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THE NATURE OF REINVENTION

THE OGIINTERVIEW

CEO Clay Williams breaks down the energy transition and NOV's role in the industry's evolution.

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TECHNOLOGY

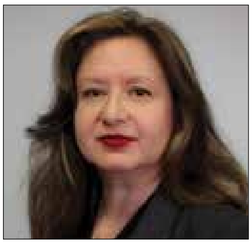
MIDSTREAM

ABOUT THE COVER: Photographer Felix Navarro captures the essence of Princeton grad, Eagle Scout and bona fide optimist Clay Williams, who also happens to be the CEO of global oilfield services and technology firm NOV. Williams was photographed at NOV's office in Houston.

▸ LETTER FROM THE EDITOR

It Takes More than a Village

Western goals of lowering global emissions require raising the standard of living for billions who live in energy poverty.



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The phrasing of "energy transition" is insufficient to describe the profound changes taking place within the industry and the world that relies on it.

Energy has been in a state of transition for millennia beginning at least with the first time someone rubbed two sticks together for warmth.

That the western world now wants to power its lifestyle in a low-carbon manner is simply another cycle driver within an industry that is composed entirely of cycles. And global impact doesn't stop at the West's borders; perhaps this will be the first time that it becomes irrefutable that Western political, philosophical and social dynamics are meaningless without the acknowledgment and cooperation of everyone else on the planet.

Let's suppose the West succeeds in capping its own emissions. Without also limiting emissions in the rest of the world, including undeveloped countries that are resource-rich but energy poor, as well as polarized nations such as Russia and China, the point of the West's success is muted.

The intent of the Paris Agreement to limit the global average temperature increase to a point well below 2°C above pre-industrial levels cannot be achieved without a global effort.

There are 195 parties that signed and ratified the Paris Agreement, a legally binding international treaty, which indicates significant, real intent to comply.

But like so many great ambitions, whether those of an individual, a state, a country or a continent, they can be thwarted by outside forces. In short, reality sets in.

I've been trying to full move out of a house near Houston and put it on the market since mid-February. It's now the middle of the year and let's just say that I vastly underestimated the endeavor.

Texas filed for primacy over the Class VI injection wells needed for CO_2 sequestration more than a year ago. The state is revising its application, according to my email dialogue with a spokesman at the U.S. Environmental Protection Agency.

Pakistan was among the countries to endorse the Paris treaty, which took effect in 2016. The country has relied on natural gas for one-third of its power, but a shortage last year led to blackouts. Russia's war on Ukraine has made prices skyrocket. Consequently, Pakistan is routinely outbid for LNG cargoes by those in Western Europe, Japan and Korea who can pay higher prices for the resource.

Gabriel Collins, the Baker Botts Fellow in Energy & Environmental Regulatory Affairs at Rice University's Baker Institute, said during a panel at Hart Energy's Super DUG conference in May that he questioned Pakistani dignitaries about their situation.

"They said, 'We're not thrilled about this decision, but coal is where we go. We have domestic resources'," Collins told a crowd of thousands in Fort Worth, Texas.

Pakistan is now working to quadruple its domestic coal-fired capacity to reduce power generation costs; its energy minister has confirmed Pakistan has no plans to build new gas-fired plants.

Hart Energy's own international managing editor, Pietro D. Pitts, has reported on the situation in Africa, a continent where 600 million people live without access to electricity. The West's calls for countries like South Africa to cease its dependence on coal are generally meaningless without international assistance.

Collins put into perspective the associated gas prolifically produced in the Permian Basin, as well as other parts of the Lower 48, and its place in the energy transition.

"If we're thinking globally about both energy abundance and sourcing our energy more cleanly, the Permian and our associated gas profile overall in the U.S. is critical to that."

And in this month's The OGInterview, NOV's CEO Clay Williams addresses the matter head-on: Is there an onus on the energy "haves" to help the "have-nots"—both from an emissions reduction perspective as well as a sort of "duty to care" angle?

The oilfield services chief heartily agreed, and you can read his full comments beginning on page 36.

Given the profound need and the corporate means, what's missing from the equation to answer the problem? Social will and political accountability in each "village" around the globe. OGI

▸ **JOE TO** THE WORLD

You Pay Him $200,000—Do You Owe Him Overtime?

You might, depending on an employee's designation under the federal Fair Labor Standards Act.

