spotlight on Canadian pipeline infrastructure. Some progress has been made to boost Canada's overall pipeline infrastructure.

On May 1, Trans Mountain Corp.'s Trans Mountain pipeline expansion project began commercial operations, creating a pipeline system with 890,000 bbl/d of capacity compared to 300,000 bbl/d earlier, according to Trans Mountain.

The event was met with applause from top executives with a number of Canadian producers.

"Completion of infrastructure projects, such as TMX, are

Trans Mountain Pipeline



The Trans Mountain Pipeline is valuable to Canadian producers.

SOURCE: REXTAG

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Rail tankers laden with crude oil head into downtown Calgary, Alberta. With Canadian crude pipelines at capacity, producers are leaning on rail to deliver oil.

crucial to the competitiveness and growth of the country's energy industry and the strength of the Canadian economy," Imperial Oil Chairman, President and CEO Brad Corson said during the company's first-quarter earnings call. "Going forward, we do expect to see a narrower [Western Canadian Select] differential that will further support strong value delivery from our upstream and a net benefit to Imperial."

The original Trans Mountain Pipeline was constructed in 1953. The Canadian government approved the Trans Mountain Expansion Project in June 2019, which would essentially twin the existing 1,150-km pipeline between Strathcona County (near Edmonton), Alberta and Burnaby, BC.

The Trans Mountain expansion will boost shipments from the British Columbia coast to Asia and the U.S. West Coast, and compete with Enbridge's Mainline and TC Energy's Keystone pipeline, which take Canadian crude to U.S. refineries.

"The addition of Canada's own international market will allow WCSB production to receive better netbacks for its production as the U.S. market has historically seen wide differentials due to the large distance to get the bbl to market and numerous bottlenecks and congestion along the way," East Daley's Oleszek said. "East Daley's production model forecasts WCSB oil production to fill TMX's added egress by year-end 2026. As this happens Canada will once again be at egress constraints limiting production growth with the only viable option being rail opportunities. East Daley believes it is very unlikely Canada will see a crude oil project of TMX's stature in the future to alleviate egress constraints."

"It is great for industry and Canada to have that tremendous asset available," MEG Energy Corp. Senior Vice President of Marketing Erik Alson said during the company's first quarter earnings call. "With this critical infrastructure now complete, we anticipate that light heavy differentials will remain narrow for years while Canadian egress remains unconstrained. Before TMX fills, I think you'll see additional egress from an Enbridge mainline expansion. And while I don't see another pipeline being built, I believe there's debottlenecking of other existing pipelines that will occur."

Canadian oil has long been heavily discounted because it only had one outlet–the U.S. Gulf Coast, which was often congested, Salazar said. Trans Mountain provides options to Canadian producers looking to international markets.

"At an astonishing cost of approximately $34 billion, it would make sense that this pipeline be used to its fullest," he said. "This, coupled with Venezuelan uncertainty, should mark an easing of such discounts. Ultimately, as a U.S. refiner in need of Canadian crude, it must feel a bit uncomfortable to know that its former dance partner now has multiple suitors."

The change is appreciated by Jon McKenzie, CEO of Cenovus Energy.

"With this critical piece of infrastructure now complete, we anticipate light-heavy differentials will remain narrow for years, while excess egress capacity exists," he said during the company's first-quarter webcast.

The Enbridge Mainline is North America's largest crude oil pipeline network. It transports light and heavy oil, NGLs and refined products from Edmonton, Alberta to different markets in Canada and the U.S. Midwest. The Canadian Mainline includes six adjacent pipelines with a combined operating capacity of 3.2 MMbbl/d that connect with the Lakehead System at the Canada-U.S. border, as well as five pipelines that deliver crude oil and refined products into eastern Canada, according to Enbridge.

TC Energy's 4,900-km liquids pipeline system, consisting of the Keystone Pipeline, directly connects the Western Canadian Sedimentary Basin to the largest refining market with 14 MMbbl/d of capacity in the U.S. Midwest and Gulf Coast.

Pembina Pipeline Corp.'s pipeline division manages a transportation capacity of 2.9 MMboe/d in key market hubs in Canada and the U.S. Pembina's oil sands and heavy oil assets transport heavy and synthetic oil produced within Alberta to the Edmonton area and offer associated storage, terminaling and rail services.

But, despite having the energy-hungry U.S. on its side logistically and commercially, Canadian crude oil producers still don't have everything easy.

Crude oil supply in Western Canada exceeds pipeline transport capacity that serves international markets. Since Canada's oil export pipelines operate at full capacity and the timing of new capacity additions is uncertain, Canadian producers have to lean increasingly on railroad transportation to ship crude oil to market, according to the EIA.

"With Trans Mountain starting, there is now adequate pipeline egress for current production levels. But a few years of incremental growth will see pipeline capacity become a constraint on further growth," Oberstoetter said. "There is rail loading capacity of approximately 600,000 bbl/d but that is not all located in the optimal locations and peak rail usage was 412,000 bbl/d in February 2020. [But] Rail capacity could be added if economics improve." OGI

Pitts: Deep in the Renewable Heart of Texas

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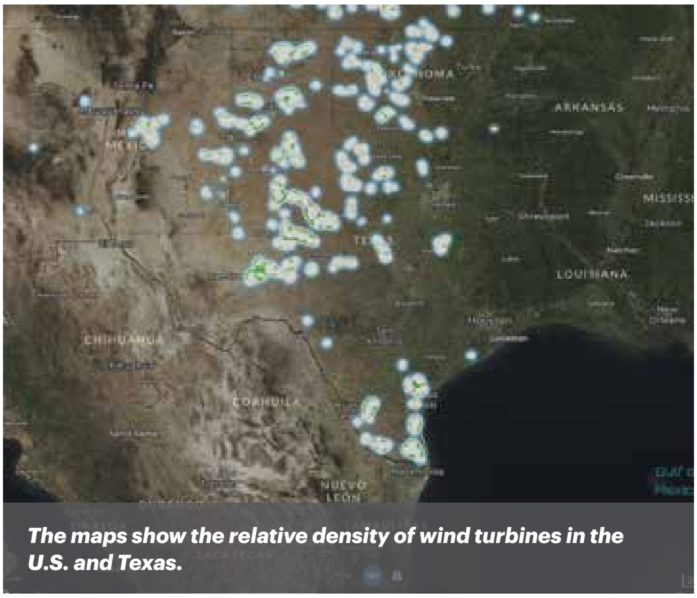
In a burst of cosmic irony, the state known as Lone Star is now the manifestation of an all-of-the-above energy policy.

Rich in fossil fuels, Texas accounts for nearly one-quarter of U.S. energy production. It's home (along with New Mexico) to the celebrated Permian Basin and the Eagle Ford Shale, as well as the Barnett, the shale revolution's birthplace. It's no exaggeration to say that Texas and its abundant shale resources have allowed the U.S. to emerge as a dominant exporter of LNG, surpassing even long-time heavyweights Australia and Qatar.

And Texas cements its position among the energy elite in the renewable sphere, as well, leading the U.S. in wind-generated electricity and ranking among the top states in solar energy potential and generation.

As a longtime oil and gas producer, the state is primed to be a major producer of geothermal energy, and is blessed with ample reserves of uranium, rare earth elements and other critical minerals, according to the U.S.-based Energy Information Administration (EIA).



The maps show the relative density of wind turbines in the U.S. and Texas.

SOIURCE: U.S. DEPARTMENT OF INTERIOR AND THE USGS' "THE U.S. WIND TURBINE DATABASE"

Bill Gates has taken notice, and commented during CERAWeek by S&P Global in Houston that there was irony in the surge of renewable energy in a state known for its oil and gas.

"If you want to see what the cutting edge of next-gen clean energy innovation looks like, it'd be hard to find a place better than Texas," Gates wrote in a blog post. "Amazing companies are breaking ground not just in Southeast Texas but across the state. Each one represents a huge boon for the local economy, America's energy security and the fight against climate change."

Gates has made no secret of his desire to fight climate change. He founded Breakthrough Energy, a company that funds research into clean energy technologies; and TerraPower, which is developing advanced technologies for nuclear energy.

Whether it's the size of its population or its economic landscape dominated by hydrocarbons, companies in the renewables space are finding Texas attractive, Gates said. These include the largest international oil companies like BP, Eni, Equinor, Repsol, Shell and TotalEnergies, among others.

Renewable energies come laden with challenges—costs and their intermittent nature are still bridges that must be crossed. And the February 2021 freeze in Texas not only took out gas facilities but wind turbines. If anything, it's a case in point about the reliability of certain renewable resources under extreme weather conditions.

But the ability of the state to dominate across the energy spectrum should head off arguments that it will not contribute mightily to a low-carbon future. As they say 'round these parts: "Don't Mess with Texas." OGI

AROUND THE WORLD

CANADA

Canada's First FLNG Project Gets Underway

Black & Veatch, in partnership with shipbuilder Samsung Heavy Industries, has received notice to proceed with a floating LNG (FLNG) facility for Cedar LNG near Kitimat, British Columbia, Canada.

Cedar LNG, a partnership between Haisla Nation and Pembina Pipeline, is developing the FLNG facility to source local gas via pipeline. The Kitimat location will provide one of the shortest shipping routes to Asian markets, according to Cedar. The near-short facility will be powered by renewable energy sources.

Black & Veatch will be responsible for complete topside design and equipment supply, including its PRICO LNG technology. Samsung will provide the hull with a containment system and fabrication and integration of all topsides modules.

Cedar LNG is a lower-carbon LNG facility, and the project is a first step toward supplying customers looking to move away from carbon-intensive feedstocks, Black & Veatch's Energy and Process Industries business President Laszlo von Lazar said in April.

Crescent Point Divests Non-core Saskatchewan Assets to Saturn Oil & Gas

Crescent Point Energy is selling non-core assets in Saskatchewan, Canada, including Flat Lake and Battrum to Saturn Oil & Gas for $437.17 million.

Crescent has been busy in the past few years rebuilding its asset portfolio in the interest of long-term sustainability, Crescent president and CEO Craig Bryksa, said in a May press release.

"This transaction allows us to realize value for these non-core assets which had limited impact in the company's future plans while continuing to focus on our priorities of operational execution, optimizing our balance sheet and increasing our return of capital," Bryksa said.

In first-quarter 2024, Crescent also divested its non-core Swan Hills and Turner Valley assets for $102.02 million. The assets had associated undiscounted asset retirement obligations of $131.16 million.

Proceeds from the divestments are being used to repay debt, which was $2.7 billion at the end of 2023. By the end of 2024, Crescent's pro-forma net debt is expected to total $2.04 billion.

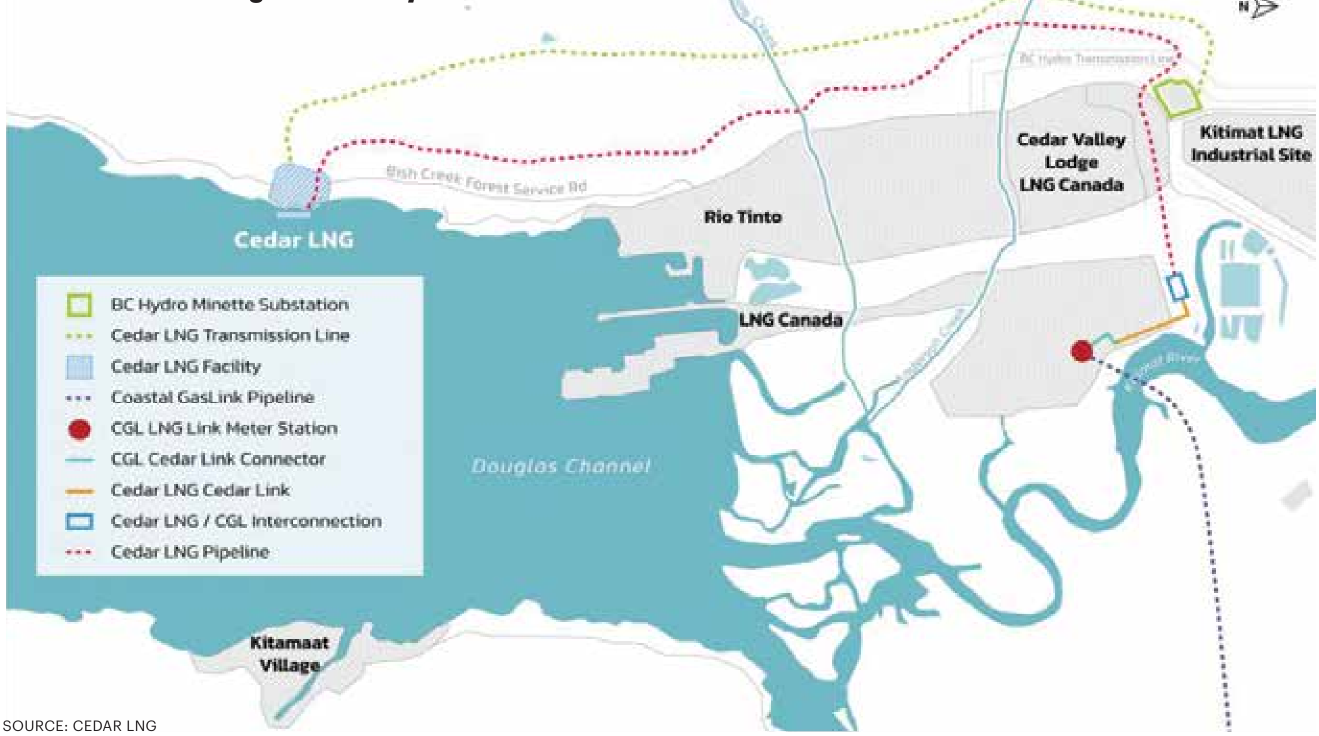
With the divestments, Crescent is also revising its 2024 annual average production guidance down by 7,000 boe/d to a range between 191,000 boe/d and 199,000 boe/d.

Over the next 12 months, production from the assets is expected to hit 13,500 boe/d (95% oil and liquids). Net operating income generated is expected to be $153.03 million at current strip commodity prices.

Scotiabank is acting as financial adviser and National Bank Financial is acting as strategic adviser to Crescent for the sale of its Flat Lake asset in southeast Saskatchewan. TD Securities and TPH & Co. are acting as financial advisers to Crescent for the sale of its Battrum asset in southwest Saskatchewan.

