Oil and Gas Investor

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MIDCON MOMENTUM

Getting the SCOOP on Oklahoma's STACK

BACK ON THE BLOCK

Private E&Ps Need Dry Powder to Reload

OVERWHELMING EXPECTATIONS

AI Boosts Gas Demand and Power Struggles

INTO THE WOODS

Woodside's Driftwood Buy Shores Up LNG Prospects

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SEPTEMBER 2024

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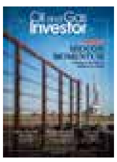

ABOUT THE COVER:
Oklahoma City photographer Marshall Hawkins captured an image of work in the SCOOP/STACK in early 2023.


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The Upstream is Consolidated—Now What?

The cyclical oil and gas industry rolls on as private sector producers refuel.

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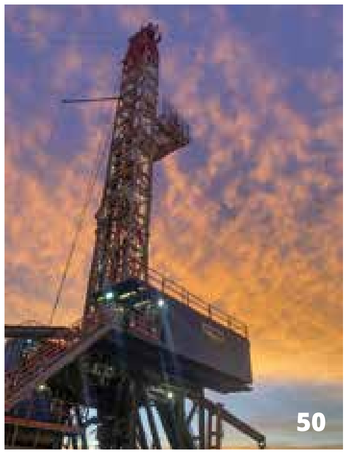


It seems the frenzy of upstream consolidation that dictated much of the industry's news in the last 18 months is settling down. And like everyone obsessed with the oil and gas industry, the team in our newsroom is contemplating what's next.

Much of the oil and gas groundwork happens at the small, private corporate level. That's where management has fewer folks to answer to and generally more ability to be nimble, innovative and risk-taking. A lot of those companies–from legacy family firms like Endeavor Energy to private equity-backed Rockcliff–have been consolidated.

In this edition of *Oil and Gas Investor (OGI)*, we've talked with commercial bankers, private equity lenders and former management, and learned that the space is already beginning to refill. The next set of private producers may access capital in different ways and pursue different assets, but the cycle will continue.

Our feature on the SCOOP/STACK examines one of the key changes that consolidation has pushed: producers are indeed looking beyond the Permian Basin. Private companies like Mach Resources and Camino Natural Resources are targeting the Midcontinent for its economics; large public producers including Marathon Oil, Coterra and Ovintiv remain active there, too.

The logic is multifaceted. It's cheaper to drill in the area, companies are increasingly looking to diversify their portfolios and, until A&D transactions fall out of the massive M&A trend, core Permian assets are hard to come by.

But as we look toward the remainder of 2024, there is more to follow than corporate machinations.

The power demands of AI are increasingly driving much of the domestic energy conversation. While AI presents an enormous opportunity for natural gas, the phenomenon remains rife with challenges. Producers, technology companies and midstream players must work in concert to make the connections needed to get supply where it's needed to meet the expected demand, which many describe as "overwhelming" given current constraints.

This, and other key midstream concerns, will be explored in depth in our upcoming relaunch of *Midstream Business*. The publication will supplement *OGI* twice a year, complementing our regular midstream coverage in the monthly flagship magazine.

And this fall, keep an eye out for our A&D Directory, which features a "who's who" of sources for the next round of dealmaking. This annual publication features in-depth reporting on capital formation issues and what to watch for in capital access.

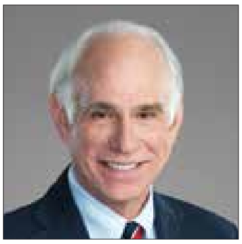
The A&D edition publishes alongside *OGI* just in time for two of our premier annual events that showcase these topics: Energy Capital Conference and A&D Strategies & Opportunities Conference, both in Dallas in October. We hope to see you there. OGI

DEON DAUGHERTY
EDITOR-IN-CHIEF

POLICY & REGULATIONS

Hirs: The State of Texas vs. Texans—A Matter of Life, Death and Money

Texas is a case study on the dangers of weak regulation.



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Texas' state-managed electricity grid is failing at every step of the electricity supply chain—the freeze of 2021 and the collapse in Houston following Hurricane Beryl are the recent examples.

There is no incentive to invest. There is incentive to not invest. Companies all along the supply chain—including renewable energy providers—profit from gaming the system at the expense of hundreds of lives and billions of dollars.

Every branch of Texas state government ratifies the thievery and shrugs off the lives lost during the state's ever more frequent and extended power outages. It is not Republican versus Democrat. It is the state government vs. its own population. It endangers national security because any power failure in the oil and gas capital of the country will cut supplies of oil, gasoline, diesel and natural gas to much of the nation. Everyone in the U.S. needs to pay attention to Texas.

It is not a market failure. The market works within the boundaries and regulations set by the state and local governments. It is a failure of state government.

The February 2021 winter storm broke the Texas grid managed by the Electric Reliability Council of Texas, better known as ERCOT. It should never have happened. Following a 2011 winter storm and grid failure, the North American Electric Reliability Corporation, noting that "…shedding load in the winter places lives and property at risk," issued a list of recommendations aimed at ensuring the power system across the Southwestern United States take preparation for winter as seriously as it does for the summer peak season.

SHUTTERSTOCK

Downed power lines near Houston following a storm in May which shut the city's grid down for days. The electric grid in Houston suffered yet another round of catastrophic damage during Hurricane Beryl just two months later, cutting power to hundreds of thousands for weeks during some of the hottest days of the year.

The Texas government did nothing. It was not until August 2021, after deadly winter storm Uri, that the Public Utility Commission of Texas adopted some of the 2011 recommendations.

The results of the freeze and blackouts are well known. Both the electricity grid and the Texas natural gas supply grid failed. More than 240 Texans died. Tens of billions of dollars in real damages and economic losses were tallied. The legal fallout continues.

Testimony taken under oath at the legislature and in the Brazos Electric Power Cooperative bankruptcy case indicates the governor ordered the state's Public Utility Commission (PUC) to set the electricity price at $9,000 per megawatt-hour (MWh).

ERCOT's independent market monitor objected and called for the refund of billions of dollars in overcharges. ERCOT refused. As a result, Luminant filed suit seeking a refund. The Texas Court of Appeals for the Third District ruled in favor of the refund for Texas consumers, finding that the $9,000/MWh price was not the result of a competitive market process as required by law.

Here's where it gets weird. The PUC appealed to the Texas State Supreme Court to overturn the Court of Appeals ruling. Never in the U.S. has a regulatory authority gone to court against the interests of its own consumers and voters. Never. And certainly not in seeking the right to overcharge consumers by billions of dollars.

The elected justices could have chosen not to hear the appeal and become heroes to Texans, but instead the Texas Supreme Court obediently overturned the Third Court of Appeals.

Why did they rule against consumers? Was it because the ensuing bankruptcies would have dragged natural gas providers into federal courts where their egregious price gouging could be unwound along with the electricity overcharges?

Natural gas prices across Texas during the freeze jumped from less than $4/MMcf to as much as $1,200/MMcf. Industry proponents declared that it was the "free market at work." But if Buc-ee's had raised the price of gasoline from $3.50/gal to $1,200/gal, it is doubtful that any Buc-ee's locations would be left standing.

Indeed, Texas Attorney General Ken Paxton, the only one empowered to sue for price gouging under the state's Deceptive Trade Practices Act, attacked La Quinta Inns because a manager had raised the price of a hotel room from $100 per night to $300 per night! La Quinta settled for $18,000. But the attorney general has been silent on the natural gas price jump, even as his counterparts in Kansas and Oklahoma have sued natural gas suppliers because the Uri price gouging extended to their states.

Natural gas suppliers shoveled campaign contributions to Texas' elected leaders even before the state had begun to thaw, and the cozy relationships continued. The Railroad Commission of Texas took less than 90 seconds to approve billions of dollars of natural gas overcharges to consumers.

If legendary Texas journalist Molly Ivins did not say it, she should have: there are no conflicts of interest in Texas politics. That is to say, there are no conflicts between regulator and the regulated, to the detriment of the 30 million Texans affected by their decisions. The State of Texas is a serial killer, for profit.

Midcon Momentum: SCOOP/STACK Plays, New Zones Draw Interest

The past decade has been difficult for the Midcontinent, where E&Ps went bankrupt and pulled back drilling activity. But bountiful oil, gas and NGL resource remain untapped across the Anadarko, the SCOOP/STACK plays and emerging zones around the region.

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When Midcontinent-heavy E&Ps were filing for bankruptcy and leaving for other plays, Tom Ward and Mach Natural Resources dug in.

Ward is someone who knows well Oklahoma and the Midcontinent plays: He previously co-founded Chesapeake Energy with Aubrey McClendon and served as its president and COO.

He later formed and led SandRidge Energy and Tapstone Energy, both of which developed deep Midcontinent positions.

Those roles gave him a front-row seat to the intense horizontal development–overdevelopment, he argues–of the Midcontinent over the past decade.

Wells were drilled too closely together, causing interference issues. Massive swathes of land traded hands for huge premiums. Costs soared, as did debt.

"The amount of drilling going on in the Midcon was just excessive," Ward told *Oil and Gas Investor (OGI)*, "and prices were excessive."

Ward saw turmoil brewing on the horizon, and that turmoil eventually arrived.

Several notable E&Ps with major stakes in Oklahoma sought protection through the Chapter 11 bankruptcy process in the ensuing years, including Linn Energy, Alta Mesa Resources, Chapparal Energy and Gulfport Energy.

Even the companies Ward founded, Chesapeake and SandRidge, weren't spared. (Of course, both companies are still around today; Chesapeake is bigger, and arguably better, than ever).

Midcontinent shale drillers that avoided bankruptcy themselves massively pulled back investment in the region. Other players, like Harold Hamm's Oklahoma mainstay Continental Resources, never stopped drilling the Anadarko.

Around 32% of Continental's total production came from the Anadarko Basin during the second quarter, the company told investors in August.

But Oklahoma, by and large, has left a sour taste in the mouths of operators since the

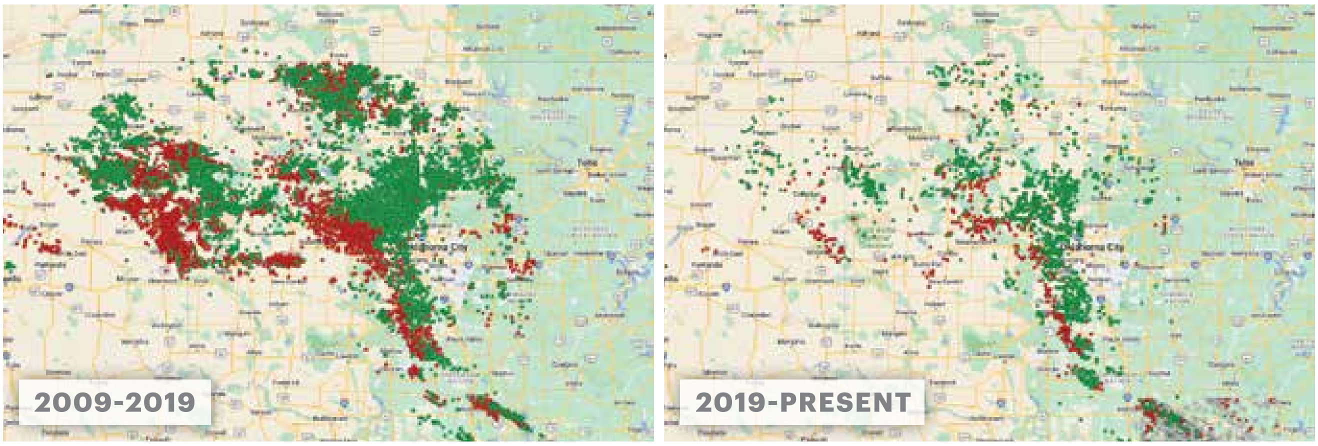
"Our focus was always on the Midcon because it was the cheapest molecule in the U.S., and that might be moving away from us."

TOM WARD, CEO and director, Mach Natural Resources

Rigs drill simultaneously for Ovintiv in a cube development in the core of the STACK play in Oklahoma. Ovintiv's Anadarko position has the lowest base decline rate across the company's entire portfolio and continues to generate significant free cash flow.

OVINTIV

Oklahoma Slowdown



SCOURCE: REXTAG

Industry veteran Tom Ward says drilling in the Midcontinent was "excessive" before a wave of E&P bankruptcies, restructurings and asset sales. Analysts say drilling over the past five years has focused on the core of the SCOOP/STACK plays. (Pictured: Anadarko Basin horizontal wells with first production from 2009-2019, vs. Anadarko horizontals with first production from 2019-present).

"[Rig activity] really fell off a cliff in early 2023 when the gas prices really fell. Definitely, it's a basin that will be a lot more associated with that commodity price."

RYAN HILL, principal analyst, Enverus Intelligence Research

middle of last decade, said Ryan Hill, principal analyst at Enverus Intelligence Research.

"One of the biggest fundamental reasons why a lot of those bankruptcies happened, in our view, was focusing on some of the lower-quality intervals, like the stuff north of the SCOOP/STACK toward that Kansas area," Hill said. "The stuff on the shelf is a lot more challenged on economics."

Since the bankruptcy bout, Midcontinent drillers have adjusted their strategies. Most of the new drilling since the COVID-19 pandemic has focused on the core of the SCOOP/STACK and less on the northern fringes of the play.

Operators have also pivoted to wider well spacing and bigger fracs as they've learned more about the subsurface characteristics of the Woodford and Meramec intervals.

And as dealmaking and prices heat up in other parts of the Lower 48—namely the Permian Basin—operators are taking a hard look at what's still left to drill in the Midcontinent.

"From an economic standpoint, the SCOOP/STACK holds the vast majority of the unconventional resource in the Midcontinent," Hill said.

Mach is certainly seeing competition and prices for Midcontinent assets creeping up, Ward said.

"Our focus was always on the Midcon because it was the cheapest molecule in the U.S.," Ward said, "and that might be moving away from us."

Cash Cow

The multitude of bankruptcies across the Midcontinent last decade left traumatized memories for many operators, but some never left Oklahoma.

Continental Resources and Devon Energy, both headquartered in Oklahoma City, remained active through the lows of the pandemic.

Other large publics, including Marathon Oil, Coterra and Ovintiv, have also kept up drilling programs on their Oklahoma acreage. Gulfport, while much more active in Appalachia today, still retains a footprint in the Midcontinent.

A handful of private operators also drill in the Anadarko, including private equity-backed E&Ps Citizen Energy III and Camino Natural Resources. Family-owned private E&P Mewbourne Oil has a large footprint in the western Anadarko and the Texas Panhandle.

The public E&Ps left in the basin are pumping less capital into the Anadarko than they are into other parts of their portfolio, like the Permian Basin.

But operators have their reasons for staying in Oklahoma. Ovintiv's Anadarko position has the lowest base decline rate across the company's entire portfolio and continues to generate significant free cash flow, which supports its goal of paying out larger dividends to shareholders each quarter.

"We are targeting the oiliest parts of our acreage to leverage the strong oil performance we saw in 2023, where the wells displayed first-year oil cuts of more than 55%, with about 85% of first year revenue coming from oil," Ovintiv COO Greg Givens said during the company's second-quarter earnings call.

"For Ovintiv, it's a big part of their cash flow," said Enverus' Hill. "Obviously, they've pulled a lot of the activity away and, from our perspective, it seems like they view the basin as non-core or secondary—but like I said, it is pretty strong on cash flow."

Coterra is running a single rig in the Anadarko and completed the bulk of its 2024 frac activity during the second quarter.

It's a basin that's shown resiliency in 2024 despite headwinds to the natural gas market, said Blake Sirgo, senior

In response to bankruptcies in the past decade, Midcontinent drillers have adjusted strategies. Most are focusing on the core of the SCOOP/STACK, rather than the northern fringes of the play.

MARSHALL HAWKINS

MARSHALL HAWKINS

The Midcontinent still has a significant and relatively untapped resource of dry gas.

“Our Anadarko assets’ proximity to Henry Hub provides us some of the strongest gas realizations in our portfolio. Those realizations, combined with significant liquid contributions from NGLs and condensate, buoy our economics, making the Anadarko an attractive place to invest capital.”

BLAKE SIRGO, senior vice president of operations, Coterra

vice president of operations for Coterra.

“Our Anadarko assets’ proximity to Henry Hub provides us some of the strongest gas realizations in our portfolio,” Sirgo said during Coterra’s second-quarter earnings call. “Those realizations, combined with significant liquid contributions from NGLs and condensate, buoy our economics, making the Anadarko an attractive place to invest capital.”

Devon Energy’s bread and butter today is the Delaware Basin, where the company is sending most of its capital spending. But Devon is still active in the Anadarko Basin under a joint venture (JV) with chemical giant Dow to jointly develop Devon’s STACK acreage.

In the second quarter, around 21% of Devon’s companywide gas volumes and 16% of companywide NGL volumes came from its Anadarko acreage.

Devon COO Clay Gaspar said the partnership with Dow helps promote returns to continue competing for development capital.

“In the Anadarko, our capital program driven by our joint venture with Dow delivered both solid returns and double-digit production growth in the quarter,” Gaspar said during Devon’s second-quarter earnings call.

Commodity Confluence

Part of the reason the Midcontinent hasn’t attracted the investment of other geographies, like the Permian, is the Midcon’s commodity mix.

The Permian Basin is an oil basin. It’s getting gassier over time as the basin gets drilled and developed, but operators buy in the Permian for crude oil exposure.

Operators consider the Midcon as an oil basin, too, Hill said. But for an oil basin, the Midcontinent is “still pretty gassy,” he said.

Compared to other basins, natural gas and NGL prices play larger roles in the economics of the Anadarko and the SCOOP/STACK plays.

The up-and-down volatility of gas prices can impact a

MARSHALL HAWKINS

Compared to other basins, natural gas and NGL prices play larger roles in the economics of the Anadarko.

producer's plans more in the Midcontinent than in the Permian Basin, where Waha gas prices frequently dip into negative territory (however, Permian E&P Diamondback Energy reported shutting in gassy Permian oil wells during the second quarter because of dismally low natural gas prices).

So, it shouldn't come as a surprise that the Midcontinent saw a healthy increase in drilling rig activity when natural gas prices skyrocketed in 2022—bolstered by Russia's invasion of Ukraine and the global economic reemergence from the COVID-19 recession.

When prices collapsed heading into 2023, so did Anadarko drilling.

"[Rig activity] really fell off a cliff in early 2023 when the gas prices really fell," Hill said. "Definitely, it's a basin that will be a lot more associated with that commodity price."

Anadarko rig activity has declined massively over the past five years. There was an average of 117 rigs across the Anadarko during January 2019, according to Enverus figures. Just a year later, there were 39 rigs drilling across the same land mass.

Rig activity in the Anadarko bottomed out at seven rigs during June and July of 2020, as the world suffered the height of the COVID-19 pandemic.

Natural gas prices are still low today, though they're moving up from record lows seen earlier this year.

Operations still active in the Anadarko have mostly shifted development toward oil- and liquids-rich sections of the SCOOP/STACK plays.

Anadarko Rig Count 2019-Present

SOURCE: ENVERUS INTELLIGENCE RESEARCH

Anadarko rig activity has declined drastically since 2019 but spiked alongside commodity prices in 2022. Experts think natural gas prices will dictate the basin's future activity.

The Midcontinent still has a significant and relatively untapped resource of dry gas, said John Frey, vice president of business development and land for FourPoint Energy.

FourPoint previously developed a footprint in the western Anadarko Basin before selling those assets to Maverick Natural Resources in late-2020. The company is active in the Permian, but FourPoint is considering new M&A opportunities in the Midcontinent today.

"If gas prices got to a certain level, there would be massive development and significant [dry gas] resource produced from the Midcon," Frey said.

Rather than the Midcontinent, experts anticipate seeing greater future LNG feed-gas volumes emerging from the Haynesville, the Eagle Ford, the Permian and Appalachia.

Hot Spots

Since the E&P bankruptcy bout and the pandemic, most Midcontinent drilling activity has centered around the core of the SCOOP/STACK plays. But certain operators see opportunity in less developed nooks and crannies hiding around the region.

Dealmaking activity is heating up in the western Anadarko Cherokee play, where private E&Ps have been delineating horizontal drilling locations.

Exxon Mobil is one of the only companies drilling in the Marietta Basin of southern Oklahoma, not far from the Texas border. North of the Marietta, development of the Ardmore Basin has been led by Continental Resources.

During the second quarter, SandRidge inked a $144 million acquisition of Cherokee assets from Upland Operating, according to regulatory filings.

The transaction includes 42 wells, four DUCs and net production of approximately 6,000 boe/d (about 40% oil) in Ellis and Roger Mills counties, Okla.

SandRidge is picking up leasehold interest in 11 drilling spacing units (DSU), adding inventory of up to 22, 2-mile lateral wells in the core of the Cherokee play.

Upland was one of the leading developers of the Cherokee play, along with family-owned Mewbourne Oil.

"[The Cherokee play] looks very interesting," Ward said. "We have close to 20,000 acres of leasehold that's held by production and we're just watching that play."

Exxon Mobil's flagship shale asset is the Permian, and its Permian footprint expanded significantly through its $60 billion acquisition of Pioneer Natural Resources. Exxon is also still active in the Bakken.

But Exxon unit XTO Energy has quietly continued drilling Woodford wells in Love County, Okla.

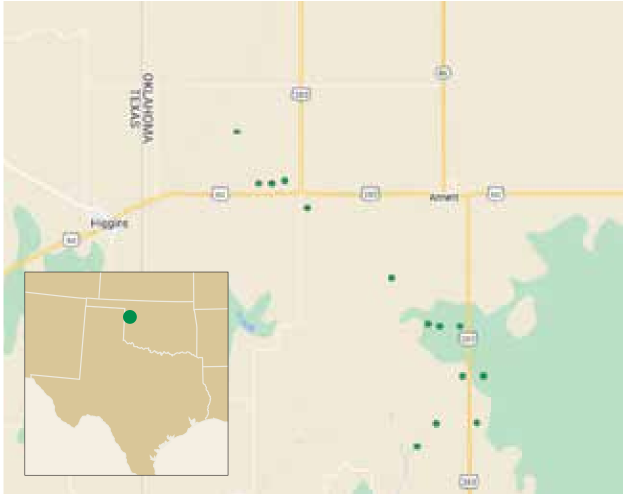
The Marietta Basin is somewhat of a geologic anomaly–one of the only places in the Lower 48 where black oil is deposited at depths between 15,000 ft and 16,500 ft, Continental Resources' Anadarko Basin Vice President Aaron Chang told *OGI*.

XTO has been wildcatting in the area for more than a decade, but it's unclear how the Woodford wells compete for capital in the company's increasingly Permian-heavy portfolio. Exxon declined to be interviewed on the Marietta Basin for this story.

The hunt for oily zones across the Midcontinent also brought operators like Continental to the South SCOOP in the Ardmore Basin.

It's been an active development area for operators like Continental and Camino, which have touted flatter declines and lower gas-oil ratios (GORs) from Ardmore wells compared to other Midcontinent plays.

Horizontal Cherokee Drilling Grows



SOURCE: REXTAG

Horizontal wells online since Jan. 1, 2020, targeting the Cherokee play, according to available Rextag data.

Mach and SandRidge have also continued drilling new wells in northern Oklahoma and across the border into southern Kansas.

Primed for Deals

It's hard to say which operators will pull away from the Midcontinent and which could dig in further through M&A.

"On the who stays and who goes–we definitely see more consolidation likely to be happening," Hill said.

Mach is hunting for deals in the Midcon, as well as in other basins. SandRidge continues to be acquisitive in the western Anadarko extensions.

Citizen Energy and Camino are at least two private E&Ps with private equity sponsors that will eventually look for a sale. Warburg Pincus is reportedly seeking a buyer for Citizen in the range of $2.5 billion.

But for larger operators, like Marathon Oil, the Midcontinent could very well be considered non-core.

During the second quarter, Marathon's Oklahoma assets produced the least total resource (42,000 boe/d) and least oil (7,000 bbl/d) across its entire portfolio. Marathon didn't turn any Oklahoma wells to sales during the quarter, either.

And as ConocoPhillips acquires Marathon in a deal valued at $22.5 billion, including debt, the pro forma company could look at non-core assets sales to pay down debt.

"Companies like Devon, Ovintiv, maybe less so Marathon now–you could see them moving out of the SCOOP/STACK," Hill said, "but you could also see them double down on the SCOOP/STACK."

Devon and Ovintiv, for their parts, appear to be focused on different basins. Devon is acquiring Bakken E&P Grayson Mill Energy for $5 billion, and Ovintiv acquired a trio of private Permian E&Ps last year for over $4.2 billion.

The key to unlocking the Midcontinent's future will likely be the movement of natural gas prices.

"It's definitely going to be an interesting year as we see what happens with gas relative to the LNG buildout," Hill said, "and then, as a result, what happens in the SCOOP/STACK." OGI

403K bbl/d

Average SCOOP/STACK oil production in 2023.

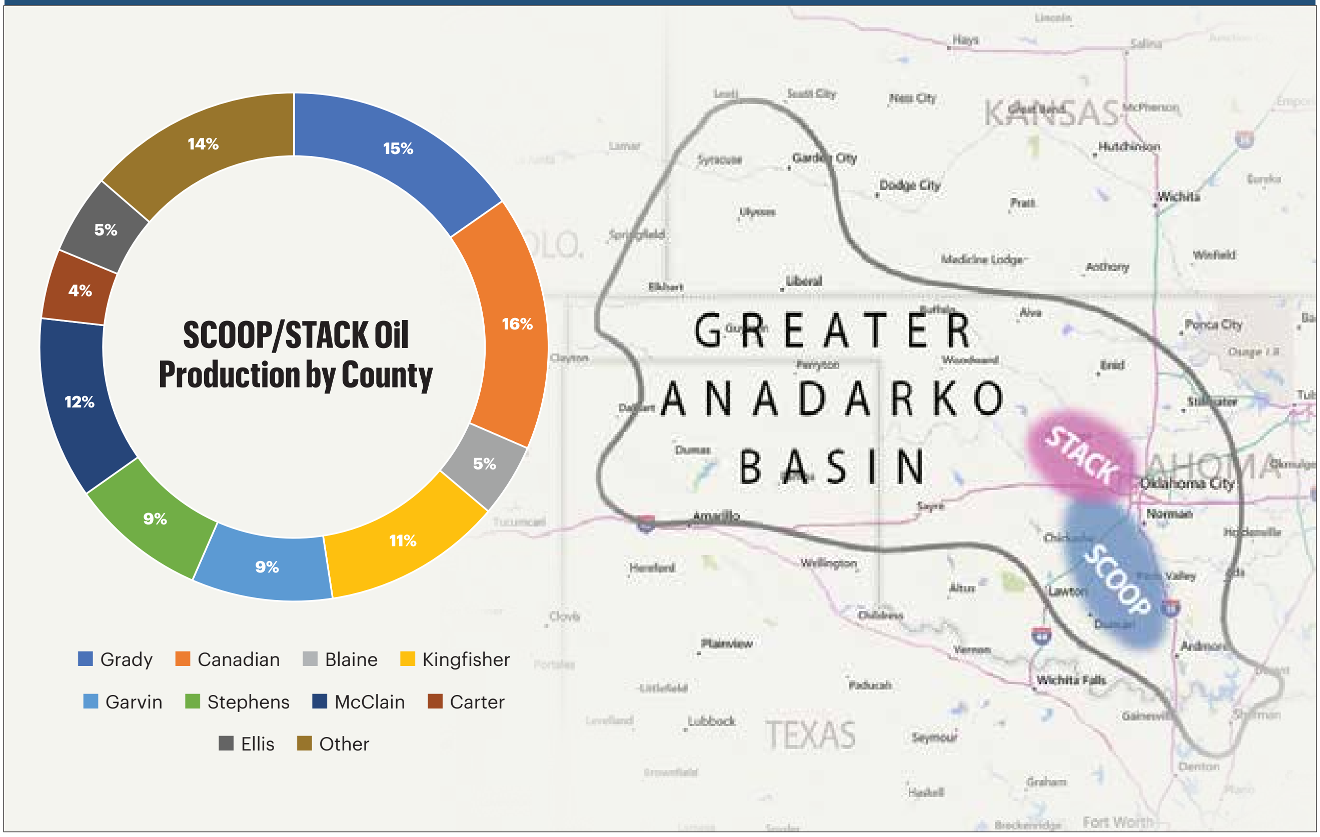
The 75-foot Golden Driller statue stands outside the Tulsa, Okla., Expo Center.

SHUTTERSTOCK

BASIN FOCUS: SCOOP/STACK

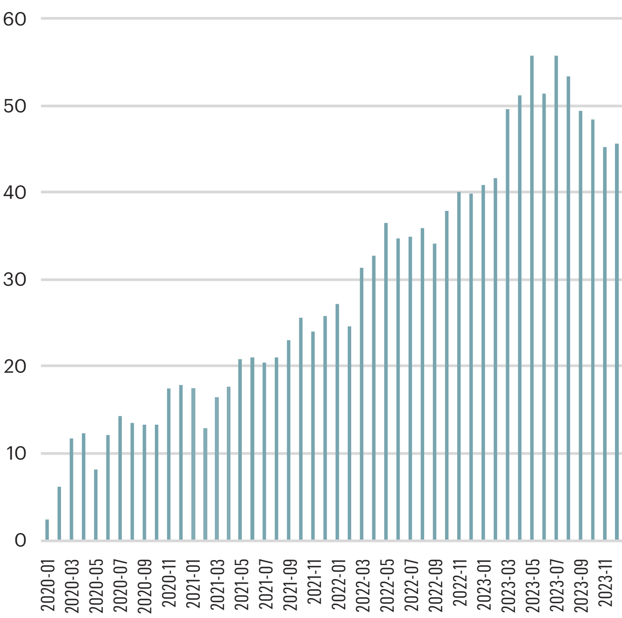
Oklahoma City-based Continental Resources leads all producers in the area.

Oklahoma Oil Provinces



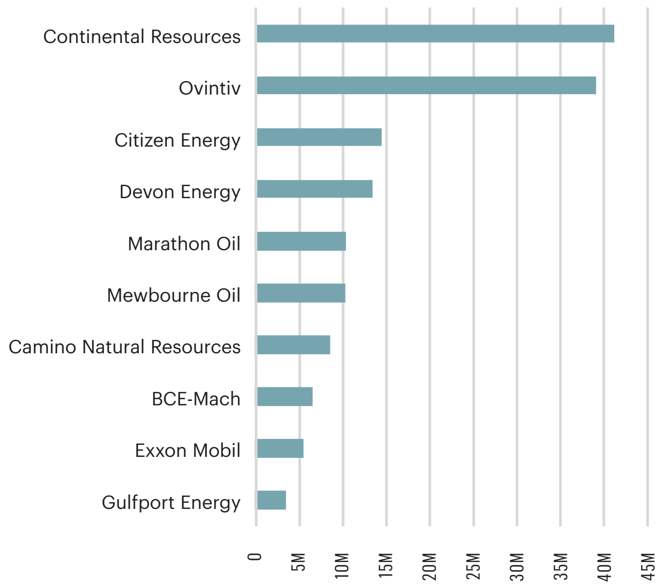
SCOOP/STACK Oil Production

bbl/month, horizontal wells drilled since 2020



Top SCOOP/STACK Operators

Oil Production, Monthly, 2020-2023



SOURCE FOR CHARTS AND MAPS: REXTAG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PERMITS

Martin and Midland counties, Texas, vied for the top of the well permit leader board in the first half of 2024.