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Are your employees who make over $200,000 a year eligible for overtime pay? Strange as it may seem, it's possible, depending on the workers' designation under federal law.

Consider Michael Hewitt, who served as a tool pusher for Houston-based Helix Energy Solutions on an offshore oil rig from 2014 to 2017. In this position, he was responsible for all drilling and well intervention activities, as well as supervising 12-14 workers. Hewitt typically worked 12-hour days, seven days a week during 28-day hitches. For this, Helix Energy paid him a daily rate that ranged from $963 to $1,341.

As far as Helix was concerned, Hewitt was a "bona fide executive," as defined by the Fair Labor Standards Act (FLSA), and the company didn't owe him overtime wages. Further, under the "highly compensated employees" rule, Hewitt's pay of more than $200,000 a year easily exceeded the $100,000 (now $107,432) level that designated him as exempt.

But Hewitt sued, claiming he was owed overtime for 44 of those 84 hours a week because he was paid on a daily rate, not on a salary basis. As a result, he argued, he was not a "bona fide executive" as defined by the law, and the overtime exemption did not apply.

In 2018, a federal judge dismissed his claims, finding that the daily rate Helix paid him met the definition of salary under FLSA. The Fifth Circuit Court of Appeals reversed that ruling in 2021. The case came before the Supreme Court in 2022.

The salary guarantee

If you don't normally think of someone making $200,000 a year as a day laborer, well, neither did Justice Clarence Thomas during oral arguments in October.

"Thomas, who was famous for his silence, actually asked questions during oral argument and those questions seemed to indicate that he was going to rule in favor of the company," Scott Fiddler, partner in the Jackson Walker law firm, told me. "Then he went the other way."

Scott Fiddler

The 6-3 majority opinion, issued in February and authored by Justice Elena Kagan, found that Hewitt was entitled to overtime pay. It rejected the contention that a day rate constituted a salary, no matter how high that rate might be. Kagan was joined by Chief Justice John Roberts and Justices Sonia Sotomayor, Amy Coney Barrett, Ketanji Brown Jackson and Thomas. Justices Samuel Alito, Neil Gorsuch and Brett Kavanaugh dissented.

Jackie Staple

"Justice Kagan's opinion really did answer that … it wasn't done correctly in this case, but you could pay a salary if you guaranteed an employee a certain number of days per week," Jackie Staple, also a partner with Jackson Walker, told me. "So, your salary guarantees, say, four or five days a week. And if you wanted to pay them for an extra day or two days at the daily rate, you could do that as long as there was a reasonable relationship between the overall compensation and the guarantee."

What can a company do?

The FLSA generates the most complaints from clients, Fiddler said, because it is nowhere near intuitive. Helix had no intention to cheat its employee but its pay structure still landed it in trouble.

"Sometimes even general counsels would call and say, 'this can't be what the law is,' and we have to tell them, 'no, I understand you're trying to pay your employees competitively, but the way you're doing it is not in compliance with the law," he said.

"It's a real paradigm shift."

So, what can a company do? Fiddler listed three options:

- Convert compensation from daily rate to a flat salary. The company could, for example, guarantee a salary for five days of work, then pay a daily rate for extra days.
- Convert the daily rate to an hourly rate. "In both these first two situations, they'll just reverse engineer whatever was being paid before to make sure that the company is not paying any more than what they were before," he said.
- Utilize service and staffing firms to provide workers, a trend that's picking up in the industry, and leave pay decisions to them. That can be a risky option, he said, because the oil and gas company can be found to be a co-employer with the staffing firm if the company exerts too much control over the worker.

Of course, these are workarounds. A long-term solution would entail an overhaul of the FLSA, or at least amendments or revisions to the law, Staple said.

"[FSLA] was made in a time where the workforce was different, technology was different," she said. "There weren't as many available pay structures."

Fred Schilling, Collection of the Supreme Court of the United States

Front row, left to right: Sonia Sotomayor, Clarence Thomas, Chief Justice John Roberts, Samuel Alito, Jr. Elena Kagan. Back row, left to right: Amy Coney Barrett, Neil Gorsuch, Brett Kavanaugh and Ketanji Brown Jackson.

President Franklin Roosevelt signed the FSLA into law in 1938. The new legislation banned child labor, mandated safer work environments and introduced a federal minimum wage. That was also the year in which the first offshore oil rig was built in the Gulf of Mexico. The Creole platform was a mile from Creole, La., at a water depth of 14 feet.