The transaction is expected to close in the second quarter, subject to customary closing conditions.

Cedar LNG's Floating LNG Facility



SOURCE: CEDAR LNG

Cedar LNG will be located approximately 8.5 km southwest of Kitimat, directly across Douglas Channel from Kitamaat Village.

SLB, OneSubsea, Subsea 7 Sign Collaboration Deal with Equinor

SLB and Subsea 7 announced that the Equinor ASA and the Subsea Integration Alliance, which comprises OneSubsea and Subsea7, signed a long-term strategic collaboration agreement that paves the way for exploratory work to begin on the Wisting Field offshore Norway and Bay Du Nord, offshore Newfoundland and Labrador, Canada.

The agreement enables early information sharing, technology innovation and other collaborative benefits expected to make subsea projects more economically viable, SLB and Subsea 7 said in early May.

The agreement paves the way for collaboration to begin immediately on early, joint concept studies for two major projects. Under the same agreement, any resulting engineering, procurement, construction and installation work execution would be directly awarded to the alliance, if Equinor reaches final investment decision (FID) on the pair of projects.

Wisting is in the Barents Sea offshore Norway, and in November 2022, Equinor decided to hold off on the Arctic project due to ballooning project costs. Equinor operates the project with 35% interest on behalf of partners Aker BP (35%), Petoro (20%) and INPEX Idemitsu (10%).

Bay Du Nord is approximately 500 km northeast of St. John's, Newfoundland and Labrador, Canada, in 3,838 ft water depth. In May 2023, Equinor and partner BP decided to postpone FID on its $12 billion Bay Du Nord project for three years in an effort to lower project costs.

C-NLOPB Issues Call for Bids in Eastern Newfoundland

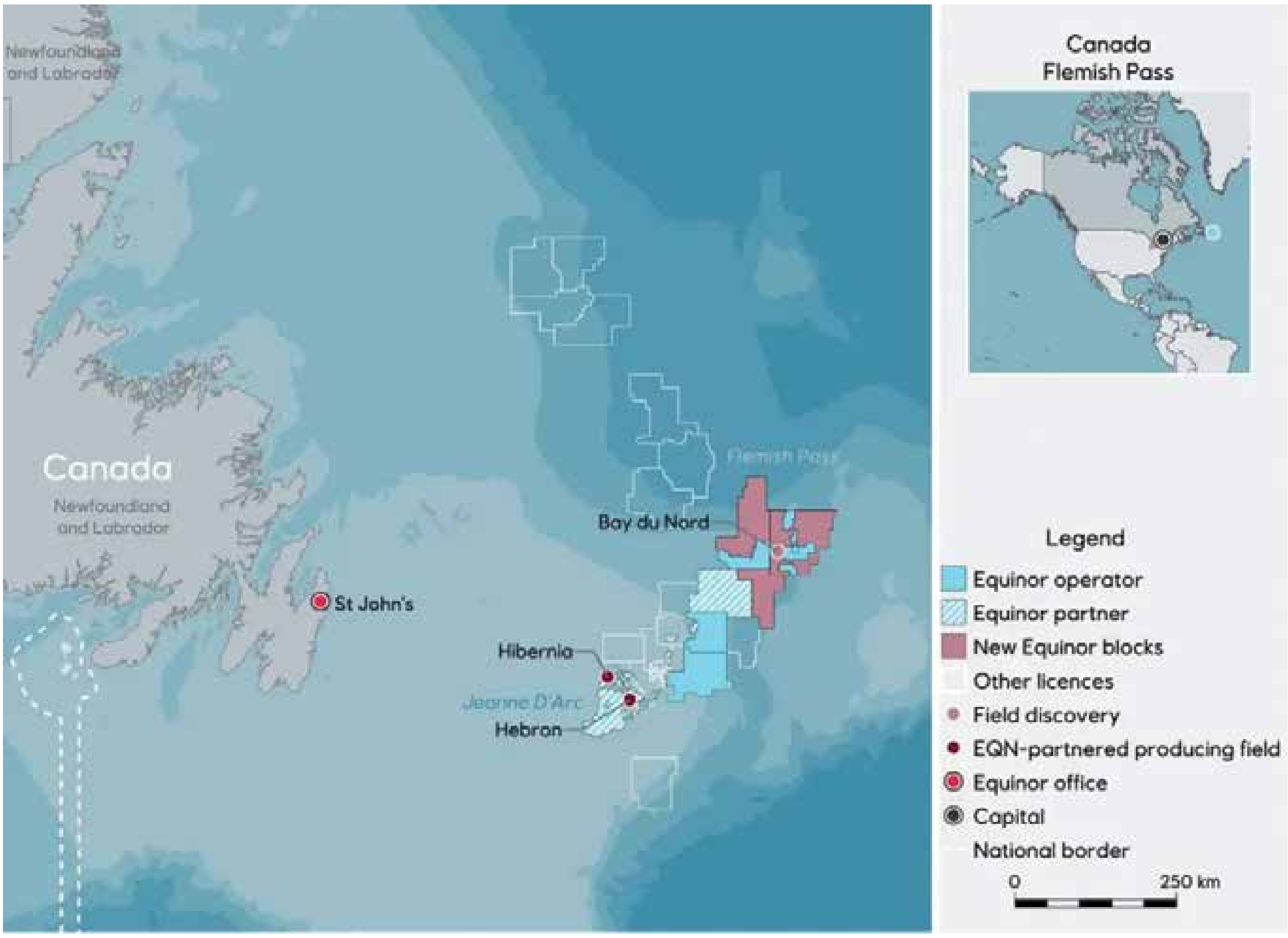
The Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) is issuing a call for bids for oil and gas exploration licenses in the Eastern Newfoundland region.

The Call for Bids No. NL24-CFB01 consists of 41 parcels totaling 10,287,196 hectares. Out of those, 32 were previously available under either separate calls for bids or through relinquishment of Crown lands. The other nine parcels are new and designed over Sector NL06-EN with consideration from stakeholder input from a previous call for nominations, C-NLOPB said in late April.

The minimum bid for a parcel is $10 million in work commitments. Winners will be selected based on the highest total of money the bidder commits to spend on exploration of a parcel during the first six years of a nine-year license, known as Period 1.

Some parcels in this call for bids overlaps with the Northeast Newfoundland Slope Marine Refuge. Regulations and the timing, spatial extent and nature of proposed oil and gas activities will determine the level of additional restrictions required. The region is important for fish harvesters, so any companies granted exploration licenses

Equinor's Bay Du Nord Project



SOURCE: EQUINOR

Equinor's operated Bay Du Nord project is offshore Newfoundland and Labrador, Canada, in 3,838 ft water depth.

One of Equinor's drill sights in the Marcellus Shale which will be swapped with EQT Corp.

EQUINOR

will be required to engage with fishing interests before oil and gas activities will be authorized.

The deadline for bids is Nov. 6 at 12:00 p.m. Newfoundland time. Successful bids will be required to receive ratification by the federal and Newfoundland and Labrador governments to be awarded any exploration licenses.

The C-NLOPB will not proceed with a call for bids in the Jeanne d'Arc Region in 2024, but will reevaluate on an annual basis.

Utility, Clean Energy Company Allete to Go Private in $6.2B Deal

U.S. utility Allete is going private in a $6.2 billion deal after agreeing to be acquired by a partnership led by Canada Pension Plan Investment Board and Global Infrastructure Partners (GIP).

The Minnesota-based clean energy company said on May 6 it entered a definitive agreement to be acquired for $67/share in cash. The purchase price, which includes debt, represents a premium of about 19.1% to Allete's closing share price on Dec. 4, 2023, the day before news broke about the company exploring a sale.

Allete's shares will no longer trade on the New York Stock Exchange, Allete said in a press release.

The transaction, which was unanimously approved by Allete's board of directors, is expected to close in mid-2025, subject to approval of its shareholders along with required regulatory approvals and other customary closing conditions.

U.S.

Spain's Repsol to Drop Marcellus Rig in June

Spain's Repsol plans to release its Marcellus Shale rig in June but will maintain another rig in the Eagle Ford Shale, CEO Josu Jon Imaz said during a first-quarter 2024 earnings webcast with analysts.

Repsol will drop the rig due to the current U.S. gas price environment, he said. As a result, Repsol will also reduce capex in the Marcellus play.

"And as a consequence of this reduction, the free cash flow breakeven for the Marcellus this year is going to be at $2/MMBtu. So, I mean, it's not a big figure taking into account current prices, but let me say that it's OK," Imaz said.

"Saying that, what we are doing is also because we have a more positive view for gas prices for coming years. And what we are doing is guaranteeing that the production is going to be there. This year, we are producing more or less [about] 135,000 barrels a day in equivalent terms. I mean we are talking about gas," Imaz said.

Imaz said the Madrid-based energy company is trying to mitigate its exposure to Henry Hub through hedging.

"Approximately 20% of our North American gas production in 2024, 50% in 2025 and 60% in 2026," has been hedged, Imaz said. "On average, around 40% of our North American production in 2024-2026 has been hedged through derivatives … with a minimum floor in all cases above $3/MMBtu. So, we are quite comfortable [in] this position."

Equinor Says EQT Asset Swap Upgrades International Portfolio

Equinor ASA's recent swap of U.S. onshore assets with EQT Corp. is an example of the Norwegian company "high-grading" its international E&P portfolio, the company's CFO Torgrim Reitan said during a quarterly webcast.

The swap allows Equinor to build "size and scale in certain areas where we do operate and where we can take advantage of that," Reitan said during Equinor's first-quarter 2024 financial webcast.

"On [the] production side, it typically will add around 15,000 bbl/d in increased production, and … lower breakeven [costs], lower emissions and [generate] better returns," Reitan said, responding to questions from analysts.

"This was sort of the last piece of operated activities within U.S. onshore activity. And it was a small operation where we lacked scale and we have come to the conclusion that we don't see ourselves as a future operator within U.S. onshore activities. And we instead want to prioritize working with the best operators," Reitan said.

On April 15, Equinor entered into a swap deal with EQT subsidiary EQT ARO. The deal will see Equinor divest its 100% interest in the Marcellus and Utica shales in the Appalachian Basin in southeastern Ohio, and transfer the operatorship to EQT. In exchange, Equinor will acquire 40% of EQT's non-operated working interest in the northern Marcellus Shale in Pennsylvania, the Norwegian company said in its quarterly financial statements.

Equinor will pay a cash consideration of $500 million to EQT to balance the overall transaction.

Following the transaction, Equinor will boost its average working interest to 25.7% from 15.7% in certain Chesapeake Energy-operated Northern Marcellus gas units, Reitan said. Closing is expected in the second quarter, subject to approval by relevant authorities. OGI

Kinetik Launches Delaware Basin M&A Valued at $1.3B

Kinetik Holdings will buy Durango Permian infrastructure for $765 million, excluding contingency payments, and sell its interests in the Gulf Coast Express pipeline to AcrLight Capital Partners for $540 million.

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Kinetik Holdings announced a series of transactions in early May, led by a cash-and-stock deal to acquire Durango Permian infrastructure for an aggregate $765 million. In a related move, Kinetik will divest its 16% equity interest in the Gulf Coast Express (GCX) pipeline to ArcLight Capital Partners for $540 million cash.

The Durango acquisition—along with a new, long-term gathering and processing contract, represents approximately $1 billion of new investment for the company, said Jamie Welch, Kinetik's president and CEO.

"Following the Durango acquisition and the expected completion of Kings Landing, Kinetik will own and operate over 2.4 billion cubic feet per day of processing capacity, entirely in the Delaware Basin, and approximately 4,600 miles of pipelines across eight counties," Welch said.

The Durango deal will expand the company's presence as a pure-play midstream provider in the northern Delaware Basin. Kinetik will pay $315 million in cash and 11.5 million shares of Class C common stock, some of it deferred until July 2025, to seller Morgan Stanley Energy Partners.

Durango's assets in Eddy, Lea and Chaves counties, N.M., include approximately 2,400 miles of gas gathering pipelines and approximately 220 MMcf/d of processing capacity. The Durango assets also bring aboard more than 60 new customers, many private operators, Kinetik said.

Kinetik's Durango transaction includes a $75 million contingent payment tied to the capital cost for the Kings Landing complex, which is currently under construction. Kings Landing is a new 200 MMcf/d greenfield processing complex in Eddy County, which is expected to be completed in April 2025. The complex will increase Durango's processing capacity to 420 MMcf/d.

To offset the purchase price, Kinetik is selling its interests in GCX, the company said. The purchase price is comprised of $510 million in upfront cash and an additional $30 million deferred cash payment due upon a final investment decision (FID) on a capacity expansion project.

Additionally, Kinetik announced a 15-year agreement to provide gathering and processing services in Eddy County for approximately $200 million. Kinetik will construct low- and high-pressure gathering infrastructure, which is expected to be approximately $200 million of aggregate capital through 2026.

Kinetik anticipates an approximately 5x run-rate EBITDA investment multiple. The contract begins at the end of 2024, starting with gathering services. It extends to processing

Kinetik's $765 million acquisition of Durango Permian will expand the company's presence in the Delaware.

KINETIK

services starting in second-quarter 2025.

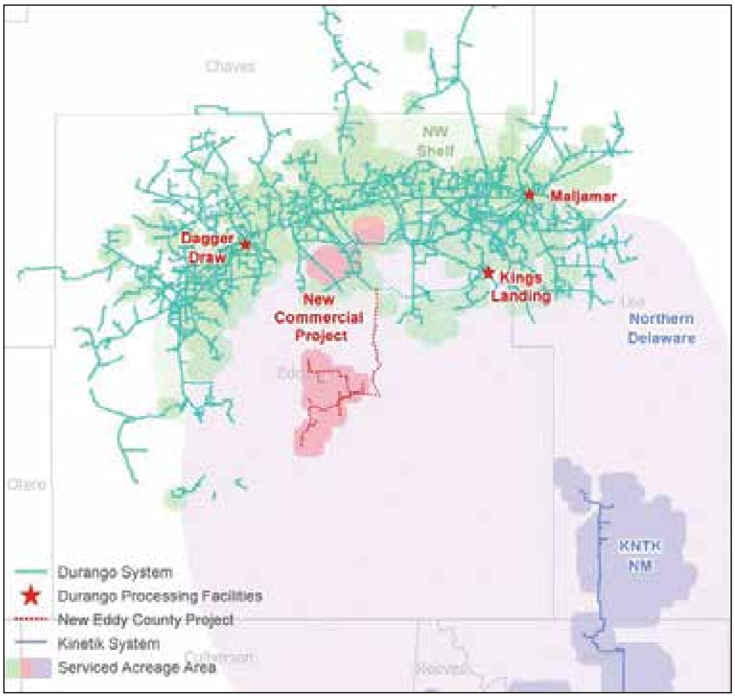
"Following on from our tremendous success with our recent Lea County, New Mexico system expansion, we are delighted to now announce this series of strategic transactions that further our expansion into New Mexico and significantly increase our footprint across the Northern Delaware Basin," Welch said.