Permitted Wells by County

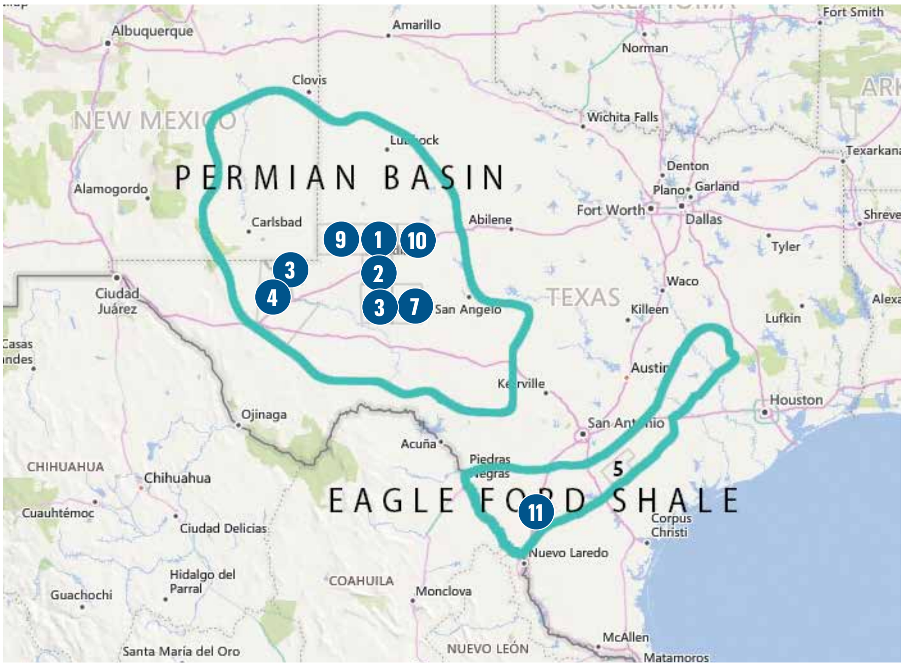
Rank	County	Well Count
1	Martin, Texas	317
2	Midland, Texas	310
3	Loving, Texas	232
4	Reeves, Texas	231
5	Karnes, Texas	163
6	Upton, Texas	144
7	Reagan, Texas	111
8	Converse, Wyo.	108
9	Andrews, Texas	103
10	Howard, Texas	102
11	La Salle, Texas	88

Permitted Wells by Operator

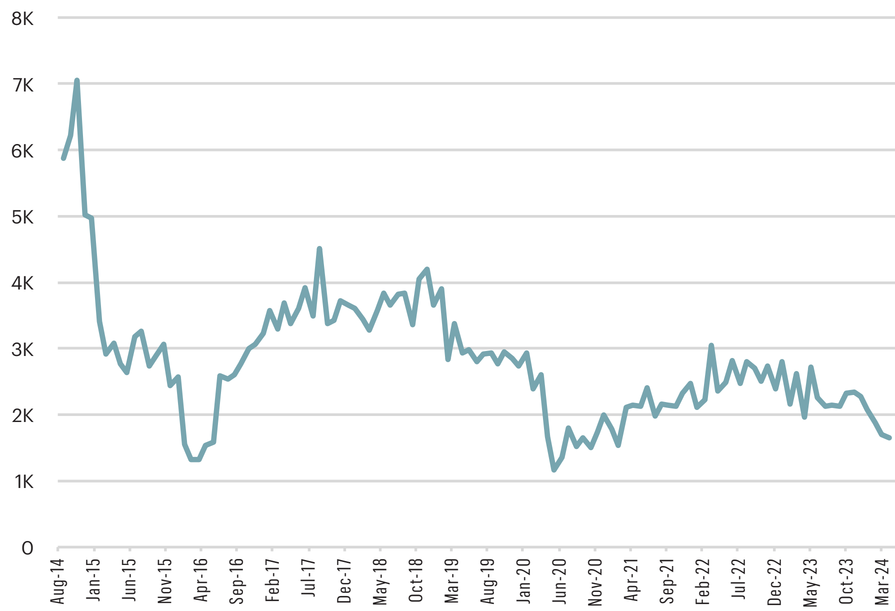
Operator	Well Count
Pioneer Natural Resources	226
Diamondback Energy	143
EOG Resources	130
Endeavor Energy	120
Marathon Oil	89
Burlington Resources	88
XTO Energy	85
BPX Operating	78
Chevron	75
CrownQuest Operating	75

Permitted Wells by State

State	Well Count
Texas	3,186
Colorado	512
Wyoming	508
North Dakota	335
Oklahoma	202
Louisiana	104



U.S. Approved Well Permits



SOURCE: RAILROAD COMMISSION OF TEXAS, WYOMING OIL AND GAS CONSERVATION COMMISSION, COLORADO ENERGY & CARBON MANAGEMENT COMMISSION, REXTAG

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IN MEMORIAM

Autry Stephens (1938-2024)

Legendary wildcatter of the Midland Basin stayed true to his 'never sell' strategy.

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It was well understood in the Midland Basin that Autry Stephens would never sell his portfolio of production and acreage that grew to 420,000 gross operated boe/d by early 2024.

It was well understood because he said so himself.

And although Stephens signed a deal in February to divest his Endeavor Energy Resources to downtown Midland neighbor and peer Diamondback Energy for $26 billion in cash and stock, he never did sell, at least not officially.

The 45-year wildcatter died Aug. 16 after a long battle with cancer at the age of 86; the deal was not yet completed and is still wrangled in the review process at the Federal Trade Commission (FTC).

His daughter, Lyndal Stephens Greth, who was Endeavor's vice chairman, assumed the post of chairman upon Stephens' death.

Greth will oversee the closing, which involves 410,000 net acres, including 339,000 in the Midland Basin, 1,380 horizontal wells, 2,250 still-active vertical wells and more than 1,100 employees.

The operator has more than 4,000 future-well locations on its property that are economic at $65/bbl WTI, according to a J.P. Morgan Securities estimate in 2023. J.P. Morgan ranked Endeavor second in inventory in the basin, trailing only Pioneer Natural Resources, another Midland Basin pure play, which was sold to Exxon Mobil earlier this year for $64.5 billion.

'Courage, Grit and Tenacity'

"Autry embodied the wildcat mentality of courage, grit and tenacity associated with the Permian Basin," Lance Robertson, Endeavor president and CEO, said in the company's announcement of Stephens' passing.

The wildcatter came up on a farm in DeLeon, Texas, "where he learned first-hand the value of hard work, growing peanuts and a variety of fruits," Endeavor reported.

Stephens told Hart Energy in an interview in 2014 that he didn't stay in the family business after high school when his father told him, "Maybe you should find something other than farming to do."

You see, he explained, "I was raised on the farm, but I wasn't a very good farmer."

He studied petroleum engineering instead, receiving master's and bachelor's degrees from the University of Texas at Austin.

"My goal at that time was to get a degree and work 30 years for a great company with a steady salary and nice retirement plan," he said.

Well, that didn't suit him, either.

After a time at Humble Oil & Refining, he packed up and moved to Midland, joining First National Bank of Midland as a reserves engineer.

That didn't suit him for long, either.

He set out on his own in 1979 with some savings and some land, drilling his first well, the McClintic B-30 #2 in Midland County, operating simply as "Autry C. Stephens" as his company's name.

In 2000, he named the portfolio he had amassed Endeavor Energy.

'Fairly Terrifying'

Setting out on his own, he told Hart Energy, "was fairly terrifying. I started out doing consulting engineering and had some consulting work lined up prior to giving up my paycheck.

"My engineering experience gave me some hope that I could sell my services and support my family, so I had a little bit of a fallback–a skill–to survive on."

He didn't have an interest in taking Endeavor public, flatly saying at the time that "my skill set does not seem well-suited for the public domain."

More specifically, he explained, a lot of the job of running a public E&P just doesn't have anything to do with what he most enjoyed: Bringing in oil wells.

"There are a lot of associated legal and accounting costs, and dealing with Wall Street takes a lot of time away from the business of producing oil," Stephens said.

Of course, he added, "I never say 'never,' but we don't have any plans for that right now."

That didn't change in the past 10 years, as Stephens continued to operate privately.

Boots on the Ground

Stephens built Endeavor the old-fashioned way: boots on the ground.

"Autry's aggregation of unloved oil wells across the Permian Basin–many acquired through live-auction processes–and his and his team's ability to improve them and extend their life set him apart," said Steve Pruett, a Midland-based oil producer and chairman of the Independent Petroleum Association of America (IPAA).

That boots-on-the-ground tack came naturally since he had

Autry Stephens visits an Endeavor Energy site in 2014. "Autry embodied the wildcat mentality of courage, grit and tenacity associated with the Permian Basin," said Endeavor President and CEO Lance Robertson.

"a love of adventure and being outdoors, which sparked an early interest in the petroleum industry," the company reported.

And there was certainly adventure: four decades of whipsaw up-and-down cycles in the oil business.

Through it all, "he created a massive Permian-focused production, acreage and infrastructure asset" that included in-house well service, drilling and completions, said Pruett, who is president and CEO of Permian-focused Elevation Resources.

When peers began rolling out horizontal, stimulated drilling and completion in the Permian—beginning first in the Midland Basin—in the early 2010s, "Endeavor was ideally positioned to capitalize on it," Pruett said.

Yet Stephens waited, watching neighbors perfect the drilling and completion recipe on these massive holes, while having leasehold already HBP and vertical wells that were cash-flowing to the company.

Going Horizontal

In 2016, though, he dove in, recruiting Robertson from his position of vice president of U.S. unconventional resources at Marathon Oil. Prior to Marathon, Robertson had been vice president of engineering and exploitation at Pioneer, which had been drilling stimulated laterals in super-tight rock for more than a decade by then.

In the 2010s, many privately held Permian E&Ps reached a point at which they had to decide whether they were going to become unconventional resource shops or retire. Many, such as the Bass family, sold.

Stephens chose not to sell; Endeavor became a tight-rock shop.

He told Hart Energy in 2014, "My experience has been that it is very difficult to predict the future in this business.

"Although some companies are very successful with a 'drill-and-flip' approach, I have observed that companies that sell properties often regret that decision when technology or commodity prices change the playing field.

"This is why I have a basic 'never sell' strategy."

Robertson told Hart Energy in 2020 that, "While we were good on the vertical side, we had to learn from our peers across the basin and through our own efforts to be effective at our horizontal development."

The leasehold was already there. "All of those assets were acquired on a low-cost basis over the years and they [were] already fully depreciated," Robertson said.

Without the pressure to HBP, Endeavor could "focus and build infrastructure in concentrated, high-quality areas."

The task at hand wasn't all over the map, "which allows our team to be more efficient."

With so many acres and so many stacked formations in the Midland Basin, Robertson expected at the time that "it's just going to take us a while to get through all of it.

"We're really blessed in a lot of ways."

A Hard 'No'

In the early days, Stephens briefly thought about operating abroad, but it wasn't suited to him, he told Hart Energy in 2014.

"I probably did have a little wanderlust in the beginning; just the names of these countries—Saudi Arabia, Venezuela, Kazakhstan, Indonesia—sounded exotic and glamorous," he said.

But they are exotic in more than just name. "The reality is that there are political risks associated with most foreign oil production and it takes a lot more time and capital to get started in the international areas."

Weighing all of this, he gave it a hard "no."

"I was content to put down roots in Midland," he said.

The most valuable property today—the Spraberry Trend area of the Midland Basin—went through a long period of being derided, he noted.

"I think a stigma has been associated with this field because of the low rate of return and long payout of drilling investment. It has been derisively referred to as the 'world's largest uneconomic oil field.'"

While that's laughable today, it was good fortune for Stephens back in the vertical day.

"For this reason, producing properties and drilling acreage were available to start-up companies such as Endeavor," he said.

'Inspired So Many'

The sale to Diamondback is expected to close by year-end after the FTC closes its review, or the time set for the FTC to respond runs out.

Robertson said in the Endeavor announcement, "Over many decades, his vision and discipline inspired so many and were the driving forces behind what makes Endeavor unique.

"He leaves a legacy that will continue to shape the future of our company, community and the oil and gas industry for years to come."

After Stephens started his career in 1962 at Humble, he left the oil company for two years to serve in the U.S. Army Corps of Engineers, where he was a lieutenant and platoon leader responsible for pipeline fuel installations in France and Germany.

Afterward, he rejoined Humble for five years and was eventually posted at Monahans, Texas, just west of Midland.

"Humble was active in drilling prolific, deep gas wells in the Delaware Basin at this time," Stephens told Hart Energy. "It was exciting to be a small part of developing such great, deep fields, such as Gomez, Coyanosa and Grey Ranch."

From there, "Autry's move to Midland would forever change the Permian Basin," Endeavor reported.

His time at the bank "informed Autry's career trajectory," beginning in 1979 when "he stepped out on his own as a sole proprietor."

One by one, he drilled vertical wells and, where he could, he also bought the mineral rights. "As others fled the market during downturns, Autry bought," Endeavor reported.

This included buying other operators as well as service companies. "This vertically integrated business model consistently provided steady access to services and exclusive pricing at lower-than-market costs for his drilling and production operations," Endeavor reported.

'He Helped Shape'

Stephens was inducted into Hart Energy's Hall of Fame in December 2023.

In 2021, he was named "Top Hand" by his peers in the Permian Basin Petroleum Association (PBPA).

Ben Shepperd, PBPA president, said in an announcement to members Aug. 16 that Stephens' "departure leaves a deep void in our hearts and in the industry he helped shape."

Stephens was "not just a pioneer of the Permian Basin but a man whose life's work touched so many. His legacy will continue to inspire and guide us."

Bryan Sheffield, founder of Permian Basin-focused Parsley Energy, which was sold to Pioneer, said at the Top

ENDEAVOR ENERGY RESOURCES

Stephens' Midland Basin portfolio produces 420,000 gross operated boe/d. "Although some companies are very successful with a 'drill and flip' approach, I have observed that companies that sell properties often regret that decision when technology or commodity prices change the playing field," he said. "This is why I have a basic 'never sell' strategy."

Hand ceremony, "What [Autry] means to the community is thousands and thousands of jobs—jobs during hard times.

"When no one was drilling, he was drilling. He found a way to drill. He found a way to acquire properties. He found a way to create jobs and keep people working," Sheffield said.

Pruett told Hart Energy upon Stephens' death, "For those who knew Autry, he enjoyed his work and his wells more than wealth or recognition."

It wasn't until his later years that he "learned to delegate tasks and most decisions to his talented management team.

"He was one of a kind that a number of oilmen, including this one, should take lessons from in building and sustaining our own oil companies."

'Be Prepared'

Stephens' advice in 2014 for industry newcomers?

"Tongue in cheek, I would quote J. Paul Getty: 'Rise early, work hard and strike oil!,'" he told Hart Energy at the time.

But "I would expand on that: Find work that you enjoy, be honest in your dealings, persevere through the ups and downs, and be prepared to grow personally and technologically throughout your career." OGI

Aethon's Driftwood Bet Pays Off

The Haynesville producer sees Woodside's acquisition of Tellurian and the Driftwood LNG project as validation of the natural gas industry's—and its own—prospects.

Private producer Aethon Energy Management owns midstream and gas processing assets across the core of the Haynesville Shale.

AETHON ENERGY

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Woodside's acquisition of Tellurian constitutes a win-win-win for the Haynesville Shale, for U.S. LNG and for Aethon Energy.

Private equity-backed E&P Aethon is one of the largest natural gas producers in the Haynesville, with a footprint stretching across northern Louisiana and East Texas.

Aethon is already a major player in the growing U.S. LNG sector; the company is the second-largest gas supplier to Cheniere Energy's liquefaction facilities on the Gulf Coast, said Gordon Huddleston, Aethon's president and partner.

The $900 million acquisition of Tellurian by Australian player Woodside Energy Group gives even more momentum to the buildout of U.S. LNG export capacity.

Tellurian's value stemmed from its fully permitted Driftwood LNG project, a pre-final investment decision (FID) project with a premier site on the Louisiana Gulf Coast.

Tellurian had faced financial uncertainty before agreeing to the sale. Tellurian's integrated upstream gas assets were tapped for liquidity and were sold to Aethon in a $260 million deal this summer.

But analysts think having Woodside behind the Driftwood LNG project could help push FID forward.

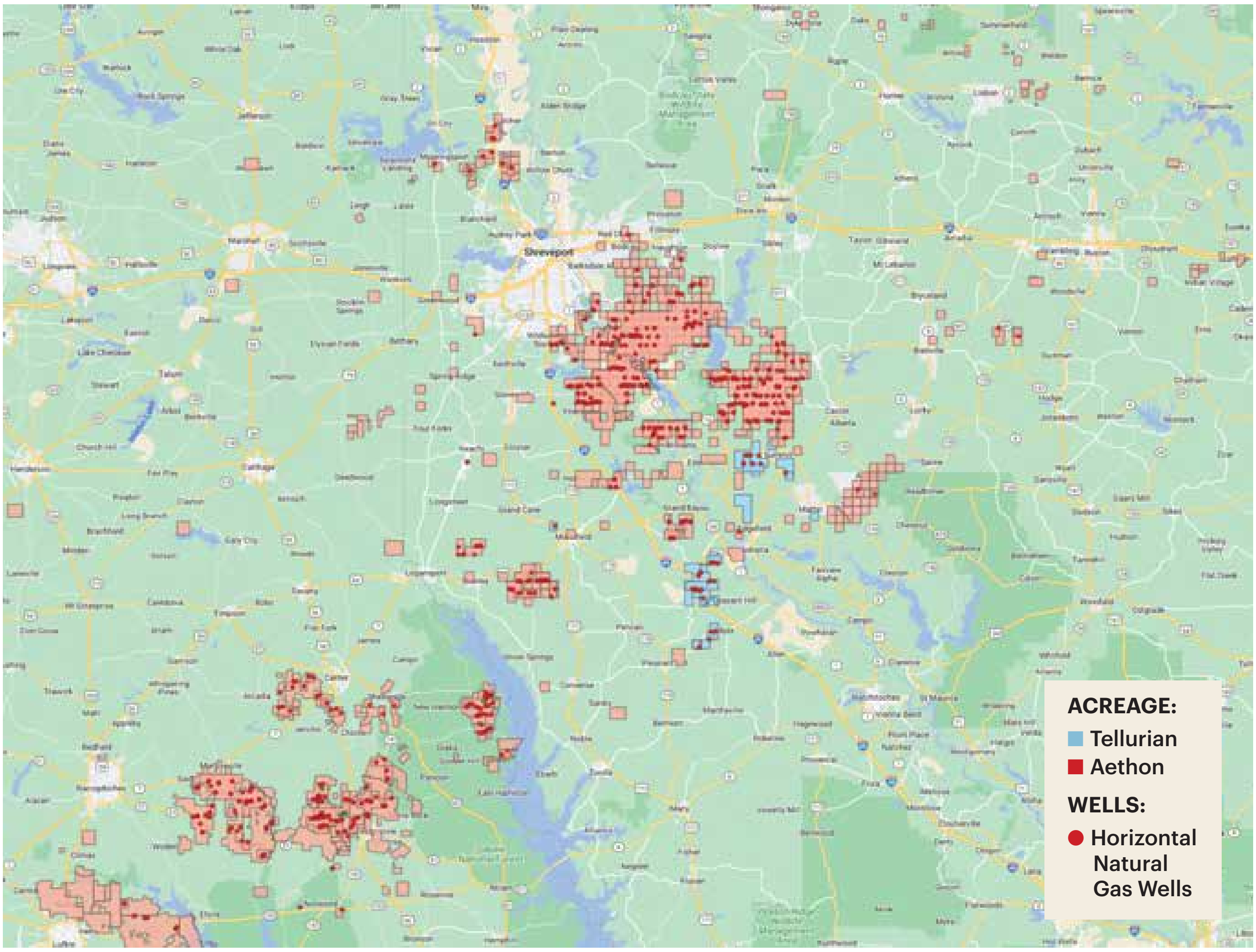
"I think [the deal] speaks volumes about the quality and importance of this resource and the long-term view that natural gas is going to make up a core part of the energy stack," Huddleston told Hart Energy in an exclusive interview.

But hurdles remain to get Driftwood LNG off the ground. Analysts at Tudor Pickering Holt & Co. currently do not even include the Driftwood project in their gas macro model.

The project will eventually need to reapply for certain certifications subject to the Biden administration's pause on LNG permits. Securing long-term offtake agreements is also a factor.

So far, Aethon itself has signed the largest offtake agreement from Driftwood LNG: The $260 million deal for Tellurian's upstream assets also included a head of agreement (HOA) for Aethon to offtake 2 million tonnes per

Aethon Consolidates Core Haynesville Acreage With Tellurian Deal



SOURCE: REXTAG

annum (mtpa) of LNG from Driftwood.

The HOA calls for a 20-year agreement, which would be indexed to Henry Hub prices plus a liquefaction fee.

The LNG offtake agreement was a key consideration for Aethon when signing the deal to acquire Tellurian's upstream gas assets, which added around 31,000 net acres in the Louisiana Haynesville and Bossier shale formations, Huddleston said.

"[Tellurian] needed to do something relatively quickly, we understood the asset and we had the ability to flow some of their gas into our own company-owned midstream system," Huddleston said.

LNG Calls, Haynesville Answers

As LNG developers look for shale plays to source feedgas, the Haynesville is pulling ahead of the rest of the pack for several reasons.

Dry gas is cheaper to produce in Appalachia's Marcellus Shale play than in the Haynesville, but much Appalachian gas is stranded in-basin due to limited pipeline transport capacity.

There's so much associated gas being produced in the Permian Basin that spot prices frequently dipped negative this spring, but the Permian, too, has limited gas pipeline capacity out of the basin. The much-anticipated Matterhorn

"I think [the deal] speaks volumes about the quality and importance of this resource and the long-term view that natural gas is going to make up a core part of the energy stack."

GORDON HUDDLESTON, president and partner, Aethon Energy

Express gas pipeline is expected to begin servicing Permian gas producers later this year, providing some pricing relief.

The Haynesville, however, has that Goldilocks "just-right" mix of nearness to liquefaction facilities, bountiful dry gas production and adequate midstream access.

Analysts anticipate significant volumes of LNG feed-gas to come out of the Haynesville. The Permian Basin and

An Aethon drillsite in the Haynesville Shale play.

AETHON ENERGY

the Eagle Ford Shale are also poised to supply significant volumes of future U.S. LNG exports.

And LNG developers need a lot of gas: Demand to fuel U.S. LNG exports is expected to grow by over 17 Bcf/d through 2030, according to East Daley Analytics.

U.S. LNG exports are expected to increase 2% to average 12.2 Bcf/d this year, according to Energy Information Administration data. In 2025, U.S. LNG exports are forecasted to grow another 18% (2.1 Bcf/d).

"You really have to change your scale and change your overall perspective about how much gas is going to be required for how long," Huddleston said, "and what the other uses are going to be throughout the country."

The amount of shale gas needed for future liquefaction and export is immense, but there are relatively few E&Ps owning the physical locations where that gas is produced.

Much of the highest-quality Haynesville drilling inventory is already owned by the likes of Aethon, Chesapeake Energy, BPX Energy, Comstock Resources and a handful of other operators.

"That means that that gas isn't necessarily going to be available unless we choose to develop it—and that's going to require the economic incentive long-term for that," Huddleston said.

International economies dependent on natural gas are also working to get ahead on owning a piece of upstream gas production.

Japanese buyers are standing out notably in the Haynesville. Late last year, East Texas gas producer Rockcliff Energy II sold to Tokyo Gas Co. in a $2.7 billion transaction.

In 2019, Osaka Gas Co. acquired Sabine Oil & Gas for $610 million.

Japanese firm Mitsui & Co. acquired shale gas assets in the Eagle Ford from private buyers this year.

Compared to the future outlooks for Henry Hub prices and international LNG prices, pricing for shale gas assets "is pretty attractive today" for international buyers.

"It's a nice natural hedge for them to get that comfort, control and visibility into the gas that they're ultimately liquefying," Huddleston said.

"I think that's why you're seeing these strategic acquisitions occur, like the Rockcliff deal," he said.

Western Haynesville

Gas demand is rising to fuel growing U.S. LNG exports. Demand is also expected to rise to meet growing demand for artificial intelligence (AI) computing and data center operations.

Analysts are unclear about just how much natural gas could eventually be needed to support domestic needs and exports—but it is a vast quantity. And as top-tier drilling locations become increasingly scarce, gas producers will need to drill into lower-quality rock.

"Both Tier 2 and Tier 3 acreage, over the long term, is going to have to be developed," Huddleston said.

Certain operators are also pushing further out and drilling deeper to find future runway. Aethon and Comstock are the two de facto leaders delineating the emerging "Western Haynesville" gas play in Leon and Robertson counties, Texas.

But the Western Haynesville—or "Waynesville"—is ultra-deep and has higher pressures and hotter temperatures to contend with, making it an expensive place to drill.

"We've seen great economics out there—but at the same time, it's early days and we like to iterate on our development as best as possible," Huddleston said. OGI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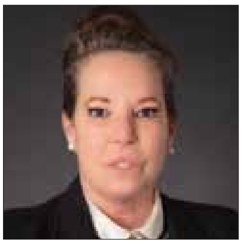
Oxy Mulls Divestment Plans After Ecopetrol Setback

The company is mum about what it might sell to prevent compromising 'our ability to maximize the value,' said CEO Vicki Hollub.



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Occidental Petroleum President and CEO Vicki Hollub took the microphone during the company's second-quarter earnings call in August to reassure rattled M&A dealmakers, buyers and investors.

Just days earlier, Colombia's Ecopetrol declined to pick up a 30% stake for $3.6 billion in Oxy's newly acquired CrownRock portfolio. What was Oxy's Plan B to raise an additional $3.5 billion in asset sales?

Hollub offered few details but made it clear that "some think that this is a fire sale and it is not."

Oxy told investors in December and credit-rating firms this summer that it planned to reduce debt by $4.5 billion to $6 billion within 18 months of the $12 billion CrownRock close on Aug. 1. Specifically, investors and the ratings firms were expecting Ecopetrol to show up for 30%.

Oxy is looking currently at property it might put on the market toward the balance due in its debt-reduction commitment.

CFO Sunil Mathew said on the call that the debt reduction goal is actually 70% met already, due to prepayment of some borrowing, $970 million in other asset sales and other instruments.

As for divestments, Hollub said, "we feel like, [if] talking in detail about what the assets would be, I would compromise our ability to maximize the value of those divestitures. We've said previously that we get a lot of incoming offers."

Meanwhile, "I can just assure you that we have high confidence that we're going to be able to achieve our debt-reduction targets," she said.

The potential list can't be revealed yet "because we really haven't made decisions on what the next set of divestitures would be. We're still under evaluation of that."

But Hollub gave a shout-out to Oxy's "onshore portfolio" specifically, saying "we welcome the opportunity to monetize some of these assets at an attractive price."

'Anti-U.S.'

Oxy reported to the Securities & Exchange Commission (SEC) in an Aug. 1 8-K filing that Colombia-based Ecopetrol "decided not to acquire any interest in the CrownRock assets."

> *"I can just assure you that we have high confidence that we're going to be able to achieve our debt-reduction targets."*
>
> **VICKI HOLLUB,** CEO, Oxy

News that Ecopetrol had bowed out of previous talks came shortly before Oxy announced it had closed the CrownRock deal, bringing in 94,000 net Midland Basin acres and 170,000 boe/d.

On Aug. 2, Oxy issued a press release that it was withdrawing its tender offer for CrownRock's $376 million of 5% senior notes due 2029.

Both Fitch Ratings and Moody's Ratings stated in their most recent reviews of credit ratings on Oxy that key assumptions included the E&P divesting $4.5 billion to $6 billion of assets to reduce its debt level to $15 billion, post-closing on CrownRock.

Each specifically expected Ecopetrol to buy 30% of the deal for $3.6 billion.

"We worked on that deal from March to just last week and we thought we were done," Hollub said on the call. "But President [Gustavo] Petro of Colombia didn't approve of it and he's made it very clear to the world that he's anti-oil and gas, anti-fracking and anti-U.S.

"And with those three strikes [against Oxy], he pretty much dealt Ecopetrol out of the deal. And that's all according to news reports," she said.

Colombia's government owns 85.5% of Ecopetrol.

She added that "unfortunately, there are others in the world like Petro and

ECOPETROL PERMIAN

Ecopetrol Permian and Oxy are part of a JV that develops oil and gas properties in the Midland Basin of Texas. Ecopetrol's recent decision to decline a 30% stake in Oxy's CrownRock portfolio in early August rattled investors, but Oxy CEO Vickie Hollub assures that this will not prevent the company from reaching its debt-reduction goals.

there are some actually in the United States like Petro who believe that oil and gas should go away and believe that we shouldn't be an industry anymore. But the reality is that, as you know, oil and gas is going to be needed for many decades to come."

Oxy does have a large CO_2 sequestration unit in development that was of interest to Ecopetrol, Hollub said, "and wanted to be a part of it." But a deal for a CrownRock stake did not happen.

Why Sell a Piece of CrownRock?

A securities analyst asked why, if the CrownRock property is as good as Oxy has described, the first asset Oxy would look to divest would be a piece of its new prize?

Hollub explained that a legacy joint venture (JV) Oxy has with Ecopetrol in the Midland Basin requires each to offer the other 49% of anything it acquires in the Midland Basin in a certain area of mutual interest.

Hollub said Oxy didn't actually want to part with any of CrownRock. "Certainly, we wanted it all; they wanted a part of it."

Meanwhile, the CrownRock property "is one of the best we've seen." The well inventory is graded Tier 1 by Oxy and, generally, by industry.

Oxy wanted to buy 100% and told Ecopetrol this, but was obligated to offer a portion to Ecopetrol.

Another analyst asked if Oxy would buy Ecopetrol out of the JV. Hollub said a break-up would simply result in Oxy being 51% operator of the mutual property; Ecopetrol, 49%.

Oxy's net production in the JV, established in 2019, is approximately 40,000 boe/d.

Broad Portfolio

A pass by Ecopetrol "wasn't necessarily anticipated as highly likely by the market," said TD Cowen managing director David Deckelbaum, who covers Oxy.

"Still, Oxy doesn't necessarily need to sell assets as they can still organically de-lever as long as pricing exceeds $55/bbl after dividends," he said. "Sales will be valuation-dependent."

Oxy has a broad portfolio of assets that can be used to generate proceeds. However, while stock market conditions improved by mid-August following a summer sell-off, Oxy's stock was underperforming its peers. OGI

Bracewell: Rising Interest in Drill-to-Earn Opportunities

With prolific consolidation in the Permian, these arrangements are a flexible and capital-efficient way to trade on acquired assets.

AUSTIN LEE AND JAY HARPER

Austin Lee is a partner and Jay Harper is an associate in Bracewell's Houston office.

The current roster of players in the Permian Basin stands in stark contrast to what it was at the peak of the shale revolution. During the last year and a half alone, the basin has seen a consolidation trend accelerate, evidenced by the acquisition of several large E&Ps that had been pillars of the Permian landscape for years.

This leaves a handful of power players controlling larger amounts of the production and delineated inventory. With that brings the need for acquiring companies to rework drill schedules and inventory stacks, as well as raise money to pay off acquisition debt. Selling portions of newly expanded asset bases is one way to do that and, given the large number of experienced management teams seeking foundational assets for new companies, buyers are excited to acquire assets that are no longer a priority for their current owners.

Amid this consolidation, Permian operators have increased drilling activity in formations beyond the Bone Spring, Spraberry and Wolfcamp—most notably the Woodford and Barnett formations. While it comes with some level of risk, interest in these less-developed formations has increased dramatically, in many cases creating unanticipated pockets of value within the newly expanded asset bases resulting from large-scale acquisitions.

In this environment, we have seen an increased interest in drill-to-earn transactions which offer participants a flexible and capital-efficient way to trade on these assets.

Drill-to-Earn Agreements

Drill-to-earn agreements have been utilized in the Permian for years. Whether styled as a joint venture, farmout agreement, development agreement or under some other moniker, these highly customizable arrangements allow a party willing to spend drilling dollars to earn interests in acreage or specific depths that the other party does not plan on developing. Earning requirements can be structured to account for both the drilling party's capital constraints and/or the need to maintain leases or depths that are subject to lease expiry or a continuous development clause.