The world has changed a lot since then. Maybe it's time for the venerable labor law to change, too. OGI

Belcher: Permitting Reform Gains Momentum

Federal compromise on NEPA legislation clears some longstanding ambiguities.

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In early June, U.S. House Speaker Kevin McCarthy (R-Calif.) and the White House reached a compromise agreement on the debt ceiling that resulted in the bipartisan passage and enactment of legislation to prevent the U.S. government from defaulting on its debt. As part of the compromise, provisions were included that make reforms to the National Environmental Policy Act (NEPA) and provided final approvals to complete the Mountain Valley Pipeline (MVP).

NEPA has long been considered by environmental activists to be the Magna Carta of U.S. environmental law, and attempts to reform or modify it have been vehemently opposed. It requires the federal government to assess the environmental impact of any federal action, such as a pipeline approval, LNG permits, or oil and gas leases. Over time, NEPA has been applied inconsistently among federal agencies, and its application and resulting litigation have been the source of long delays in federal actions and approvals.

The debt limit legislation made minor adjustments to NEPA in an attempt to clear up ambiguity over what impacts are "avoidable," create more certainty over lead federal agencies and inter-agency coordination, shorten and simplify environmental documentation, narrow the timeline for providing environmental opinions and create a clearer pathway for categorical exclusions to be put in place.

The MVP provision essentially deems the pipeline, which has been held up for years, to be in the national interest and mandates its permitting. The law also removes the ability to challenge the pipeline in the Fourth Circuit Court of Appeals by moving jurisdiction to the D.C. Circuit Court of Appeals, which is unlikely to delay the pipeline from moving forward.

While the reforms to NEPA will not suddenly make permitting energy projects easy, the passage of these provisions is significant because it marks the first time since the early 1980s that any substantial changes have been made to NEPA. There appears to be significant momentum with regard to additional permitting reform, due in no small part to what was not included in the legislation. Items left on the cutting room floor include transmission citing authority, judicial review, hydroelectric licensing, semi-conductor permitting relief, critical minerals, federal lands access, and Class VI carbon injection wells and primacy.

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The NEPA reforms mark the first substantial changes to the act since the early 1980s and, while items of interest to both parties were left on the cutting room floor, there now appears to be an opportunity for additional permitting legislation in the future.

Given unresolved issues of interest to both parties, there appears to be an opportunity for additional permitting legislation, with champions of such an effort including Senate Energy Committee Chairman Joe Manchin (D-W.Va.), among others.

A recent unanimous U.S. Supreme Court decision will also improve the environment for permitting projects and thus contribute to the positive momentum for permitting reform momentum. On May 25, the court narrowed the ability of states and environmental activists to block infrastructure and energy projects over environmental concerns under the Clean Water Act. In Sackett v. EPA, the court significantly reduced the number of areas that would qualify as "navigable waters" under the act, which has been used widely to block pipelines, roads, ports and other infrastructure projects. The decision significantly reduces the regulatory authority that U.S. Environmental Protection Agency and the U.S. Army Corps of Engineers can exercise over such projects. While the decision doesn't make it more likely for Congress to reach an agreement on permitting reform, it will take away an important tool that anti-development forces have used to block energy projects.

The momentum toward a more rational regulatory and permitting environmental landscape is real. However, with presidential and congressional elections looming in 2024, time is of the essence and any such package would likely need to be passed by the end of the year. OGI

ACTIVITY HIGHLIGHTS

IN 2022, WILLISTON BASIN E&PS PRODUCED 383.2 MMBBL OF OIL


Tom Reichner/Shutterstock

▸ **ACTIVITY** HIGHLIGHTS

FOCUS ON: WILLISTON BASIN

The prolific Permian Basin might steal headlines, but E&Ps are still tapping the Williston Basin for oil and gas production.

The Williston Basin, which stretches across swaths of North Dakota, South Dakota, Montana and Canada, is home to the Bakken Formation—the top oil-producing region in the U.S. Lower 48 outside of the Permian, according to the U.S. Energy Information Administration.

The top oil- and gas-producing county in the Williston Basin is McKenzie County, N.D., which saw net production of 108.92 million boe over the past 12 months, according to Rextag.