"Proceeds from the GCX sale and the aggregate issuance of $450 million of Kinetik Class C shares, in two installments, will be reinvested into projects at a mid-single digit EBITDA multiple," Welch said. "These actions efficiently and accretively recycle cash proceeds from a non-operated asset into highly strategic, operated assets."

The transactions are expected to be over 10% accretive to free cash flow per share starting in the second half of 2025, with the level of accretion increasing thereafter, which coincides with an expected acceleration of capital returns to shareholders.

The Durango acquisition and new Eddy County agreement also offer full control of plant products, including more than 350 MMcf/d of residue gas and more than 60,000 bbl/d of NGLs. The volumes will provide "significant additional upside value via system optimization, modifications to existing commercial contracts and integration with our pipeline transportation segment," Welch said. OGJ

Durango System



SOURCE: KINETIK

(1) Pro forma for 200 Mmcfod Kings Landing Cryo. Estimated completion April 2025.
(2) A non-GAAP measure. See appendix for definitions of the non-GAAP financial measures used in this presentation.

The Durango System that Kinetik is acquiring from Morgan Stanley Energy Partners.

MIDSTREAM

Segrist: At Last, Good News for Gas Producers

Artificial intelligence: Humanity's power-hungry new friend?

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It's been a long, bad stretch for the people who sell natural gas.

In the winter of 2021-2022, bitterly cold weather shut down production and caused people to use up much of the available gas supply. Prices started to rise, peaking on Aug. 22, 2022, when the Henry Hub price hit $9.85/MMbtu, the highest since the summer of 2008.

After that, it's been mostly downhill.

Two winters followed that didn't bring winter with them. The Henry Hub price fell below $4/MMBtu at the start of 2023. The nation's gas supply kept shooting up, regardless.

According to the U.S. Energy Information Administration, the U.S. had 2.563 Tcf of natural gas in underground storage by the beginning of May. It was another monthly five-year storage record, the fifth in a row going back to January 2024.

The Henry Hub dropped below $2/MMBtu at the start of February. Natural gas production leaders EQT and Chesapeake Energy announced production cuts in February and March. The picture at the regional Waha price hub in Pecos, Texas, was bleaker. Daily spot prices started dipping into negative territory, forcing producers in the region to pay customers to take the excess gas off their hands.

So why do so many gas producers and midstream companies sound happy?

"I think that growing data center demand on the doorstep of our asset base is something that has really surprised us, in that the more we study it, the more excited we get," said Jeremy Knop, CFO of EQT.

Trends and power

An exploding artificial intelligence (AI) sector and its need for gas-fired power generation has been growing in the consciousness of the energy industry over the past year.

In October 2023, Scientific American published an interview titled, "The AI Boom Could Use a Shocking Amount of Electricity." Journalist Lauren Leffer talked to data scientist Alex de Vries, who had just published a study on AI energy requirements.

Globally, data centers currently use around 1% to 1.5% of the world's electricity.

De Vries said that number was going to rise, quickly. If trends hold, NVIDIA, the corporate leader in AI, will ship out 1.5 million AI server units each year until 2027. And each year, the 1.5 million servers will require 85 terawatt-hours of electricity to run at capacity. One terawatt-hour can power a billion 100-watt light bulbs for an hour.

An International Energy Agency report highlighted that an average Google search uses 0.3 watt-hours of electricity. A ChatGPT query uses 2.9 watt-hours, more than nine times the amount of electricity.

According to de Vries, if all 9 billion daily Google searches were done using ChatGPT, Google would need the amount of power used by Ireland each day to meet the demand.

De Vries noted his study did not include the energy needed to keep the servers cool, which he guessed would add another 50% to the overall energy cost. While it is possible that massive increases in efficiency will soften the oncoming blow to the U.S. electrical grid, rising demand is coming.

Natural gas producers and the midstream industry see an opportunity, and many executives shared their enthusiasm during their first-quarter earnings reports.

Gas by default

Industry analysts say gas-fired generators are the likely path if the U.S. needs a lot more power quickly.

The EIA reported in 2022 that developers had no new plans for a coal power plant in the U.S., and that utilities planned to retire 25% of the current inventory by 2029. Wind and solar power would have a difficult time providing the massive amount of energy needed, especially during cloudy or still days.

The brand new nuclear plants at the Vogtle complex near Augusta, Ga., were completed seven years late and $17 billion over budget, according to the Associated Press.

With a much shorter development time of three to four years for a gas-fired generator, and abundant gas supplies available, producers say they are hearing from the tech sector.

"Everybody understands the energy that they require. They want it affordable, they want it reliable and they want it clean," said EQT President and CEO Toby Rice at his company's quarterly earnings call in April.

"And certainly, with data centers, reliability is at the top of the list. But the other dynamic at play is going to be speed. And there's only one energy source that has that track record."

Rice noted that the Mountain Valley Pipeline, which will extend gas produced in the Marcellus

The rapid growth of the artificial intelligence is driving increasing energy consumption to power large-scale data processing centers used to support the burgeoning industry—exciting news for natural gas producers.

SHUTTERSTOCK

"Everybody understands the energy that they require. They want it affordable, they want it reliable and they want it clean. And certainly, with data centers, reliability is at the top of the list. But the other dynamic at play is going to be speed. And there's only one energy source that has that track record."

TOBY RICE, president and CEO, EQT

Shale through West Virginia and southern Virginia, will help the tech sector develop in the region.

Midstream company TC Energy reported that executives are working with developers in the tech sector, primarily in Virginia and Wisconsin. Planning for an upcoming surge, the company has been reinforcing parts of its pipeline network to handle the extra load.

In Texas, Energy Transfer is in talks with a chip manufacturer for a gas pipeline, said ET co-CEO Mackie McCrea.

"We're believers like everybody else," McCrea said. "The data centers–especially around AI–it's going to happen."

An April report by Wells Fargo analysts forecast that U.S. electrical demand for data centers would cause a 10 Bcf increase in daily natural gas usage. Today's demand could reach 45 Bcf/d, over the current 35 Bcf/d used for power generation.

Static shock

The optimism about AI is not universal, however.

Jeremy Grantham, an investment strategist for GMO, who is otherwise known for predicting both the dot-com crash in 2000 and the financial crisis of 2008, recently wrote a blog post predicting a bursting AI bubble.

AI "seems likely to be every bit as powerful and world-changing as the internet, and quite possibly much more so," he wrote. "But every technological revolution like this–going back from the Internet to telephones, railroads, or canals–has been accompanied by early massive hype and a stock market bubble as investors focus on the ultimate possibilities of the technology, pricing most of the very long-term potential immediately into current market prices."

The result is that initial enthusiasm for a new thing dims when people realize that bringing the potential of the new thing into reality requires several missteps and building a solid support structure, which can take years, Grantham wrote.

Power up

Even if the AI build-out fizzles, the world is still going to need far more electricity than it has on hand today, said Scott Tinker, director emeritus of the Bureau of Economic Geology, who talks on global energy issues.

Since the late 2000s, U.S. electrical production has been largely flat. The country continued to advance technologically, but new products, such as LEDs for traditional light bulbs, increased efficiency and decreased the need for new power generation. That's no longer the case, Tinker said.

The need for data centers, AI or otherwise, will continue to draw more power. And if EVs continue to be adopted, it amounts to a massive addition of power demand.

"EVs are a whole 'nother sector of electricity consumption that we currently don't have, and it'll be as big as commercial, residential and industrial potentially," Tinker said. "Where is that going to come from?"

For natural gas producers, it's an easy question to answer. OGI

Energy Transfer Remains Hungry for M&A

First-quarter crude volumes set a record with rising demand expected.

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After reporting a 44% increase in crude volumes on its network in first-quarter 2024, Energy Transfer (ET) plans to keep its aggressive stance toward growth in the future, according to co-CEO Tom Long.

"Overall, worldwide demand for crude oil, natural gas, natural gas liquids and refined products remains strong, as does demand for our products and services," said Long, speaking during ET's first-quarter earnings call. "We will continue to position ourselves to meet this demand by strategically targeting optimization and expansion projects that enhance our existing asset base and generate attractive returns."

For the quarter, the company reported $21.6 billion in revenue, a 14% increase in revenue over the same period in 2023. The company pointed to several major additions to its assets, both organic and through M&A, that contributed to its financial results.

Since 2022, ET has bought Woodford Express, Lotus Midstream and Crestwood Equity Partners in deals totaling about $9 billion.

In 2024, the company benefited from Sunoco's acquisition of NuStar, which closed in early May. Energy Transfer owns Sunoco's general partner. ET bumped up its 2024 EBITDA guidance by $500 million to between $15 billion and $15.3 billion, largely because of the Sunoco deal.

The company plans to keep looking for other assets to add in the near future, upping its 2024 growth capex to $2.9 billion from the earlier guidance of $2.5 billion. Long said the extra cash will be spent primarily on facilities for NGL and other refined products as well as midstream segments.

"We still feel like consolidation makes sense in the midstream space," he said. "We are still fully intent on evaluating various opportunities as we look out. So, we're not going to slow down on that front."

One other area of supply growth is in the natural gas market. The company approved eight 10-MW natural gas-fired generators—expected to enter service over the next two years—to support ET's operations in Texas. The company has also been in conversations with utilities and, in some cases, manufacturers, who are interested in a power supply.

Energy Transfer is in talks with a Texas chip manufacturer for a gas pipeline and sees a growing opportunity for natural gas demand that dovetails with data center growth, said co-CEO Mackie McCrea.

"We're believers like everybody else," McCrea said. "The data centers—especially around AI—it's going to happen."

A TPH Energy analysis said Energy Transfer could benefit from an AI data center boom.

"We have even more conviction that ET is in one of the best positions to capture the upcoming AI and natural gas demand ramp, especially in the Texas region," analyst Zack Van Everen wrote in a May report.

Litigation status

The company gave no updates on several lawsuits regarding rights-of-way on its network in Louisiana.

Last year, Energy Transfer took legal action to prevent other midstream companies, Williams, DT Midstream and Momentum Midstream, from crossing ET's pipeline network. The suit alleges the companies did not meet Energy Transfer's safety standards.

The other companies responded in their various lawsuits that ET was more interested in protecting its market share. In April, a Louisiana appeals court ruled against Energy Transfer in its case against DT Midstream. The other rulings are pending. Williams Cos. executives said during their first-quarter earnings call that they expect to win their case.

"We still feel like consolidation makes sense in the midstream space. We are still fully intent on evaluating various opportunities as we look out. So, we're not going to slow down on that front."

TOM LONG, co-CEO, Energy Transfer

Howard: AI and Gas Demand

HINDS HOWARD
CRBE INVESTMENT MANAGEMENT

Hinds Howard is a portfolio manager at CRBE Investment Management, where he evaluates listed infrastructure and transportation companies in North America and coordinates research of listed transportation companies globally. He is based in Wayne, Pa.

I have three children, the oldest of which is finishing up her junior year of high school. We are early enough in the college process where anything is possible. This time next year, the reality of low acceptance rates will set in and there may be some disappointment.

Similarly, when it comes to potential impact of artificial intelligence (AI), the world is just beginning to consider what is possible. We don't yet know how much power AI will need 10 years from now and how real the demand is for more natural gas to support data centers tied to that technology at some point in the future.

With earnings this quarter, utilities and midstream companies have started rolling out estimates and frameworks for considering the scale and total addressable market potential of that new demand source.

Load growth

Demand for electricity in the U.S. has been stagnant for a long time, to the tune of roughly 0% growth in the last decade and just 0.5% annually for the last 20 years.

Several new trends have emerged that appear to be changing that trajectory, including:

- Growth in industrial/manufacturing production from reshoring supply chains;
- Electrification of transportation and other things; and
- Data center power demand from the explosion of generative AI applications.

Load growth is here now, with power demand growth expected to finish above 2% in 2024. There is potential for much higher load growth by the end of the decade, maybe as much as 5% annually, driven by 15% CAGR in data center power demand. Such a step change in demand for electricity has implications across the energy value chain that will require massive investment in power generation, around $50 billion estimated by Goldman Sachs.

That level of power generation investment, assuming 60% is natural gas-fired, would lead to around 3.3 Bcf/d of incremental natural gas needed, according to Goldman Sachs. Citi has run numbers on AI demand, coupled with slowing of retirement of existing coal plants, and a series of other assumptions that pegs a base case of incremental natural gas demand from AI data center demand by 2030 of 3.8 Bcf/d in a base case or more than 5 Bcf/d in an upside case with greater than expected data center growth.

Recently, the market seems to have had an awakening as to how much infrastructure would be needed to supply that much power, and utilities are suddenly the best performing sector in the market after being largely ignored for 18-plus months.

Electricity demand is growing three times faster this decade than in the prior decade. Natural gas as a percentage of total U.S. power generation is at an all-time high already at more than 40%.

That electricity demand needs reliable natural gas to function as coal capacity is retired and less reliable renewables take a greater share of the power supply stack.

Things that could throw cold water on this demand growth party:

- Ability for utilities to permit and build out new power plants, challenges when it comes to rolling that demand into rate base;
- Natural gas supply challenges, related to permitting new pipelines; and
- Technology company budgets and/or demand, or maybe even pushback on carbon emissions.

Technology companies that have made carbon reduction goals may need to walk back energy transition goals which seem at odds with a ramp-up in natural gas-based power. That dynamic may be why technology companies have been so aggressive in contracting for new renewables related to data center demand.