The amount of interest earned as compared to that retained by the non-drilling party, as well as the split of economics from the development under these arrangements, can be structured to address a party's specific goals.

In some situations, the non-drilling party wants to retain an override to maintain upside from acreage it would never have drilled. In others, the non-drilling party will retain a non-operated working interest to keep barrels of production on its books. In most cases, the retained working interest will be "carried" in some form by the drilling party, which not only offloads the risk of exploration to the drilling party but allows the non-drilling party to maintain upside without associated production costs.

The Benefits to Drill-to-Earn

Drill-to-earn arrangements convey just as many benefits to the drilling party. The consolidation of the Permian has made obtaining interest through traditional acquisitions difficult and costly. Drill-to-earn arrangements may avoid expensive upfront acquisition costs and allow a party to earn in-demand interest directly through the expenditure of development dollars.

When a drilling party acquires a foundational asset through one of these arrangements, they are typically spending "equity" dollars up front, as they most likely do not have a production base to lever up. In these situations, a drill-to-earn arrangement can provide an efficient way to spend those equity dollars with a quicker path to cash flow generation.

It can also accelerate the development of a production base on which the company can obtain more traditional (less expensive) bank

"Drill-to-earn agreements ... allow a party willing to spend drilling dollars to earn interests in acreage or specific depths that the other party does not plan on developing."

"Parties to a drill-to-earn agreement must be mindful of, and account for, the tax implications associated with these arrangements."

financing. The efficiency and flexibility in tailoring these arrangements to align with a drilling party's initial capital position are key reasons why many management teams are targeting drill-to-earn arrangements to attract investors and capital sponsors.

By leveraging its operational track record to get access to one of these transactions, a management team can also get a leg up in the fundraising process as investors typically prefer investing in a team with line of sight to an asset rather than the blind pool capital commitments employed in the early stages of the shale revolution.

Working as an Asset Acquisition

Drill-to-earn arrangements are a form of asset acquisition at their core. They present the same "asset level" issues encountered in normal asset acquisitions. Applicable consents and preferential purchase rights will need to be addressed.

The drilling party may also become subject to any midstream or produced water arrangements that are binding on the earned acreage under dedications. Where the interest being earned is limited to specific depths, the parties will need to be mindful of both existing operations and the needs (or requirements) to develop other depths within that same acreage. This may require the parties to obtain additional agreements to secure adequate surface and subsurface rights or agreements for the shared use of facilities serving wells both on and off the earned acreage.

Where the parties each maintain a working interest in the earned acreage, they must establish a regime of governance for future development of the relevant assets, usually through an agreed form of joint operating agreement. Restrictions on the ability to transfer one's interest in the acreage and/or areas of mutual interest are common mechanisms used to incentivize development and maintain alignment for development of the earned acreage and the surrounding area.

Finally, parties to a drill-to-earn agreement must be mindful of, and account for, the tax implications associated with these arrangements. A tax partnership between the parties is often necessary to properly allocate tax attributes, such as intangible drilling costs, to the parties based on the share of the development costs they are bearing.

Consolidation has washed over the Permian and is showing no signs of slowing. The resulting needs to rationalize portions of expanding asset bases, coupled with the emerging value proposition that some of the less developed formations now represent, has piqued interest in drill-to-earn opportunities throughout the basin.

The future will tell if this trend continues and to what level these versatile arrangements will be utilized in the Permian landscape going forward. OGI

Oxy's DAC Project on Track for 2025 Startup

The Stratos commercial-scale facility in Texas is designed to capture up to 500,000 metric tons of CO_2 annually.

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Occidental Petroleum's direct air capture (DAC) project, Stratos, is on track to start up in summer 2025, company executives said in August.

Located on about a 65-acre site in Texas' Ector County, the commercial-scale facility is designed to capture up to 500,000 metric tons of CO_2 annually when it becomes fully operational.

"We're now moving away from bulk fill. By that I mean putting in the large piping … et cetera into completing the systems one by one. So, we're at that stage now so that we can commission in the right sequence," said Kenneth Dillon, senior vice president and president of international oil and gas operations for Occidental. "We get power live this month [August 2024], which then means we can start getting the control room up and running and testing all of the instrumentation throughout the plant. So, [it's] going really well at the moment."

The facility, being developed by Occidental Petroleum's 1PointFive with Carbon Engineering's DAC technology, is expected to be one of the largest facilities of its kind.

The facility is among the 130 or so large-scale DAC facilities being developed in the world, according to the International Energy Agency. Despite being on the more expensive side of carbon capture and storage methods, DAC technologies are expected to play a role in global efforts to lower emissions. Currently, only 27 DAC plants have been commissioned worldwide; however, numbers are growing–including in the U.S. where tax incentives are spurring interest.

Tax Credits

The carbon sequestration tax credit, known as 45Q, is $17/metric ton for sequestered qualified carbon oxide, but the value jumps to $60/ton for storage associated with enhanced oil recovery (EOR), $85/ton for dedicated geologic storage, $130/ton for DAC with carbon utilization and up to $180/ton for DAC with carbon storage.

CO_2 removal (CDR) credits, which allow companies to fund projects focused on removing carbon, have been instrumental in advancing Stratos. The credits, also called carbon offsets, allow owners to emit a certain amount of CO_2 or another greenhouse gas (GHG). Each credit permits one ton of CO_2, or other GHG, to be emitted.

In July, 1PointFive said it entered a deal to sell 500,000 metric tons (mt) of Stratos DAC CDR credits to tech giant Microsoft over six years.

"The agreement is the largest single purchase of direct air capture CDR credits to date and highlights the increasing recognition of Carbon Engineering technology as a solution to help organizations achieve their net-zero goals," Occidental CEO Vicki Hollub said on the company's second-quarter earnings call.

She later added that Stratos has generated a lot of interest from companies around the world.

"We believe that as we prove it up, as we make it better, that it's going to be much more valuable than what people realize today," she said.

Richard Jackson, operations president of Occidental's U.S. onshore resources and carbon management, said the company is monitoring CDR sales and remains optimistic on the outlook for that market. However, it hasn't set any specific parameters on CDR targets, though it will be a major component of final investment decision criteria for DAC projects.

Cost Down

Innovative techniques seen during construction are providing line of sight to cost down, Occidental executives said. The DAC process utilizes a liquid sorbent. Some of the materials used in the process–such as potassium hydroxide and decomposed calcium oxide pellets–can be reused.

"We are seeing really great potential for performance improvements and cost-down improvements, and we're looking at how to incorporate these learnings as quickly as possible," Dillon said. "Companies like Technip Energies are also focused on how to achieve cost down for their equipment, and that's driven from the top of the company. So, we're getting great support from our visionary vendors who have

CARBON ENGINEERING

Rendering of Stratos, Occidental petroleum's planned direct air capture (DAC) project with 1PointFive and Carbon Engineering. Located in Ector County, Texas, the facility is expected to be the largest DAC facility in the world when it becomes operational in summer 2025, according to Occidental.

"We are seeing really great potential for performance improvements and cost-down improvements, and we're looking at how to incorporate these learnings as quickly as possible."

KENNETH DILLON, president of international oil and gas operations, Occidental

bought into long-term DAC future."

1PointFive is also developing the South Texas DAC hub in partnership with King Ranch, Carbon Engineering and Worley in South Texas. The DAC facility landed funding from the U.S. Department of Energy.

"King Ranch is really what we've targeted for the next kind of development beyond the Permian. And it really has a lot of scale advantages that we've talked about in the past, both with the subsurface and as we think about it at the balance of plant," Jackson said. "Think about key power inputs, emission-free power inputs, water or other advantages," he said, adding subsurface engineering work continues.

Plans are to incorporate learnings from Stratos, Oxy's first DAC project, to other projects.

"The exciting part about that King Ranch development [is that it's] a 30 million ton per year hub," Jackson said. "And so, you get these tremendous economies of scale that we really think add to the R&D improvements in terms of a cost down." OGI

Prowling for Profit: Exxon Mobil Continues Low-carbon Market Chase

The supermajor is bringing the full weight of its technological prowess to bear on unlocking value in low-carbon solutions.

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As Exxon Mobil sees massive profits from its upstream and refined products segments, the supermajor is sniffing out potential value in the low-carbon space utilizing its existing expertise.

Projects seeking capital, however, must generate returns high enough to satisfy shareholders while meeting energy needs, even if the project is part of a new market in the making. That was the gist of remarks from Exxon Mobil CEO Darren Woods on the company's second-quarter earnings call.

"Any investment will have to generate competitive returns, possess clear competitive advantages, and be resilient to the bottom of any commodity cycle," Woods said. "As we've demonstrated, our capital allocation decisions have generated robust earnings, cash flow and shareholder returns."

The company has been active in low-carbon products and services, recently signing agreements related to carbon capture and storage (CCS), hydrogen and lithium. And the supermajor is bringing the full weight of its technological prowess to bear on unlocking value in low carbon, even in markets that don't yet exist.

Still, as Woods alluded to, the company is looking for returns. It found them in the second quarter, as Exxon reported earnings of $9.2 billion, its second-highest second-quarter earnings in the past decade, on high product sales and oil production. Earnings were about $7.9 billion about a year ago.

Since restructuring in 2022, when its refining and chemicals businesses merged to create product solutions, Exxon has sought more ways to capitalize on its core capabilities.

The company's other two business units are upstream and low-carbon solutions.

"Some of it includes our existing footprint, but a lot of it includes our ability to upsell and to identify value and use applications and combine that with a technology organization that's very focused on applying core technology capabilities to business challenges and business opportunities," Woods said.

Applications that would not have been identified previously because of the organization's structure are being unlocked, he added.

The Texas-based company sees opportunities in carbon materials, polyolefin thermosets, hydrogen, lithium and CCS, with projects and new ventures underway. These include a new resin system called Proxxima, entry to the lithium supplier market with direct lithium extraction (DLE) technology and moves to become a major hydrogen and carbon capture player.

However, low-carbon businesses have unique challenges, particularly in areas where markets don't yet exist, Woods said, using carbon capture as an example.

"There's not an existing market today that pays for carbon removal that's being incentivized with government policy," he said. "Government policy is forming while at the same time you're trying to build the infrastructure to support that market, the logistics, the supply and then at the same time develop a customer base."

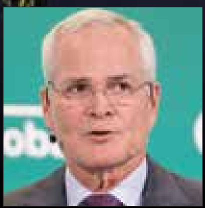
Piecing together multiple moving parts while establishing a business and business model with long-term sustainability and competitive returns makes the low-carbon space complex, according to Woods. "But I have to say, we're geared to do that kind of work. Our experience lends itself to that," he said.

Exxon is pursuing more than $20 billion in lower emissions opportunities through 2027. These include biofuels, CCS, hydrogen and lithium. Together, they are expected to generate aggregate returns of about 15%.

Exxon projects global energy demand will be 15% higher in 2050 than it is today and oil demand will remain steady at about 100 MMbbl/d as renewables and natural gas demand grows.

"The world will come to rely more on technologies where we have an advantage, including hydrogen, biofuels and carbon capture and storage," Woods said. "A serious approach to the transition should focus on moving the world from high carbon to low carbon energy, not simply from oil and gas to wind and solar.

"The data, science and economics all support this as fundamentally necessary."



"The world will come to rely more on technologies where we have an advantage, including hydrogen, biofuels and carbon capture and storage. A serious approach to the transition should focus on moving the world from high carbon to low carbon energy, not simply from oil and gas to wind and solar. The data, science and economics all support this as fundamentally necessary."

DARREN WOODS, CEO, Exxon Mobil

Exxon's planned hydrogen facility at its Baytown, Texas, complex is expected to be the world's largest.

EXXON MOBIL

Hydrogen

Exxon's planned hydrogen facility at its Baytown, Texas, complex is expected to be the world's largest. The site plans to produce 1 Bcf of hydrogen daily and more than 1 million tons of ammonia annually, capturing more than 98% of associated CO_2 emissions.

The company is working through engineering for the project as it awaits federal action.

"A critical element of that is getting the IRA [Inflation Reduction Act] legislation translated into final regulations… We're optimistic that the regulations will reflect the intent of the legislation," Woods said. "And if it does, I think we'll have a very attractive project that we can then FID once those regulations are finalized."

In late July, Exxon signed its fourth CCS agreement with a major industrial customer, agreeing to transport and permanently store up to 500,000 metric tons per year of captured CO_2 from CF Industries' complex in Yazoo City, Miss.

"We see continued opportunity and growth with good returns in the carbon capture side of the equation," he said.

Lithium

Exxon is also combining its subsurface exploration, drilling and chemical processing expertise to advance a new production method for lithium, a key energy storage system ingredient. Exxon has produced lithium carbonate from the Smackover Formation in Arkansas using DLE technology.

"We're not looking to rush this through and get something, get money spent. We're looking to make sure that we build a very strong long-term foundation…. It's all about establishing successful long-term foundations."

Proxxima, Carbon Ventures

Proxxima, as Woods tells it, transforms lower value gasoline molecules into high-performance thermoset resin used in coatings, lightweight construction materials and advanced composites for cars and trucks, including battery boxes for electric vehicles.

The systems also have less than half of the greenhouse-gas emissions than most traditional thermoset resins on a cradle-to-gate basis, the company said.

"We see the total addressable market potential for Proxxima at 5 million tons and $30 billion by 2030, with demand growing faster than GDP and returns above 15%," Exxon Mobil CFO Kathy Mikells said in her prepared remarks. "Based on this, we're progressing projects in Texas, with startups planned in 2025, that will significantly expand our production of Proxxima."

In carbon materials, transforming carbon into products, Exxon is targeting segments with margins of several thousand dollars per ton with growth rates outpacing GDP, she said. "Carbon Ventures is still early in the technology cycle, but I think we've gone far enough along to see some real opportunity there." OGI

NEW ENERGIES

Startup Aims to Lower Cost of Hydrogen

Advanced Ionics has developed an electrolyzer that uses process or waste heat already present at industrial facilities to help lower costs and electricity needs.

SHUTTERSTOCK

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A BP- and Repsol-backed startup is advancing technology that aims to lower the cost and amount of electricity needed to split water molecules to produce hydrogen.

Advanced Ionics is nearing the end of two pilot projects–one with Repsol and another with the U.S. Department of Energy's (DOE) Advanced Research Projects Agency-Energy (ARPA-E) to bring its electrolyzer technology closer to gigawatt-scale production.

To boost its competitiveness with other forms of energy, including fossil fuels, efforts are underway to lower costs associated with producing electrolytic hydrogen. The steps are being taken amid ongoing moves to lower greenhouse gas emissions. Hydrogen is considered an attainable solution given its high energy density, versatility and lack of CO_2 emissions.

Hydrogen is produced via various techniques and feedstocks that include water electrolysis using electricity from renewables, and steam methane reforming or autothermal reforming with natural gas. Each form comes with a different carbon intensity and price tag.

"The things we have under our control are the ability to use cheap electricity to make hydrogen or use less electricity, and what we do at Advanced Ionics is, we enable people to use less electricity," Advanced Ionics CEO Chad Mason told Hart Energy.

Wisconsin-based Advanced Ionics has developed a new class of electrolyzers that uses process or waste heat already present at industrial facilities to help bring down costs. The water vapor electrolyzer, called Symbion, is made using steel and materials that are widely available.

"We designed an electrolyzer that can be integrated into industrial processes, into a refinery, much in the same way you currently take methane, do steam methane reforming on site, make the hydrogen, feed it to the processes that need it," Mason said. "We're basically going to be doing the same thing with electrolysis in a very effective manner.... It's important to do this with abundant materials, easy to build systems, easy to integrate balance of plant."

Symbion electrolyzers use process or waste heat with temperatures at least 100 C and higher, which helps reduce electricity costs.

The electrolyzers can be scaled and use off-the-shelf components such as stainless steel and nickel instead of expensive catalysts like platinum or iridium.

Targeting Lower Costs

Electrolysis, the process of splitting water into hydrogen and oxygen with electricity from renewable and nuclear resources, can be carried out with a variety of electrolyzers. Each type has different operating requirements. Some electrolyzers require large amounts of electricity, ceramics or catalysts.

Today, thermal conversion of fossil fuels–mainly by steam methane reforming–is the dominant lowest cost method of hydrogen production; but the method emits about 10 kg of CO_2 equivalents per kg of hydrogen produced on a life-cycle basis, according to the DOE. While hydrogen from clean and renewable energy sources emit less, costs can be more than $5/kg.

The U.S. aims to reduce the cost of clean hydrogen by 80% to $1/kg by 2031.

ADVANCED IONICS

Advanced Ionics' water vapor electrolyzer, called Symbion, is made using steel and materials that are widely available.

"Electricity use accounts for more than 70% of green hydrogen production costs," according to BP. "Advanced Ionics' electrolyzer stack requires less than 35 [kilowatt-hour] kWh per kilogram of produced hydrogen compared to more than 50 kWh per kilogram for typical electrolyzers. This lower electricity requirement could make green hydrogen accessible for less than $1 per kilogram at scale."

Whether the electrolyzer technology helps make electrolytic hydrogen cost-competitive with other forms of hydrogen—including blue hydrogen—depends on a variety of factors. Geography is one.

"I always tell people, 'pick your location and then I'll pick the numbers for you.' It gets down to what's that price of that electricity from the renewables that you have," Mason said. "If you're in Texas and you do a combined wind and solar project, you can have quite low-cost electricity, which will get you below $2 per kilogram hydrogen wholesale that gets fed into the unit. You can even do the math and find a path towards below a dollar per kilogram. But it is challenging. You need a variety of circumstances to line up in the right way."

Blue hydrogen also must check a lot of boxes to be cost-effective and decarbonized, he added, noting needed proximity to CO_2 storage.

"I think blue hydrogen's generally been quite overhyped for what it can do," he said. "I think the proof is in the pudding, but time will tell."

"I always tell people, 'pick your location and then I'll pick the numbers for you.' It gets down to what's that price of that electricity from the renewables that you have."

CHAD MASON, CEO, Advanced Ionics

Next Steps

The company plans to announce another project with an oil and gas major soon, Mason said.

"We're going to be progressively stepping up in size. So, going from a single small stack to progressively larger stack and then stacks," Mason said. "These will be done in demonstration and pilot scale systems.… Eventually, we will be commercializing these in the second half of the decade."

The Repsol project allowed the company to show it could deliver the first stack, or a collection of stacked electrolytic cells connected that make up the core of an electrolyzer. The ARPA-E project allowed the company to progress up in electrolyzer size to prove ability, reliability and performance, Mason said. "Then, we'll march onward from there."

Mason's approach has been shaped in part by his childhood growing up on the family farm in North Dakota. His upbringing gave him early exposure to the importance of hydrogen for fertilizers, fuels and chemicals. The industries are among the company's targets.

Looking forward, he sees the greatest opportunity for growth for hydrogen in green steel and green ammonia.

"Green ammonia, of course, we already have existing uses of ammonia in ammonium and nitrate-based products that go into fertilizers, explosives and all sorts of other chemicals downstream," Mason said. "With steel, this is really a market that'll go from zero to 100 at some point as you replace coal and coke as the, let's call it, reducing medium that's used to convert iron ore to iron. Basically, you do that with hydrogen."

Like others, Mason pointed out what appears to be a transition underway for hydrogen from hype to reality.

"I think the hype is dying down now, and people are starting to get more clear-eyed about the things that are needed to deploy real projects that actually reach final investment decision," he said. "The vast majority of hydrogen projects that are being proposed right now are not reaching FID [final investment decision], and you have to ask why. Well, a lot of those projects don't actually pencil out. And part of the reason they don't pencil out is they need lower-cost hydrogen. And that's basically what we're attacking head on." OGI

Carbon Capture Could Be the Next Offshore Trend

Interest is growing. but the technology faces significant challenges.

QUAIM CHOUDHURY
ABS

Quaim Choudhury is a Senior Managing Principal Engineer with ABS.

Carbon capture and storage (CCS) technology has been around for longer than many people think.

During the 1920s, CO_2 scrubbers were used to remove impurities from methane to make it a commercially viable product. This early CCS technology has stood the test of time and now provides the first step in modern carbon capture processes.

CCS took off in the 1970s when it was known as enhanced oil recovery. CO_2 captured from oil and gas production was reused by injecting it into depleted oil and gas reservoirs to re-pressurize them, enabling the extraction of more hydrocarbons.

As climate change and sustainability priorities have gained momentum, the process was rebranded as carbon capture and storage (CCS) and carbon capture, utilization and storage (CCUS). Despite the name change, most CCS projects are in enhanced oil recovery.

However, there is a sizable potential for CCS and CCUS technologies to play an important role in meeting global emissions reduction targets. This is because they enable the mitigation of CO_2 emissions from large output generation industrial sites such as power plants and refineries. In addition, the technologies can remove existing CO_2 from the atmosphere.

There are several methods of CCS. Most new technologies and improvements center around three systems–post-combustion, pre-combustion and oxy-fuel combustion.

Post-combustion capture separates CO_2 from combustion flue gas. Chemical absorption using amine-based solvents is the most technologically mature CO_2 separation technique for power plants This is also the technique most applicable to the marine and offshore sectors at present.

In the pre-combustion method, the fuel is processed with steam and/or oxygen to produce a gaseous mixture of carbon monoxide and hydrogen, known as syngas. Syngas is free of contaminants such as particulates, sulfur, ammonia, chlorides, mercury and other trace metals, and possibly carbon, depending on the source fuel and processes. Syngas can be a low-carbon or even a carbon-free substitute for fossil fuels. It is combustible and can be used as a fuel in gas turbines and internal combustion engines.

Finally, oxy-fuel combustion capture uses nearly pure oxygen (using air separation units) instead of air to combust fuel. This results in a flue gas composed of CO_2 and water vapor, and dehydrating the flue gas generates a high-purity CO_2 stream. This process reduces the carbon release in the atmosphere and is recognized as one of the solutions for decarbonization.

CCS and the Offshore Sector

How far down the track is the offshore industry with CCS?

There is growing interest regarding the use of CCS on oil and gas platforms and FPSO units, but key challenges remain around offshore storage in deepwater environments because of constraints caused by water pressure. These facilities often use large gas turbines that produce emissions around the clock, presenting a strong argument for some kind of CCS solution.

The key challenges include space, weight and power limitations, although the extent of the type of CCS system to be fitted will depend on the platform or site in question. Arguably, the most significant obstacle to overcome centers around how to remove the captured CO_2. Offshore installations are stationary and require infrastructure for offloading via pipeline, or ships to transport it to appropriate reception facilities at a port or other offshore hub for sequestration.

For platforms that produce e-fuels, a class of synthetic fuels in gas or liquid form that are made by synthesizing captured CO_2 and hydrogen produced from renewable power sources such as solar and wind power, conversations are taking place about using captured CO_2 to synthesize methanol.

The most feasible scenario is a combined plant which processes water for generating hydrogen and can be used for other e-fuels such as ammonia. Offshore platforms already process chemicals and store various substances, so it is not a huge change to make this part of a processing facility subject to the same usual constraints on space, weight and power.

There is no one-size-fits-all CCS solution, especially for offshore applications. Any of the potential pathways could be suited for a

There is growing interest regarding the use of CCS on oil and gas platforms and floating production storage and offloading (FPSO) units, but key challenges remain around offshore storage in deepwater environments because of constraints caused by water pressure.

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particular project depending on the economics and the technical aspects, and we have seen activity across several types of systems. Indeed, there have been encouraging results in several post-combustion concepts like amine absorption and CO_2 liquefaction, as well as chemical processes which produce calcium carbonate solids. Precombustion reactors are also in various stages of study, and some are very close to being adopted.

CCS Onboard Vessels—Will it Happen?

There is a lot of R&D taking place, especially around leveraging amine-based post-combustion techniques and adapting what has been used for land-based industries such as power generation and refining. Transfer of these land-based technologies onboard ships can be a way to remove CO_2 emissions from the exhaust of hydrocarbon fuel burning equipment. For existing ships, this will reduce vessel-specific CO_2 emissions and improve the Carbon Intensity Indicator (CII).

However, there are limitations and various challenges to installing these systems onboard existing ships such as: space constraints, additional power requirements, mitigation of risks affecting people on board, the structural strength and integrity of the vessel. Currently, some lower capacity systems (20%-30% carbon capture) are installed onboard ships as pilot projects but it will take time for them to get to maturity.

The key issue is scale. Ships have more constraints than offshore platforms, and there are complex issues such as weight and center of gravity to consider. Likewise, ships already have onboard systems for applications such as electricity and water capacity. Indeed, CCS systems will use energy, which also needs to be considered–if a higher capacity CCS is installed then proportionately more of everything is needed.

To overcome some of these issues, alternative CCS technologies to amine absorption are being evaluated, including membrane systems and processes that use chemicals to produce solid outputs. However, they are still very nascent concepts compared to amine-based processes, with very few systems installed on vessels or on land.

It is not just the practicalities of the vessel that need to be considered. Port infrastructure is another key challenge, as captured material, in whatever state, needs to be unloaded. Potential solutions include modularized offtakes in the form of containers which can be unloaded onto land. Facilities accommodating this idea could spring up in green ports and corridors initially, but these hubs are not likely to become mainstream assets in the near future.

As a part of global decarbonization efforts, ABS is actively engaged in work on vessel-based CCS systems. Several approvals in principle for vessel designs submitted by shipyards/designers in Asia and Europe have been completed, including amine-based designs and other types of CCS processes. Additionally, ABS has worked with other vendors to pilot technologies onboard ships, carrying out small-scale tests to analyze concepts and feasibility.

There is a lot of interesting CCS work going on both offshore platforms and vessels. As the industry accelerates its efforts to decarbonize and transition to a net-zero future, it will be intriguing to see the extent to which carbon capture and storage plays a role. OGI

Romito: Complacency is Industry's Greatest Threat

Be wary of the role environmental NGOs play in emissions oversight.

DAN ROMITO
PICKERING ENERGY PARTNERS

Dan Romito is a consulting partner at Pickering Energy Partners focusing on quantitative ESG strategy and implementation.

As anticipated, the political landscape in the United States is anything but calm. The next four months will undoubtedly produce a mixture of tension, anxiety, and frustration. At the very least, recent polls indicate that Donald Trump's probability of retaking the White House has slightly improved. Nothing is guaranteed, but Trump's campaign is experiencing a distinct degree of positive momentum, mainly because Kamala Harris never even cleared the Iowa caucuses the last time she campaigned for president.

We urge the broader oil and gas space to take this momentum with a grain of salt. We increasingly notice a premature sense of relief beginning to permeate the energy sector, which is troubling.

The Supreme Court's overturning of the Chevron deference doctrine is also a positive trend for the industry, and when combined with the Trump momentum, it is reasonable for people to feel more optimistic about the White House returning to a Republican administration–and sensible policy. Unfortunately, some of these convictions have introduced a notion that most environmentally focused mandates passed over the last three years will be wiped away. We cannot stress hard enough that this belief is incredibly dangerous and short-sighted.

Irrespective of the political landscape, it's essential to recognize the pivotal role that environmental non-government organizations (NGOs) play in emissions oversight. The Supreme Court's ruling has only fueled the motivation and strengthened the convictions of anti-fossil fuel groups.

The sector must understand that these well-funded and sophisticated organizations have effectively been "deputized" as the newly minted emissions police and technically, they do not have to answer to anybody. Their influence is significant, their financial resources are substantial and their activities should be constantly monitored. Ignoring their actions will lead to severe consequences.

The financial and technological resources at the disposal of environmental NGOs are staggering. The Sierra Club, Environmental Defense Fund and Greenpeace collectively hold over $1 billion in assets and generate annual revenues exceeding $100 million.

These groups are dedicated to implementing advanced technologies to continuously track the energy sector, particularly among smaller private operators. MethaneSAT, CarbonTracker, and the ClimateWorks database are prime examples of how regulation, oversight and monitoring have been permanently outsourced and now function as an unchecked extension of the executive branch.

The energy sector must not over-conflate the political scene with the regulatory landscape. Of course, there is overlap, but it is diverging. According to ClimateWorks, roughly 124 climate-focused organizations and over 60,000 trained climate activists are "assigned" to monitoring fossil fuel companies. This arrangement showcases how there are now essentially two levels of oversight–government and the deputized NGO space. A change in administration will not deter, let alone slow, the latter.

As we consider the potential outcomes of the U.S. presidential election, it's essential to understand the implications for the energy sector. If Harris wins the presidency, we can expect an increase in the existing regulatory burden for energy. On the other hand, if Trump wins, we may see a rise in deputized NGOs. This is no time for the energy industry to be complacent.

More understanding and analysis can help us prepare for the potential changes and challenges that lie ahead. In practice, these NGOs will operate in a concerted fashion. Environmental NGO technology, i.e., MethaneSAT, will continuously monitor the space. Once a potential detection occurs, it will be recorded in an aggregated database that will eventually evolve into a publicly available dataset. This dataset will emerge as a "scoring" apparatus, i.e., MSCI, and will be utilized to influence policy, capital markets and public narrative.

No, I am not wearing a tinfoil hat while writing this article. My team and I are observing this dynamic in real time. As always, the increased need for the energy space to improve the quantitative tracking of material non-financial metrics is critical.

Implementing an effective defense against this growing threat inherently means going on the data offensive and ensuring that all individual material non-financial metrics are tight. Unfortunately, the reality is that the energy space will be continuously monitored by obsessive groups that would love nothing more than to permanently put oil and gas out of business. Let's not fuel their fire. OGI

TRANSITION IN FOCUS

Clean Energy's RNG production facility at Ash Grove Dairy, Lake Benton, Minn.

BUSINESS WIRE/CLEAN ENERGY FUELS

Bioenergy

Clean Energy Begins RNG Project at Texas Dairy Farm

California-based Clean Energy Fuels started producing renewable natural gas (RNG) from its facility in Minnesota, the company said.

Located at the Ash Grove Dairy in Lake Benton, the facility is expected to supply up to 480,000 gasoline gallon equivalent of negative carbon-intensity RNG annually when at full capacity, according to a news release. The facility will process up to 60,000 gallons of manure daily, capturing methane and converting it into 165,000 MMBtu of RNG daily.

The $22 million project was financed through one of Clean Energy's production joint ventures and developed by Dynamic Renewables. The dairy is home to more than 2,000 milking cows, according to the news release.

Clean Energy also broke ground on an RNG production facility at South Fork Dairy in Dimmitt, Texas. Construction of anaerobic digesters and the processing plant is forecast to cost about $85 million with expected completion in 2025, the company said.

The dairy farm, home to a 16,000-cow herd, will produce RNG made from organic waste that Clean Energy said receives a negative carbon-intensity score.

The company said the South Fork Dairy facility is set to be one of the biggest RNG production developments in the country with an anticipated annual production of 2.6million gallons. RNG fuel produced at the site will make its way into Clean Energy's nationwide network of stations.

BUSINESS WIRE/CLEAN ENERGY FUELS

Clean Energy Fuels expects to complete construction of anaerobic digesters and the processing plant at South Fork Dairy in Texas in 2025.

The South Fork project will help the farm monetize sizeable amounts of manure waste while benefiting from the environmental credits an RNG facility brings, Clay Corbus, senior vice president of renewables at Clean Energy, said in a press release.

Agriculture accounts for nearly 10% of U.S. greenhouse-gas (GHG) emissions, according to the U.S. Environmental Protection Agency.

Capturing methane from farm waste can lower these emissions. RNG is a transportation fuel made entirely from organic waste and reduces GHG emissions by an average of 300% compared to diesel, according to Clean Energy.

Cemvita Rolls Out Biotech to Boost Sustainable Oil Production

Biofuels company Cemvita rolled out new technology at its commercial plant in Houston that allows production of up to 500 bbl/d of sustainable oil from crude glycerin, a milestone originally projected for 2029.