McKenzie was followed by Dunn County, N.D., where production totaled 56.45 million boe over the past year, and Mountrail County, N.D., which supplied 49.95 million boe.

The basin's top oil-producing operator is Oklahoma City-based Continental Resources, which produced 30.97 million bbl in the region over the past year.

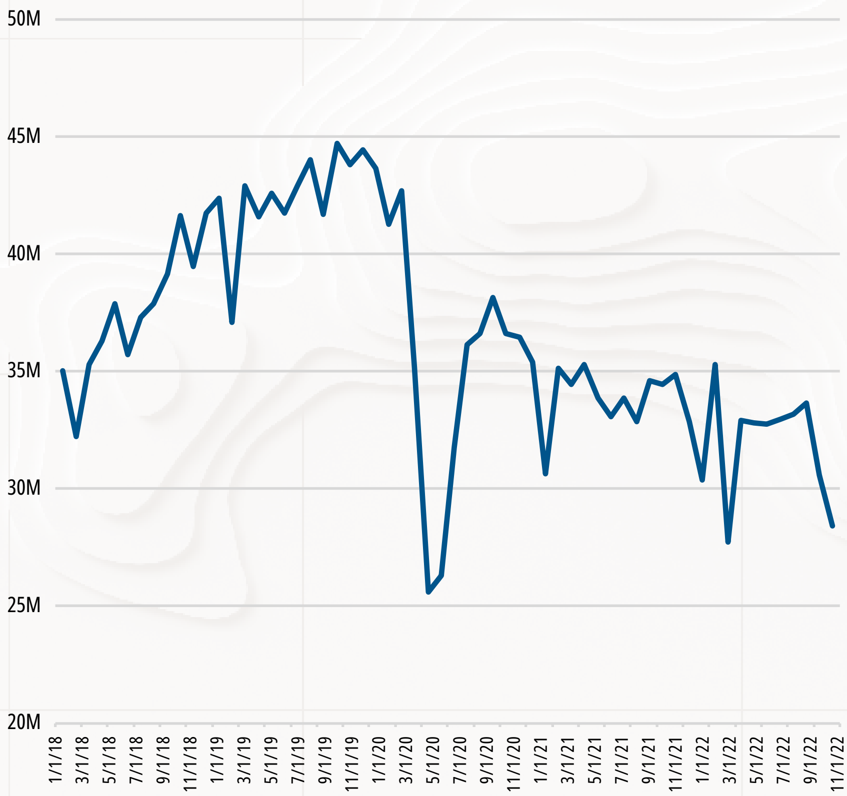
Continental is followed by Houston-based Marathon Oil's 15.7 million bbl and Hess Corp.'s 14.45 million bbl.

Whiting Oil & Gas, which merged with Oasis Petroleum last summer to form the Williston-focused Chord Energy, was the basin's fourth-largest oil producer in the past year at 13.17 million bbl.

In late May, Chord Energy boosted its Williston position with a $375 million acquisition from Exxon Mobil subsidiary XTO Energy. Exxon was the basin's fifth-largest oil producer in the past year with 12.23 million bbl.

Williston Monthly Oil Production

(2018-2022)



Top 10 Producing Counties in the Last 12 Months

County	BOE
McKenzie , N.D.	108,924,538.7
Dunn , N.D.	56,454,593.67
Mountrail , N.D.	49,949,106.5
Williams , N.D.	46,650,573.5
Richland, Mont.	5,590,367.667
Divide, N.D.	3,320,333.5
Burke, N.D.	2,170,712.333
Billings, N.D.	2026,389.833
Bowman, N.D.	2,018,507.5
Fallon , Mont.	1,466,344.667
Stark, N.D.	1,313,481.667

Source: Rextag

Top 5 Oil Producers in the Last 12 Months

Company	BBL
Continental	30,968,356
Marathon Oil	15,703,429
Hess	14,454,431
Whiting	13,174,905
Exxon Mobil	12,229,895

PERMITS

Operators refocused on the Texas side of the Permian Basin in the most recent month that data is available, with six of the top seven counties for well permits located in the Lone Star State.

Midland County, Texas, in the core of the Permian's Midland Basin, led the pack with 93 permits issued, according to Rextag.

Martin County, Texas, north of Midland, took the second spot on the leaderboard with 76 permits issued in May.