What midstream companies say

On earnings calls this quarter, midstream companies were ready to discuss AI data center demand growth. It was popular for sell-side research analysts to tally up the number of times data center was mentioned on calls (using AI to do so in some cases). According to Wolfe Energy's equity research team, "data center" was mentioned on first-quarter conference calls 86 times overall, including 26 in prepared remarks and 60 times in Q&A.

Kinder Morgan Executive Chairman Rich Kinder offered up his answer to the AI demand question like a recent MBA interviewing for a job at an investment bank: "AI demand alone is projected at about 15% of demand in 2030. If just 40% of that AI demand is served by natural gas, that would result in an incremental demand of 7 to 10 Bcf a day."

So, the demand potential is somewhere between around 3.5 Bcf/d and 10 Bcf/d by 2030, with most folks coalescing around 5-6 Bcf/d. Either end of that range would be big if it comes true, but I will take the under if we're talking about by 2030, even though I might believe the high-end number is realistic if we add another 10 years.

In the near term, the upstream and midstream sections of the natural gas value chain are happy to have some hope for future demand growth to hold up the longer end of the natural gas futures curve, keeping the curve in contango in a year when Waha natural gas prices have at times been negative and Henry Hub has struggled to break $2/MMBtu. Rather than rely exclusively on global demand for LNG for incremental demand, adding in the potential for a meaningful domestic demand source is welcome. OGI

BP-owned Archaea Energy's Starlee Sykes Talks RNG

BP became the largest producer of RNG in the U.S. when it acquired Archaea Energy in 2022. Sykes was named CEO in 2023.

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There is treasure in trash, and the U.S. is sitting on more than 146 million tons of it.

That is just at municipal landfills, according to the U.S. Environmental Protection Agency.

Add wastewater, livestock waste and other agricultural waste to the mix, and the potential to transform trash—specifically the methane emanating from it—to make renewable natural gas (RNG) grows.

Used in the same ways as conventional natural gas, RNG is formed when moisture and impurities—such as CO_2 and hydrogen sulfide—are removed from methane to create pipeline-quality gas. The lower-carbon energy resource is capturing the attention of energy companies, including BP, as the world seeks ways to reduce emissions. The RNG sector expects to see more action in 2024 following a year filled with deal-making, project starts and regulatory moves—including the final renewable fuel standards rule through 2025, to further incentivize development.

In the U.S. and Canada, more than 330 RNG production facilities are in operation, according to the Coalition for Renewable Natural Gas. Another 165 are under construction and more than 320 in development. Nearly three-quarters of the RNG volumes use municipal solid waste as feedstock.

Q&A

BP became the largest producer of RNG in the U.S. when it acquired Archaea Energy in 2022, a move that opened up another revenue stream for the company and another route toward reduced emissions. Archaea produced about 11 million MMbtus of RNG from its sites, which span more than 30 states. BP said it believes it can increase its biogas volumes this decade to about 70,000 Boe/d by scaling Archaea.

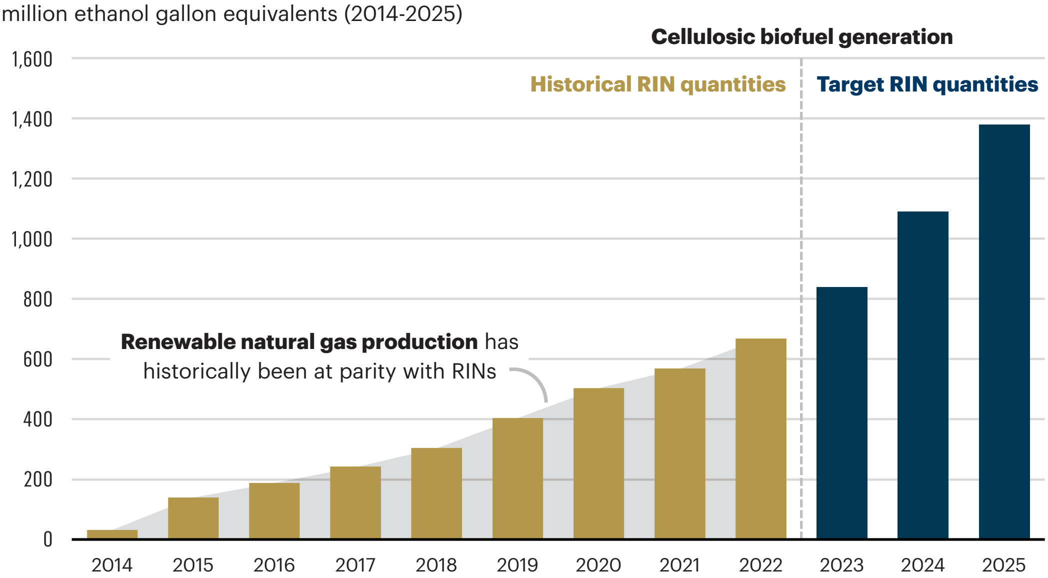
The company has its sight set on building 15 RNG plants annually during the next couple of years with Starlee Sykes at the helm as Archaea Energy's CEO. Sykes last served as senior vice president of BP's Gulf of Mexico and Canadian operations.

She spoke to Oil and Gas Investor *just after marking her one-year anniversary in the CEO role.*

"When this opportunity came up, it was a chance to learn something new, to learn to do another new side of the energy industry in which I'm really passionate about," Sykes said. "Honestly, it's been fantastic."

Annual Cellulosic Biofuel Production and New Volume Targets Under the RFS

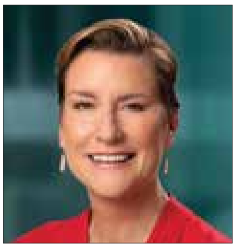
million ethanol gallon equivalents (2014-2025)



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION

Archaea Energy CEO Starlee Sykes visits an RNG plant in the state of Kansas.

BP



"It's exciting to be a part of an industry that, while it's been around for a long time, [has] gotten more attention in recent years and it's really growing as an industry, but also from a demand perspective."

STARLEE SYKES, CEO, Archaea Energy

Velda Addison: What skills and expertise are you bringing to RNG from your experience in oil and gas?

Starlee Sykes: I've been really surprised and excited about how much is transferable. There's the obvious stuff like being a leader. So, leadership and caring for people and supporting people and building a team and a culture–all of that is 100% transferable. But it's also understanding the value drivers. What drives revenue and earnings has been transferable. Safety is a big part of who I am. And understanding how to lead a safe organization from a personal and process safety perspective is definitely transferable because even though it's renewable natural gas, it's still natural gas, which for all scientific purposes is the same composition as the gas that I was used to dealing with oil and gas. It is just that it comes from landfills and dairy rather than from fossil fuels.

That's all transferable as well as technical knowledge and problem solving. Understanding how to build and operate plants is something that I've done a lot of my career and it's still applicable here. I guess the last thing would be relations with the government, stakeholders and suppliers. How do you build those relationships and maintain them in a healthy way that supports the business?

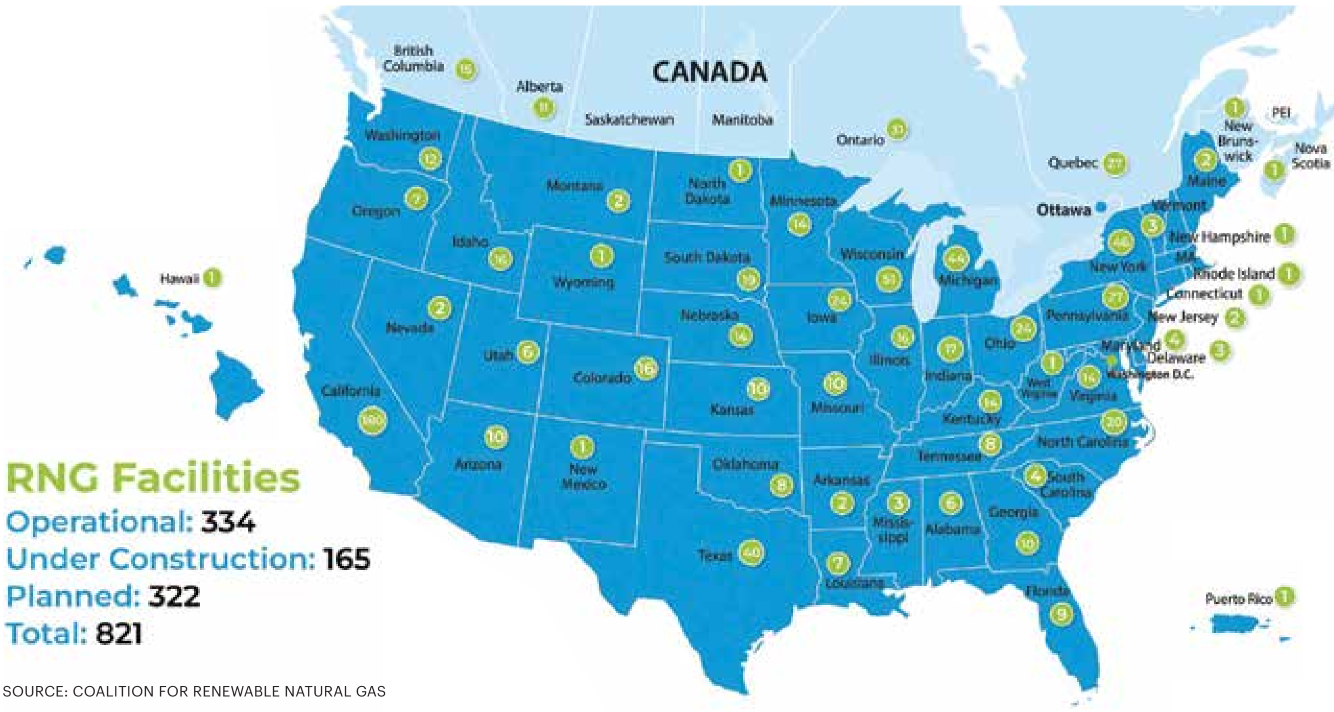
VA: How would you characterize the state of the RNG sector today in the U.S.?

SS: It's exciting. Renewable natural gas, as you know, comes from the gas produced from waste as it decomposes. It's considered renewable because it is, and it's helping to have beneficial use from gas that otherwise would just be released into the environment. So, that's a positive thing for our customers, for the environment and for people. And there's an increasing market for that as corporates, governments and people put more emphasis on renewables and more emphasis on doing the right thing for the climate.

The demand for renewable natural gas is growing. It's exciting to be a part of an industry that, while it's been around for a long time, [has] gotten more attention in recent years and it's really growing as an industry, but also from a demand perspective. I've loved learning about the fundamentals of the business and understanding how BP can uniquely add value and be a part of it at scale.

VA: Where do you see the greatest opportunities for RNG both in terms of supply and demand or offtake?

SS: When I think about RNG, there are two primary markets for demand. One would be into the voluntary market, which is people, whether it's corporates or university systems or others that have made voluntary commitments to their customers, stakeholders [or] investors that they're going to use a certain percentage of renewables or shift their profiles in a way that supports better environmental goals by using RNG. That market is growing, again, as there's more pressure from investors and from people in general to do the right thing for the environment. The demand for that on the



SOURCE: COALITION FOR RENEWABLE NATURAL GAS

voluntary side is growing.

Then, the other side of the demand would be the compliance market, which is support from government programs and legislation such as the Renewable Fuel Standard or the Low Carbon Fuel Standard in California and from the IRA that was put in place where you've got investment tax credits and production tax credits that are driving increased demand and production of renewable natural gas.

VA: Where do you see some of the challenges that are ahead for the sector? Is permitting still a problem like it seems to be for most other energy industry projects?

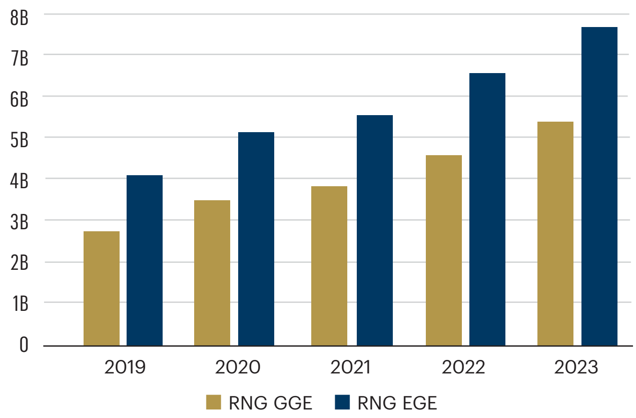
SS: Yes, it absolutely is. It's the time it takes to get permits. For this industry to thrive, it needs regulatory certainty and support is very helpful. We'll continue to have good implementation of the Renewable Fuel Standard and the Low Carbon Fuel Standard markets, and hopefully that will grow, spreading to places beyond California, and then also looking at investment tax credits and the guidance for that to make sure that it is fully supportive of incorporating the language that will help support renewable natural gas production.

Those support the industry, but the challenges you see are [not only] permitting, but also inflationary pressures and supply chain delays. That's not unique to the RNG industry, but it's an issue. And then, also, some markets of labor can be expensive. Focus on getting the right people and the right skill sets is important, too. The last thing I'd say is utility interconnects. So, how do you get the power to run the plants and interconnect to the pipelines to sell the gas?

VA: When it comes to securing customers and offtake agreements, is it a tough sell to customers who can opt for lower cost natural gas for the same uses?

RNG Growth

(2019-2023)



SS: No, I think it depends on the customer, and that's one of the things that's really exciting about BP buying Archaea. When Archaea was a standalone company, it was looking very much towards the voluntary markets because it needed the stable revenues and flows in order to justify getting capital from the markets. But what's exciting about BP is we have a very mature and advanced trading organization. While I'm focused, as the leader of Archaea, on operating our plants well, building new plants and building out our very large development pipeline, I've got a whole trading organization that helps with managing the offtake. That is an advantage BP has in the way that we are able to take that gas to market.

VA: Let's talk a little bit more about BP's plans. Can you tell me about some of your targets in terms of production, pipeline of projects and the amount of

The Archaea Modular Design allows plants to be built on skids with interchangeable components for faster builds. The plant is located in Shawnee, Kansas, just outside of Kansas City.

BP

capex being allocated for RNG?
SS: We currently have 50 plants in operation and we've got a development pipeline of over 80 more projects. So, we're currently the largest renewable natural gas supplier in the U.S. We currently have the largest RNG plant in the U.S., and we're building out a really impressive development pipeline. It's our intent to continue to be a leader in the renewable natural gas industry in the U.S. for a long, long time to come. And we're growing at a rate that's pretty impressive.… We're building 15 plants [per year in 2024 and 2025] … and really looking to grow this business beyond what it is today in a very material way.