As part of the company's microbial waste-to-oil process, Cemvita advanced its lipid productivity to quadruple its planned output. Reactor optimization has also increased oil extraction efficiency by at least 330%, Cemvita said.

The achievement is expected to increase Cemvita's production capacity, improve operational efficiency and strengthen its position in the sustainable oil market, the company said.

"Our focus on the first principles has allowed us to design and create new biotech more cheaply and faster than ever before," said Moji Karimi, CEO of Cemvita. "Our combination of low-capex design, innovations in bioprocess engineering and increased productivity, enabled by synthetic biology, sets us apart."

Carbon management

CF Industries Enters CO_2 Transport, Sequester Deal with Exxon

CF Industries Holdings entered a commercial agreement with Exxon Mobil to transport and sequester CO_2 from its carbon capture and sequestration (CCS) project in Mississippi.

The project, located in Yazoo City, is expected to reduce CO_2 emitted in the atmosphere from the facility by up to 500,000 metric tons (mt) annually. Sequestration is expected to start in 2028.

CF Industries plans to invest about $100 million into the complex to build a CO_2 dehydration and compression unit. This will allow up to 500,000 mt of CO_2, generated as a byproduct of ammonia production, to be captured, transported and stored.

Once the project's sequestration starts, CF Industries expects the project to qualify for tax credits under Section 45Q of the Internal Revenue Code, which provides a credit per metric ton of CO_2 sequestered.

The Yazoo City CCS project represents CF Industries' second major decarbonization project leveraging CCS technologies as well as its second CCS project with Exxon.

The companies are progressing on a CCS project at CF Industries' Donaldsonville, La., facility that will sequester up to 2 million tons of CO_2 annually. Sequestration at this facility is expected to start in 2025.

SLB, Aker Carbon Capture JV Awarded Carbon Removal Contract

CO280 Solutions has awarded SLB and Aker Carbon Capture's joint venture (JV) the front-end engineering and design (FEED) contract for a large-scale carbon capture plant at a pulp and paper mill on the U.S. Gulf Coast, the Aker JV said.

The project aims to remove 800,000 tonnes of carbon emissions annually and deliver permanent, verifiable and affordable carbon dioxide removals (CDRs).

"Partnerships are the key to removing megatons of carbon before 2030," CO280 CEO Jonathan Rhone said in a press release. "By capturing and permanently storing biogenic CO_2 at mills, we can unlock a vast carbon removal opportunity in the pulp and paper industry and scale up the CDR market."

The concept design for the FEED of the carbon capture plant is based on Just Catch 400, the joint venture's standardized and modular technology that enables the pre-fabrication of carbon capture units.

Geothermal

Sage Geothermal Selects Site for Geopressured Geothermal System

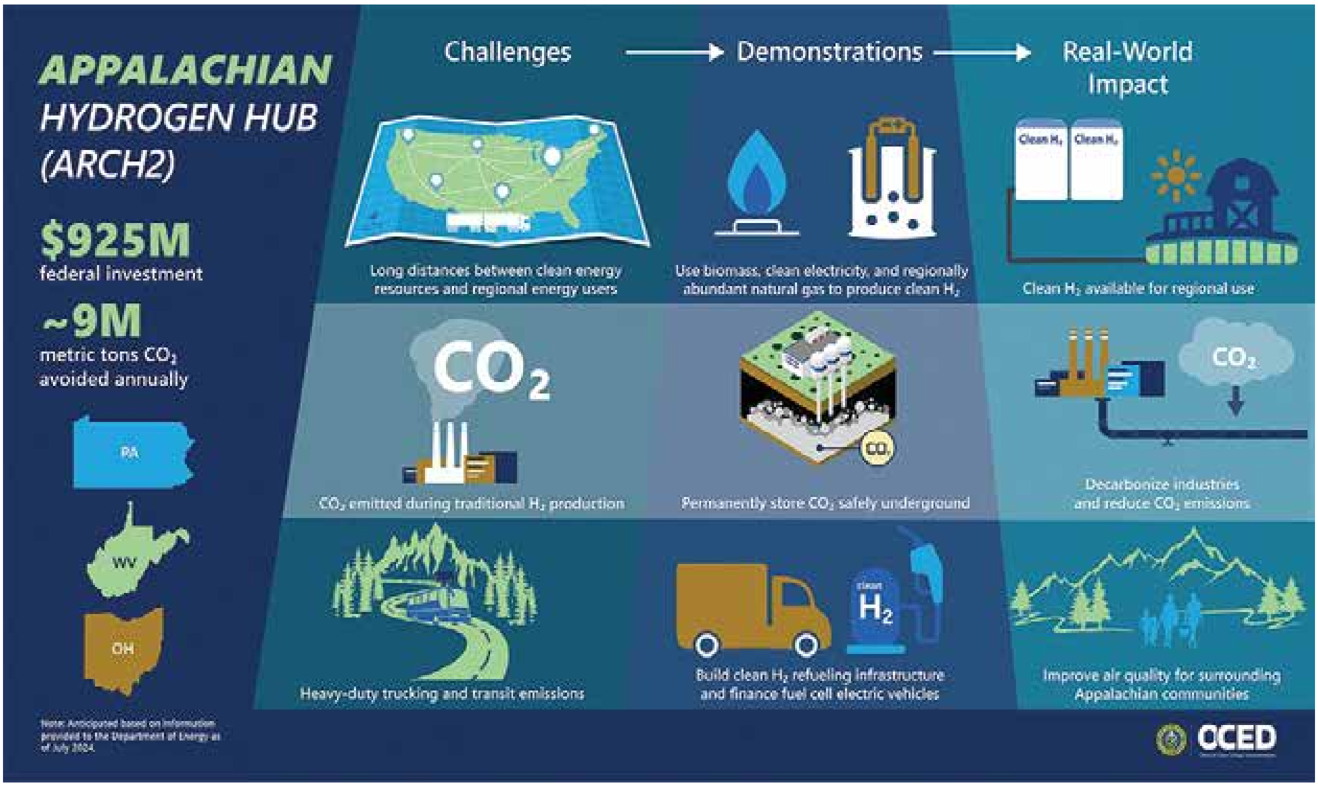
SAGE GEOSYSTEMS

A rendering of Sage Geosystems' 3-MW energy storage system.

Houston-based Sage Geosystems plans to locate its 3-megawatt geopressured geothermal system energy storage facility in Christine, Texas, having reached a land use agreement with San Miguel Electric Cooperative Inc. (SMECI).

The first-of-its-kind project, which is expected to launch later in 2024, will use Sage's proprietary technology called EarthStore to store energy. The company said it is targeting 6- to-10-hour storage durations. The energy storage system will be paired with renewable energy to provide baseload and dispatchable power to the Electric Reliability Council of Texas (ERCOT) grid.

"Once operational, our EarthStore facility in Christine will be the first geothermal energy storage



SOURCE: U.S. DEPARTMENT OF ENERGY'S OFFICE OF CLEAN ENERGY DEMONSTRATIONS

system to store potential energy deep in the earth and supply electrons to a power grid," said Sage Geosystems CEO Cindy Taff. "Geothermal energy storage is a viable solution for long-duration storage and an alternative for short-duration lithium-ion batteries. Electric utilities and co-ops like SMECI will be able to use our technology to complement wind and solar, and stabilize the grid."

The site will be located near SMECI's lignite coal power plant in Christine, which is south of San Antonio. Sage said it will operate as a merchant, buying and selling electricity to ERCOT.

Hydrogen

Appalachian Hydrogen Hub Secures Funding, Moves to Phase 1

The Appalachian Regional Clean Hydrogen Hub, led by Battelle with EQT Corp., CNX Resources Corp. and others as partners, became the third hub to secure federal funding as the U.S. works to boost hydrogen production.

The U.S. Department of Energy (DOE) said the hub, known as ARCH2, was awarded $30 million, the first tranche of the federal government's up to $925 million cost share, to start the project's first phase. Activities include planning, analysis and design activities as well as ongoing stakeholder and community engagement in West Virginia, Ohio and Pennsylvania, where a network of projects will be developed.

The funding is part of up to $7 billion the U.S. has allocated to establish hydrogen hubs across the country. The hubs, which position hydrogen producers and consumers together with infrastructure, are part of an effort to boost a sector that could play a vital role in lowering GHG emissions. The nation aims to produce 10 million metric tonnes of hydrogen annually by 2030.

Nearly one dozen projects associated with ARCH2 are in the works. EQT said it will construct and operate a clean hydrogen production facility to convert natural gas into syngas using autothermal reforming and into low-carbon aviation fuel and other liquids.

Other hydrogen hubs that have moved into Phase 1, expected to last up to 36 months, include the Pacific Northwest Hydrogen Hub (PNWH2). The hub was awarded $27.5 million, the first tranche of up to $1 billion. Located in Washington, Oregon and Montana, the PNWH2 hub will use renewable resources to produce clean hydrogen via electrolysis.

The Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES) was awarded $30 million, part of its up to $1.2 billion in federal cost sharing. It intends to use renewable energy to produce hydrogen at more than 10 sites.

TES, Palantir Form AI Partnership

Electric natural gas producer Tree Energy Solutions (TES) and Palantir Technologies formed a partnership to leverage the tech company's artificial intelligence software, according to a news release.

"Through this partnership, Palantir Foundry and Palantir Artificial Intelligence Platform (AIP) will support TES in supply chain management, simulation and scenario modeling for investment optimization, site selection, asset management, carbon emissions tracking, and modeling the energy transformation pipeline," the release states.

TES makes electric natural gas (e-NG) derived from hydrogen. Chemically identical to natural gas, e-NG is made by combining green hydrogen with biogenic or recycled CO_2. OGI

FINANCE & INVESTMENT

Private Producers Find Dry Powder to Reload

An E&P consolidation trend took out many of the biggest private producers inside of two years, but banks, private equity and other lenders are ready to fund a new crop of self-starters in oil and gas.

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Massive consolidation sweeping across the E&P space has reshaped the landscape. Large public companies merged with larger public companies and private operators, which produce roughly 40% of U.S. supply, were swept up in the frenzy.

But don't count out the private producer space.

"We've had too much fun doing what we did over the last 20 years," Robert Anderson, Earthstone Energy's former CEO, told *Oil and Gas Investor (OGI)*.

In a cyclical industry as capital-intensive as oil and gas production, M&A is a fundamental mechanism of the business machine. But in a relatively short period, recent consolidation has removed key legacy producers, both large and small, from the field. Large companies beget larger companies. Old-time wildcatters have handed over the reins. And some private equity firms ran out the clock on their holdings.

Private E&Ps have been party to 169 sales since the beginning of 2023, Andrew Dittmar, senior vice president at Enverus Intelligence, told *OGI*. That doesn't include mineral deals and it's not all necessarily corporate mergers; some are simply assets that changed hands. It's tricky to fully tabulate everything in the private world.

Still, it adds up to $78.3 billion and total associated production of 1,774Mboe/d worth of private transactions within 20 months.

Indeed, the opportunity to sell is significant.

While industry leaders' basic instinct is to insist that oil and gas is here to stay, that bravado has been tempered by concern that current inventories won't be enough to meet projected demand. A rush for the dwindling sets of available top tier assets now includes a sentiment that, with the right technology and enough stamina, the industry can enchant assets that are close-enough-to-core from mere pumpkins into royal carriages.

The consolidations have happened so swiftly that four of the top six private producers listed in the July edition of *OGI* are either waiting for their sales to close or no longer exist:

- ▶ Diamondback Energy bought Endeavor Energy in February 2024 for $26 billion;
- ▶ Occidental Petroleum acquired CrownRock, a joint venture of CrownQuest Operating and Lime Rock Partners, in December for $12 billion;
- ▶ Devon Energy grew its Williston footprint with the purchase of Grayson Mill Energy in July 2024 for $5 billion; and
- ▶ California Resources merged with Aera Energy to become California's largest oil and gas producer in July 2024 with a $1.1 billion deal.

The M&A craze has created a void in the upstream sector once filled by the small, private companies that tend to drive innovation.

So, what's next?

Despite lingering underinvestment in the space, commercial banks, regional banks, private equity firms and family offices say they're open to the oil and gas business. And by virtue of M&A, there are plenty of displaced

"What I don't want to do is build myself out of a company. I want to build a company for the long haul, and it doesn't have to be a gigantic public company. What we want to do is build something that is more distribution, yield-driven and cash-flow generating to have a legacy long-term business that can be passed on to the next generation of Robert Andersons or whomever it is behind us."

ROBERT ANDERSON, CEO, Petro Peak Energy

A Unit Corp. rig drills for Earthstone Energy in the Midland Basin, January 2021. Permian Resources bought Earthstone Energy for a cool $4.5 billion in December of 2023, but former CEO Robert Anderson isn't done, yet, now heading up a smaller company called Petro Peak Energy.

EARTHSTONE ENERGY

Top 20 Private Oil Operators (as of June 2024)

Bbl/d Ranking	Boe/d Ranking	Operator	Bbl/d
1	1	**CONTINENTAL RESOURCES**	337,040
2	4	**MEWBOURNE OIL**	240,327
3	5	**ENDEAVOR ENERGY***	220,403
4	12	**CROWNQUEST OPERATING***	93,635
5	13	**GRAYSON MILL OPERATING***	93,414
6	31	**AERA ENERGY***	77,692
7	16	**BIRCH OPERATIONS**	74,585
8	20	**GBK CORP.**	65,178
9	33	**SURGE OPERATING**	56,053
10	30	**VERDUN OIL CO.**	54,520
11	41	**KRAKEN RESOURCES**	49,625
12	39	**INEOS ENERGY**	47,705
13	47	**XCL RESOURCES***	44,831
14	34	**BTA OIL PRODUCERS**	42,795
15	50	**WILDFIRE ENERGY**	41,347
16	38	**PETRO-HUNT**	41,265
17	48	**SLAWSON EXPLORATION**	39,477
18	52	**FRANKLIN MOUNTAIN ENERGY**	38,568
19	8	**ENCINO ENERGY**	38,301
20	36	**TAP ROCK RESOURCES***	38,247

SOURCE: ENVERUS
* INVOLVED IN A PENDING OR RECENTLY COMPLETED SALE

"There's not a question of if we move forward, of course we will move forward. But how we move forward and maybe at what pace will have something to do with the rate at which—no pun intended—but how quickly interest rates come down."

JASON REIMBOLD, managing director of energy investment banking, BOK Financial

executives who are ready to start over.

"But it's not all easy; there's a lot of hard work," Anderson said.

At 62, Anderson certainly had the option of retreating to his "honey-do" list when Permian Resources bought Earthstone Energy for a cool $4.5 billion in December.

Turning over the chief executive role at Earthstone didn't mean he wasn't ready to take on another one. Indeed, when Anderson spoke with *OGI* in early 2023, he expected Earthstone to be on the buying side of the impending M&A cycle.

Instead, this spring Anderson opted to create a new business called Petro Peak Energy with a handful of other Earthstone executive refugees, including former COO Steve Collins.

But this time, the business plan is different.

Endeavor Energy Resources' Midland operations, October 2021. Diamondback Energy bought Endeavor in February 2024 for $26 billion.

ENDEAVOR ENERGY RESOURCES

"What I don't want to do is build myself out of a company. I want to build a company for the long haul, and it doesn't have to be a gigantic public company," he said. "What we want to do is build something that is more distribution, yield-driven and cash-flow generating to have a legacy long-term business that can be passed on to the next generation of Robert Andersons or whomever it is behind us."

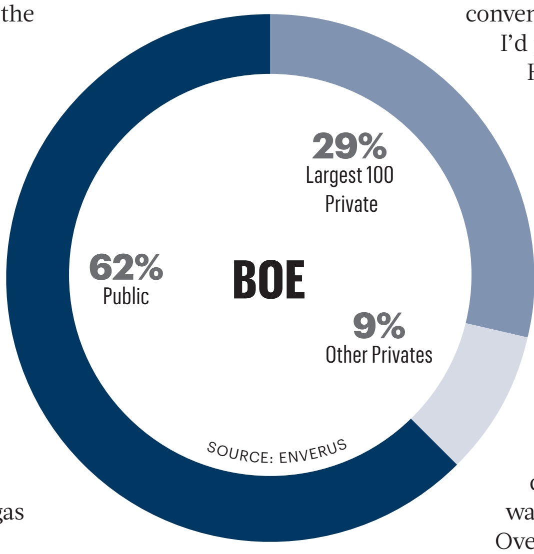
The different business plan means the investor set may differ, too.

While Anderson has had great success with private equity, the traditional quick exit strategy doesn't necessarily align with what he wants for Petro Peak.

"We need to attract or look for different investors," he said.

Enter the family office financing phenomenon that has become a common refrain in 2024 deal-making discussions. The wealth of these high net-worth individuals may originate in industries such as health care, insurance or aviation, but they are increasingly attracted to the oil and gas industry's rate of return.

Gaining entrance into the private world of this selective group takes time. Still, Anderson said, Petro Peak is making some headway and he's already established a relationship with one family office, the Vlasic Group, which has been a source of capital for both Earthstone and Oak Valley Resources, a private producer where Anderson was CEO prior to its merger with Earthstone in 2014.



Petro Peak will avoid the "knife fight for acreage" in hot spots such as the Haynesville Shale or the Midland and Delaware basins, where the build-and-flip model still reigns.

To make his case, Anderson is taking Petro Peak to conventionals and mature plays like the Central Basin Platform and the Eastern Shelf in New Mexico.

"Those are all fair game for us. And then conventional assets anywhere in Texas, and I'd put East Texas gas in there that's not Haynesville or the Western Extension, then up into the Midcontinent," he said. "There's great historical fields that have been undercapitalized and maybe sort of avoided or just haven't had the time and attention put on it by other companies. We think we can operate a little cheaper and a little more efficiently and get a few more barrels out of the ground or a few more MCFs out of the ground and just operate better and improve margins and drive returns for our investors that way."

Over time, Eagle Ford, Bakken and even Midland Basin assets will mature and be viewed as non-core by consolidated companies. That's the next cycle of M&A, Anderson said.

"It'll be startups that are folks coming out of the Pioneers, the Endeavors and changing their strategy and staying away from these hot plays, but looking for the new areas," he said. "That's what this is all about. How do we create the next round of innovation? Where is the industry

Earthstone's six-well Ratliff 9-7 pad in Upton County, Texas, completed December 2020. Former Earthstone CEO Robert Anderson says that the new start-ups that will be made after this rush of consolidation will stay away from the hot plays and focus more on innovation in new areas.

EARTHSTONE ENERGY

"[Some private equity teams] are just trying to peel off crust from these big deals, and it's hard for them to get the attention of the companies that are in the midst of this M&A. But they are trying to—either through acreage trades or farm-ins—they're trying to achieve little company makers."

JEFF TREADWAY, senior vice president and director of energy finance, Comerica

going with all this consolidation? Exxon isn't going to own everybody."

Capital X

As is the case with most oil and gas dealmaking, these transactions are composed of several moving parts. A relatively consistent oil price maintained over time gives the market some confidence, Jason Reimbold, managing director for energy investment banking at BOK Financial Securities, told *OGI*.

"We have started to see banks increase their appetite for exposure to oil and gas loans again," he said.

Several factors are at play. ESG fervor has calmed during the last year. The upstream sector's rate of return rivals that of most other industries listed on the S&P 500. And many E&Ps have managed to pay off and pay down loans.

Banks are "now looking to at least maintain, if not grow, the loan portfolios," Reimbold said. "We have started to see some competitive pressure on rates for loans in the market simply because there are more banks now pursuing these lending opportunities," despite current interest rates.

Large commercial banks with long interest in the space are also watching for the next set of E&Ps, said Jeff Treadway, senior vice president and director of energy finance at Comerica.

"Almost every bank that's in the energy business is very interested and eager to find new opportunities to fend off all of the deals that we've had pay off and go away," he told *OGI*. "Commercial banks, specifically, they all want grow loans; it's just what banks do. So, we're trying to make those businesses. We really like the energy industry. We really love the upstream and midstream subsector of it, and so we are trying to find opportunities wherever we can."

Ongoing global population growth and economic progress will make the Lower 48 the main provider of hydrocarbons to the global economy for several reasons, Marc Graham, Texas Capital's head of energy, told *OGI*.

Domestic operators have a relatively low cost of production; they work in a politically stable environment; and the Lower 48 is one of the few jurisdictions where producers are taking steps to not only decrease their carbon footprint, but also making strides in CCUS technologies, he said.

"I believe we will continue to expand where hydrocarbons

California Resources' operations. Part of the recent consolidation flurry, California Resources merged with Aera Energy to become California's largest oil and gas producer in July 2024 with a $1.1 billion deal.

CALIFORNIA RESOURCES

"The investor who wants exposure to the potential upside of discovering the next new play doesn't want the return presented by the stability of a large publicly traded, dividend-paying company. So, new companies will be formed to push the boundaries of the current basin maps and experiment with new technologies and everywhere along the spectrum of potential returns."

MARC GRAHAM, head of energy, Texas Capital

are produced in the Lower 48," Graham said. "And the expansion of plays isn't necessarily the space where large, publicly listed companies will experiment.

"New companies will be formed to turn second tier assets into first tier assets, which is the second reason I am optimistic about the formation of new E&Ps in the Lower 48. Investors sit along a spectrum of risk/return trade-offs. The investor who wants exposure to the potential upside of discovering the next new play doesn't want the return presented by the stability of a large publicly traded, dividend-paying company. So, new companies will be formed to push the boundaries of the current basin maps and experiment with new technologies and everywhere along the spectrum of potential returns."

In some instances, it will be management teams of the companies that were absorbed by consolidation. Other emerging leaders will be the up-and-comers who've been waiting for an opportunity.

"There certainly are management teams that are going to continue on, albeit it is just a part of business. We will see some people leave the sector altogether. However, I think it's going to require both to be successful," Reimbold said. "There's always going to be a need for highly experienced professionals, especially in such a highly technical sector. At the same time, there's a need for new professionals to help build these businesses, then take them forward."

The historic underinvestment in the space is where opportunity may be found.

"There simply are going to be more opportunities to build companies than there will likely be people to [work] in those companies. That's not a bad spot to be in if you happen to be one that's in the business," Reimbold said.

The funding behind the founding of those new firms may take on a different look, he said.

"I think that we very well may see more direct investment that would be groups that possibly were LPs of larger funds in the past, [that are] now backing management teams individually or bringing on people to manage investments for them.

But there will always be a role for private equity, Reimbold said.

"Debt financing, given its structure, is only going to provide so much. Truly equity is going to remain a significant component to these financings. I expect some of that is going to come from what had become the household name traditional private equity funds," he said. "And we may see new entrants to this sector as well, especially as we see an increase in deal flow and opportunities."

The impact of interest rates on bankers' engagement may depend on who you ask and the size of the transaction. Reimbold said that for the next 12 months or so, "the significance of interest rate cuts could not be overstated."

But it won't dictate whether lending happens.

"There's not a question of if we move forward, of course we will move forward. But how we move forward and maybe at what pace will have something to do with the rate at which—no pun intended—but how quickly interest rates come down," Reimbold said.

The acquiring companies during the record consolidation trend likely have billions of dollars' worth of assets to sell. That's a "hunting ground for new teams, management teams and people who were displaced as a result of these consolidations." he said.

Interest rate relief, combined with stronger market valuations, could motivate those firms with ample non-core assets from their acquisitions to sell.

But meanwhile, most of the large public E&Ps have reduced their leverage to the point they don't have to sell to pay down debt—especially if low valuations dictate asset price and high interest rates encumber potential buyers.

Several bankers stepped back from saying it would be a "wave" of emerging private producers. Consequently, the round of widely expected A&D activity may take longer to manifest.

"You'll start seeing some deals around the edges, but it's going to take time for Exxon to digest exactly what they have with Pioneer. It's going to take time for Diamondback and Endeavor to really figure out [if] there are truly non-core things that they're holding that [they] were never going to get to," Treadway said.

Discussions with some private equity teams indicates to Treadway that some "are just trying to peel off crust from these big deals, and it's hard for them to get the attention of the companies that are in the midst of this M&A. But they are trying to—either through acreage trades or farm-ins—they're trying to achieve little company makers."

"There's a whole new generation of great leaders that are coming up in the industry [who] grew up in the shales … that are starting to think about starting their own businesses."

WIL VANLOH, founder and CEO, Quantum Capital Group

Private Equity

But there is only so much private equity cash to go around in oil and gas. The amount available to the industry has diminished by up to 85% during the last five to seven years, Wil VanLoh, founder and CEO of Quantum Capital Group, told *OGI*.

Quantum is steadfast in the energy space and VanLoh is busy. The private equity firm's portfolio company, Trace Midstream Partners II, agreed in August to acquire New Mexico midstream company LM Energy Delaware, which was backed by another stalwart in the space, Old Ironsides Energy.

Private deal-making being private, though, the financial terms of the deal weren't disclosed.

VanLoh is a big believer in the need for a new crop of E&Ps, too.

"It's a really interesting position we find ourselves in because privates drove so much of the innovation in the shales. They drove so much of the growth of production. And as those assets migrate into the hands of public companies, you're probably going to see less innovation," he said.

Indeed, the so-called shale revolution was driven by the scale, technology and access to capital of the public companies in combination with the innovation, entrepreneurism and capital access of private companies, he said.

Private companies tend to be willing to take on more risk; public companies need predictability for their shareholders.

And some leaders of private companies that were sold to large enterprises still have work to do.

At the beginning of this year, Quantum Energy-backed Rockcliff Energy sold to Tokyo Gas subsidiary TG Natural Resources in a $2.7 billion deal.

After 20 years and several businesses made in conjunction with Quantum, then-Rockcliff CEO Alan Smith needed to step back and figure out what was next for him, an industry veteran.

"Maybe there's a different way to do it. And so I have been partners with Quantum for 20 years, a little over actually. And Wil [VanLoh] and I have been partners that entire time so, some discussion and strategizing and sort of working through what would be the appropriate thing for me to do at this juncture in life," he said.

Smith took on the executive chairman role of the June venture, Rockcliff III, and a new spot at Quantum as an operating partner.

The team brought in a new CEO, Sheldon Burleson, a former top executive for strategy and planning at Chesapeake Energy, to lead the business in a direction that will differ from Rockcliff's previous iterations.

"We're probably going to shift a little bit. The Haynesville has been our backyard. That's what our team has done and certainly knows how to do that. We drilled over 300 Haynesville wells in Rockcliff II, but that basin is more consolidated today," Smith said.

Rockcliff III's direction will largely focus on the Eagle Ford, based largely in the expertise of the new team. Burleson was a key executive at Chesapeake when the company had a significant holding in the South Texas Shale play. And, Smith said, much of the Rockcliff III team came from Petrohawk, which had a major presence in the Eagle Ford prior to selling to BHP.

"We just like the fact that the Eagle Ford has not been as consolidated. And we also like the different fluid windows. On the northern side of that trend line for the Eagle Ford, which literally runs from Louisiana to Mexico … North of that line is black oil, and then you go into a volatile oil, then retrograde condensate and then wet gas and finally, you go into dry gas. Those phase windows change pretty rapidly. So, you can own a position, we think, potentially and have exposure to liquids and natural gas. That is intriguing to us." OGI

FINANCE & INVESTMENT

EPC Market Keeps Its Head Above Water

Offshore investments are rising, but are hindered by project delays and inflation, according to Westwood.

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Well into the second half of 2024, E&Ps are still trying to decipher trends in a chaotic market pummeled by economic and geopolitical reverberations.

Along with ongoing wars in the Middle East and Europe, OPEC has held fast to production cuts, as the oil market contends with a 1.8 MMbbl/d undersupply, based on OPEC and International Energy Agency estimates.

A notable reduction in planned final investment decisions (FID) for offshore oil, gas and LNG projects represents a substantial downward revision from earlier projections. The sector is facing dual trends of project delays and inflationary pressures, which are taking a toll.

The offshore sector, particularly in shallow water, remains a crucial component in addressing global oil demand. Offshore engineering, procurement and construction (EPC) contracts are forecast to close at $61 billion in 2024—a 47% year-over-year increase, according to Westwood Global Energy Group.

The 2020 to 2025 period has been characterized by a steady rise in demand, which has increased by more than 1 MMbbl/d annually as the market rebounded from the COVID-19 pandemic. The growth and market stabilization has been spurred by fixed and floating platforms as well as shale operations in the Middle East and the U.S., but forecasts suggest that this growth will slow after 2025, with peak demand for liquids expected around 2030.

"So, of all this talk of new fixed and floating units, the question is, how will that begin to change the picture for offshore production when it comes to water depths?" Ben Wilby, senior analyst at Westwood, asked during a July webinar. "Truth is, it doesn't massively change things over the forecast, but the slow and gradual change in proportion of production between shallow and deep."

In 2023, shallow water fields accounted for 73% of offshore production. This dominance is expected to decline slightly, with shallow water's share projected to fall to 70% by 2028. Most of the production comes from fixed platform developments in the Gulf Cooperation Council (GCC) region comprised of Bahrain, Kuwait, Oman, Qatar, Saudi Arabia and the United Arab Emirates. The GCC is anticipated to counterbalance the decline in shallow water output as the industry transitions toward deeper waters.

"Deepwater production is forecasted [to] reach about 16.1 million barrels of water equivalent per day by 2028 and that's up from 12.7 million barrels of water equivalent per day in 2023 and this will primarily be a result of those aforementioned FPS [floating production and storage] units entering the market," Wilby said.

Offshore Investments

So far in 2024, 43 FIDs have been forecast for offshore field investments. High-profile projects such as Pemex's Zama development and Repsol's Polok and Chinwol projects offshore Mexico, as well as Ping Petroleum's Avalon development in the U.K.'s North Sea, have all faced delays. But despite these setbacks, significant developments are underway.

"For the remainder of 2024, we currently anticipate another 26 field FIDs to be sanctioned, with TotalEnergies' Block 58 project offshore Suriname being the headline for that one," Mark Adeosun, research director at Westwood, said.

BP's Kaskida project in the U.S. Gulf of Mexico (GoM) is another key project looking to come online during the period. BP said on July 30 it made an FID on the project, which is expected to start producing in 2029. Some projects from 2023, such as Shell's Sparta in the GoM, saw their FID announcements in late 2023 but only began EPC contracts in early 2024.

In the Americas, Brazil, Guyana and Mexico are on track to bolster their offshore production capabilities, with Mexico introducing 12 new projects by 2028, Westwood analysts said. The GoM will see six new FPSOs deployed in deepwater, including major projects like Beacon Offshore Energy's Shenandoah and Shell's Spar and Whale projects.

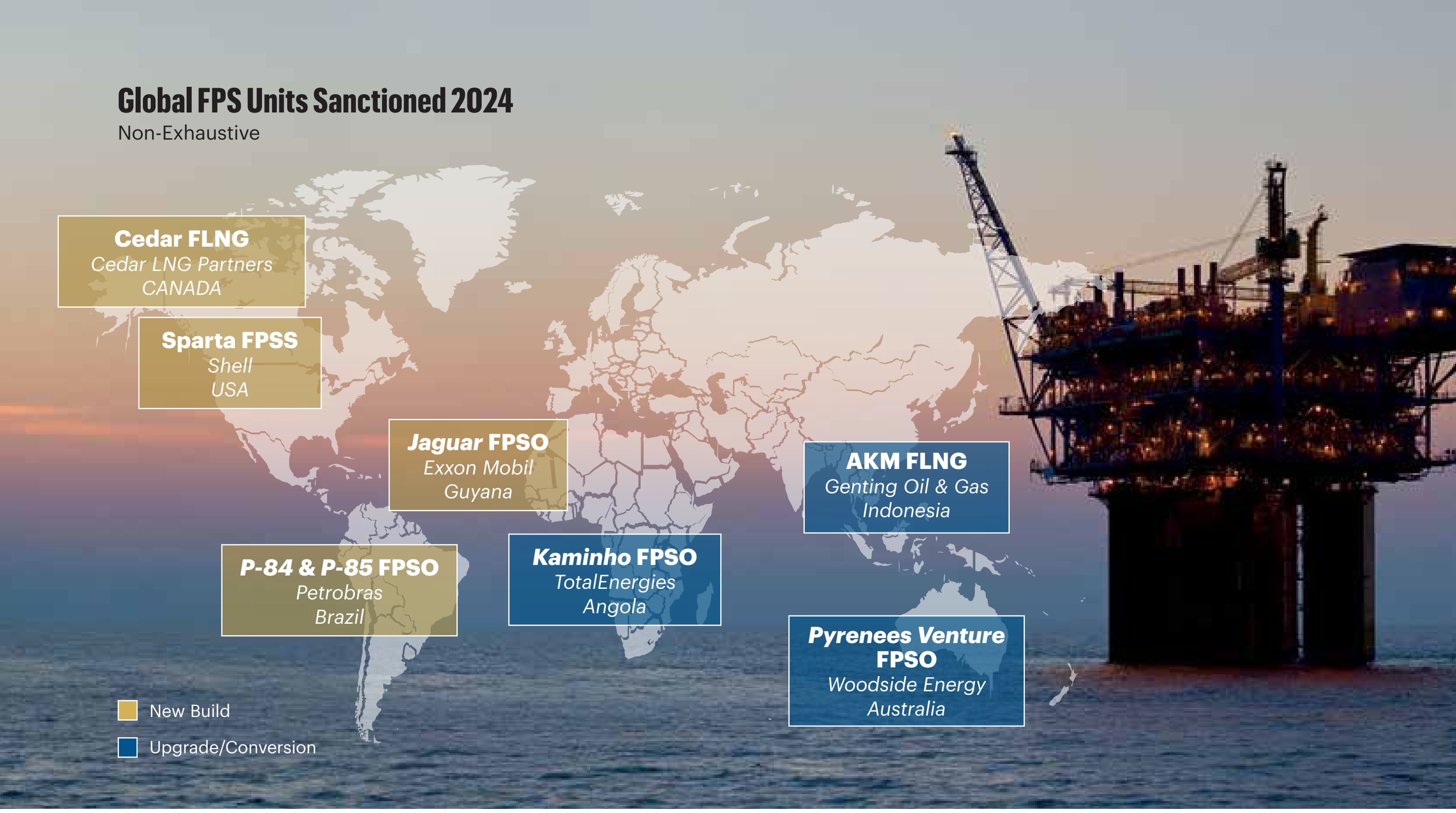
Wilby noted that shallow water production "is declining quite rapidly, but the deepwater production is of such a scale that it's still increasing," which will help balance lost volumes.

Subsea Equipment Outlook

Exxon Mobil's Whiptail project offshore Guyana has been a major driver in the subsea

Global FPS Units Sanctioned 2024

Non-Exhaustive



WESTWOOD GLOBAL ENERGY GROUP, REPSOL

Offshore engineering, procurement and construction (EPC) contracts are forecast to close at $61 billion in 2024—a 47% year-over-year increase, according to Westwood Global Energy Group.

equipment market, accounting for 44% of the subsea tree units recorded in the first half of the year. Additionally, Petrobras' Atapu Phase 2 and Sepia 2 projects offshore Brazil are notable, with an EPC award value of approximately $8.1 billion for newbuild FPSO units. Other significant projects include Energean's Kaplan project offshore Israel and Woodside's Xena III project in Australia.

The demand for subsea equipment remains robust, with forecasts indicating the need for 260 subsea tree units for the remainder of 2024. Approximately 110 of these units were awarded in the first half of the year, with about 4,200 km of subsea lines anticipated to be awarded throughout the year.

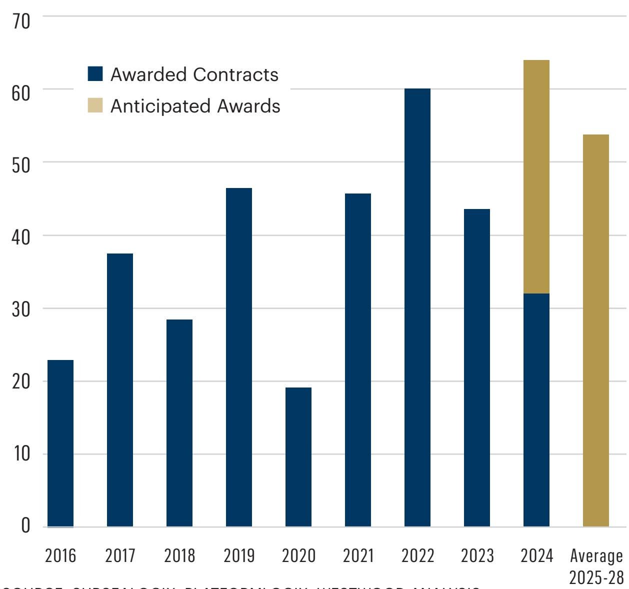
The outlook from 2025 to 2028 suggests continued strong demand for offshore EPC spending, projected at $51 billion despite inflationary pressures. The supply chain is expected to adapt, with spare capacity set to accommodate upcoming projects. Subsea tree demand is projected to average between 280 and 290 units annually post-2024, with 2025 expected to close with over 300 units.

"Though we've recorded some delays, as well as project cancellations or tender cancellations, we believe that we're beginning to expect spare capacity within the supply chain to be able to accommodate some of the projects that [are] currently in the pipeline," Adeosun said.

Adeosun's key projects to watch include Shell's Bonga North development offshore Nigeria and Aker Energy's Pecan project offshore Ghana, though both face delays. Eni's Coral North project offshore Mozambique is also a major development expected to support subsea tree demand. In Latin America, significant subsea developments include Exxon Mobil's Hammerhead and Longtail projects, as well as Shell's Gato Do Mato project offshore Brazil.

The period from 2024 to 2028 will be crucial for balancing offshore production with global demand, Westwood analysts said. With 67 FPSO deployments anticipated, including 19 units yet to be sanctioned, the industry faces potential project delays and shifts in the supply-demand equilibrium. Despite inflationary pressures and project delays, offshore production—in shallow and deep waters—remains vital to meeting the world's evolving energy needs throughout the decade, Woodside analysts said. OGI

Offshore EPC Contract Award Value



SOURCE: SUBSEALOGIX, PLATFORMLOGIX, WESTWOOD ANALYSIS

Second-Quarter Upstream Deals Topped $30B

The quarter was a stunner for U.S. upstream M&A, with transactions covering Utah, the Eagle Ford and the Bakken.

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A frenzy of upstream oil and gas dealmaking continued unabated during the second quarter, with transactions inked across Lower 48 oil country.

Upstream M&A activity surpassed more than $30 billion, according to data from Enverus Intelligence Research (EIR).

Before the latest run of consolidation, quarterly M&A value had only topped $30 billion on three occasions since the start of 2017, the firm said.

The U.S. upstream market has seen nearly $250 billion transacted in the past 12 months; nearly $90 billion worth of transactions, including July deals, have been announced this year.

"M&A momentum carried into the second quarter as pressure built on companies like ConocoPhillips, Devon Energy and SM Energy, that had previously stayed out of the market to keep pace with peers and grow in scale," said Andrew Dittmar, principal analyst at EIR. "In the case of ConocoPhillips and Devon Energy, running out of inventory doesn't appear to be as high a concern, but there is still a perception that successfully navigating the maturing phase of shale requires building resource base with M&A."

The largest transaction of the quarter was ConocoPhillips' blockbuster acquisition of public rival Marathon Oil, valued at $17.1 billion, not including debt.

The tie-up between ConocoPhillips and Marathon Oil will consolidate huge swathes of land in the Permian Basin, the Eagle Ford Shale and the Bakken.

The second-largest deal of the quarter was a joint bid by SM Energy and Northern Oil & Gas (NOG) to acquire XCL Resources, a private operator in Utah's Uinta Basin.

NOG, in partnership with SM Energy, will buy a 20% stake in XCL for $510 million. SM is paying $2.04 billion for the 80% majority interest, bringing the total deal value to $2.55 billion.

Coming in at third was Crescent Energy's agreement to acquire SilverBow Resources for $2.1 billion.

The deal, which closed on July 30, creates the second-largest operator in the Eagle Ford Shale of South Texas. Crescent also has a footprint in Utah's Uinta Basin.

In the mighty Permian Basin, Matador Resources announced a $1.9 billion acquisition of private E&P Ameredev II—the fourth-largest upstream transaction of the quarter.

The Ameredev deal includes producing assets and undeveloped acreage in Lea County, N.M., and Loving and Winkler counties, Texas—an area that operators and experts largely consider to be the core of the Permian's Delaware Basin.

A Williston Basin deal ranked fifth-largest was inked in the second quarter: TXO Partners' acquisitions from Eagle Mountain Energy Partners and Kaiser-Francis Oil Co. for $298 million.

The deals will deliver to TXO assets in the Elm Coulee field of Montana and the Russian Creek field of North Dakota.

Dealmaking extended into the third quarter, too. Devon Energy announced a $5 billion acquisition of Bakken E&P Grayson Mill Energy in early July.

Permian Priced Out

The Permian Basin, the nation's top oil-producing region, dominated dealmaking activity last year and into early 2024.

Major Permian transactions included Exxon Mobil's $60 billion acquisition of Pioneer Natural Resources, Diamondback Energy's $26 billion acquisition of Endeavor Energy Resources, and Occidental Petroleum's $12 billion acquisition of CrownRock.

But the increasing cost of buying drilling inventory in the Permian has emerged as a major theme in upstream M&A throughout this year, Dittmar said.

"With the highest quality inventory selling at premium pricing, there has been a scramble for middle-tier inventory that provides strong returns even if it isn't as economic as core Permian assets," Dittmar said.

That dynamic has led to an uptick in deal activity in mature horizontal plays, like the Eagle Ford Shale and the Williston Basin.

It also drove SM Energy into Utah's Uinta Basin, a waxy crude oil play where the company has never drilled before.

Dittmar said there's an opportunity for private equity sponsors to divest even more portfolio companies in the Eagle Ford and in the Midcontinent's SCOOP/STACK plays.

Verdun Oil, backed by EnCap Investments, and WildFire Energy, backed by Kayne Anderson and Warburg Pincus, "would be two likely sellers in the Eagle Ford," according to Enverus. OGI

KC Fed Survey: NatGas to Rise, but Not Enough for Profitability

The bank's energy survey saw activity decline in the second quarter as producers look to the back half of 2024 for natural gas prices to improve.

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Even as the price of natural gas slipped to a two-month low on July 15, producers could see better times in the upcoming winter, according to the Federal Reserve Bank of Kansas City's July energy survey.

The survey painted a less than rosy current price environment for natural gas. Since breaking $3/MMBtu in mid-June, Henry Hub prices have declined steadily. In mid-August, prices were around $2.30/MMBtu.

Those prices contrast with what respondents said they needed on average for drilling to be profitable across the fields in which they are active: $3.47/MMBtu.

"Gas prices in the Rockies are so low, we are shutting in production," said one of the respondents.

Said another: "Natural gas is a small part of our business, but even so we are going to reduce production due to historically low prices. Oil prices seem to have a bottom and reside at a comfortable level."

The survey includes a snapshot of a wide swath of states. Survey respondents offered their take on an oversupplied natural gas market and their expectations for LNG, as well as their view of other topics such as the Permian Basin's gas potential.

The second-quarter survey ran from June 14 to June 28 and included 30 responses from firms in Colorado, Kansas, Nebraska, Oklahoma, Wyoming, northern New Mexico and western Missouri.

Energy firms largely expect oil prices to remain close to $80/bbl for the next 12 months, according to the survey. Executives were more optimistic on natural gas prices, saying the Henry Hub price would rise to $3/MMBtu by the end of 2025.

Respondents' expectations on natural gas prices are in line with what other producers have said regarding demand. As more LNG export demand comes online and electrical demand rises with the construction of data centers and growth in the electric vehicle market, the gas market is expected to tighten.

"LNG export capacity will increase as new plants are commissioned. This should stabilize the market price swings to a degree," said one survey respondent. The Fed released several comments along with the survey press release, but did not identify who made the input.

In the second quarter, overall activity in the district declined, according to the survey. The survey's drilling activity index showed drilling activity, revenues and profits fell. Capex also fell, but firms reported better access to capital than at this point last year.

Respondents said the greatest risks confronting them are increased regulation, slowing economic activity and production decisions by OPEC.

"District drilling and business activity posted a decline for the sixth consecutive quarter in Q2, but is expected to rebound in coming months along with natural gas prices," Chad Wilkerson, senior vice president at the Kansas City Fed bank, said in the press release.

Firms were also asked what prices were needed for a substantial increase in drilling to occur across the fields in which they are active. The average oil price needed was $91/bbl and an average natural gas price needed was $4.68/MMBtu.

Some respondents also offered differing takes on their operations in the Midcontinent, compared to the Permian and Appalachian basins.

"The MidCon is less distressed than any time in the past six years. We are seeing more competition move here from the Permian," one respondent told the survey.

Another executive, however, observed, "Appalachia and the Permian can fully supply the USA needs for natural gas." OGI

Natural Gas Prices

Firms surveyed by the Federal Reserve Bank of Kansas City were asked the price per million Btus they needed for natural gas drilling to be profitable, and the price needed to warrant a substantial increase in drilling.

SOURCE: FEDERAL RESERVE BANK OF KANSAS CITY

Belcher: What Happens If Trump Wins?

Oil and gas industry should continue to benefit from energy transition incentives.

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As November elections approach, energy companies are starting to analyze what various outcomes could mean for their operations.

For the oil and gas sector, it is pretty clear that a Trump victory could mean less onerous regulations, more access and leasing on federal lands and offshore, and greater support for domestic production, transportation and exports.

SHUTTERSTOCK

However, with so many investments being placed in energy transition solutions, such as carbon capture, use and storage (CCUS), and hydrogen, some producers are starting to wonder if some of the tax incentives, grants and loans offered under the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA), would be rolled back under a Trump administration.

Certainly, former President Trump and many Republicans have been critical of the IRA and IIJA as wasteful spending that is itself inflationary. The IRA and IIJA programs, coupled with the CHIPS & Science Act, authorize over $1.6 trillion in federal dollars and tax credits and $1.1 trillion in direct funding.

As of April 2024, Politico reported that only 17% of that direct funding had been distributed, a fact that has been a source of criticism of the program overall. Yet while the federal government works to accelerate getting funds out the door, companies are making significant investments in projects for which they assume that tax credits will be available and to which federal grants and loans could potentially be applied.

To assume that Trump would seek and implement a wholesale repeal of the IRA and IIJA is an oversimplification of how a Trump administration would address clean energy and energy transition incentives.

First of all, a cornerstone of a Trump energy and economic policy is achieving what he calls "energy dominance"—the United States making maximum use of its ability to produce fossil energy for domestic use and global export. Therefore, it is highly unlikely that he would take any steps that would jeopardize U.S. competitiveness in the energy space, such as cutting off 45Q tax credits for CCUS projects or 45V tax credits for hydrogen production.

Trump is also a big supporter of nuclear power and advanced nuclear technology, so it is likewise unlikely that he would support a repeal of 45U or 45J tax credits for traditional and advanced nuclear power facilities.

There is also a question of political will within the Republican Party. An outright repeal would require legislation. At the very least, it would necessitate Republicans holding the House and taking control of the Senate. If they were to capture both Houses, their margins of control would likely be very small, likely negating the votes necessary to repeal the statutes or eliminate certain programs.

Responding to potential threats to commercial project economics that would result from an IRA repeal, 18 U.S. House Republican lawmakers recently sent a letter to House Speaker Mike Johnson (R-La.) asking him not to repeal the IRA, citing projects already underway that are dependent on IRA funding. In fact, many potentially impacted projects are in Johnson's home state of Louisiana.

"Prematurely repealing energy tax credits, particularly those which were used to justify investments that already broke ground, would undermine private investments and stop development that is already ongoing," the letter read. "We hear from industry and our constituents who fear the energy tax regime will once again be turned on its head due to Republican repeal efforts."

Another reason that Trump is unlikely to gut the IRA and IIJA is that these incentives play into overall trade policy. Trump will look at all of the policies in place in terms of their impact on U.S. competitiveness and global trade, especially with respect to China. He would be expected to take another look at some of the approaches that he previously used to further U.S. competitiveness, such as steel tariffs.

Trump has often commented on the Biden administration's policies to expand renewables as a "plan to make China rich" due to the fact that China is able to produce solar panels, components of batteries and electric vehicles (EV) much cheaper than U.S. manufacturers of these items.

While Trump is not in favor of expanded use of EV and renewable energy sources, he would have to balance that with the consideration that repealing the IRA and IIJA could hurt American competitiveness with China in those areas.

What is much more likely under a Trump administration would be a more surgical approach to IRA and IIJA incentives. To address the political realities associated with impacts on existing projects, not having sufficient votes to overturn statutes, and implications for global competitiveness, a Trump administration is more likely to target some of the more vulnerable programs supported by IRA and IIJA incentives.

One potential target might be EVs and EV charging stations. Last May, Transportation Secretary Pete Buttigieg revealed that of the 500,000 EV charging stations that the federal government is spending $7.5 billion to build, only eight have actually been built. It stands to reason that, given his dislike for EVs and the slow progress in building these stations, this might be a program that Trump could target, along with renewable energy incentives.

To take surgical jabs at select IRA/IIJA funded programs, a Trump administration might not need to go through a regulatory process nor a legislative process. It could choose to slow-walk those programs at the agency level. Such a process would be subject to legal challenges, which could be buttressed by the recent Supreme Court decision on the Chevron deference.

Should Trump win and Republicans take control of both houses of Congress, Congress could selectively strike certain programs and/or defund or restrict, through appropriations, federal agencies' ability to implement such programs.

In terms of issues that are of most importance to the oil and gas industry, such as CCUS and hydrogen, Trump would be unlikely to take steps that would jeopardize projects that depend on IRA/IIJA incentives. He would also likely continue to utilize oil and gas energy experts to advise his administration or serve in his cabinet.

Trump will be surrounded by advisers who support these projects, such as North Dakota Gov. Doug Burgum, a big CCUS advocate rumored to be a potential energy secretary candidate. Additionally, as Trump does not harbor any dislike for hydrogen as a fuel source, it appears unlikely that he would pursue a wholesale repeal of the hydrogen credit. Instead, Trump would likely aim to make the credit more technology-expansive, expressly including hydrogen derived from fossil fuels and nuclear energy.

For all these reasons, oil and gas projects benefiting from federal tax incentives, grants, or loans established under the IRA or IIJA will likely continue to be able to access those benefits regardless of the outcome of the election in November.

Kissler: What a Trump Win Would Mean for Oil, Stocks

It might move the price needle slightly, but OPEC would retain the upper hand in any outcome.

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This election cycle is anything but ordinary. With the events of the past few months, the U.S.–and the financial markets–are in entirely uncharted territory. Many industries, oil and gas included, are speculating what a change in presidential administration would mean.

For the oil industry, a Donald Trump win likely would move the production needle slightly, increasing production in some areas that are currently banned. However, the overall impact on global prices would be minimal but skewed to lower.

Company costs, particularly around permitting, would decline, so that oil companies would likely become more profitable. Even so, these companies probably won't be incentivized to increase production, especially if prices move lower.

We have history to show us that. From 2011 to 2019, oil production in the U.S. more than doubled, growing from below 6 MMbbl/d to more than 12 MMbbl/d. Meanwhile, energy stocks were among the worst performers in the market. As a result, the industry consolidated and focused on returns rather than growth. I believe that mentality will remain in place regardless of who is elected in November.

And what about OPEC? With ample spare capacity, OPEC is managing oil prices, which will most likely remain in a $75-$90/bbl range for Brent crude. That said, one negative scenario to consider is: If the U.S. truly increases production substantially, will OPEC counter by flooding the market?

If OPEC does so, it would hurt U.S. producers by making it unprofitable for them to drill. Saudi Arabia, the largest and most influential member of OPEC, has used that tactic to gain control of oil prices in the past–most recently, in its oil price war with Russia in 2020.

What About Equities?

Then, there's the impact to energy-related equities. If Trump were to win, it likely would be positive for the valuation of energy-related equities in the near term. Right now, energy equities trade at roughly the price-earnings (P/E) multiple of the market and generate significant free cash flow at these oil price levels. Part of this discount is concern about the terminal value of oil. That is, the question of whether it will be worthless as we move to electric vehicles (EVs) and other ways to generate electricity.

Who wins the White House can help us answer that question somewhat. For example, a Trump victory would boost oil stock valuations and, while use of EVs would continue to expand, the pace would be slow until newer technology or infrastructure is in place.

Meanwhile, having a Trump administration in place again could be negative for solar and wind power, as well as EV penetration. Since White House policy would shift away from being supportive, valuations for solar and wind likely would contract, despite the need for increased electricity coming from EV and data center demand.

Then, there's nuclear power to consider. We are maintaining a positive outlook for nuclear power-related equities and believe they may thrive in either a Trump or Kamala Harris presidency. The biggest headwind for the creation of new nuclear plants is regulation and cost, and a Trump victory likely would be positive for both.

The Bottom Line

The biggest impact on U.S. oil providers may not come from who is in the White House, but rather from OPEC. The cartel has adequate spare capacity, so oil prices are likely to remain in a tight range for some time, providing great economics for U.S. producers even as growth remains tepid. However, as mentioned earlier, there is the threat of OPEC feeling threatened and substantially increasing production to flood the market.

If Trump wins, investors likely would bid up the terminal value of oil, which would be positive for energy-related equity valuations. Additionally, the entire fossil fuel complex would likely get a lift should Trump win the election. However, that lift would come at the expense of sentiment for solar and wind power, which probably would drive valuations for those stocks lower.

Meanwhile, nuclear is probably a winner regardless of who becomes president. In fact, in 2023, 50% of Democrats and Democrat-leaning Americans and 67% of Republicans and Republican-leaning Americans supported more nuclear power plants generating electricity in the U.S., according to a Pew Research Center poll. That's the highest level of support for nuclear I've ever seen.

No one knows who will win the White House in November, but one thing is for sure: Given the increasing energy demand from artificial intelligence data centers, we're going to need more and more power in this country that's reliable and efficient.

Tellurian Deal Could Propel Woodside to LNG Powerhouse

The acquisition adds Driftwood LNG's first-phase capacity of 11 mtpa into the Australian energy giant's portfolio.

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Woodside Energy Group's $900 million deal to acquire Tellurian, which was struggling to develop its 27-million tonnes per annum (mtpa) Driftwood LNG project, not only boosts the presence of the Aussie company in the U.S. but creates a global liquefaction powerhouse to compete with the likes of Cheniere Energy, Shell, TotalEnergies, Petronas and Exxon Mobil.

The deal, announced in July, implies an enterprise value of $1.2 billion, the companies said.

"By incorporating the first phase of the Driftwood LNG project, which consists of an 11 mtpa liquefaction capacity, into Woodside's existing 20-mtpa portfolio, Woodside will emerge as one of the largest global LNG suppliers by volume," Daniel Toleman, research director for global LNG at Wood Mackenzie, said in a research note.

It is the first time a major portfolio player has assumed full strategic control of a U.S. project, Toleman said.

"We have seen companies take strategic, non-operated positions in the past, but this move indicates that Woodside wants to determine its own future by taking control of one of the best remaining LNG development sites on the Gulf Coast," he said.

Located in Louisiana, Driftwood LNG is fully permitted with both a valid non-Free Trade Agreement (FTA) LNG export authorization from the Department of Energy (DOE), and a Federal Energy Regulatory Commission (FERC) authorization, which was recently approved for an extension.

The Biden administration's pause on permitting LNG projects doesn't impact Driftwood.

Perth, Australia-based Woodside has a diversified, large-scale, low-risk portfolio with operations in Australia, Canada, the U.S. Gulf of Mexico (projects including Shenzi, Mad Dog and Atlantis), Mexico, Senegal, Timor-Leste, and Trinidad and Tobago. Woodside is also focused on leveraging infrastructure to monetize undeveloped gas, including optionality for hydrogen.

> *"We have seen companies take strategic, non-operated positions in the past, but this move indicates that Woodside wants to determine its own future by taking control of one of the best remaining LNG development sites on the Gulf Coast."*
>
> **DANIEL TOLEMAN,** research director for global LNG, Wood Mackenzie

Woodside CEO and Managing Director Meg O'Neill said the Tellurian acquisition was an attractive entry into a fully permitted pre-final investment decision (FID) development option with expansion potential. Pre-FID activities have incurred over $1 billion in expenditures to date, O'Neill said in July.

"Starting with our portfolio, this acquisition improves our already strong asset base, adding depth and optionality to our growth pipeline for the 2030s," she said. "It positions Woodside to be a global LNG powerhouse, differentiated with significant exposure across both the Pacific and Atlantic Basins.

"The Driftwood LNG development offers a pathway to complement our existing Australian LNG position, with an increase in material presence in the Atlantic Basin," O'Neill continued. "This creates opportunity for value optimization and arbitrage between the basins, underpinned by multiple competitive cost of supply LNG sources."

O'Neill said Woodside would also leverage its LNG development, operations and marketing expertise. "We will bring our multidecade track record as a world-class LNG player and our strong relationships with key suppliers and customers," she said.

Woodside's offer came at a perfect time for Tellurian, which has struggled in recent years.

Under former Executive Chairman Charif Souki, the company struggled to move forward with Driftwood. Tellurian lacked both offtake

Rendering of the Driftwood LNG site in Louisiana.

SOURCE: DRIFTWOOD LNG

"We found a great buyer. Woodside is a great company, a great LNG operator, and I think they'll be a great custodian of the assets going forward."

MARTIN HOUSTON, executive chairman, Tellurian

agreements and equity backing. However, in May 2024, under new Executive Chairman Martin Houston, Tellurian relaunched itself as a pure-play LNG company with the divestment of its Haynesville Shale upstream assets to Aethon Energy for $260 million. The Woodside deal followed two months later.

With Tellurian's liquefaction project not likely to be developed anytime soon, its decision earlier this year to sell its upstream assets extended its financial runway and also made the company a more straightforward acquisition target, Rystad Energy said in a research report.

Houston told Hart Energy that the Woodside transaction was "the right deal for everyone."

"We found a great buyer. Woodside is a great company, a great LNG operator, and I think they'll be a great custodian of the assets going forward," Houston said.

"With their very significant and well-established, well-regarded and well-run position in Australia, I think they are a global LNG force to be reckoned with," said Houston, who was part of the team that created Cheniere Energy, which today boasts 45 mtpa of capacity with plans to continue expanding.

Premium Location

SOURCE: REXTAG

Driftwood LNG Development Plan

Wood Mackenzie's base case scenario forecasts global LNG demand to grow 53% by 2033, supported by China, emerging Asian markets and growth in Europe. The Tellurian acquisition significantly improves Woodside's already well-positioned standing in the space.

Construction of Driftwood LNG's five trains will entail five phases. Phase 1 will consist of two trains with processing capacity of 5.5 mtpa each. Phases 2, 3 and 4 will each consist of a single train with a processing capacity of 5.5 mtpa each.

Woodside intends to increase capacity in the first three trains from Phases 1 and 2. The company then plans to manage the pace of investment in subsequent phases to allow the incorporation of the latest technology, said Daniel Kalms, Woodside's international COO.

Driftwood also includes a 37-mile pipeline, which provides multiple options for sourcing low-cost feedgas from the Haynesville and other regions, such as the Eagle Ford.

There is a second 780-acre expansion site further south that offers future development optionality. A second Driftwood LNG site could allow for an additional 30 mtpa in the future, subject to obtaining necessary permits and export authorization.

Kalms said Woodside currently estimates a development cost between $900 per tonne and $960 per tonne of capacity for Phases 1 and 2. This includes engineering, procurement and construction (EPC), and owner's costs and contingency, but excludes the pipeline. A fully developed Driftwood LNG, excluding the pipeline, could require a minimal investment of $24.8 billion to $26.4 billion.

Woodside expects to complete the Tellurian deal in fourth-quarter 2024. The company is targeting FID readiness for Phase 1 in first-quarter 2025, Kalms said, "with a pathway to achieving the return targets of our capital allocation framework."

Kalms said Driftwood had FERC approval until second-quarter 2029.

"While several U.S. LNG projects are currently navigating challenges in light of the Biden administration's pause, the Driftwood LNG project's favorable position may propel it ahead in the pre-FID queue, reinforcing Woodside's strategic foresight in navigating the evolving dynamics of the LNG market," said Wood Mackenzie's Toleman.

O'Neill said that, despite all the potential new LNG coming into the market, Woodside was well positioned to be competitive with other projects to capture the market.

Funding Driftwood

Woodside has three near-term growth opportunities in the pipeline, O'Neill told *Oil and Gas Investor* in April.

The projects include a massive liquefaction project at Pluto Train 2 in Australia, a deepwater project in Mexico at Trion and another deepwater project in Senegal at Sangomar. Of the three, the latter is already online and the two in Australia and Mexico will come online within the next five years.

Woodside's purchase of Tellurian could re-prioritize the Australian company's project pipeline, potentially sidelining Browse, Australia's largest untapped conventional gas resource, according to Rystad. The analysts expect Woodside to invest around $21 billion between 2024 and 2030. If Driftwood LNG Phase 1 is developed with 100% equity, total investment could exceed $30 billion.

"It would make Woodside the sixth-biggest public player in the world by net liquefaction capacity by 2030 and the fourth largest when excluding national oil companies and infrastructure players," Rystad said.

Woodside has a strong underlying business generating significant cashflows, a robust investment grade credit rating and a strong balance sheet.

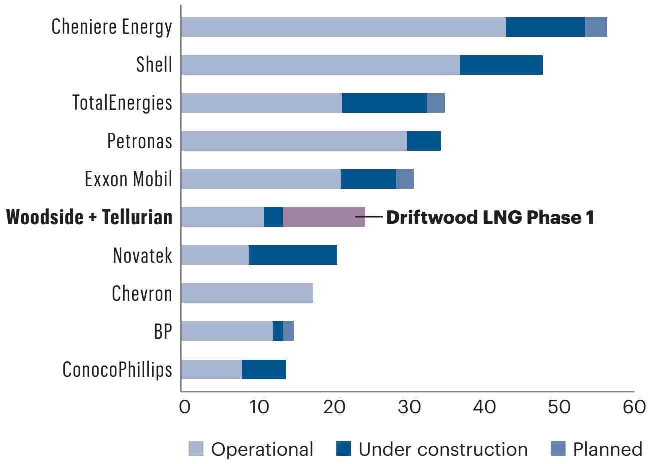
O'Neill said Woodside's balance sheet was "in great shape with approximately 13% gearing at the end of June, which is at the lower end of our target range, and liquidity of

PHOTO CREDIT

First modules arrive for Pluto Train 2 in Karratha, Western Australia. The massive liquefaction project is one of three near-term growth opportunities in the pipeline, Woodside CEO and Managing Director Meg O'Neill told Oil and Gas Investor in April. The purchase of Tellurian could re-prioritize the Australian company's project pipeline.

Top 10 Public Companies by Net Liquefaction Capacity by 2030

Million tonnes of liquefied natural gas (LNG)



SOURCE: RYSTAD

approximately $8.5 billion."

Woodside doesn't intend to use any project financing, O'Neill said. The company expects to bring in high-quality partners to Driftwood LNG and is targeting an equity sell-down of around 50%.

"We have multiple pathways to funding, including bringing in strategic partners to reduce our equity exposure in this project. We have already received multiple inbounds from companies interested in working with us in the U.S. LNG market," she said.

Rystad said potential suitors could include Saudi Aramco and ADNOC, as well as Japanese LNG buyers.

But Rystad warned that Woodside's ability to reach FID by first-quarter 2025 was ambitious. The company must first complete the acquisition and finalize the EPC contract with Bechtel, while it simultaneously works to sell down its equity, the consultancy said.