VA: What's being done to bring costs down to make it more cost-competitive and what role do you see government incentives playing in further bringing down costs?
SS: Cost competitive[ness] obviously is very important, and we feel like we have a unique solution to that in that we have what we call our Archaea modular design. This is a standardized design that has several different sizes of plants. As I've learned in my previous roles building projects around the world, the more often you do the same thing the more cost-effective it is and the more you can learn from it. So, by deploying this standard design at all of our locations, the cost of those developments should come down over time. It will also help you get more effective at operating and maintaining those plants, because you've got standardization across all of our locations, which is, I believe, a big advantage for us.

You mentioned government incentives. To elaborate on that a little bit, I think there are three big things we're focused on when it comes to government incentives. One is maintaining the Renewable Fuel Standard and the Low Carbon Fuel Standard, expanding the Low Carbon Fuel Standard markets where it makes sense. I mentioned the IRA earlier—in particular, the ITC. We're working with Treasury on making sure the guidance is supportive of being able to get investment tax credits for the equipment associated with producing renewable natural gas. Then, the last thing is a focus on ERINs (electric renewable identification numbers) as an additional pathway for RNG offtake.

VA: Is there anything in the [ITC] that you would like to see changed or added?
SS: It's a technical correction. In February, the IRS issued a technical correction to the language. The original guidance that was put out was very helpful, but it didn't properly incorporate the typical structure of landfill-to-biogas projects. The correction classifies upgrading equipment as integral and not functionally interdependent, when it really is functionally interdependent. The language as it reads right now could disqualify ITC for taxpayers like Archaea from being able to claim the cleaning and conditioning equipment for ITC. We would have to also own a fractional interest in the gas collection system, which is historically owned separately by the landfill owners. So, we are asking and working with others in advocating for a correction in that language to make it more inclusive, which we believe was the intent of the legislation.

VA: If you don't mind pulling out your crystal ball. A year from now, how do you think the RNG sector will look?
SS: I'm always careful on forward-looking statements, as you can imagine. But, I think a year from now it's going to look like progress is being made and growth is happening. I think, in particular, Archaea will have a bit more of a track record, being a leader in the RNG space. And, I think it'll still be a very exciting place to invest and be in. I think our employees will be excited to be a part of it, and I'm optimistic that I'll be very happy with our progress. OGI

NEW ENERGIES

Phillips 66 Weighs Divestments, Targets Renewable Fuel Increase

Phillips 66 looks to boost renewable fuels production by 67% through the end of the second quarter 2024 at its Rodeo complex in San Francisco while weighing a potential divestiture of its retail marketing businesses in Austria and Germany.

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Phillips 66 is targeting a 67% uptick in renewable fuels production in San Francisco by the end of second-quarter 2024, which will position the downstream energy company "as a world leader in renewable fuels," CEO Mark Lashier said during the company's first-quarter earnings presentation.

Renewable fuels production from Phillips 66's Rodeo Renewable Energy Complex is currently averaging about 30,000 bbl/d. The facility is on track to produce 50,000 bbl/d at full throttle—equivalent to about 800 million gallons per year—by the end of the next quarter, Lashier said in late April.

Currently, production from Rodeo comes from the Unit 250 hydrotreater—which is producing around 10,000 bbl/d of renewable diesel—and the first hydrocrackers at the complex.

"During the first quarter, we achieved a major milestone with the startup of our Rodeo Renewable Energy Complex," Lashier said. "The facility benefits as a superior location to secure renewable feedstocks and market renewable fuels. The project leverages existing assets and is expected to generate strong returns."

Once the conversion is complete, Houston-based Phillips 66 will be able to produce renewable jet fuel, a key component of sustainable aviation fuel, Lashier said.

The first transition at Rodeo occurred at the first hydrocracker, which went into renewable fuels feedstock production in March, Rich Harbison, Phillips 66's refining executive vice president, said.

"That's allowed the facility with Unit 250 and the first hydrocracker to produce about 30,000 bbl/d of renewable fuel," he said. "The second hydrocracker and the pretreatment unit will both finish construction in the May timeframe, and we will start those up in the June time frame. So, by the end of the second quarter, the facility will be at full production rates."

Rodeo evolution

Phillips 66's San Francisco Refinery consists of two facilities linked by the company's pipelines. The Santa Maria facility is in Arroyo Grande, Calif., 200 miles south of San Francisco. The Rodeo facility is located in the San Francisco Bay Area.

Intermediate refined products from the Santa Maria facility are shipped by pipeline to the Rodeo facility for upgrading into finished petroleum products.

Phillips 66 has advanced conversion plans at Rodeo to address the growing demand for renewable fuels. As a result, the company ceased operations of the Santa Maria facility in February 2023, they said in a statement on its website.

Once the conversion at Rodeo is complete, the repurposed facility will reduce emissions and produce lower carbon intensity transportation fuels. Phillips 66 plans to distribute its renewable

"During the first quarter, we achieved a major milestone with the startup of our Rodeo Renewable Energy Complex. The facility benefits as a superior location to secure renewable feedstocks and market renewable fuels. The project leverages existing assets and is expected to generate strong returns."

MARK LASHIER, CEO, Phillips 66

PHILLIPS 66

Phillips 66 is counting on its Rodeo Renewable Energy Complex in San Francisco to make it a world leader in renewable fuels.

diesel through new and existing channels, including 600 branded retail sites in California.

Monetizing European assets

Phillips 66 is planning to sell off assets that no longer fit its long-term strategy, executives said.

The company is progressing on the divestiture of its retail marketing business in Europe. Completion of the dispositions is subject to satisfactory market conditions and customary approvals, according to the company's first-quarter earnings release.

"We're selling the Germany and Austria retail assets," Phillips 66 CFO Kevin Mitchell said.

Phillips 66 markets retail and wholesale products in Austria and Germany under the JET brand.

"That's a company-owned dealer operated model, with almost 1,000 sites across those two countries. It's a high-performing business, top rated … and great business, but doesn't really integrate with the core strategic focus areas that we have as a company," Mitchell said.

The divestments don't include Phillips 66's ownership in the Mineraloelraffinerie Oberrhein GmbH (MiRO) Refinery located on the Rhine River in Karlsruhe, Germany, some 95 miles south of Frankfurt.

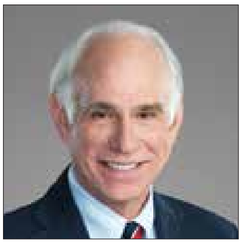
"And the reason for that is the majority of buyers for those types of retail assets would not be interested in refinery ownership," Mitchell said. "If there's a buyer that is interested then that's a separate conversation and we'll handle that separately, but this package right now is focused on those marketing assets."

Phillips 66's other marketing businesses are in Switzerland and the U.K., which also market products under the JET brand, Lashier said.

"The two are very different in that the Switzerland business is somewhat of a standalone retail business, but it's also in a joint venture structure and so the dynamics are a little bit different around that," Lashier said.

The U.K.'s marketing business is integrated with Phillips 66's refining in the U.K., Lashier said. That arrangement is in line with the U.S. model, in which the marketing business helps ensure product placement coming out of the Humber refinery. The refinery is located on the east coast of England in North Lincolnshire, approximately 180 miles north of London. OGJ

Hirs: How the Cost of Carbon Avoidance Bolsters Nuclear Power



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Nuclear power plants that do not generate a profit for their owners may still provide a net benefit to the economy once the benefit of reduced CO_2 emissions is taken into account. Because the U.S. has not yet adopted an emissions pricing mechanism, there is not a market-based solution for policymakers. They can make one.

Carbon pricing is implicit in the Inflation Reduction Act. States and the EU have introduced nascent carbon pricing schemes with taxes, tax benefits and offsets. It isn't unreasonable to assume that carbon pricing will become increasingly tangible.

The social cost of carbon, or SCC, is a measure that considers the economic impacts of rising sea levels, volatile and more extreme weather, and the economic costs of migration. Many homeowners and businesses are facing these costs via higher insurance premiums today.

The EPA's current estimate of the SCC is $190 per metric ton (mt), hence the levels of tax benefits and subsidies contained in the Inflation Reduction Act. Nobel winner William Nordhaus estimates the SCC at $80/mt today, an estimate that increases substantially in the decades ahead.

The increasing social cost of carbon over time means that the payoff for acting today also increases over time.

Longtime oil and gas banker Karl Pettersen likens the imposition of carbon pricing on industry to an unfunded liability, albeit one that is imposed by society. Corporations can choose to make an offsetting capital investment to reduce emissions (same as paying down principal), or they can purchase carbon offsets annually (incurring highly punitive interest).

With the SCC steadily increasing, many corporations will spend ever more to purchase the offsets without addressing their own emissions, ultimately reaching net zero by way of bankruptcy court.

Wind farms, solar farms and batteries can help in the interim, but these solutions require volatile pricing to provide returns to investors with the added risk of volatile service. On this basis—and a few others—the Federal Reserve Bank of Dallas suggests that building more nuclear plants can be a cost-effective solution to improve the shaky reliability of the Texas grid and reduce wholesale price volatility in Texas.

Carbon pricing

The carbon emissions from a 1,000-megawatt (MW) combined-cycle natural gas power plant amount to approximately 800 to 900 pounds per hour, or about 3.7 MMmt/year for a plant running 24/7. Therefore, a carbon tax of $100/mt would generate approximately $370 million in costs for the combined-cycle gas power plant, or in additional tax revenues for the federal government. A simple cycle gas turbine power plant that produces approximately 1,100 pounds per megawatt hour of CO_2—4.4 MMmt/year—would have an annual carbon tax of $440 million.

While China is routinely condemned for having more than 100 coal power plants under construction, it is also building more than 100 nuclear power plants. Several of the new nuclear plants are based on the standard design of the Westinghouse AP1000, with a capacity of 1,110 MW at an estimated cost of less than $5 billion each. If China were to impose a $100/mt carbon tax, the payback in avoided taxes would take less than 15 years. The expected operating life of a nuclear power plant is growing, and the Nuclear Regulatory Commission has extended the licenses of a few plants to operate for a total of 80 years.

France, which generates 70% of its daily electricity requirements from its nuclear power plant fleet, is replacing and upgrading its standardized nuclear portfolio with the EPR2 design, which will generate 1,600 MW of electricity. The estimated cost of the six planned 1,600-MW power plants is €67.4 billion or about $72.4 billion at the current exchange rate.

Each EPR2 power plant avoids approximately 6 MMmt/year of CO_2 emissions. With EU carbon credits currently trading at €65/mt, the annual savings would be €390 million (almost $421 million in U.S. currency), or €31 billion ($33.4 billion) over an 80-year operating lifespan.

In the U.S., corporations are beginning to embrace nuclear power as an alternative to depending on increasingly shaky electricity grids. Dow Chemical is building four small modular reactors, capable of generating 80 MW each, at the company's Seadrift, Texas chemical plant. Dow estimates that switching to nuclear will avoid the release of 440,000 mt/year of CO_2-equivalent, at an estimated $1.5 billion to $2 billion capital investment.

CO_2 emissions for the U.S. in 2022 were a net 5,489 MMmt, with electricity production responsible for approximately 25% of the total. Making a dent in emissions with the current technologies for direct air and point-source capture is going to be difficult as a practical matter. It is better not to produce CO_2 in the first place, and nuclear power plants are the economically viable option.

NEW ENERGIES

TRANSITION IN FOCUS

Energy storage

Equinor Acquires Stake in Standard Lithium Smackover Projects

Equinor has acquired a 45% interest in two lithium projects in Arkansas and Texas under development by Standard Lithium, which aims to commercialize direct lithium extraction (DLE) technology in the U.S.

As part of the agreement, Equinor said it will pay Standard Lithium $30 million to compensate for past project costs and interest. The Norway-based company also said it will pay $33 million to progress the assets toward a possible final investment decision (FID) and up to another $70 million if FID is taken, according to a press release.

The transaction involves Standard Lithium's flagship South West Arkansas Project (SWA) and East Texas properties. The company will retain operatorship of the properties and have a 55% stake.

Standard's SWA project is located on about 36,000 acres in the Smackover Formation in southwestern Arkansas. A preliminary feasibility study indicated the project could have a base case production of 30,000 tonnes per annum (tpa) of battery-quality lithium hydroxide monohydrate with an upside of 35,000 tpa, Standard has said.

IBAT, US Mag Partner to Advance Modular DLE Plant

INTERNATIONAL BATTERY METALS

International Battery Metals modular direct lithium extraction technology

US Magnesium (US Mag) and International Battery Metals (IBAT) are installing what is expected to become North America's first commercial modular direct lithium extraction (DLE) plant.

Located at US Mag's existing operations in Utah, the facility is capable of initially producing 5,000 metric tons per year (mt/year). Full commissioning and startup is expected within the next three months, the companies said. Commercial production is anticipated shortly afterward.

The launch of commercial operations from the modular DLE plant would be a leap forward for U.S. efforts to ramp up domestic production of lithium.

IBAT's modular plant has a footprint of less than three acres compared to the hundreds required for evaporation. And its DLE technology has been proven effective in extracting lithium from oilfield produced brines, subterranean brine and geothermal brine, IBAT said.

As part of the agreement, IBAT's plant co-located at the US Mag site near Salt Lake City will process brine produced from lithium-containing waste-magnesium salts, the companies said. The resulting lithium chloride will provide feed for high-purity lithium carbonate production by US Mag. The Utah-based company already has the capacity to produce 63,500 mt/year of magnesium, 9,000 mt/year of lithium carbonate and other chemical products.

What sets IBAT's first-of-its-kind DLE plant apart is its modularity and mobility, the company said. The plant is described as having a Lego-like design that provides scalability and lower opex and capex.

Anson Inks Offtake Deal with LG Energy Solution

Australia-based Anson Resources said it will supply LG Energy Solution with battery-grade lithium carbonate from Anson's project in Utah's Paradox Basin.

As part of the offtake agreement, Anson said it will supply up to 4,000 dry tonnes per annum (tpa) of battery-grade lithium carbonate from the project. The project, which has a first-phase startup production capacity of about 10,000 tpa, is expected to start operations in 2027.