"While Woodside's involvement improves the prospects of achieving Driftwood's FID, challenges remain," Rystad said. OGI

Tellurian's Houston: 'Right Deal for Everyone'

Executive chairman lauds Woodside's plans for Driftwood LNG following its purchase.

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Q&A

Woodside Energy Group's $900 million deal to buy Tellurian, announced in July, brings a strong natural gas player to the Texas Gulf Coast that is financially capable of bringing the massive Driftwood LNG project to fruition.

Woodside boasts a diversified, large-scale, low-risk portfolio. The Perth, Australia-based company operates in Australia, Canada, the Gulf of Mexico, Mexico, Senegal, Timor-Leste, and Trinidad and Tobago. In the piped-gas and LNG spaces, Woodside is focused on leveraging infrastructure to monetize undeveloped gas, including optionality for hydrogen.

With Driftwood LNG, Tellurian's proposed export project in Calcasieu Parish, La., Woodside gains a project with a potential liquefaction capacity of up to 27.6 million tonnes per annum (mtpa). The development, when both phases are completed, includes five plants, up to 20 liquefaction trains, three full containment LNG storage tanks and three marine berths. The deal with Woodside puts Tellurian's earlier estimates of producing its first LNG by 2028 back on track.

Tellurian's Executive Chairman Martin Houston discussed the transaction, which he stressed "was the right deal," with Pietro D. Pitts, Hart Energy's international managing editor, in July.

Pietro Donatello Pitts: Seems a lot has happened in the last year, starting with Executive Chairman Charif Souki's departure, then the Aethon Energy deal and now this. Do you think that's what really attracted Woodside?

Martin Houston: We had to play the hand we were dealt, and we prosecuted a lot of commercial options. But we feel this was the right deal. I can't stress enough that this was the right deal and the proxy [statement] will tell the story in graphic detail. But, for those that wonder whether what could have been or might have been or should have been, based on my 40-plus years in this industry and the board's judgement, this is the right call.

PDP: Are you satisfied with the $1 per share offer from Woodside, considering the difficulties you've had progressing Driftwood and then Tellurian's stock price before the deal was announced?

MH: We opened the aperture and looked at all of the commercial opportunities. We looked at a much broader range of transaction sites, including those of the company. And over the seven months we prosecuted on lots of discussions and conversations and negotiations, at the same time managing the balance sheets, the permits and a whole bunch of other things.

When the board came to review where we were and the options in front of us, of all of the options that we faced, this was the right one, in our view, for all of our stakeholders. And our stakeholders include our shareholders, employees, contractors [Bechtel and Baker Hughes and others] and the local communities in Louisiana.

We had a bunch of diverse and differentiated stakeholders, and we took the view that this is the right deal for everyone. We found a great buyer. Woodside is a great company, a great LNG operator, and I think they'll be a great custodian of the assets going forward.

PDP: Over the course of the first half of 2024, Tellurian was shopping Driftwood to companies other than Woodside, including Aramco. Was the Woodside offer the only offer?

MH: When the proxy statement is published in less than 60 days, it'll outline everything from what the board considered, who we were talking to and what the options were. It will be a full and very transparent view of what happened and this whole transaction. I don't want to preface it; I want people to see the full story rather than pick one or two aspects of it. Clearly, we did have a lot of discussions on different commercial aspects, such as continuing to sell LNG. We were looking at tolling arrangements. We were looking at the sale of the company and a part in Driftwood. And we had great help from [financial adviser] Lazard and other advisers, and we basically didn't leave a stone unturned.

PDP: The transaction will close in fourth-quarter 2024 and Woodside looks to take a final investment decision (FID) in first-quarter 2025. Is there an idea of whether that FID will only be for Phase I?

MH: I think it depends on [Woodside's] own process of potentially finding investors. I think they have lots of options in front of them. I think they're determined to meet the FID dates

Woodside Energy's Pluto LNG plant in western Australia processes natural gas from the offshore Pluto and Xena fields. The company's purchase of Tellurian brings a global LNG powerhouse to the Gulf Coast.

WOODSIDE ENERGY GROUP

"I think buyers will appear. They will like the speed of delivery of Driftwood and frankly, I think the pricing is good."

MARTIN HOUSTON, executive chairman, Tellurian

they have published. They are basically funding technical and construction activities from now going forward and putting money into the project in a view to maintain that timeline, honoring the permits, working with the regulators and local officials. I think they're doing the right thing. They're pressing ahead with speed and determination.

PDP: Where does Driftwood stand in terms of construction progress?
MH: We've continued to have Bechtel on site and continued to do small amounts of work, including around another batch of piles to be driven into the ground at the site. Bechtel was [always] working in the background, and I'm pleased for the people of Louisiana, for the stakeholders in the state, for the regulators who supported those and put their faith in those.

PDP: Are there any updates regarding previous and current offtake announcements, one of which includes Aethon Energy, that you can talk about?
MH: We've had plenty of FID discussions going on, but going forward, this is very much Woodside's business. There will be a handover process so they understand where we were and what we were doing. My global macro sense, given the additional certainty now with Woodside's balance sheet connected to the project: I think buyers will appear. They will like the speed of delivery of Driftwood and frankly, I think the pricing is good. I think it's very attractive. And it's a new project, which gives diversity. My sense is that it's going to look very attractive for LNG buyers, particularly with Woodside as the owner.

PDP: What was the impact of the Biden administration's permitting pause on Tellurian's ability to turn around its situation and attract a company like Woodside?
MH: I think it was a double-edged sword. It is clearly p ositive for Woodside because they're stepping into a fully approved project which is already under construction and moving ahead.

For us, the pause caused people to stop and wonder what was going to happen with a potential change of [presidential] administration and so on. It got people thinking, there's no doubt about it. I think it happened at a time when global prices were pretty moderate and as people have calmed down after the Ukraine situation. Then, we had a globally warm winter, which had a dampening effect on prices. So, it was a good time to be fully approved, and the appetite for the buyers was tempered by external events, and also, a lack of understanding about what the future is likely to hold in U.S. politics.

So, I think in some ways it was an advantage and [in] other ways it wasn't, but certainly in terms of getting the deal done with Woodside, it was a great advantage.

PDP: The Driftwood location lends itself to LNG exports to Europe and then Asia. Do you see any perceived change in that strategy?
MH: I can't talk on behalf of Woodside but they have a great global portfolio and this makes them a huge player in North America if you look at the potential 27.6 mtpa with Driftwood. It makes them a very serious player in U.S. LNG. With their very significant and well-established, well-regarded and well-run position in Australia, I think they are a global LNG force to be reckoned with. OGI

Paisie: Geopolitics, Economic News Rattle Oil Markets

Demand expected to outstrip supply in 3Q, with prices in the $80s.

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.

Since our article in the August *Oil and Gas Investor*, oil prices have been volatile for several reasons, including concerns about the strength of demand because of disappointing economic news, and especially so with respect to China.

- The National Bureau of Statistics (NBS) purchasing managers' index (PMI) for manufacturing decreased to 49.4 in July from 49.5 in June, which is the third consecutive month of contraction (readings below 50 indicate contraction).
- China's non-manufacturing sector is also showing signs of stress, with the NBS PMI, which includes services and construction, decreasing to 50.2 from 50.5 in June.
- While the economy has been stagnating, it does not appear that the Chinese government is planning to provide any significant economic stimulus; instead the government is indicating that the focus will remain on long-term goals, which include the development of advanced technologies.

The concerns about demand were further exasperated by the weak July jobs reports, which showed that the U.S. added only 114,000 nonfarm jobs in July, and the number of jobs added in June was revised downward to 179,000. For the previous 12 months, the monthly increase in jobs averaged 215,000. Additionally, the unemployment rate increased to 4.3%, which is the highest since October 2021.

Coupled with the disappointing economic news were concerns about the alignment of oil supply with demand. While OPEC+ announced that it was maintaining its current supply cuts, the cartel also stated the voluntary cuts of 2.2 MMbbl/d would be phased out starting in October 2024. These factors pushed oil prices downward through July and the beginning of August, with the price of WTI decreasing from $83.88/bbl on July 3 to $72.54/bbl on Aug. 5.

Oil prices started rebounding from the lows in the following week with data pertaining to the U.S. service sector surprising to the upside. The PMI for non-manufacturing released by the Institute for Supply Management (ISM) came in at 51.4 for July from 48.8 in June with a strengthening in new orders and the first uptick in employment since February of this year.

Additional support has been provided by crude inventories in the U.S. being drawn down for six consecutive weeks and inventory levels falling below the five-year average. Moreover, the geopolitical situation in the Middle East has become more precarious with concerns that Iran and Hezbollah could attack Israel in response to recent high-profile attacks undertaken by Israel. The risk of a wider conflict is also increasing, with the potential for Iran to get direct support from China and Russia.

The U.S. is already involved in the conflict with two aircraft carrier groups and a guided missile submarine in the region, and has previously helped Israel defend against the Iranian missile attack in April in response to Israel assassinating high-level Iranian officials in Syria.

While the geopolitical risk premium has increased, we are not expecting any major price spikes because we do not expect any material disruption to the volume of oil being put into the market. And despite the concerns about the resiliency of the global economy, we are maintaining our forecast that oil demand for 2024 will increase by 1.2 MMbbl/d in comparison to 2023. We are also forecasting that demand in the fourth quarter will be 2.08 MMbbl/d more than in fourth-quarter 2023.

Coupled with our expectations for supply, we are forecasting that demand will outstrip supply by 1.32 MMbbl/d during the third quarter, and by 1.62 MMbbl/d during the fourth quarter. Therefore, we think supply/demand fundamentals will be supportive of higher oil prices during the remainder of the year, with the price of Brent moving back to around $85/bbl and the price of WTI moving above $80/bbl.

As we pointed out in August, there are risks to the price forecasts. Besides the possibility of geopolitical shocks stemming from the Middle East–as well as from the Russia-Ukraine conflict–there are risks pertaining to the supply/demand fundamentals, most notably downside risks.

China's oil demand could continue to disappoint as it did in the second quarter when demand, in comparison to second-quarter 2023, was slightly negative. With respect to oil supply, OPEC+ faces the inherently difficult challenge of getting its members to comply with the agreed quotas. OGI

Pitts: Is the Permian-Mexico-Asia Gas Route at Risk?

Delayed construction of Mexican LNG projects hinders U.S. producers' ability to improve access to thriving markets.

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Five natural gas liquefaction projects planned on Mexico's Pacific Coast present vast opportunity for Mexico, as well as the potential for U.S. producers to boost gas exports to Asian buyers who represent enormous growing demand.

Mexico currently takes on Texas piped-gas to the tune of around 6 Bcf/d. In the future, the plan is to also take on Permian Basin feedgas to liquefy and export, particularly to Asia, which leads global LNG demand and will drive long-term growth.

The advantages would be game-changing. LNG cargoes from the U.S. Gulf Coast must traverse an arduous route through the Panama Canal to reach Asia. Exports from Mexico's Pacific Coast, however, offer a clear competitive advantage because they take a direct route to key Asian markets. Securing those markets clears the way forward for the proposed liquefaction projects, which would add processing capacity of 7.8 Bcf/d to the global market.

But there are several hurdles for project developers, and only a fraction of the new capacity is coming to near-term fruition.

So far, the sole final investment decision was made by Sempra Infrastructure for first-phase development of its Energía Costa Azul (ECA) project in Ensenada, Baja California. Capacity of the first phase is 0.4 Bcf/d. No other plants are under construction.

Projects that remain uncertain include ECA's 1.6 Bcf/d second phase; Mexico Pacific's 4 Bcf/d Saguaro Energia LNG project in Sonora (Puerto Libertad); LNG Alliance's 1 Bcf/d Amigo LNG (Epcilon LNG) project in Sonora (Guaymas); Sempra Infrastructure's 0.4 Bcf/d Vista Pacifico LNG project in Sinaloa (Topolobampo); and Sempra Infrastructure and Mexico's Federal Electric Commission's 0.4 Bcf/d Salina Cruz LNG project in Oaxaca (Salina Cruz).

Asian buyers are especially keen to see Mexico's projects come online. Growing populations translate to growing demand, and Asian buyers subject to price inflation in recent years are serious about diversifying the source of their suppliers.

Many Asian buyers were priced out of the market in 2022, following Russia's spring invasion of Ukraine. When Europe's LNG buyers realized the peril of depending on Russian natural gas, they sought supply

SEMPRA INFRASTRUCTURE

Sempra Infrastructure has made a final investment decision on the first stage of development for its Energía Costa Azul (ECA) project in Ensenada, Baja California—the sole project to reach that point out of five currently planned on Mexico's Pacific Coast.

elsewhere in a buying spree that lifted the price of LNG beyond what some Asian customers could afford. For now, LNG prices at the Title Transfer Facility in Europe and the Japan Korea Marker in Asia have stabilized as piped-gas and LNG supply security risks have all but ceased.

Asian countries in general have moved to lock in long-term LNG volumes from a diverse base of suppliers including Australia, the U.S. and Qatar to avoid a repeat of the summer of 2022. Those buying tendencies were somewhat amplified when the Biden administration enacted a pause in permitting for LNG facilities in January that raised uncertainties around U.S. LNG projects post-2030.

The future build-out of these Mexican LNG projects is mired in uncertainty tied to recent elections in Mexico, which saw Claudia Sheinbaum Pardo win the presidency.

In Mexico, developers of the Mexican liquefaction projects have to deal with inherent issues such as security risks, a slow regulatory process and overlay of U.S. regulation for gas exports. They also have to contend with potential changes related to Mexico's national security or energy security, as well as land disputes or environmental and social impact permit challenges. Mexico is also lagging on pipeline transport.

Asian LNG buyers have reason to be concerned about future Mexico LNG cargoes. Will that push them into the welcoming arms of the Qataris, the Aussies, the Canadians or other LNG exporters? Most likely, but to what extent, only time will tell. OGI

AROUND THE WORLD

Argentina's Vaca Muerta Shale could see ramped up production from Vista Energy.

SHUTTERSTOCK

Argentina

Vista CEO: Bidding for Exxon's Vaca Muerta Assets 'Very Competitive'

Vista Energy is ramping up oil and gas production from Argentina's prolific Vaca Muerta Shale amid a competitive landscape for M&A, CEO Miguel Galuccio said during Vista's second-quarter earnings call in July.

Vista is Argentina's second-largest oil and gas producer, only behind state-owned YPF.

As competition to purchase U.S. shale assets heats up, analysts say producers are weighing their options in international shale plays like Argentina's Vaca Muerta or Canada's Montney Shale.

Competition for assets within Argentina is intense, Galuccio said. U.S. supermajor Exxon Mobil is reportedly exploring a $1 billion sale of its shale assets in the Vaca Muerta play. Galuccio said Vista is participating in Exxon's Argentina divestment process.

"I think we are a competitive bidder," Galuccio said during the earnings call. "It's a very competitive process."

Exxon was granted a 35-year concession in Vaca Muerta for the Bajo del Choique-La Invernada Block by the Neuquén provincial government in 2015.

The concession includes a 99,000-acre block located around 58 miles northwest of Añelo and 114 miles northwest of Neuquén city.

Across its Argentina portfolio, Exxon held 2.9 million net acres as of year-end 2023, 2.6 million of which were offshore.

Exxon completed 4.4 net development wells within Argentina in 2023, per regulatory filings. The company began the process to divest the assets around August 2023, according to Reuters.

Exxon's Vaca Muerta assets would be "nice to have" for Vista, Galuccio said, but emphasized that an unsuccessful bidding process wouldn't impact the company's plans going forward.

Canada

Shell Targets Mid-2025 for Start of Canadian LNG Project

U.K.-based Shell expects first production from the LNG Canada export project in Kitimat, British Columbia, to start flowing in mid-2025.

"We're working hard to achieve first production from our large LNG joint venture project in Canada by [the] middle of next year," Shell CEO Wael Sawan said in August.

LNG Canada will consist of two trains with a combined processing capacity of 14 million tonnes per annum (mtpa). The project's global customers include China, where LNG will be used to generate power at 45% to 55% of the carbon emissions released by burning coal, according to Shell.

“We’re working hard to achieve first production from our large LNG joint venture project in Canada by [the] middle of next year.”

WAEL SAWAN, CEO, Shell

LNG Canada is the largest energy investment in Canadian history. Shell has a non-operated 40% interest in the project, which also includes partners Petronas, PetroChina, Mitsubishi and KOGAS.

Sawan remains bullish around LNG demand through 2040.

“[LNG,] with a 50% growth trajectory between now and 2040, with this being really the only serious credible solution that gives you both energy security as well as decarbonizing the energy system in the particular sectors in which it works,” Sawan said. “I continue to be very bullish about the role of LNG. And we will go through cycles, we will undoubtedly go through cycles.”

To get through the cycles, Sawan said Shell linked Henry Hub offtake agreements into Brent markets.

Sawan continued: “We look at locking in long-term agreements so that we do not have the volatility of the market in the short term while still having some exposure to spot.”

Guyana

Offshore Guyana Keeps on Giving

Hess Corp.’s net production in Stabroek, where it has a 30% interest, averaged 192,000 bbl/d in the second quarter, up 75% compared to 110,000 bbl/d in second-quarter 2023. Higher production was due to the start of Hess’ third development on the block, Payara, in November 2023.

Payara reached its initial gross production capacity of 220,000 bbl/d in January.

In the second quarter, 14 oil cargos were sold from Guyana, compared to nine in second-quarter 2023. In the third quarter, Hess expects 14 oil cargos to be sold.

Also in the third quarter, Hess expects net production to dip to between 170,000 bbl/d and 175,000 bbl/d, reflecting downtime associated with the *Liza Destiny* and the *Liza Unity* FPSOs. The downtime is related to pipeline and field hook-up for a planned gas-to-energy project and production optimization work at the *Liza Unity*.

Production in Stabroek is expected to continue to rise as additional FPSOs are brought online by operator Exxon Mobil.

Yellowtail, the fourth development, was sanctioned in April 2022. It will have a gross production capacity of 250,000 bbl/d. First production is expected in 2025.

Uaru, the fifth development, was sanctioned in April 2023. It will have a gross production capacity of 250,000 bbl/d. First production is expected in 2026.

Whiptail, the sixth development, was sanctioned in April 2024. It will have a gross production capacity of 250,000 bbl/d. First production is expected by year-end 2027.

Exxon Surprises with Smaller FPSO for Guyana’s Hammerhead Project

Exxon Mobil’s seventh project offshore Guyana, Hammerhead, will feature an FPSO with 28% less processing capacity than the previous three FPSOs announced for the deepwater Stabroek Block–Yellowtail, Uaru and Whiptail.

The FPSO for Hammerhead is expected to add 120,000 bbl/d to 180,000 bbl/d of production capacity. The FPSO will be able to store between 1.4 MMbbl and 2 MMbbl, Exxon said in its June application for environmental authorization filed with Guyana’s Environmental Protection Agency (EPA). The document was officially posted to the Guyana EPA’s website and made available to the public in July.

As a result, the Hammerhead FPSO will be the second-smallest in the Exxon fleet offshore Guyana, along with the 140,000 bbl/d *Liza Destiny* FPSO assigned to the Liza Phase 1 development.

“Like all our vessel designs, we consider a range of factors that allow us to maximize resource recovery given the characteristics of a particular location,” Exxon told Hart Energy via email. “As a result, Hammerhead will likely be a different size than the other six FPSOs, but with the same degree of optimism for yet another industry-leading development.”

Hammerhead will have an estimated duration of at least 20 years, with startup expected in 2029. The project will also produce between 60 MMcf/d and 120 MMcf/d of gas, according to the project summary that accompanied the application.

Exxon affiliate Exxon Mobil Guyana operates the 6.6-million-acre Stabroek Block with 45% interest on behalf of partners Hess Guyana Exploration, which holds 30% interest, and CNOOC Petroleum Guyana, with 25% interest.

The consortium started producing oil from Stabroek in December 2019. To date, three developments with associated FPSOs are producing over 600,000 bbl/d. Exxon and Hess have reiterated there is potential for up to 10 FPSOs to develop the over 11 Bboe of estimated gross discovered recoverable resources in Stabroek.

Stabroek Projects Offshore Guyana

Project Queue	Project Name	Initial Capacity (bbl/d)	Status
1	Liza Phase I	140,000	FID taken
2	Liza Phase II	220,000	FID taken
3	Payara	220,000	FID taken
4	Yellowtail	250,000	FID taken
5	Uaru	250,000	FID taken
6	Whiptail	250,000	FID taken
7	Hammerhead	180,000	EPA application filed
	TOTALS	1,510,000	

NOTE: INITIAL FPSO CAPACITIES BEFORE BOTTLENECKING.
SOURCE: DATA FROM EXXON MOBILE AND HESS COMPANY REPORTS.

Mexico

Pemex Hits Debt Target, Struggles to Reverse Production Declines

Petróleos Mexicanos (Pemex) further reduced its long-term debt during the second quarter, which now sits just below the $100 billion mark. But the company continues to struggle to reverse production declines.

State-owned Pemex reported total long-term debt of $99.4 billion at the end of the second quarter, down $2.1 billion compared to the end of the first quarter, Carlos Cortez, the company's corporate finance director said during the company's second-quarter earnings webcast in July.

Pemex has reduced its debt by $6.7 billion since the end of 2023, when it stood at $106.1 billion.

The debt reduction efforts have been possible due to coordination between Mexico's Ministry of Finance and Public Credit, which addresses Pemex's financial needs, coupled with capital contributions from the Federal Government, Cortez said.

Trinidad and Tobago

Shell Trinidad Takes FID at Manatee Offshore Gas Field

Shell's subsidiary Shell Trinidad and Tobago has taken FID on the Manatee cross-border gas field straddling the maritime borders of Trinidad and Tobago and Venezuela.

Manatee will start production in 2027 and add much-needed volumes to Trinidad's gas production profile.

Manatee's production is expected to peak at 104,000 boe/d or 604 MMcf/d of natural gas, Shell said in July. This represents around 19% of Trinidad's average gas production of 2,367 MMcf/d in March 2024, according to Trinidad's Minister of Energy and Energy Industries (MEEI).

"Today's announcement by Shell is a great achievement for Trinidad and Tobago," Stuart R. Young, who heads the twin-island country's MEEI, told Hart Energy in a July email. "This development will be the most significant hydrocarbon development in Trinidad and Tobago."

Trinidad's gas production has in general trended downward after peaking at 4.52 MMcf/d in February 2010, according to MEEI data, owing to declines at mature fields and a lack of attractive fiscal reforms. However, over the near term, a number of gas developments in Trinidad are expected to continue to add to the Caribbean country's existing gas production profile.

"This is a very significant development for Trinidad and Tobago and will help create stability for the country's gas industry and by extension, our energy services companies," the Energy Chamber of Trinidad and Tobago said in July on its website.

The Manatee gas field will supply Trinidad's Atlantic LNG facility, maximizing Shell's asset potential by expanding utilization at existing LNG plants, Shell said in a press release.

The announcement bodes well for Trinidad's four-train 14.8 million tonnes per annum (mtpa) Atlantic liquefaction plant. Atlantic LNG continues to operate with just three trains, owing to a scarcity of gas supply and disagreements among partners in the facility. Production at Train 1 has been halted since December 2020, according to the MEEI data.

Additionally, a number of Trinidad-based plants that produce ammonia and methanol for export and have been impacted by the gas shortage will also benefit from the uptick in production to come from Manatee and other developments in the future.

"This project will help meet the increasing demand for natural gas globally while also addressing the energy needs of our customers domestically in Trinidad," Shell's Integrated Gas and Upstream Director Zoë Yujnovich said in the release.

Venezuela

BP and NGC Sign E&P Deal for Offshore Venezuelan Cocuina Field

BP and The National Gas Company of Trinidad and Tobago signed a 20-year natural gas E&P agreement related to the offshore Venezuelan Cocuina gas field.

Development of the Cocuina Field, in Venezuela's Plataforma Deltana, will allow Venezuela to develop its non-associated gas reserves and provide Trinidad with gas to supply its ammonia, methanol and LNG sectors.

Cocuina, part of Manakin-Cocuina cross border gas field, will produce an estimated 400 MMcf/d, the Energy Chamber of Trinidad and Tobago said in a July press release. BP already holds the license for the Manakin Field located on the Trinidad side of the maritime border.

Production from the field is anticipated to supply 25% of Trinidad's petrochemical sector while 75% will be destined to supply Atlantic LNG with much needed feedgas.

"This achievement is unprecedented and has never been done before in Trinidad and Tobago and Venezuela for a cross-border hydrocarbon field," Stuart Young, the head of Trinidad's Ministry of Energy and Energy Industries (MEEI) said in July on social media. OGI

Shell Trinidad and Tobago's FID on the Manatee cross-border gas field bodes well for Trinidad's Atlantic LNG facility.

ATLANTIC LNG

MIDSTREAM

Overwhelming Expectations for AI and Natural Gas

Producers and midstream companies anticipate a major boost in demand, but building up the power supply will be a complicated process.

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Some of Jim Grice's clients have been so focused on scooping up natural gas for data centers that they've invented a new, not-exactly-accurate conversion.

"I had a client call the other day and talk about how they had confirmed that they had 400 megawatts of gas supply at the site," said Grice, co-chair of the energy and infrastructure team at Akerman, a corporate law firm based in Houston with clients around the country.

"I thought that was an interesting way to look at it. Usually, they talk about BTUs, and the person I was talking to was making the conversion from gas capacity all the way down to energy," he told *Oil and Gas Investor (OGI)*.

Grice's office specializes in advising those in the business of data centers, real estate, electric power, energy and infrastructure. Its practitioners have a bird's-eye view of the diverse business sectors developing artificial intelligence (AI) data centers and the buildup of energy supplies required.

It's also a vantage point that offers some clarity on the complications involved. The energy industry is in the middle of building up massive nationwide energy infrastructure for data centers and these new facilities bring along new types of contract requirements. Among them, keeping prices stable for a commodity that fluctuates wildly.

Data centers are developing quickly and each facility's lifespan comes with a question mark. For natural gas suppliers, that entails long-term commitments for a commodity with a price that is rarely stable.

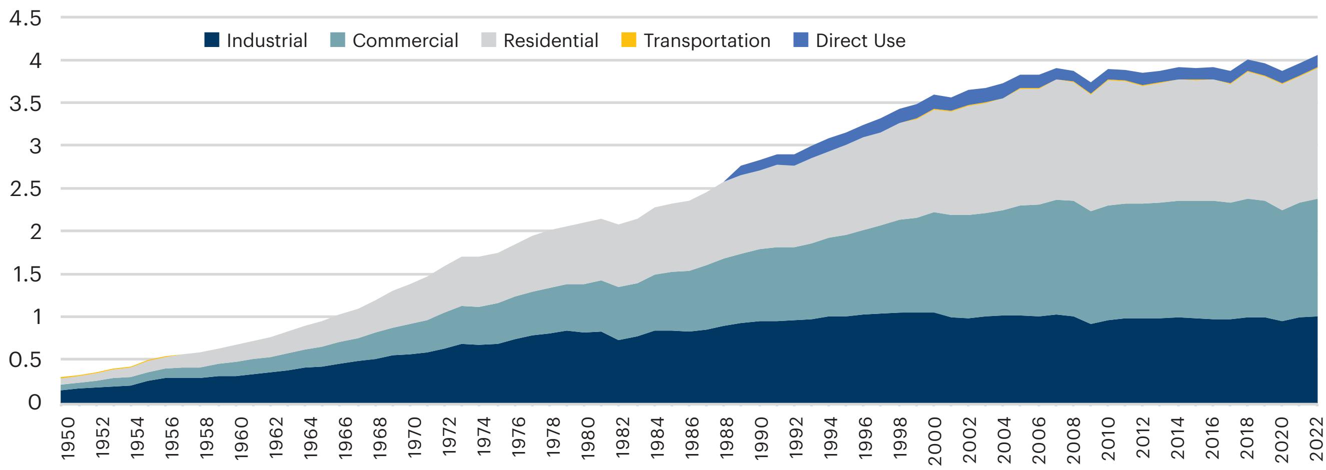
Grice said the data centers and their gas suppliers will most likely find a solution, but challenges lie ahead.

"Most of those folks (tech companies) have very responsible approaches towards renewables and carbon emissions and climate change, but they still have a job to do as well. That's the balancing act for all of them."

JIM GRICE, co-chair of the energy and infrastructure team, Akerman

U.S. Electricity Retail Sales

U.S. electricity retail sales to major end-use sectors and electricity direct use by all sectors, trillion kilowatt hours (KWh), 1950-2022



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION

Rising Demand

Midstream companies pulled out positive forecasts aplenty during their second-quarter earnings calls, even as the Henry Hub price has struggled to remain above $2/MMbtu since June.

"There has been extensive discussion on this topic with the consensus developing that electricity demand will increase dramatically by the end of the decade, driven in large part by AI and new data centers," said Rich Kinder, executive chairman of Kinder Morgan, during his company's earnings call in July. "I'm a firm believer in anecdotal evidence, particularly when it comes from the actual users of that power and the utilities who will supply it, and from the regulators who have to make sure that the need gets satisfied. And the anecdotal evidence over the last few months has been jaw-dropping."

The sentiment resonated throughout midstream earnings season.

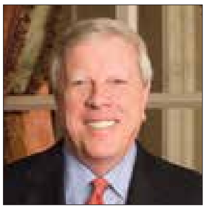
"I guess everybody's kind of seeing the truth," said Energy Transfer Co-CEO Mackie McCrea during his company's call. "We're about to transfer into untold demand for natural gas."

Williams Cos. CEO Alan Armstrong told investors that the number of inquiries his company has received from people looking for data center power has been "a little bit overwhelming."

The available numbers back up the forecasts. AI queries are estimated to require 10 times the energy of traditional Google queries, according to a white paper published by the Electric Power Research Institute (EPRI), an energy market research organization based in Washington, D.C. By 2030, data centers could be consuming 9.1% of U.S. electricity generation, as opposed to 4% in 2024.

Grice said that AI requires a denser energy cohort than the typical data stack, Grice said. Cloud server racks typically work in the 8-kilowatt (KW) range. The AI technology clients he works with now are designing stacks to handle power loads in the 30- to 40-KW range.

Goldman Sachs forecasts the extra natural gas needed to support the energy load will be around 3.3 Bcf/d. The current overall U.S. gas demand is around 103 Bcf/d, according to the U.S. Energy Information Administration (EIA).



"I'm a firm believer in anecdotal evidence, particularly when it comes from the actual users of that power and the utilities who will supply it, and from the regulators who have to make sure that the need gets satisfied. And the anecdotal evidence over the last few months has been jaw-dropping."

RICH KINDER, executive chairman, Kinder Morgan

"I guess everybody's kind of seeing the truth. We're about to transfer into untold demand for natural gas."

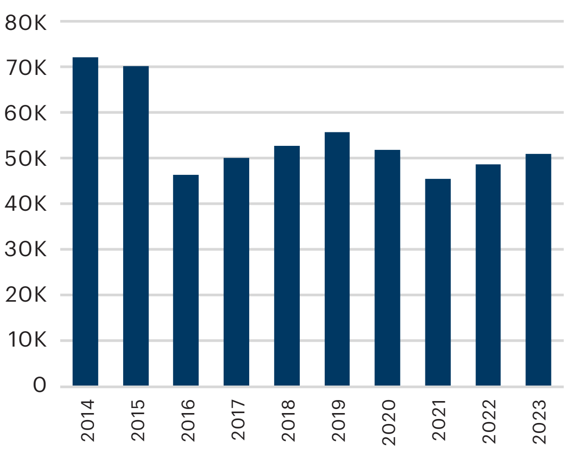
MACKIE MCCREA, Co-CEO, Energy Transfer

Through 2030, data centers and AI operations are expected to consume between 10% and 20% more electricity each year. Natural gas is currently the favored option based on its reliability and low emissions profile, Evercore ISI anaylsts said.