The company said it also continues to progress negotiations with other potential customers.

Geothermal

Sage Geosystems Advances Commercial-scale Energy Storage Facility

SAGE GEOSYSTEMS

A scale rendering of Sage Geosystems' 3-MW energy storage system.

Sage Geosystems, seeking to unlock energy storage with geothermal technology, is making progress on its commercial-scale energy storage facility in Texas. Sage plans to drill a well in June or July and commission the project by year's end.

Located in Atascosa County, Texas, south of San Antonio, the 3-megawatt (MW) EarthStore energy storage project will be the first of its kind and part of the ERCOT South Load Zone of Texas. Its startup is expected to not only help bolster the reliability of the grid as more intermittent renewables come online. The project will also accelerate deployment of Sage's geopressured geothermal system (GGS).

The technology collects energy from pressurized water stored underground for both short- and long-duration periods. That energy can be dispatched when needed to the grid.

"All of our equipment is ordered. We're currently working on a land use agreement with the utility company," Sage Geosystems CEO Cindy Taff told Hart Energy. She said the utility company hasn't been named because an agreement is not yet finalized.

If all goes as planned, Sage expects to commission the facility, which it says will be the world's first commercial GGS facility, in December.

However, the project will likely not interconnect to the grid until 2025.

Eavor, Alberta Government Launch Geothermal Drilling Accelerator

Geothermal company Eavor Technologies said it joined the Alberta government and other stakeholders to develop the Alberta Drilling Accelerator (ADA), a "technology-agnostic, market-driven geothermal test site."

The first-of-its-kind site in Canada will be available for use by any geothermal company as they pursue novel drilling techniques and technology development, according to a news release.

"With cumulative geothermal investment poised to reach $1 trillion by 2050, a geothermal arms race is very much underway to commercialize novel drilling techniques that accelerate geothermal development–exhibited by testing facilities in the United States, China and Iceland," Eavor Technologies CEO John Redfern said.

The ADA also aims to help the province keep pace with other government-supported geothermal test sites, such as Utah FORGE in the U.S., the Continental Deep Drilling Program in Germany, the Deep Drilling Project in Iceland and China's drilling program, the release states.

Hybrid

Microsoft Taps Brookfield for 10.5+ GW of Renewable Power

Brookfield and tech giant Microsoft have joined forces to develop more than 10.5 gigawatts (GW) of new renewable power capacity.

That's equivalent to more than 3,100 utility-scale wind turbines or 20,000 Corvette Z06s, based on the U.S. Department of Energy's equivalent examples of gigawatts of power.

The five-year agreement reflects how the companies are working toward common goals of reducing emissions and as Microsoft seeks more renewable energy to meet growing demand for its cloud services. Financial terms of the agreement were not disclosed.

"This first of its kind agreement, which is almost eight times larger than the largest single corporate PPA ever signed, is a testament to our ability to reliably deliver clean power solutions at scale to our corporate partners and accelerate the energy transition," said Connor Teskey, CEO of Brookfield Renewable and president of Brookfield Asset Management.

Brookfield Renewable aims to deliver the renewable capacity between 2026 and 2030 in the U.S. and Europe, but projects could expand to include Asia-Pacific, India and Latin America, the company said in a news release. The projects will include solar, wind and other carbon-free energy generation technologies.

Microsoft aims to become carbon negative by 2030.

Solar

Southern Power Expands Miller Branch Solar Facility in Texas

SOUTHERN CO.

The second phase of the Miller Branch Solar facility is expected to begin commercial operations in the second quarter of 2026.

Southern Co. subsidiary Southern Power will add a 180-MW second phase to its 200-MW Miller Branch Solar facility in Texas, the company said.

Construction is about to start for the project's first phase. The project, which Southern said has the potential to expand approximately another 500 MW, is located in Haskell County, Texas.

The expansion will increase Southern Power's portfolio of solar generation, operating or under construction, to more than 2,920 MW, the company said.

The second phase of the Miller Branch Solar facility is expected to begin commercial operations in second-quarter 2026.

Birch Creek, MN8 Energy Taps First Solar Modules

BUSINESS WIRE

First Solar announced that MN8 Energy LLC placed orders for 457 MW of advanced thin film solar modules, including 170 MW of Series 6 Plus bifacial modules and 287 MW of Series 7 modules.

MN8 Energy, a New York-based renewable energy producer, has placed an order for 457 MW of advanced thin film solar modules from First Solar, the manufacturer said.

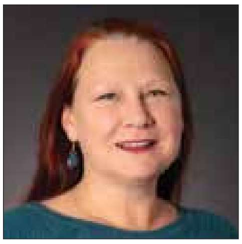
The order, which comprises 170 MW of Series 6 Plus bifacial modules and 287 MW of Series 7 modules, will power projects in the northeastern and southern U.S.

Founded as Goldman Sachs Renewable Power in 2017, MN8 has a 3.2-GW renewable energy portfolio delivering energy to corporations, government entities and utilities.

In a separate news release, First Solar said it will supply St. Louis-headquartered Birch Creek Energy with 547 MW of advanced Series 6 Plus Bifacial thin film photovoltaics modules for projects across the U.S. OGI

Time is Money: Shell Prioritizes Speed with Brownfield Strategy

The replicant strategy trades customization of the production unit for a sped-up cycle time for the Whale and Sparta developments in the deepwater Gulf of Mexico.



JENNIFER PALLANICH
CONTRIBUTING EDITOR

Shell's quest for speedy development cycles in the Gulf of Mexico (GoM) has the supermajor applying brownfield thinking to greenfield developments.

The approach isn't easy as the development activities at the outset start with different questions, Shell experts said during a panel on the Whale project during the Offshore Technology Conference (OTC).

In the deepwater GoM, Shell is largely replicating its operated Vito production semisubmersible for the Whale and Sparta developments to save time and money. Shell brought its Vito production semisubmersible in more than 4,000 ft water depth online in 2023 after reaching final investment decision (FID) on the project in 2018. Equinor is Shell's Vito partner. Shell sanctioned its operated Whale project in nearly 9,000-ft water depth in July 2021 with first production set for this year, and its operated Sparta project in 7,000-ft water depth in December 2023, with first oil from the 20,000 psi development expected in 2028. Equinor is Shell's partner for the Sparta project.

The decision to replicate comes with some trade-offs.

"As engineers, we love to optimize. We love to have a vessel that's just the right size to separate these fluids. A compressor that's exactly the right size to do this. So [it's] really the trade-offs, or what's good enough? What can do the job?" Jason Gage, Whale's host manager for Shell, said.

The result is that sometimes something is slightly overdesigned, but there can be more benefit in accepting that in order to speed delivery time rather than redesigning, he said.

"It's thinking about a project as really a brownfield project, almost. If you really had to change it, what would you change?" he said.

With a brownfield, "you have what you have, right? You've got to be very deliberate in brownfield as far as what you change," he said, noting the change of approach is not easy.

Oro Awaritefe, Whale's project manager at Shell, said one way to think about it is like a subsea tieback bringing new oil to an established asset.

"We deal with it," he said. "Once you've made the decision that we are replicating, which by the way it wasn't so easy to come to that decision, but once you do, everything is now about 'how does it fit into the host?' and that's a whole different mindset. It's a tieback mindset, it's a brownfield mindset."

Throughout development, Awaritefe said, Gage as the host manager had three main rules around what types of change would be permitted.

"He said, 'No change unless you find something unsafe, unless there's a regulatory requirement and unless there is an opportunity problem.' If none of these are in play, then he doesn't want to hear about change," Awaritefe said.

Gage acknowledged that brownfield thinking is more constrained than greenfield development thinking.

"Everybody loves greenfield because it's a blank sheet of paper, but if it's paint by numbers, you have a little less creativity involved," Gage said.

On the other hand, Jonathan Johnson, business opportunity manager for Shell Exploration, noted that replication is not void of innovation.

"Everybody loves greenfield because it's a blank sheet of paper, but if it's paint by numbers, you have a little less creativity involved."

JASON GAGE, Whale host manager, Shell

1. The Whale production semi heading for the Gulf of Mexico for Shell. Shell operates Whale with 60% interest on behalf of partner Chevron with 40% interest. (Source: Seatrium) 2. The Vito platform in the U.S. Gulf of Mexico started production in 2023. Shell operates Vito, originally discovered in 2009, with 63.11% interest on behalf of partner Equinor with 36.89% interest. (Source: Equinor) 3. Rendering of Shell's Sparta Development. Shell operates Sparta, which was originally discovered in 2012 by Cobalt Energy, with 51% interest on behalf of partner Equinor with 49% interest. (Source: Shell Offshore)

"I think that replication allows you to focus innovation in areas … where you can innovate to create additional value," he said.

Whale project

Located in the ultra-deepwaters of the Alaminos Canyon region of the GoM, Whale was discovered in 2018 and appraised in 2019. At the time of its discovery, oil was around $50/bbl and the industry was in a "lower for longer" phase. Chevron is Shell's partner in the Whale project.

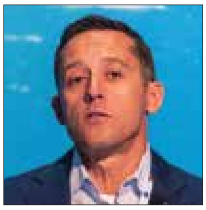
With its proximity to the Perdido host 10 miles away, Shell briefly considered a subsea tieback to the development but determined a tieback was not the optimal solution for the volume of discovered reserves. Shell also evaluated a number of production solutions early in the development phase, finding many of them inadequate to meet the company's desire for speed and simplicity, while others weren't right for other aspects, such as metocean conditions, Johnson said.

Replicating the Vito semisubmersible production platform "quickly emerged" as the preferred option for speedily developing Whale at a lower cost.

One of the chief reasons that was possible is that the reservoirs for Vito and Whale are similar.

"The rocks helped us out a lot," Gage said.

Phase one of Whale will see 15 wells drilled.



"I think that replication allows you to focus innovation in areas … where you can innovate to create additional value."

JONATHAN JOHNSON, business opportunity manager for Shell Exploration

The production semi has a capacity for 100,000 bbl/d, 200 MMcf/d and a 30-year design life. Oil is exported via pipeline to Texas and gas via a shared gas export line shared with Perdido.

The subsea equipment is rated for 10,000 psi, and Awaritefe said subsea is one of the aspects varying from Vito.

"Our subsea is terribly different from Vito subsea, so you can't lift and shift and make that design, but there are elements that you can replicate," he said. "The more you push that standardization and replication, I think the more flawless our execution becomes."

Examples are using the same standardized designs for subsea trees or umbilicals across all projects, he said.

On the other hand, the topsides had some changes from the Vito host.

"We typically say that the topsides is an 80% replication, the hull is 99% replication," Awaritefe said.

One reason for the larger variation on the topsides is changes in technology, such as obsolescence.

"What we've tried to do is, 'if it's not broke, don't fix it,' that way we gain the most out of it, but if it's getting obsolete then we need to change it, we change it," he said.

The hull, however, is "predominantly dumb steel" and therefore subject to less change, he said.

For Whale, the equipment package is about 95% a copy of Vito's equipment, the topsides about 80% and the hull about 99%. Shell went with the same mooring and installation concept for Whale as for Vito, but the water depth was different and a different vendor was used. The dry transport used the same vendor but a different vessel.

But due to Whale's further distance from the heliport, a different kind of helipad was needed.

And experience with Vito allowed for some optimization on the topsides that will deliver higher payload and flexibility later in life.

"We now understood better the design that we had made on the rebuild, and we saw that we could actually accommodate, provide for future expansion or for future equipment, future things that we could not originally provide for on Vito," Awaritefe said.

Typical offshore production unit designs start off with a weight budget with large margins.

"Since we were replicating, Vito had as-built weights of different equipment and whatnot, so we could go into the design with a very tight margin on the weight and controls," Gage said.

That also allowed the finetuning of wind loads and other variables.

"What are the two things that you always want at the end of the project that it's hard to add later in brownfield? Payload and space," he said.

For minimal cost, the design gained extra space with the wing deck and 1,500 additional tons of payload onto the platform, he said.

In October 2023, Seatrium delivered the Whale production semi. The Whale host is installed, and commissioning is in progress. The export lines have been installed while the infield flowlines are under construction. The team is "working hard at" meeting the FID promise of delivering first oil this year, Johnson said.

Replication benefits

This series of replication projects isn't a first for Shell.

In the late '90s, Johnson said Shell "did somewhat of a replication" with the Mars, Ram Powell and Brutus tension leg platform (TLP) deepwater production units.

Having served as an operations manager at the Ram Powell field, he understood the value of look-alike facilities.

"Being able to get on the deck of Ram Powell, having to work on the deck of Mars as an engineer and knowing where everything is the second you land on the facility. And so, the value of replication really resonated with me," he said. "I've been all in ever since."

He said replications allow for standardization throughout the full life cycle of the asset.

"The more you push that standardization and replication, I think the more flawless our execution becomes."

ORO AWARITEFE, Whale project manager, Shell

"We look towards the operations phase of the project, being able to take a mechanic or an operator or an electrician off of Vito and send them to Whale, and it's just almost like a plug and play. When some of our other assets that aren't replicants, it's much, much harder to do that," Johnson said.

Vito's cycle time from discovery to first oil was 13 years; the production semi required 13 million manhours to construct. Whale's cycle time is 7 years, and the production facility required 11 million manhours to construct.

William Gu, executive vice president and head of oil and gas international at Seatrium, said replication doesn't mean a facility is identical.

It is possible during the various manufacturing processes to identify places where performance can improve, he said.

As replications, Whale and Sparta realized benefits including a better-defined front end, less effort in executing contracts, reduced uncertainty, baselines for benchmarking, focused risk management for known "hot spots," elimination of learning curves and the opportunity to use improved methods, Awaritefe said. Hull engineering was reduced by 15 months and the topsides engineering time was cut by 20% for Whale.

Shaving 2 million manhours off of Whale's fabrication was "huge," he said, and overall, there was a decrease in weld rejection rates.

Seatrium, which is fabricating and integrating the trio of host facilities, in April signed a memorandum of understanding with Shell focused on driving project standardization and replication, and seeking to promote best practices in designing and constructing floating production systems.

And while there are a lot of benefits to replication, Awaritefe said, it's not without its challenges. Sometimes it is easier said than done, he said.

For example, replication is a learned skill that requires resisting the impulse to change designs, he said.