While the macro numbers are favorable, the tech and gas sectors are still working out how things connect locally, and how to factor in two major diverging trends happening at the national level.

U.S. Natural Gas Consumption for Electricity Generation in the Commercial Sector

MMcF



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION

Irrationally Exuberant Forecasts?

Not all forecasts for an oncoming explosion in natural gas demand have been rosy.

Politico's E&E news reported some consumer groups are concerned about paying for a power buildout that may not be needed if the demand ultimately fails to materialize.

In 1999, Forbes magazine published an article entitled "Dig more coal—the PCs are coming." The piece predicted massive growth, about 13%, in electrical demand that would power the increasing use of the internet.

A follow-up study by the Berkeley National Laboratory found the Forbes story overshot its estimates, "in some cases by more than an order of magnitude."

According to the EIA, the growth in retail electricity after 1999 continued at roughly the same pace as it had for the prior 30 years. In 2007, the growth rate flattened until the 2020s, when more demand from electrification began to come online.

While internet use did explode, new efficiencies in design and the retirement of older systems dampened the demand for a power buildout.

Renewable Preference

Many technology companies face a dilemma with their expansion proposals.

"First and foremost, I think all of the information technology industry would like to do as much sustainable and renewable energy as they can," Grice said.

And renewable energy sources continue expanding. The Energy Information Administration (EIA) reported this spring that the amount of electricity generated from wind surpassed that from coal generation, setting a record.

However, renewables come with problems of their own. Wind and solar farms are often located in isolated places. Their output can fluctuate wildly when the wind drops or clouds cover the sun, which makes them a difficult choice for data centers that are running full-time.

"Most of those folks (tech companies) have very responsible approaches towards renewables and carbon emissions and climate change, but they still have a job to do as well," Grice said. "That's the balancing act for all of them."

To tech companies, the solution is that other sources of energy, whether natural gas, nuclear or some of the developing sectors of electrical generation, such as hydrogen, will serve to "bridge the gap" left over by renewables, he said. Natural gas is the current go-to solution because it's widely available and cheap, as opposed to building a small nuclear reactor on site.

However, the rapid deployment of data centers can cause a problem with an electrical supply system that is used to moving much more slowly.

Different Times

Data centers can vary widely in scale and design, but the development cycle usually takes two years or less, depending on the availability of contractors and supplies. The permitting process and construction time for a gas-fired utility plant can range from one year to 10 years. Data centers also have the option to add on-site power generation.

Beyond that, a tech company will rarely commit to more than 20 years of occupancy on a lease. The largest AI facilities typically sign for 15 years, Grice said. Such a short time scale may run up against the investment required to build a power plant and ship the natural gas required to run it.

A gas generation plant usually does not amortize in 15 years and is generally more of a 30-year asset at a minimum.

"There will probably be some challenges of matching the operating pro forma of a gas power plant to the data center," he said.

Beyond the decades-long considerations of a power plant, tech companies will also have the more immediate problem of dealing with the daily market fluctuations of a commodity. In just the last two years, the Henry Hub price for natural gas hit over \$9/MMbtu in summer 2022, and sunk to under \$2/MMbtu by spring 2024.

"There's going to have to be some sophisticated purchasing of gas," Grice said. "The disruptive cost of it is not a friend of data center operations."

Still, Grice said price fluctuations were not a new problem in the industry and that a solution could be found, wherever the facilities are installed.

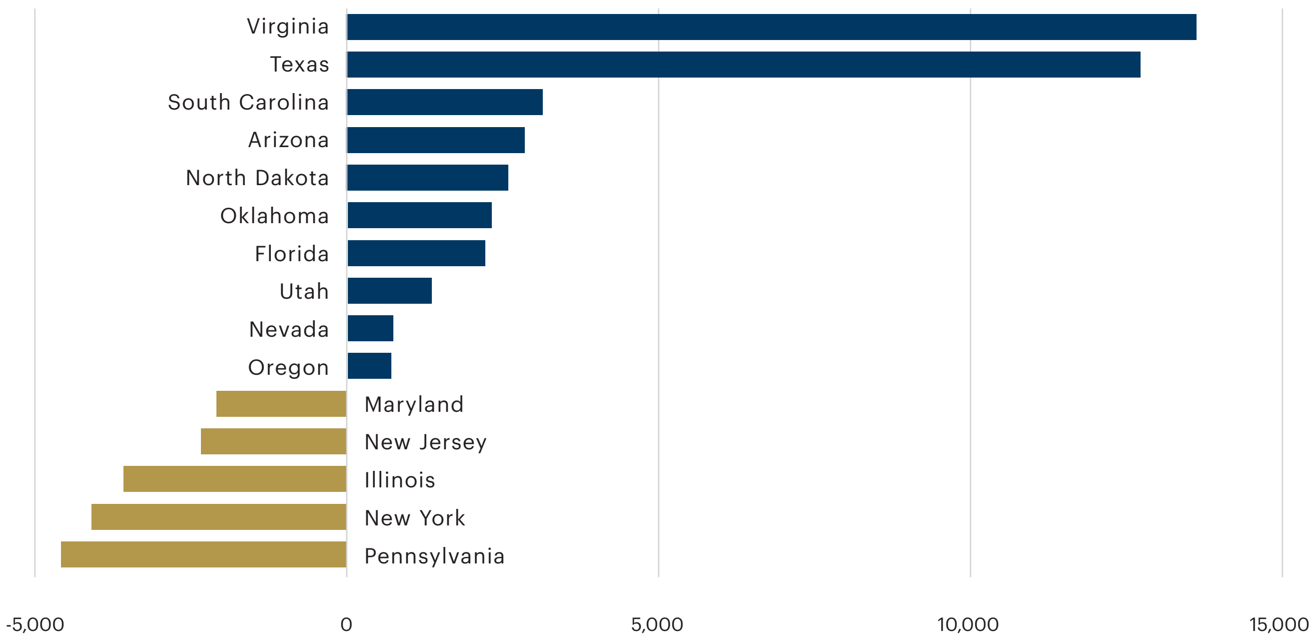
AI Cloud Atlas or Location, Location, Location

In a growing nationwide data center market, Virginia is king. The state accounted for 22% of the nation's data center demand, and the facilities consumed 23% of the state's electrical load in 2023, according to the EPRI study.

Why Virginia? The state offers strong internet connections, few disruptive events, a labor force with the necessary skills and reliable backup power sources. The next three states offer some of the same amenities. Together with Virginia, the states of Texas, California and Illinois make up 50% of the current data center load, with most of the data centers

Select States by Growth in Commercial Sector Electricity Consumption (2019-2023)

Change in annual sales of electricity to commercial customers, gigawatthours (GWh)



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION

SHUTTERSTOCK

AI rendering of a data center co-located on a natural gas drill site. As the power demand from AI data centers grows, tech developers have to be innovative about sourcing reliable and secure 24-hour energy. In order to stay true to the tech industry's approach toward renewables and lowering carbon emissions, tech companies are increasingly leaning on alternative sources of lower emission energy, such as natural gas.

located close to urban areas.

However, with the oncoming buildout of AI data centers, the location becomes less important, or at least more flexible.

The key difference is the importance of latency. For the applications that handle market transactions on Wall Street, a couple of microseconds can make a major difference when buying and selling. The data centers are, therefore, built close to the users.

AI applications generally perform best when the task isn't time-sensitive, such as facial recognition, mapping applications or chatbots. With less of an emphasis on time, data centers have far fewer limitations on their location, according to TechHQ, a tech news website.

This allows tech companies to diversify their locations, focusing on available land and potentially nearby gas pipelines.

"You're seeing projects popping up in the Dakotas, West Texas, areas of the country that really would not have been good candidates for traditional data centers," Grice said.

In July, Houston-based tech company Lancium and Denver-based Crusoe Energy Systems announced that they were developing a 200-megawatt AI data center near Abilene, Texas.

Abilene is a town of 125,000 people two hours west of Fort Worth, Texas, along I-20, and home to three universities.

The region also has access to both types of power that tech companies are seeking. The nearby Trent Mesa project is one the state's oldest and largest wind-power developments, and some of the state's major gas lines crisscross the area.

At buildout, Lancium expects to have a 1.2-gigawatt project that will be one of the largest AI data centers on the planet.

Analytical firm RBN Energy recently published a study that projected a fizzle could happen with the power demands for AI.

Focusing on the Northeast, the firm found that growing supplies of renewable energy in the region could dampen the explosion in gas-generated demand before it happens. Renewable energy growth continues to trend upward nationwide.

The EIA recently forecast gas-fired generation in the region declining overall, from 5.2 Bcf/d in 2023 to 4.1 Bcf/d in 2030 in its latest forecast.

"AI may be the next big thing, but that does not necessarily translate to huge opportunities to supply natural gas to fuel the implied power demand," RBN's Rusty Braziel wrote in the analysis. "The data center industry's focus on energy efficiency and technological advancements is likely to mitigate the anticipated increase in power consumption."

Tech companies and energy suppliers will continue to move forward, however, with plans to supply a rapidly developing market. Data centers, regardless of how many are built, need a stable supply of energy. From Grice's vantage point, tech companies are open to natural gas because of the reliability it provides to the grid.

"Natural gas can make a lot of sense in the right circumstances, the right location," he said. OGI

MIDSTREAM

WhiteWater May Have Sunk Rivals in Permian Pipeline Race

FID for the Blackcomb gas line, with in-service planned for 2026, could convince other companies to delay or scrap their projects, an analyst says.

SHUTTERSTOCK

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The latest Permian Basin natural gas pipeline project is poised to win the race for the next line to be built and could wipe some other proposals off the table, an analyst said.

WhiteWater Midstream reached a final investment decision (FID) for its Blackcomb Pipeline in July, answering the natural gas takeaway question Midland and Delaware basin E&Ps had been asking for months.

With the WhiteWater-operated Matterhorn Express coming online this year with 2.5 Bcf/d of capacity, the region's natural gas egress is not expected to hit capacity again until 2026. Matterhorn has an in-service date in September.

Blackcomb will take up the slack from there. The line will move natural gas out of West Texas to pipeline networks along the Gulf Coast. With 2.5 Bcf/d capacity, the line will be able to handle the additional natural gas the region is expected to produce in the 2026 timeframe.

At least four other projects had been publicly proposed to do roughly the same thing, but none had reached an FID before July 31. Since a large intrastate pipeline in Texas takes about two years to build, the decision to make an FID this year was crucial in order for a line to be ready by 2026.

The other proposed projects were Energy Transfer's Warrior, Targa's Apex, private company Moss Lake's DeLa Express and Kinder Morgan's Gulf Coast Express (GCX) expansion project.

"This FID makes these projects unlikely, aside from potentially GCX's expansion opportunity," said Alex Gafford, an analyst at East Daley Analytics.

One further potential advantage of the Blackcomb pipeline will be the route. The line is expected to follow a path similar to WhiteWater's Whistler pipeline, meaning the partners behind Blackcomb already have expertise on the terrain and installation in the area, Gafford said.

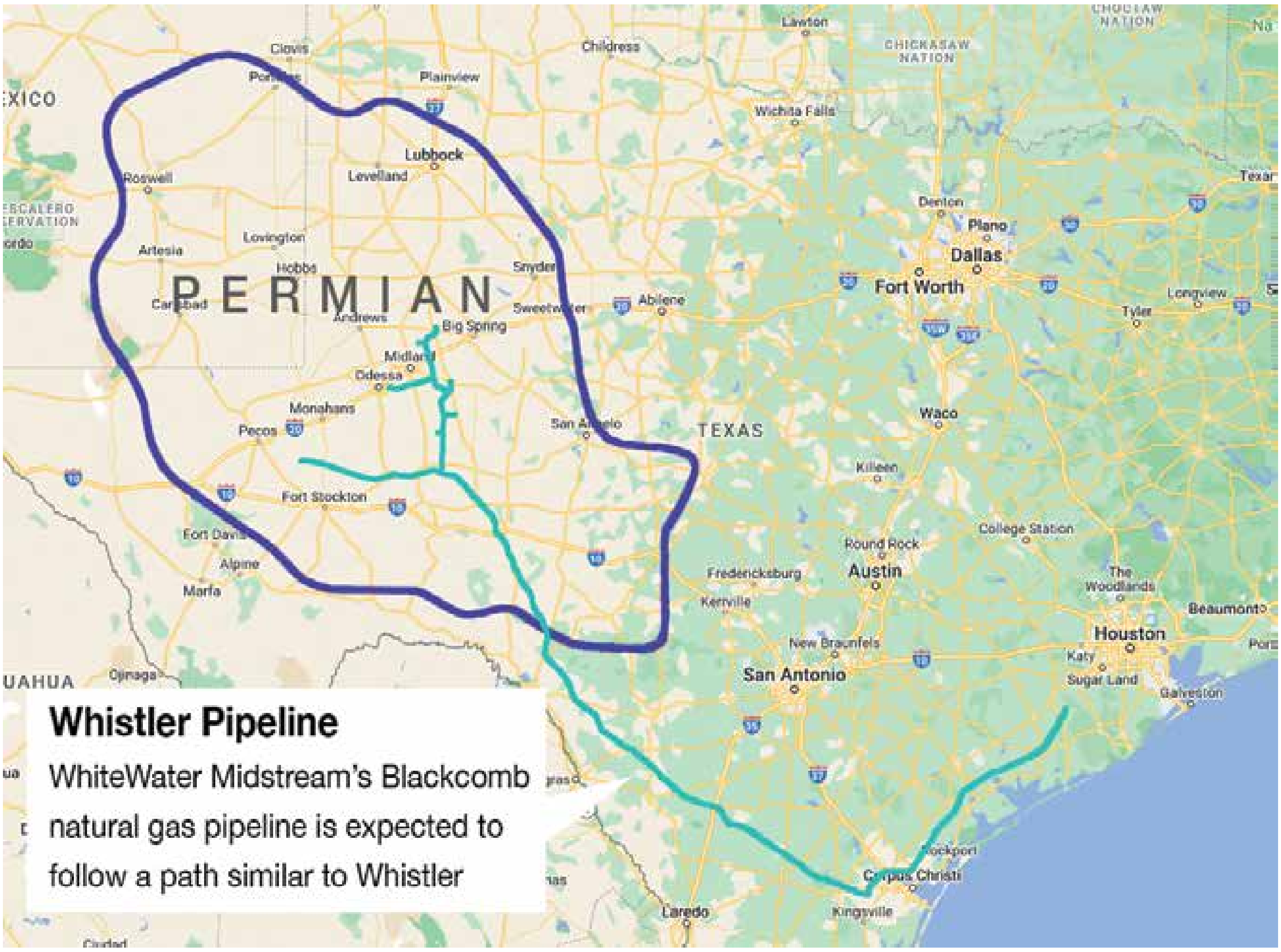
WhiteWater, MPLX and Enbridge, the consortium that owns the Whistler Pipeline, along with an affiliate of Targa Resources, are part of a joint venture (JV) to build Blackcomb.

Of the remaining projects, the GCX expansion is most likely to still happen by 2026 because it's a smaller-scale project. The expansion would add 500 MMcf/d of natural gas capacity to a line already in place. According to East Daley, Kinder Morgan has stated that talks with GCX customers are ongoing, but no final decision has been made.

The other lines are much less probable over the next two years, Gafford said. "Targa's partnership on this project makes Apex especially unlikely."

Prior to the Blackcomb announcement, Targa had proposed the Apex Pipeline. Executives at the company had noted earlier in the year that they expected a pipeline to reach FID this summer, but that it wouldn't necessarily be for Apex.

Energy Transfer's Warrior Pipeline is a



SOURCE: REXTAG

shorter project that would deliver gas to the North Texas area and connect with the company's extensive network. Following the Blackcomb announcement, Energy Transfer reaffirmed its intention to continue developing its Warrior Pipeline. The other large pipeline project that has been proposed, the DeLa Express, is not slated for an in-service date until 2028, meaning it wasn't part in the running this year for an FID.

Blackcomb followed a different development approach than the other projects. The companies backing other pipelines had discussed their plans publicly, in some cases, for years.

The expected price for Blackcomb was not announced with the project. During the company's second-quarter earnings call, Targa executives said they did not expect to spend more than $200 million for their share of the line's capital investment because the pipeline is expected to be project financed.

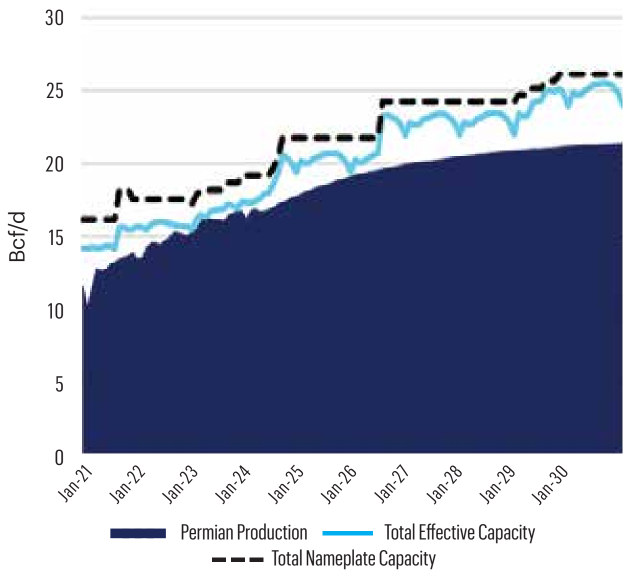
One other major project in the Permian, ONEOK's 2 Bcf/d Saguaro Pipeline, isn't necessarily competing with the other projects. The proposed line would deliver Permian natural gas to the Mexican border, where it would then be piped to a proposed LNG export terminal on Mexico's west coast.

The proposed LNG plant has not reached FID. Gafford said he did not expect Saguaro to come online until 2029.

During ONEOK's second-quarter earnings call on Aug. 6, executives said the company did not expect any capex spending on the project in 2024. However, they felt the line remains a good opportunity.

"This really is a commercially strong project with world-class customers, and it makes great commercial sense," said Charles Kelley, ONEOK's senior vice president of commercial natural gas pipelines. "You've got Permian supplies. LNG demand pull is competitively advantaged to the Asian markets." OGJ

Permian Pipe Egress vs. Gas Production



EAST DALEY ANALYTICS

MIDSTREAM

Despite Ruling, Williams Running Mid-Atlantic NatGas Project

Williams opened Regional Energy Access despite an appellate court vacating its FERC permit. It plans to seek a temporary permit to keep the new system open.

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The District of Columbia Court of Appeals reversed a permit approval for Regional Energy Access, but the system is up and running.

SHUTTERSTOCK

The $950 million Regional Energy Access project (REA), which enhances the infrastructure of the Transco Pipeline Network in Pennsylvania, New Jersey and Maryland, went into full service ahead of schedule in the first week of August, Williams Cos. announced during its second-quarter earnings call.

Williams President and CEO Alan Armstrong confirmed the project was operational and congratulated his team for finishing the job early in a difficult area.

The same week that the project began operating, the D.C. Court of Appeals struck down a Federal Energy Regulatory Commission (FERC) permit necessary for the interstate project to operate. Eight states joined the suit against the project, including New Jersey. The state passed a law in 2023 requiring that 100% of all state power come from renewable sources by 2035.

The court ruled the FERC should have better assessed the effect of greenhouse-gas emissions caused by the project and to determine whether the area requires the extra natural gas capacity.

During the earnings call, Williams executives discussed the next legal move on the project, which they expect will remain operational.

"The next step will be seeking a temporary certificate. This is not new to FERC," said Lane Wilson, general counsel for Williams. "We fully anticipate they'll be defending the certificate. We'll be seeking a rehearing on a timely basis, and that's probably about 35 days out at this point.

"But we don't have any concerns that we're going to be able to continue to operate, don't have any concerns about getting a temporary certificate and ultimately don't have any concerns about defending what FERC has done on this project."

The D.C. Appeals Court ruling was one of three made by the judicial panel over the last month that threw out FERC permits. The reasoning behind the decisions varies, though all rulings do state that the FERC failed to determine the overall effect of greenhouse-gas emissions of each project. The FERC leadership has said it is following the current law.

The REA is designed to increase the natural gas capacity in the mid-Atlantic region by 829 MMcf/d. Williams planned to have the facilities in place by the 2024 heating season. The design of the project consisted of additional compression stations and two new loop segments along the current Transco route.

The new facilities are needed to meet rising regional demand for gas as older coal stations are decommissioned and to provide reserve power for intermittent renewable sources, according to the Williams' project outline. OGI

An Un-Appealing Pause

An ongoing battle with the D.C. Court of Appeals may affect all future FERC-related projects.

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NextDecade Chairman and CEO Matt Schatzman is not happy with the District of Columbia Circuit Court of Appeals—which makes him a member of an exclusive but steadily growing group of energy CEOs.

On Aug. 6, the court shot down the Federal Energy Regulatory Commission (FERC) permits for the Rio Grande LNG development, along with the permits for Glenfarne Group's Texas LNG project. Both facilities are located in the Brownsville Shipping Channel in South Texas.

"We appreciate the significant disruption vacatur may cause the projects," Judge Bradley Garcia wrote in the decision. "But that does not outweigh the seriousness of the Commission's procedural defects."

The court ruled that FERC did not properly consider the environmental impact of the plants. Schatzman said the decision could have industrywide negative implications.

"If the ruling stands, the precedent that would be set by the court's action has the potential to impact viability of all federally permitted infrastructure projects because it will be difficult for these projects to attract capital investments until they receive final unappealable permits," he said in NextDecade's August business update.

It was the third time in two months that the same court remanded permits for natural gas projects to the FERC. The reasoning behind the rulings differed, but each admonished the FERC for not taking the "public interest" seriously. It's a phrase that may be familiar to critics of the White House's LNG permit pause issued at the beginning of the year.

Public Interest Pause

When the Department of Energy (DOE) announced it was pausing new permits for LNG exports in January, it called the decision a "public interest analysis."

"… The data and global circumstances relevant to these factors has changed over time, and DOE must reflect these changes when applying the factors to a new public interest determination," the DOE announcement stated.

Specifically, the public interest update is to consider a broader assessment of "greenhouse gas emissions, including carbon dioxide and methane." That raised the eyebrows of some analysts.

"The impacts to climate change are global in nature," said Tom Sharp, director of permitting intelligece at Arbo, following

"I'm really excited to see (the Uinta rail Supreme Court case.) That could really reform permitting in a way that's meaningful and really stop people from being able to just arbitrarily stop projects."

ALAN ARMSTRONG, President and CEO, The Williams Cos.

the announcement. "The question is, where do you draw the line? At what point are the climate change impacts from a single proposed project significant enough to warrant not approving it?"

The pause has been criticized as an election-year decision made by an administration attempting to appease its environmentalist backers.

A federal judge overturned the LNG pause in July. The judge, a Trump appointee based in Louisiana, said the pause was unnecessary to study the issue and agreed with a suit filed by 16 red states.

The effect of the ruling was unclear, as the DOE was told to rule on a "public interest" standard that was now up in the air. The DOE responded that it was evaluating its next steps.

A couple of weeks later, another court would start ruling in the opposite direction.

Permits, Pipes and LNG

The Commonwealth LNG project lost its FERC permits to proceed on July 16.

The D.C. appeals court ruled that FERC needed to review its approval to include climate impacts of the project. The court did not scrap the permits but demanded a re-evaluation of FERC's "public interest determination."

Garcia, writing for the three-judge panel, said FERC had "inadequately explained its failure to determine the environmental significance of the project's greenhouse gas emissions, and it failed to adequately assess the cumulative effects of the project's

NextDecade's Rio Grande LNG and Texas LNG permits were remanded in August, with the court ruling that the Federal Energy Regulatory Commission had failed to properly consider the environmental impact of the plants.

NEXTDECADE

nitrogen dioxide emissions."

Commonwealth LNG, a 9.5 MMmt/y project in Cameron Parish, La., has not reached FID yet, but has reached commitments for half of its capacity.

On July 30, the court voided FERC's approval for Williams Cos.' Regional Energy Access Expansion Project (REA). The court ruled that FERC had dismissed viable studies showing the project was not needed, and that it had failed to determine the significance of greenhouse gas emissions.

REA is an expansion project that would increase the natural gas capacity of Williams' existing network in the Northeast. The company had brought the project online before the ruling and expected to work with FERC to receive final permit approval.

One week later, the appeals court ruled against the Rio Grande and Texas LNG projects. Leadership from both companies have said they are hopeful of working through the process and eventually getting FERC permits that will stand.

"It's worth noting that judges (Bradley) Garcia and (Michelle) Childs were on the panel for both the REA and Rio LNG decisions, and that Chief Judge (Sri) Srinivasan was also on the Rio LNG panel, though he did not write the opinion," Sharp said. "This shows some internal visibility and alignment within the D.C. Circuit on the substance of the decisions, particularly because rehearing requests are likely, and they are rarely granted."

The Court Form

All of the FERC suits were brought by a combination of environmental groups and a local civic jurisdiction, and all the cases ended up at the D.C. court by default.

It isn't that the environmentalist groups are court shopping, but they do have a slight home-field advantage.

When organizations decide to sue FERC, the cases are almost always filed with the D.C. Court of Appeals, unless there's a specific circumstance to hold the hearing in another jurisdiction, according to FERC.

Appeals court cases are decided by a panel of three judges, randomly assigned. The D.C. court directory lists 15 judges. Democratic presidents appointed nine of them. (There are 11 "active" judges on the court who handle the majority of the work. Democratic administrations appointed seven, four were selected by Republicans.)

The Train from Uinta

Ultimately, an earlier decision from the appeals court may point toward the final outcome of the permitting fight.

In August 2023, the court ruled against a railroad project for the Uinta Basin. The rail was a group effort involving seven counties to improve crude takeaway capacity for the basin.

Uinta Basin oil is highly waxy, and producers consider rail the best way to move it. The court shot the project down, saying the project violated the National Environmental Policy Act (NEPA) by failing to fully analyze the railway's potential harm to wildlife, the Colorado River and the environmental justice of communities downstream of the project.

The county coalition in Utah filed an appeal, challenging whether the NEPA process requires an agency to examine environmental impacts beyond "the proximate effects of an action within its regulatory authority."

The Supreme Court agreed to hear this case during its 2024-2025 term, which starts in the fall.

Willams Cos. President and CEO Alan Armstrong said the case, coupled with the recent Chevron deference ruling, could halt the court's ongoing fight with the FERC.

"The problem really revolves around the NEPA process and the handles that it gives to environmental opposition to take up issues that have very little to do with the pipeline construction but have to do with their own fight against fossil fuels," Armstrong said.

"I'm really excited to see (the Uinta rail Supreme Court case.) That could really reform permitting in a way that's meaningful and really stop people from being able to just arbitrarily stop projects." OGJ

East Daley: Double H Conversion to Double Volatility

Kinder Morgan's challenge to ONEOK over Bakken NGL could upset the market's balance.

AJAY BAKSHANI
EAST DALEY ANALYTICS

KRISTINE OLESCZEK
EAST DALEY ANALYTICS

Ajay Bakshani is director of midstream equity and Kristine Olesczek is a crude market analyst at East Daley Analytics.

Kinder Morgan plans to convert the Double H crude oil pipeline out of the Williston Basin to NGL service. In doing so, Kinder will challenge ONEOK to be the leading midstream service provider for Bakken NGL, and in the process could tip a delicate balance in crude oil and NGL markets.

Kinder Morgan announced the Double H conversion in its second-quarter earnings update. Double H runs 462 miles from Dore, N.D., in the heart of the Bakken play, to the Guernsey market in Wyoming, adjacent to ONEOK's Bakken NGL and Elk Creek pipelines. Kinder is targeting first-quarter 2026 to begin service on the conversion, giving producers and midstream companies in the play a short window to adapt.

Pipeline egress from the Williston Basin is tight all around, and disruptions to one commodity market can create imbalances in others. The project will add capacity for NGL yet also constrain crude oil flow to Guernsey, providing a big opportunity for other pipeline expansions.

Crude Constraint

In the crude oil market, the Kinder project will take away one option for Bakken barrels to reach the Cushing hub. Double H can move up to 88,000 bbl/d of crude oil, and along with True Companies' Bridger Pipeline, currently transports Bakken barrels to Guernsey. From Guernsey, the Saddlehorn and Pony Express pipelines provide favorable netbacks to ship crude to Cushing.

Once Double H converts to NGL service, the Bakken-to-Guernsey corridor becomes immediately constrained, according to East Daley's Crude Hub Model. Bridger Pipeline picks up a portion of Double H's volume and fills to capacity, and shippers divert other crude oil to the Dakota Access Pipeline (DAPL) and to secondary markets. These secondary markets include shipping by rail or using Enbridge's Bakken North Pipeline to move barrels into Canada and then south into the Midwest (PADD 2). Both of these are relatively expensive options, and we would expect to see downward pressure on Bakken crude prices if shippers lean on them to transport more crude oil.

Battle for Bakken NGL

NGL infrastructure from the Williston is the most pressing bottleneck for now. Spare capacity is very limited on the Elk Creek and Bakken NGL pipelines, the two routes out of the basin, according to East Daley's NGL Hub Model. Constraints moving NGL out of North Dakota are forcing some operators to blend more butane into the Bakken crude stream, sources tell East Daley.

ONEOK plans to start a 100,000 bbl/d expansion of the Elk Creek pipeline in first-quarter 2025 that will open new NGL egress and resolve the constraint. In fact, our regional model shows that producers in the Bakken play don't really need the additional NGL capacity from the Double H conversion once OKE expands Elk Creek. Nevertheless, we expect operators will welcome an alternative.

The Double H project creates not only new NGL pipeline takeaway, but also new competition for ONEOK. Kinder is positioning itself as an alternative provider for producers, a move that could potentially enhance the competitiveness of Bakken supply in NGL markets. As E&Ps consolidate in the Bakken, we expect larger firms like ConocoPhillips, Devon Energy and Chevron to take a closer look at NGL netbacks and be willing to shop around for the best options.

ONEOK will still be the dominant midstream player as it controls about 48% (about 1.9 Bcf/d) of the gathering and processing capacity in the Bakken, and its assets produce about 250,000 bbl/d of NGL. Kinder owns 9% (380 MMcf/d) of Bakken gathering and processing capacity and its plants average about 30,000 bbl/d of NGL production. We estimate a converted Double H line will have capacity to move about 66,000 bbl/d of NGL (using the same ratio from Enterprise Product Partners' conversion of the 150,000-bbl/d Seminole NGL pipe to the 200,000-bbl/d Midland-to-ECHO 2 crude pipe). Thus, Kinder should be able to fill approximately half of the Double H capacity with NGL from its own plants. Hess Midstream, Energy Transfer, MPLX and Targa Resources combine for 1.4 Bcf/d of gas processing capacity in the basin and could benefit from diversification on Double H.

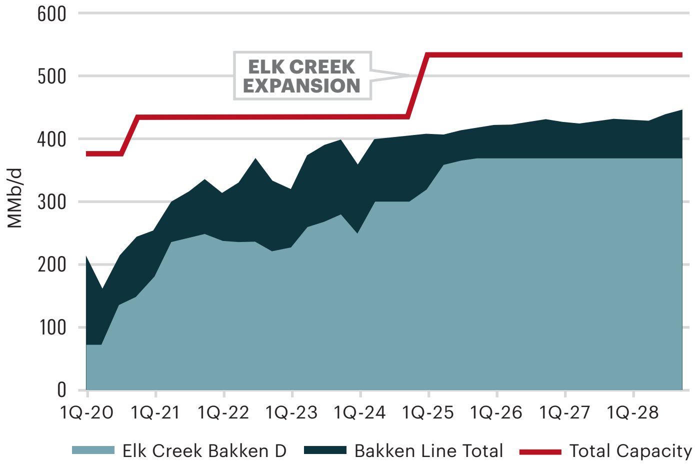
To challenge ONEOK, Kinder will need to build out connections between Double H and (possibly third-party) plants, as well as partner with other pipelines to move NGL to market, either to Conway or, ideally, Mont Belvieu. Two options are Energy Transfer's White Cliffs pipeline from the Denver-Julesburg Basin, or Williams Co.'s Overland Pass Pipeline. Energy Transfer also has a presence in the gathering and processing business in the Bakken via its Crestwood Equity acquisition (430 MMcf/d of capacity), which could help fill up Double H and allow Energy Transfer to recover those barrels for its downstream NGL assets.