Other potential pitfalls include the possibility of adopting errors from the previous design, execution complacency and staff stagnation, he said.

Future replicant potential?

Awaritefe said he expects Shell will look at every greenfield in the GoM with a brownfield lens. However, Johnson noted, a lot of factors play into the suitability of a specific production facility in any location, such as metocean, weather conditions and access to a means of export.

"Sometimes replication won't work. You've got to understand that going in.… If you try to force it, it's not going to end well, generally," Gage said. OGI

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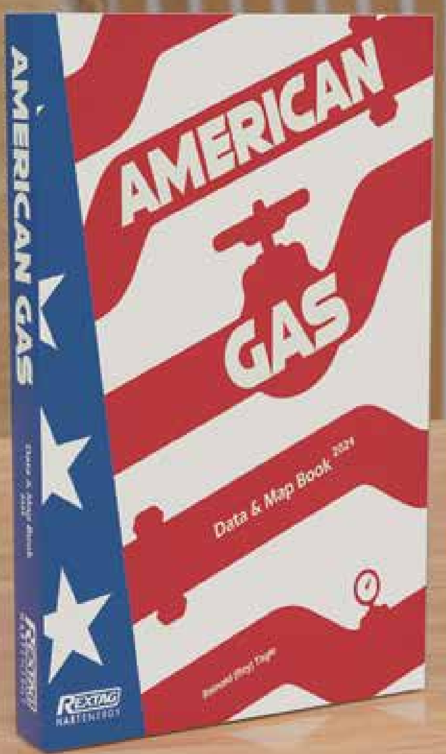

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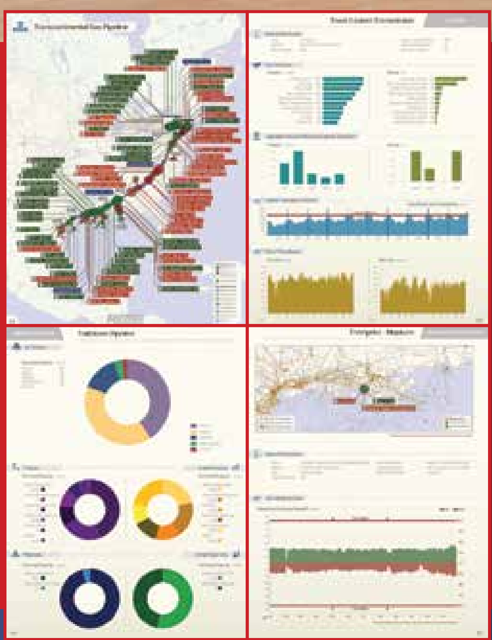

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Petrobras' Field of Tech Dreams

From discovery to revitalization, the deepwater Marlim Field offshore Brazil has driven development of technology while delivering more than 2.9 Bboe.

JENNIFER PALLANICH
CONTRIBUTING EDITOR

Petrobras' deepwater Marlim Field has long been a home to technology development—first from its 1985 discovery and again with its recent revitalization project.

"In '85, when the Marlim Field was discovered, there were no commercial solutions for producing oil in the deepwaters. Petrobras had to lead the development of much of the deepwater technologies that now we take for granted," said Paulo Marinho de Paiva Neto, deepwater executive manager at Petrobras, during the Offshore Technology Conference (OTC) in Houston.

Those technologies included subsea trees, FPSOs, polyester mooring, deepwater flow assurance and well control procedures, subsea separation systems and more.

In 1991, Petrobras started production from the Marlim Field, which is in water depths of around 2,100 ft to 3,400 ft in the Campos Basin offshore Brazil, and about 15 years later started doing infill drilling. Over the years, nine production units were added to the giant field, where 326 wells were constructed.

The field has produced more than 2.9 Bboe. It also was a "huge water producer," Mariana Cavassin, executive manager at Petrobras, said.

In recent years, Petrobras determined Marlim still had a lot of production potential but would need to revamp the whole production strategy to cope with the high water production and H_2S content. In 2019, Petrobras sanctioned the Marlim revitalization project, extending the concession through 2048, decommissioning the nine existing production facilities and installing two new FPSOs.

There were revitalization naysayers at the time, she said, but it was the company's mission to extract the remaining oil in the field.

The objective of the revitalization project, Cavassin said, was to extend the field's productive life through 2048 and produce 860 MMboe while reducing operational costs and CO_2 emissions. The approach called for decommissioning five FPSOs and four

OTC

PETROBRAS

The Anna Nery *FPSO started production last May as part of Petrobras' Marlim and Voador Fields revitalization project.*

production semisubmersibles and replacing them with two FPSOs. Additionally, eight large subsea installations were decommissioned and replaced with 15 production and injection manifolds. About 1,200 km of flexible pipes and umbilicals were decommissioned and replaced with 700 km. Ninety wells were plugged and abandoned, leaving a total of 708 new and relocated wells.

The effort also reduced CO_2 emissions from 1,520 kiltons/year to 700 kilotons/year—a 55% reduction in greenhouse gas emissions from platforms.

Cavassin said production in the mature basin means "constantly facing new challenges to increase recovery" that require innovative and breakthrough technologies.

Neto said the Campos Basin in general and the Marlim Field in particular pose challenges.

"This requires special treatment, it needs to be managed differently than newer fields. In conclusion, it needs a specific business model for brown fields," he said.

The Campos Basin has both turbidites and carbonates. The fluid averages 17 API and viscosity of 30, while the rock averages 19% porosity with an average permeability of 1,176 millidarcy.

Increasing the lifetime of field equipment is one strategy for improving oil recovery.

"This is always the first option," he said.

Petrobras was able to extend the life of six production units by about 14 years per facility to add 500 MMboe of production.

It also extended the life of subsea equipment by reusing items where possible, such as flexible pipes and 70% of the subsea trees.

"It's been used as a way to generate flexibility," Neto said.

But new technology was needed to help make the revitalization project cost-efficient.

One such enabler is the True-One-Trip 3 Phases (TOT-3P) technology that reduced average well construction time from 101 days to 58 days, resulting in a 53% reduction in well costs, Cavassin said.

Petrobras also optimized well configuration for post-salt formations such that six of Petrobras' fastest 10-well construction times are in the Marlim Field, and the other four are also in the Campos Basin. Those wells took 35-46 days, she said.

In 2023, the *Anna Nery* FPSO and the *Anita Garibaldi* FPSO both entered production in the Marlim Field. This year, Petrobras received OTC's Distinguished Achievement Award 2024 for its contribution to the Campos Basin renewal program, which represents the largest recovery project for mature deepwater assets in the world.

Thinking about the future of the Campos Basin, Cavassin sees "so many projects to do."

Petrobras expects to bring three operated units and one non-operated unit online from 2025 through 2028. The company plans to invest $22 billion into the basin between 2024 and 2028, she said. OGI

TECHNOLOGY

High Pressure, Temps, No Problem: BP Dives Deeper in Gulf of Mexico

BP prepares for 2024 FID on Kaskida and 2025 FID on Tiber projects in the Gulf of Mexico, an executive said during OTC keynote.

JENNIFER PALLANICH
CONTRIBUTING EDITOR

Advances in 20,000 psi technology are paving the way for BP's expected production growth in the deepwater Gulf of Mexico (GoM) later this decade.

BP discovered the Kaskida reserves in 2006 but had to wait for technology capable of handling the higher pressures and higher temperatures of the reservoir to become available. Given the progress in development of 20K equipment, BP expects to reach a final investment decision (FID) on the Kaskida development later this year, Andy Krieger, BP's senior vice president for the GoM and Canada, said during the 2024 Offshore Technology Conference in Houston.

"The Paleogene will lead our growth through the end of the decade with new hub developments," he said.

In addition to Kaskida likely reaching FID this year, BP sees the possibility in 2025 to also sanction the Tiber development, he said.

BP has discovered 9 Bbbl of resource in place in the Paleogene across the Kaskida, Tiber, Gibson, Gila and Guadalupe discoveries. Together, they have the potential to deliver 150,000 bbl/d in the early part of the next decade.

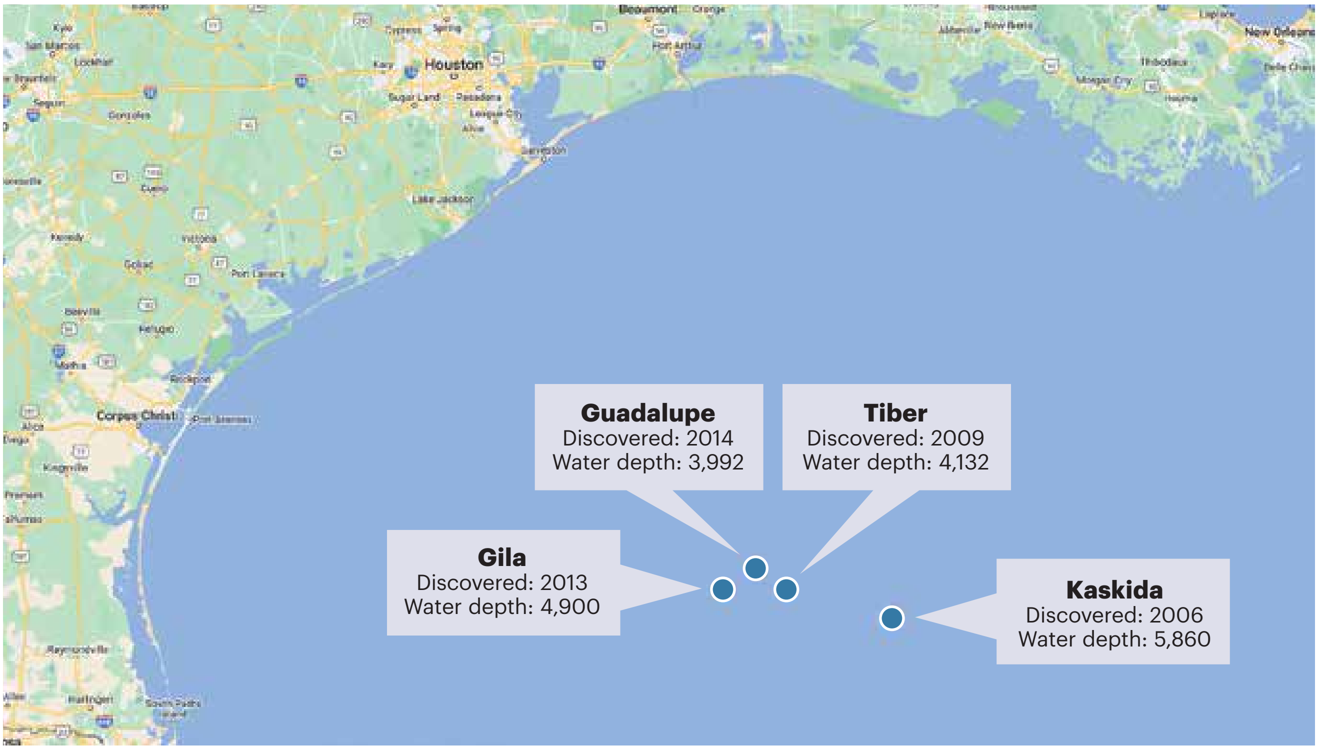
"That's 9 billion barrels of discovered resource in place that's already been penetrated that doesn't require exploration," Krieger said.

All those barrels needed tech advances.

The industry has continued to develop the technology needed to develop 20K fields that is now "commercially available, really, across the spectrum of drilling, completions and facilities and topsides," he said. "In my career, I remember at one point we were dealing with 5,000 (psi) equipment, and we made the breakthrough to 10,000 (psi) equipment, and it wasn't that long after that that 15K (psi) equipment was cutting edge as we started to begin to develop our Thunder Horse facility. And now the industry is sitting at 20K (psi)."

He said one of the things that has fundamentally transformed the Paleogene is completion technology, with the introduction

BP's Gulf of Mexico Discoveries



SOURCE: REXTAG

Between 2022 and 2025, BP plans to invest $7 billion in its Gulf of Mexico business.

BP

and extensive use of multi-stage fracking to access the reservoirs.

Kaskida has "one of the thickest gross height intervals across the Paleogene, at least what we've seen to date," Krieger said. "What that requires is use of a multi-zone fracking tool, a tool that's actually been used literally over hundreds of times within the Gulf of Mexico today."

That's proven technology, he said, while fracking individual stages in the deep water with 700,000 lb/d or more of proppant is more recent.

"It's certainly not been the completion type that has underpinned the Gulf of Mexico production for the last two to three decades. But it has been successfully deployed many, many, many times," he said.

Design one, build many

BP and others are pursuing a "design one and build many philosophy" to bring more efficiency into the historically lengthy, complex and costly construction of topsides for floating production units.

"I think … the days of the very large and bespoke production facilities of the past are probably just that," Krieger said.

From BP's perspective, the GoM will deploy smaller facilities capable of handling 80,000 bbl/d to 100,000 bbl/d.

"They're simpler facilities. They're simpler to construct. They're simpler to commission. They're simpler to operate, and they require fewer people to be offshore," he said.

When BP developed Thunder Horse as the 15K-psi operating environment was involving, they had "a lot of serial number zero-zero-ones because the equipment just didn't exist," he said. "What we've seen in this case, we've taken a somewhat more patient posture as it's related to the Paleogene. And those solutions have come through, developed by our drilling contractors, developed by our service providers and now successfully employed by other operators that have gone before us." OGI

BP's Gulf of Mexico Production and Operation Sites

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Belcher: Challenges to Funding Rapid Deployment of Energy Transition Technology

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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.

Over the last few years there has been a great deal of optimism expressed about the pace of the energy transition, about new technologies and about net-zero carbon goals. The Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA) passed Congress and were signed into law providing trillions of dollars of grants, loans and tax incentives to support investment in clean energy technologies such as electric vehicle (EV) charging stations, carbon capture and storage (CCS), hydrogen and other clean forms of energy and related infrastructure.

The additional revenue and the private sector investment in the energy transition created positive confidence about the future. It was also accompanied by regulatory actions that served as the accompanying stick to the investment carrots.

Critical to the success of the energy transition is the development and implementation of new technologies, including renewable energy sources, EVs and EV charging stations, carbon capture and storage, hydrogen, methane detection biofuels, energy storage, and advanced nuclear technology, to name a few.

Enormous progress is taking place in all of these areas, as are enormous investments from the public and private sector. At the same time, public policies in the U.S., as well as Canada, Europe and Asia, are being developed to drive transition goals through lower carbon/net zero commitments, emissions limits, trade restriction and public funding of technology.

Enormous capital investments are needed to meet these public policy and societal goals. According to the International Energy Agency (IEA), global investment in clean energy technology needs to be \$4.5 trillion by the early 2030s if the Paris Agreement's 2050 net-zero target is going to be reached.

Over the past couple of years, the U.S. has passed and enacted four landmark spending bills—the IRA, the IIJA, the American Rescue Plan and the CHIPS Act all passed Congress and were signed into law by President Joe Biden, providing \$1.6 trillion for grants, loans and tax incentives to support investment in the climate and energy transition, infrastructure and computer chips. This triggered a massive movement by the U.S. government to provide programs and processes to deliver money to companies, universities and communities that qualify for the grants, loans and tax incentives, and will have a profound impact on U.S. energy, infrastructure and manufacturing.

But shortly after their passage, reality struck about the enormous task of actually administering these programs, obtaining the personnel to manage them, developing the metrics used to determine winners, creating the mechanisms to distribute them and enacting the procedures to monitor them and ensuring that funds are being used appropriately.

Much of the \$393.7 billion in funds from the IRA that focus on energy are distributed through the Department of Energy (DOE) and its Loan Program Office (LPO). DOE never really played the role of banker before so it has had to hire personnel to manage these programs. That has been a lengthy process. It has also had to work with the U.S. Treasury to develop guidance for the issuance of these funds.

Thus far, of the aforementioned \$1.6 trillion, only \$125 billion has been spent and another \$89 billion has been announced.

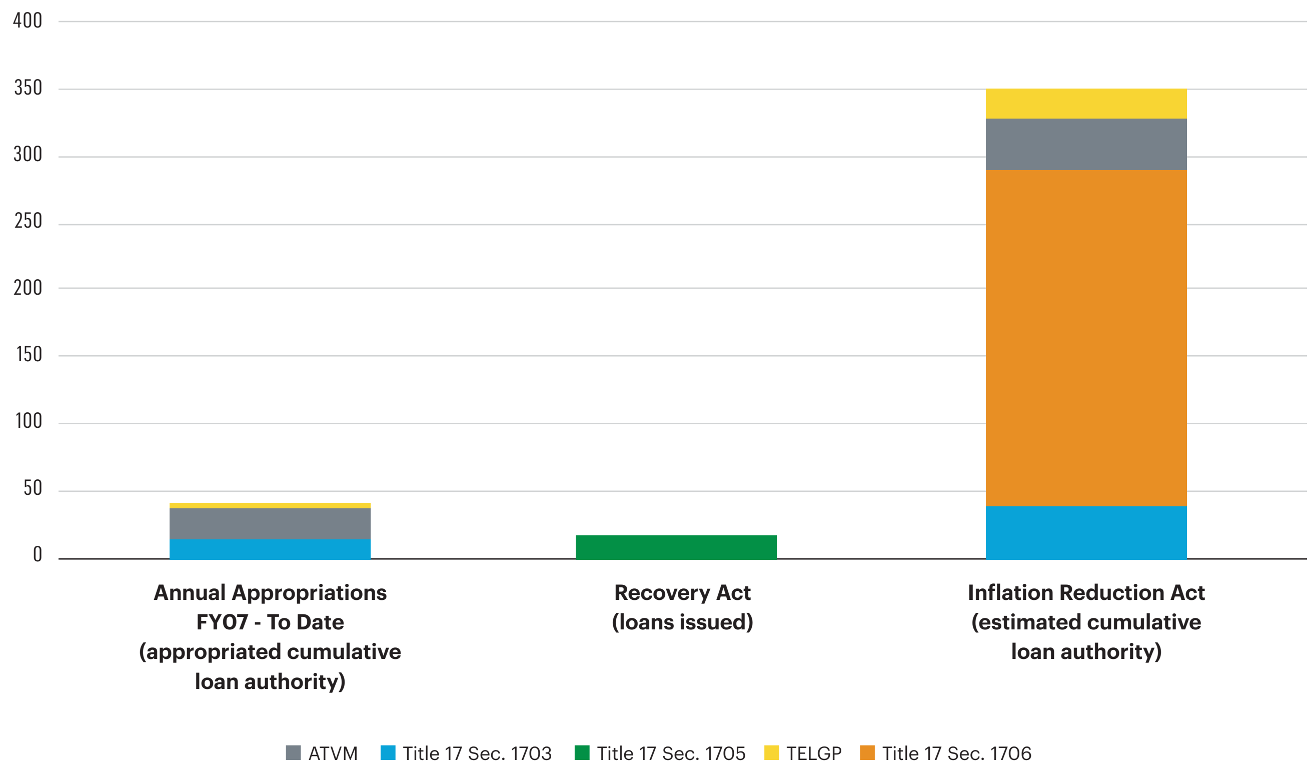
Perhaps the most important timeline for the Biden administration is Nov. 5–Election Day. Thus far, Americans are quite unaware of the programs initiated under the IRA, IIJA, CHIPS Act and American Rescue Plan. The benefits of these plans are not being recognized by voters around the country, which is frustrating for the administration.

The administration is now working overtime to get out this money to impact voters around the states and satisfy core constituencies like the environmental community. It also fears that, if Biden is not re-elected, Donald Trump, who often refers to Biden's "Green New Scam," will work administratively (or potentially with a Republican Senate) to thwart some of the energy transition-focused funding sources.

In the meantime, new technologies are being developed and introduced to address the energy transition. Some of them will receive federal funding and tax credits, while others will pursue private sector sources of finance.

Private equity deals in renewable power, for instance, reached a record high \$7.5 billion in 2023. PE money is also being applied increasingly to technologies that address things like methane emissions and detection, battery storage, distributed generation and grid resilience. OGI

LPO Loan Authority by Funding Source



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URTeC	June 17-19	Houston	George R. Brown Conv. Ctr.	urtec.org/2024
IPAA Leaders in Industry Luncheon	June 18	Houston	Petroleum Club of Houston	ipaa.org
CIPA 2024 Annual Meeting	June 20-23	San Diego	Marriott Marquis San Diego Marina	cipa.org
Carbon Management Americas Conference	June 25-27	Denver	The Ritz-Carlton	commodityinsights.spglobal.com
IAEE International Conference	June 25-28	Istanbul, Turkey	Boğaziçi Üniversitesi	iaee2024.org.tr
SGA Operations Conference 2024	July 22-24	Nashville, Tenn.	DoubleTree by Hilton Nashville Downtown	southerngas.org
SPE/IADC Asia Pacific Drilling Technology Conference and Exhibition	Aug. 7-8	Bangkok, Thailand	Bangkok Convention Center at CentralWorld	spe-events.org
SPE Energy Transition Symposium	Aug. 12-14	Houston	Hyatt Regency Baytown	spe-events.org
EnerCom Denver	Aug. 18-21	Denver	Westin Denver Downtown	enercomdenver.com
SPE Artificial Lift Conference and Exhibition	Aug. 20-22	The Woodlands, Texas	The Woodlands Waterway Marriott & Convention Center	spe-events.org
IMAGE	Aug. 25-30	Houston	George R. Brown Conv. Ctr.	aapg.org
New Energies Summit	**Aug. 27-28**	**Houston**	**Hilton Americas-Houston**	**hartenergy.com/events**
IADC Advanced Rig Technology	Aug. 27-28	Austin, Texas	Hyatt Regency Hotel	iadc.org
Forty Under 40 Awards	Sept. 6	Houston	TBD	hartenergy.com/events
Gastech Exhibition & Conference	Sept. 17-20	Houston	George R. Brown Conv. Ctr.	gastechevent.com
GPA Midstream Convention	Sept. 22-25	San Antonio, Texas	Marriott Rivercenter on the Riverwalk	gpamidstreamconvention.org
SPE/ATCE	Sept. 23-25	New Orleans	Ernest N. Morial Convention Center	atce.org
SHALE INSIGHT 2024	Sept. 24-26	Erie, Pa.	Bayfront Convention Center	shaleinsight.com
Energy Capital Conference	**Oct. 3**	**Dallas**	**Thompson Dallas**	**hartenergy.com/events**
2024 Gas Machinery Conference	Oct. 6-9	Tampa, Fla.	Tampa Convention Center	southerngas.org
SPE Asia Pacific Oil & Gas Conference and Exhibition 2024	Oct. 15-17	Perth, Australia	Crown Perth	spe-events.org
A&D Strategies and Opportunities Conference	**Oct. 23**	**Dallas**	**OMNI Hotel**	**hartenergy.com/events**
Offshore Windpower Conference & Exhibition	Oct. 28-30	Atlantic City, N.J.	Atlantic City Convention Center	cleanpower.org
SEG 4D Forum	Nov. 4-6	Galveston, Texas	Grand Galvez	seg.org
ADIPEC 2024	Nov. 4-7	Abu Dhabi, UAE	Abu Dhabi National Exhibition Centre	adipec.com
DUG Appalachia	**Nov. 6-7**	**Pittsburgh**	**David L. Lawrence Convention Center**	**hartenergy.com/events**
International Geomechanics Conference	Nov. 18-21	Kuala Lumpur, Malaysia	TBD	igsevent.org
DUG Executive Oil	**Nov. 20-21**	**Midland, Texas**	**Midland County Horseshoe Arena**	**hartenergy.com/events**
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
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Oil and Gas Investor

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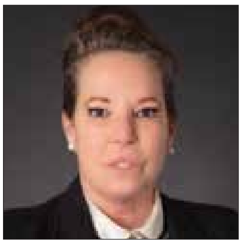
AT CLOSING

Coterra Energy's 54-Well Wolfcamp-Harkey Test

The operator plans to experiment where it has Harkey Mills sandstone in the Delaware Basin by landing three wells in it while making 51 Wolfcamp wells.



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Coterra Energy is now experimenting with when to land wells in the Harkey Mills sandstone where it has the extra formation in the Delaware Basin.

The experiment will be part of a 54-well, 12-section drilling spacing unit (DSU).

The Harkey sits between the second and third Bone Spring benches, which are above the Wolfcamp.

The project, which Coterra calls Windham Row, will consist of 51 wells landed in Upper Wolfcamp and three in Harkey. In the area, the Wolfcamp is at some 9,000 feet.

Tom Jorden, Coterra chairman, president and CEO, told investors in May that his and the team's observation in the Delaware is generally that there isn't an EUR boost from a DSU "whether we exploit these reservoirs one layer at a time or not."

But it might help pare the cost of infrastructure if the company is able to add wells over time. "Doing them in stages allows us to … not have to build facilities for absolute peak production—because these wells do decline," he said.

With tank batteries built for peak production, for example, "you find that very early in their life they're underutilized."

Yet, Coterra saw in the past couple of years in an experiment with "co-developing the Harkey and the Wolfcamp at the same time—versus waiting 12 to 24 months and coming back with the Harkey—we did see what we think is an incremental boost in recovery.

"We're not concluding that, but we prudently added in the [Windham] Row a few Harkey wells."

Blake Sirgo, Coterra senior vice president of operations, said 34 of the Windham Row wells are drilled already and were being completed in early May. Some of the wells will begin to go into production this month.

"We've just seen some results lately that say the performance of the Harkey is better when we co-develop [it] with the Upper Wolfcamp versus overfill [it later] and we're interested in learning more about that," he told investors.

Coterra reported on the Harkey in the spring of 2023. "We love the Harkey," Jorden told investors at the time. "In a lot of our position, it competes very nicely with Wolfcamp."

A Coterra test in 2023 consisted of a co-development of nine Wolfcamp and four Harkey wells. Coterra reported in May that the DSU was "performing in line with expectations."

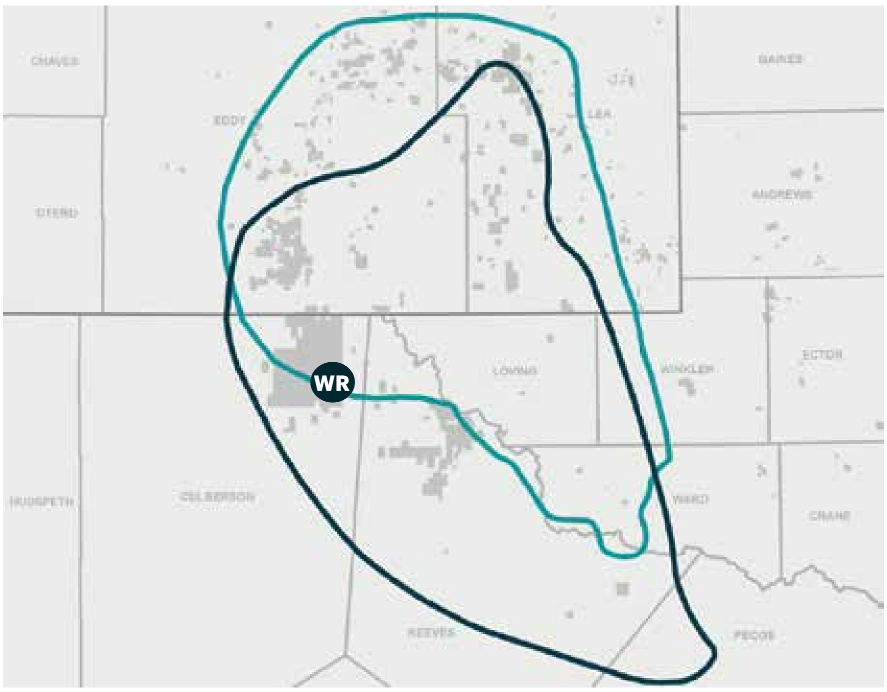
Randy Nickerson, Caza Petroleum's COO, told Hart Energy in 2019 that the Harkey in the northern Delaware Basin, such as in Eddy County, N.M., "is a little more highly oil saturated than the other [zones]. I think you're going to see that's going to be a new bench out there."

The 51 Wolfcamp wells and three Harkey wells will be made first. Coterra plans to return to the project with one more Harkey well some 12 months after the 54-well project is online.

The project is Coterra's largest to date. OGI

Targeting Prolific Wolfcamp & Harkey

Coterra Energy's Windham Row project is in northeastern Culberson County.



Coterra Acreage Wolfcamp Bone Spring

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