Similarly, Williams' Overland Pass eventually connects to Targa's Grand Prix pipeline, and Targa can leverage its 300 MMcf/d Bakken system and Double H to execute a similar strategy. We do not know the length of the commitments between ONEOK's NGL pipes and the Energy Transfer/Targa plants, so it could take longer to migrate those barrels to Double H.

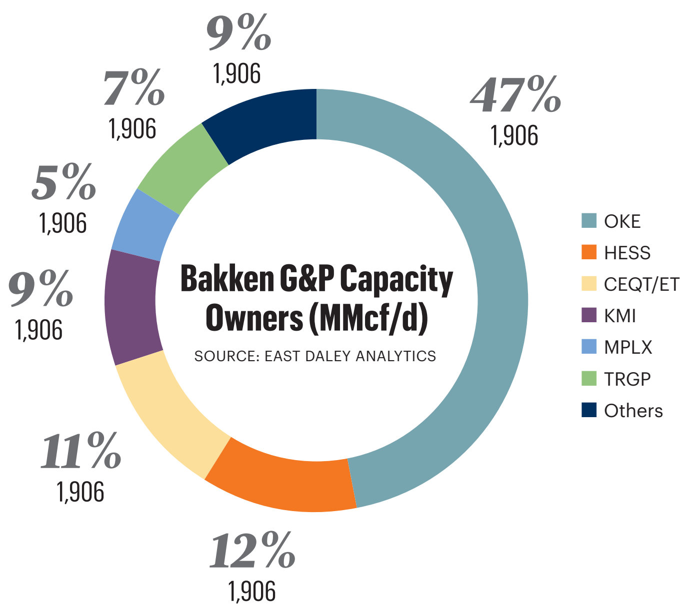
According to East Daley's Blueprint Financial Models, a 30,000 bbl/d drop in ONEOK's Bakken NGL Pipeline gathering volumes and Elk Creek long-haul volumes would result in an impact of about $85 million to annual EBITDA. This hit represents about 8% of ONEOK's combined Bakken NGL and Elk Creek pipeline earnings, or 1% of total company earnings for fiscal year 2024. The impact on ONEOK could be offset by higher-than-expected Bakken production, specifically from increased ethane recovery. On the downside, there may be rate risk as well, but we expect joint rates between Double H and downstream pipes would be in line with current Elk Creek rates (about 21 cents/gal).

Kinder's announcement is only the first move in this potential battle over Bakken NGL. There are still many unknowns in terms of who else will back the conversion and how companies will transport barrels from Guernsey to Mont Belvieu. One thing is certain: the fight over NGL barrels is moving beyond the Permian. OGI

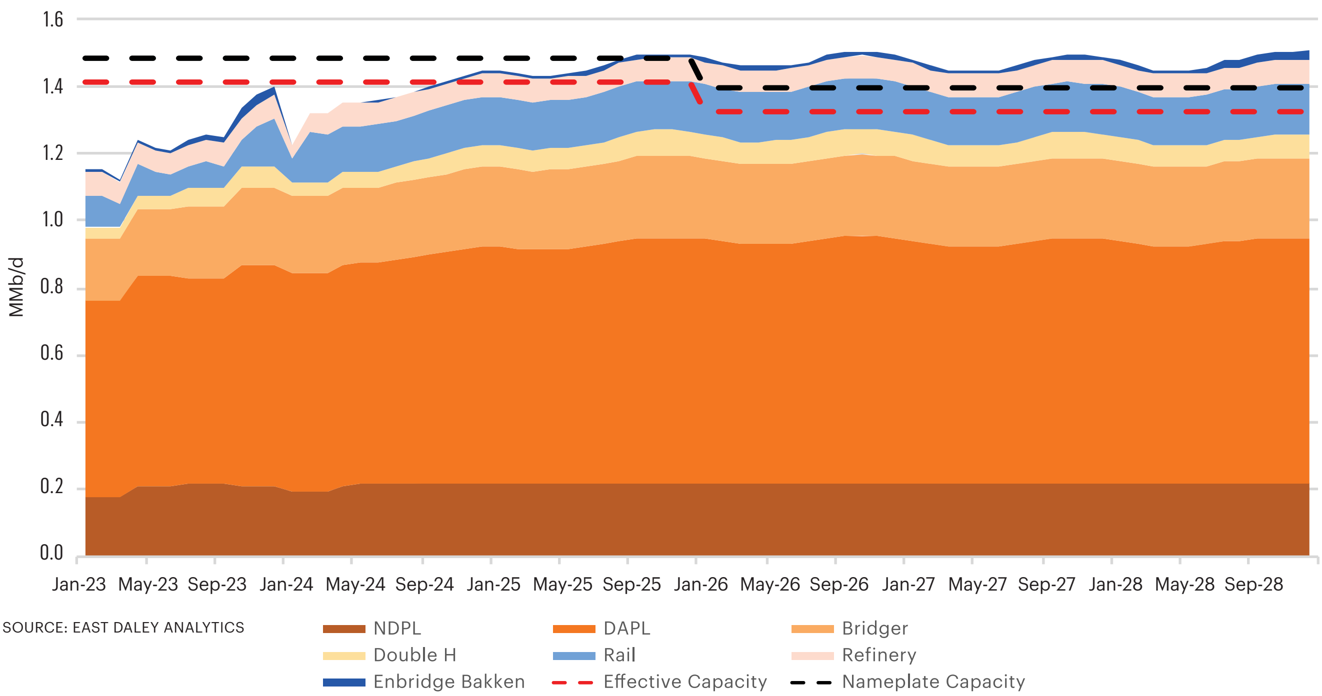
Williston Basin NGLs - Elk Creek & Bakken Lines



SOURCE: EAST DALEY ANALYTICS



Bakken Crude Egress - Double H Conversion



SOURCE: EAST DALEY ANALYTICS

EOG Finds Success in 700-ft Spacing in Ohio's Utica

The test at the northern end of its leasehold produced IPs similar to those from a nearby pad.

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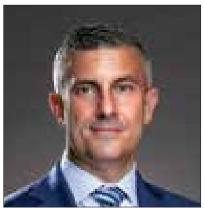
EOG Resources has dropped a new five-well pad in its Ohio Utica oil play, showing 700-ft spacing will make IPs as strong as 1,000-ft-spaced pads.

Its new pad, called Shadow, is in Carroll County at the northern end of its 140-mile-long north-south leasehold, which it grew by 10,000 net acres this spring to total 445,000, the company told investors in August.

Shadow's 30-day IP averaged 2,125 boe/d per well, 50% oil and 80% liquids.



"Nothing fills our email inboxes with hate mail like positive comments we make on EOG's activity in the Utica Shale."

TIM REZVAN, analyst, KeyBanc Capital Markets

It is near EOG's four-well Timberwolf pad, which was D&C'ed last summer at 1,000-ft spacing. It IP'ed a 30-day average of 2,150 boe/d per well, 55% oil and 85% liquids.

Through first-quarter-end, it made 780,068 bbl of oil, averaging 886 bbl/d per well in the first 220 days, according to Ohio Department of Natural Resources (DNR) data. First-37-day production had averaged 1,214 bbl/d per well.

Longer-Term Data

During the second-quarter earnings call, a securities analyst asked Keith Trasko, EOG senior vice president of E&P, how long it would take until it was clear that the spacing test was a success.

Trasko responded, "We just want to see more production data [in the next], at least, six [to] nine months or so and compare that to the dataset that we have on some of our older packages."

In addition to the Timberwolf pad, EOG made the three-well Xavier last fall in the middle of its north-south leasehold with 1,000-ft spacing and the four-well White Rhino this spring at the southern end with 800-ft spacing.

In Harrison County, Xavier's three wells produced 667,366 bbl in its first 179 days online, averaging 1,243 bbl/d each, according to Ohio DNR data. First-88-day production was 1,536 bbl/d each. It had IP'ed a 30-day average of 3,250 boe/d per well, 55% oil and 75% liquids.

In Noble County, White Rhino made 30,800 bbl in its first eight days, averaging 963 bbl/d per well. It had a 30-day IP of 1,700 boe/d per well, 70% oil and 85% liquids.

The Xavier wells were placed at 800-ft spacing; Timberwolf and White Rhino, 1,000-ft. All of the wells' results are normalized to 3-mile laterals.

The Utica reservoir is thinner at the southern end, thus smaller IPs, EOG reported. But it has 100% mineral rights there, it noted, thus 100% net revenue interest.

'Haters Gonna Hate'

After EOG released an earnings report, KeyBanc Capital Markets analyst Tim Rezvan wrote, "Haters gonna hate, but [EOG's] Utica results continue to look good."

He explained, "Nothing fills our email inboxes with hate mail like positive comments we make on EOG's activity in the Utica Shale."

The spacing-test results at the Shadow pad "suggest spacing tighter than 1,000 feet is feasible."

COO Jeff Leitzell said during the earnings call that the Utica oil findings "have delivered strong initial results and continue to demonstrate the premium quality of this play."

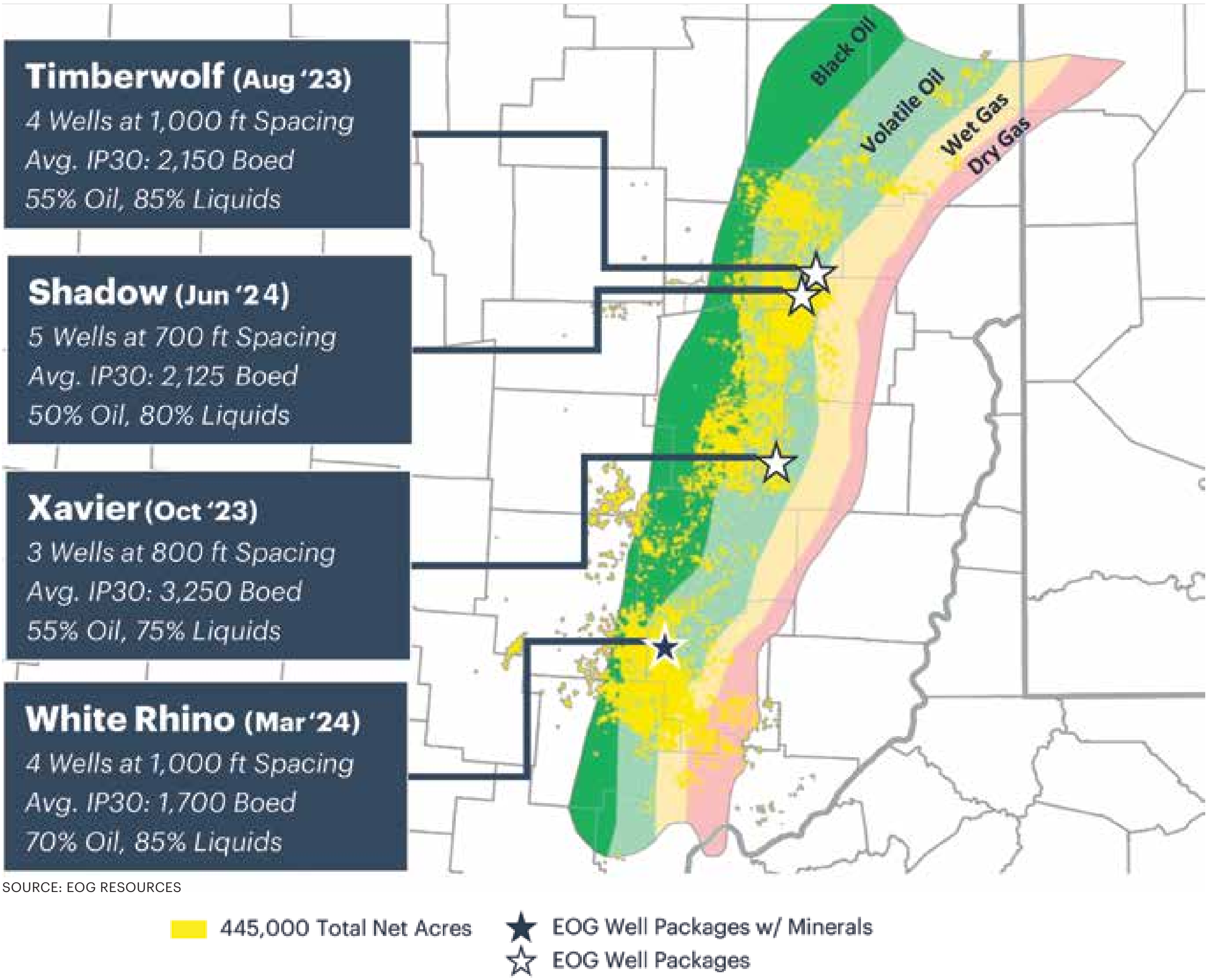
EOG reported this spring that Utica results can compete with the best acres in the Permian Basin.

'Glacial Event'

Virtually all of EOG's acreage in the Utica is HBP. So, when will it ramp up the play from delineation mode to development mode?

Doug Leggate, analyst with Wolfe Research, asked this during the call, adding that "delineation is kind of a glacial event for a lot of companies."

EOG Utica Wells



SOURCE: EOG RESOURCES

EOG Resources added the Shadow pad this summer to its new play, testing if it can increase development density.

4	16	3	35,775	57.2%
pads	wells	regions	boe/d total IPs	oil (avg.)

"When would you anticipate a more meaningful development plan as you move forward? … [Are you just still] figuring this thing out?"

Ezra Jacob, EOG chairman and CEO, said, "Everything you're saying is correct. It's how we feel about it, too. Geologically, we're doing a great job figuring it out."

In the north, "I would say we're feeling very confident there," while still "not a 100% satisfied with a spacing number" and whether it could go lower.

"But in any North American shale play, … it's going to be between 600-foot and 1,000-foot spacing probably on average, depending on the play."

At the southern end where White Rhino is, "we're a little bit further behind on delineation … even though that package did come online within our expectations," Jacob said.

Otherwise, "it is too early to talk about 2025."

Leggate replied, "To be honest, I think some of us were a little skeptical [about the Ohio oil play] to begin with, and you're proving us wrong, so congratulations on that."

Black Oil Fairway

EOG's 445,000 net acres in the play include 220,000 in the Utica's black oil window along the western side of the volatile-oil fairway. Leitzell said the operator's focus will remain on the volatile-oil window for now "where we have a more comprehensive geologic dataset."

EOG reported earlier this year that it is acquiring seismic and other data on the window before testing it.

It expects to complete 20 net wells in the volatile-oil play this year and has one rig drilling it full time, while it is using a frac spread half-time. OGI

TECHNOLOGY

NexTier Turns to Electric-Powered Wirelines

Advanced electric-drive equipment, automation-enabled pumpdown technology and digital connectivity are optimizing operations during completions.

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The evolution toward pad drilling and longer laterals has pushed service providers to innovate as they work toward optimizing completions.

Shale E&Ps need oilfield service companies (OFS) to increase efficiency, consistency and reliability during hydraulic fracturing operations. NexTier's secret: switch out drive mechanisms powered by diesel with drives powered by electricity.

During a Society of Petroleum Engineers' Tech Talk, Kenny Jones, director of wireline technology and engineering at NexTier, explained how service providers are identifying safe, sustainable and differentiated technologies and value-added services to boost completion performance.

"The advent of longer laterals and multi-well pads associated with today's shale operations have caused a shift in the way operators are using surface wireline equipment for plug and perf completions," Jones said in July.

On some locations, there are six wells on a single pad, creating a major shift in job scope.

"When you look at wireline for this type of operation, it's become strictly a pumpdown operation," Jones said. "In long laterals, we are using fluid to pump and push the tool out in that lateral section so that you can set plugs to isolate the previous zone and do perforating holes into the next zone for optimized fracking."

The frac operation becomes a continuous "zipper operation." When operations are completed on one well, the wireline crew is able to start the next job without breaking down and moving the equipment to the next well. This enables continuous operation, which Jones said can be converted to 24-hour operations.

"We went from fracking four to eight stages in a week, maybe to as high as 16 stages per day," Jones said. Now, it's possible to keep the equipment on the same location for weeks, even months between pad moves. "It's a massive acceleration in efficiency."

Any downtime negatively affects the efficiency of operations. The operator's expectation is that the wireline shouldn't disrupt the fracturing operation. NexTier's goal is to produce a wireline system that stays out of the work zone while ensuring that fracturing operations are continuous.

> *"We went from fracking four to eight stages in a week, maybe to as high as 16 stages per day... It's a massive acceleration in efficiency."*
>
> **KENNY JONES,** director of wireline technology and engineering, NexTier

The zipper frac has created a new set of challenges for OFS companies. NexTier is concentrating on three technology pillars to improve the multi-pad plug and perf shale completion process:

- Improving electric drive equipment;
- Incorporating automation enabled operations; and
- Implementing enhanced digital connectivity.

Power Up

Electric-driven field equipment is starting to improve wireline operations, Jones said.

In the past, OFS firms deployed a truck, a spooled chassis and a diesel engine to run the wireline. The setup was mechanical and easy to move from well to well.

However, with multi-pad locations now the rule, the mobility of a truck-mounted system no longer offers a significant benefit.

The full electric winch is more efficient in terms of energy use. With the advent of electric fracking fleets, it makes sense for wireline operations to tap into the same grid at the location, Jones said.

"There's either grid power or some type of power generation system that they have set up for that frac fleet," Jones said. Using electric drive equipment reduces fuel costs and increases operational efficiency.

"If no e-frac system is available, we can source electricity from a generator, which is

NEXTIER

With the advent of electric fracking fleets, it makes sense for wireline operations to also go electric, according to Kenny Jones, director of wireline technology and engineering at NexTier.

a more fit-for-purpose power source," Jones said. "There's very little wasted energy when the power source is right sized for electricity being consumed."

NexTier has digitized its e-winch, which can now be run by an application specific software program.

"Operators can program the system to maintain target tension and speed. It's essentially adaptive cruise control," he said. "You can program in safeguards where there's an automatic torque limitation near surface or automatically close the tool trap at a certain depth. These advances enable the e-winch to rapidly respond to dynamic environments, making the system less dependent on human competency."

Also, automation-enabled pumpdown operations use fluid to push the tool farther out in a lateral section. It's a smart control system that can automatically achieve target rate with a simple touchscreen.

The technology is replacing the manual gear selection process to adjust RPM by a dedicated pumpdown operator. Automating the process has eliminated the need for a pump operator.

The system automatically optimizes engine performance and fuel economy, with "smart logic" accounting for engine health and transmission shiftability, Jones said.

"The automated pumpdown control system is very consistent with less variation from person to person. This translates into cost savings because operators are not using as much fluid during the run," Jones said.

In one case, a swelled plug caused the e-winch to accelerate quickly. The automated system was able to recover without incident, saving non-productive time (NPT) and additional costs of a lost tool.

'Complete Visibility'

Other benefits that digital connectivity has on auxiliary wireline equipment include control heads, the tool trap and the safety apparatus on pressure control equipment.

Previously controlled outside the recorder cap and run by various crew members, digital control systems enable a command center with a single point of control at heart of an operation.

"You get complete visibility of vital data that can be recorded and transmitted to NexTier's hub for enhanced oversight," Jones said.

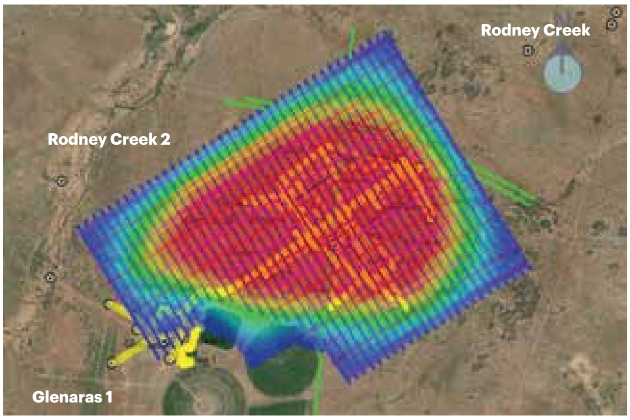
Centralizing data eliminates multiple points of failure and optimizes running parameters, while reducing typical NPT drivers. The e-winch and adoption of digital technologies have significantly reduced human-induced mistakes during wireline operations.

Jones said meaningful advances have been made, but he sees room for improvement.

"The statistics that wireline companies are publishing are just incredible compared to where we were in the past," he said.

TECH BYTES

Oceania Geo Deploys New Seismic Solution in Australia



SOURCE: OCEANIA GEO

Pad3D was able to mitigate issues, HSE risks and environmental disruptions with their accurate subsurface images.

In collaboration with STRYDE and Earth Signal Processing for Galilee Energy, Oceania Geo's new Pad3D seismic solution was deployed at Galilee Energy's Glenaras project onshore Australia to demonstrate the viability of acquiring small footprint 3D seismic surveys, using lower cost and lower environmental impact technology for well planning and field optimization.

Pad3D offers high-resolution seismic data to identify production enhancement opportunities by delivering rapid drill-ready subsurface images for drilling decisions.

"At the heart of the new offering lies the STRYDE Node," Cameron Grant, Chief Commercial Officer at STRYDE, said in a press release. "This compact, wireless technology is purposefully engineered for deployment in any land setting, enabling companies to rapidly survey areas with existing infrastructure while minimizing land disturbance. This approach facilitates the creation of high-resolution subsurface images required to make informed production optimization decisions."

The project "surpassed expectations," Mitchell said. The 3D imaging speed aligned with planning and pad development schedules while mitigating environmental disruptions and navigating existing infrastructure.

In addition to oil and gas developments, STRYDE and Oceania Geo have also opened new exploration opportunities for the renewables sector across Australia, such as mining and geothermal.

SLB Collaborates with Aker BP on AI-driven Digital Platform

SLB has agreed to a long-term partnership with Aker BP to co-develop a digital platform driven by AI to deliver improvements in efficiency across the company's E&P operations.

SLB and Aker BP plan to create a unified data environment in the cloud on an integrated platform for subsurface workflows. The platform will use AI and domain expertise from SLB and Aker BP to glean insights on previously inaccessible data.

"By co-developing AI-powered digital technologies, we will transform Aker BP's subsurface workflows, accelerate planning cycles, increase production and reduce costs across their entire E&P life cycle," said Rakesh Jaggi, president of digital and integration at SLB.

"The platform we develop with SLB is a key step in realizing our strategy to build the E&P company of the future and cement our position as a digital leader," said Per Øyvind Seljebotn, senior vice president of exploration and reservoir development at Aker BP.

In a similar partnership, SLB collaborated with Rockwell Automation, Sensia and Cognite in May 2023 to fundamentally transform FPSO asset design, construction and operation using digital technologies.

Halliburton Unveils Sensori Fracturing Monitoring Service

HALLIBURTON

The Sensori fracture monitoring service provides true, real-time data acquisition and processing of near-well and far-field subsurface measurements.

Halliburton's new Sensori fracture monitoring service is billed as a cost-effective fracture monitoring solution for automated, continuous measurement and visualization of the subsurface.

The Sensori fracture monitoring service provides real-time data acquisition and processing of near-well and far-field subsurface measurements. Using automation, cloud processing and data analytics, the Sensori service provides continuous subsurface feedback for multiple well pads across an entire asset. With the integration of non-intrusive downhole diagnostics, the service allows more frequent, cost-effective acquisition of quality subsurface measurements, Halliburton said.

Shell Signs Multi-Year Deal for TGS Imaging AnyWare Software

Shell Information Technology International signed a global multi-year agreement to license TGS' Imaging AnyWare software suite, TGS said in a press release.

Through the agreement, Shell will transition from its current in-house software to Imaging AnyWare, a fully integrated enterprise-class imaging system.

"Joint collaboration opportunities have already been identified between Shell and TGS to continuously improve Imaging AnyWare software performance while at the same time reducing project turnaround time and cost," Liz Sturman, vice president of petroleum engineering at Shell, said in the press release. OGI

EVENTS CALENDAR

Investment and networking opportunities for industry executives and financiers.

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EVENT	DATE	CITY	VENUE	CONTACT
2024				
Permian Energy Dialogues	Sept. 4-5	Santa Fe, N.M.	Inn and Spa at Loretto	energy-dialogues.com/ped
Gastech Exhibition & Conference	Sept. 17-20	Houston	George R. Brown Conv. Ctr.	gastechevent.com
GPA Midstream Convention	Sept. 22-25	San Antonio	Marriott Rivercenter on the River Walk	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 Hotel**	**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**	**Thompson Hotel**	**hartenergy.com/events**
IPAA Annual Meeting	Oct. 28-29	Boca Raton, Fla.	The Boca Raton Resort	ipaa.org
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 Galves	seg.org
ADIPEC 2024	Nov. 4-7	Abu Dhabi, UAE	Abu Dhabi National Exhibition Centre	adipec.com
DUG Appalachia	**Nov. 7**	**Pittsburgh**	**David L. Lawrence Convention Center**	**hartenergy.com/events**
API Cybersecurity Conference	Nov. 12-13	The Woodlands, Texas	Woodlands Waterway Marriott	https://events.api.org/
International Geomechanics Conference	Nov. 18-21	Kuala Lumpur, Malaysia	TBD	igsevent.org
DUG Executive Oil Conference & Expo	**Nov. 20-21**	**Midland, Texas**	**Midland County Horseshoe Arena**	**hartenergy.com/events**
National Pipe Line Conference	Nov. 28-29	Houston	Omni Houston Hotel	plca.org
North American Gas Forum	Dec. 2-4	Washington, D.C.	TBD	energy-dialogues.com/nagf
SPE Thermal Well Integrity and Production Symposium	Dec. 2-5	Banff, Alberta, Canada	The Fairmont Banff Springs	spe-events.org
2025				
Floating Wind Solutions 2025	Jan. 15-17	Houston	The Marriott Marquis	floatingwindsolutions.com
Mexico Infrastructure Projects Forum	Jan. 22-23	Monterrey, Mexico	Hotel Camino Real Monterrey	mexicoinfrastructure.com
SPE Hydraulic Fracturing Tech Conference and Exhibition	Feb. 4-6	The Woodlands, Texas	The Woodlands Waterway Marriott & Convention Center	spe-events.org
NAPE	Feb. 5-7	Houston	George R. Brown Conv. Ctr.	napeexpo.com
6th American LNG Forum	Feb. 10-11	Houston	Westin Galleria	americanlngforum.com
Oil & Gas Automation and Technology Week	Feb. 11-12	Houston	Hyatt Regency Intercontinental Airport Hotel	oilandgasautomationandtechnology.com
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Tuesday, odd mos.	Fort Worth, Texas	Petroleum Club of Fort Worth	adamenergyfortworth.org
ADAM-Greater East Texas	First Wed., odd mos.	Tyler, Texas	Willow Brook Country Club	etxadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.org
ADAM-Permian	Bi-monthly	Midland, Texas	Petroleum Club of Midland	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.org
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin, Texas	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Petroleum Club of Houston	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	hefg.net
Houston Producers' Forum	Third Tuesday	Houston	Petroleum Club of Houston	houstonproducersforum.org
IPAA-Tipro Speaker Series	Third Tuesday	Houston	Petroleum Club of Houston	ipaa.org

Email details of your event to Jennifer Martinez at jmartinez@hartenergy.com.
For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com/events.

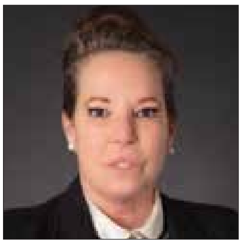
Oil and Gas Investor

COMPANIES IN THIS ISSUE

This index refers to the pages of the story or news item in which the company is first mentioned. Advertisers are in boldface.

The Matisse, the Federal Government, Oil, Gas and Nelson Rockefeller

A 1909 painting demonstrates the outcome if any one of the U.S.' pillars falls down.



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Henri Matisse, "La Danse" (1909), is part of the Museum of Modern Art, New York, collection.

The Matisse paintings known as "The Dance" often remind me of the nature of things, and that includes the U.S. oil and gas industry.

Although it isn't discussed in viewer critiques, which focus on color and form, what is apparent is the fragility of relationships–equity and debt markets, social, supply chain and more, including energy.

In each of the two paintings (1909 and 1910), five figures are in clockwise motion, holding hands, on a pedestal rendered as a green lawn on the edge of what can be construed as a blue abyss.

Less noticed is that the two positioned at the abyss' edge at that moment are looking down with angst at their feet in this precarious position.

Firmly on land, the one on their left appears to be pulling with all of her might, understanding the implications if failing and having herself successfully relied on the one to her own left in getting her past this potential doom.

It's her job at this moment.

But that individual to her left is now slipping on the grass. There is a visible gap in that one's grasp of the hand of the individual on her own left and who is on the cusp of entering the edge of the abyss.

While momentum had resulted in successful execution of this circle dance to this point, the imminent interruption in this momentum is now certain to result in collapse.

Once, tension kept the pillars upright, all on equal footing and each supporting another.

Disruption of that parity will mean they all fall down.

And they are falling down.

Had there been a subsequent frame, three of the five would be in lock-chain, dangling in the abyss and only one individual would still be standing on the pedestal, singly trying to bring the others back up.

The image is representative of multi-pillar, interlocking dependencies—such as the U.S.' need for a healthy oil and gas industry—that make this continued American democracy work.

Trusted financial markets are key, too, as well as the rule of law.

Another is hopefulness—the most overlooked attribute of sustainable democracies, economies, interpersonal relationships and, well, everything.

It's a vicious cycle, in a way, to repeat this trial again and again in a circular motion, knowing the odds are against success in perpetuity.

Yet hopeful Americans hold tight, crawl back up and, starting with the one pair of legs still standing, help pull it all back together.

And they resume 'the dance.' Slowly at first and then again at vortex speed.

Today, there are weak links in the renewed, strong "America is long, not short, energy" pillar.

Sadly, it's from within: Federal policies, machinations and other means of foiling oil and gas free enterprise are septic.

Federal policy is the dancer who is in mid-slip. The abyss is representative of the bad actors worldwide who dream of collapsing the U.S.—this ever-forward, ever-stronger, ever-optimistic Whoville.

One of these bad actors happens to own the other of the two "The Dance" paintings. Made in 1910 and having dancers in terracotta tone, the 1910 version is in Russia's The Hermitage Museum.

The 1909 one is in the Museum of Modern Art (MOMA) in New York. In this one, the link still standing is the nation's founding principles: reason, rule of law, property rights, human rights, freedom of trade and other noble pursuits.

But the U.S. has been turning its back on the very industry that makes everything in America—the world, really—possible: oil and gas.

LNG, for example. In a move to vote-bait the energy illiterate—frustratingly a large portion of the U.S. demographic—the Biden administration paused issuance of new LNG export project permits. And now, an unwitting federal judge in Washington, D.C., was persuaded by the Sierra Club into thinking some past-approved permits were illegitimately issued.

Another is disruption by the Federal Trade Commission (FTC) in the normal course of energy M&A.

Ironically, the 1909 version of "The Dance" has one degree of separation to the FTC, the federal government as a whole, and oil and gas itself.

Or possibly "amusingly" is the correct word.

It was donated to MOMA by Nelson Rockefeller.

He was an heir of the country's first integrated oil company, Standard Oil, that was famously broken up in the early 20th century for violation of federal anti-trust rules.

And he was vice president of the United States, serving in the mid-1970s when the U.S. was infamously caught both oil-short and gas-short by OPEC and other unfriendlies of that era.

And Rockefeller had purchased the 1909 "The Dance" in 1963 from an heir of Walter Chrysler, founder of Chrysler Corp.

In the painting, Earth is blue and green.