Of the top seven counties for issued well permits, the only place not located in the Permian is Campbell County, Wyo., in the heart of the Powder River Basin. Regulators approved 62 well permits in Campbell last month.

Texas led all other states for new well permits during the period with 749 permits—a 154% month-over-month increase.

As the Lower 48's top oil-producing basin, the Permian has E&Ps from small independents to supermajors jockeying for scale and inventory runway. Public companies including Callon Petroleum, Ovintiv, Matador Resources and Diamondback Energy have deployed billions of dollars on M&A in the past year to grow their respective Permian footprints.

Meanwhile, Wyoming vaulted to second in well permitting with 132 total well permits issued—an increase of 164% month over month.

Permitted Wells By State

State	Well Count
Texas	749
Wyoming	132
Colorado	92
North Dakota	71
Oklahoma	58
Louisiana	41

Permitted Wells By Operator

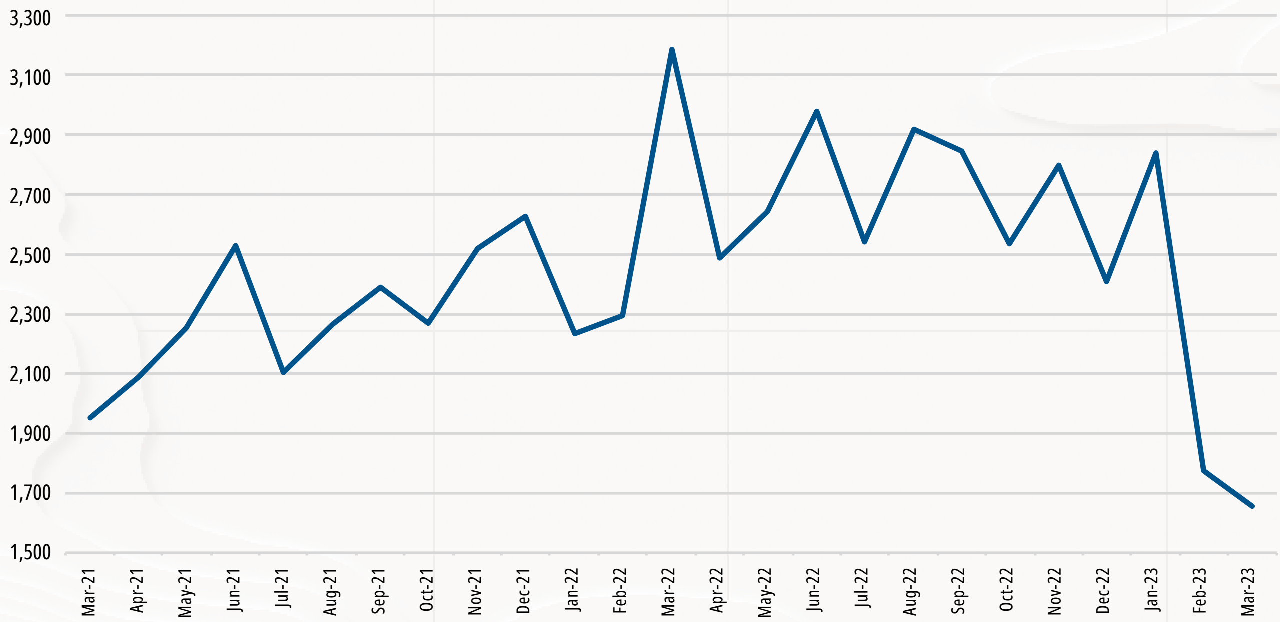
Operator	Well Count
Exxon Mobil	35
EOG Resources	34
ConocoPhillips	33
Continental Resources	32
Pioneer Natural Resources	31
Endeavor Energy Resources	28
Anshutz Exploration	25
TRP Operating	24
PDC Energy	23

Permitted Wells By County

County	Well Count
Midland, Texas	93
Martin, Texas	76
Loving, Texas	65
Campbell, Wyo.	62
Upton, Texas	45
Reeves, Texas	43
Ward, Texas	40
Converse, Wyo.	31
Webb, Texas	24
Williams, N.D.	21
Reagan, Texas	20
De Soto, La.	19
Karnes, Texas	18
Weld, Colo.	17
Mountrail, N.D.	16
Dunn, N.D.	14
McKenzie, N.D.	14
Laramie, Wyo.	13

U.S. Drilling Permits

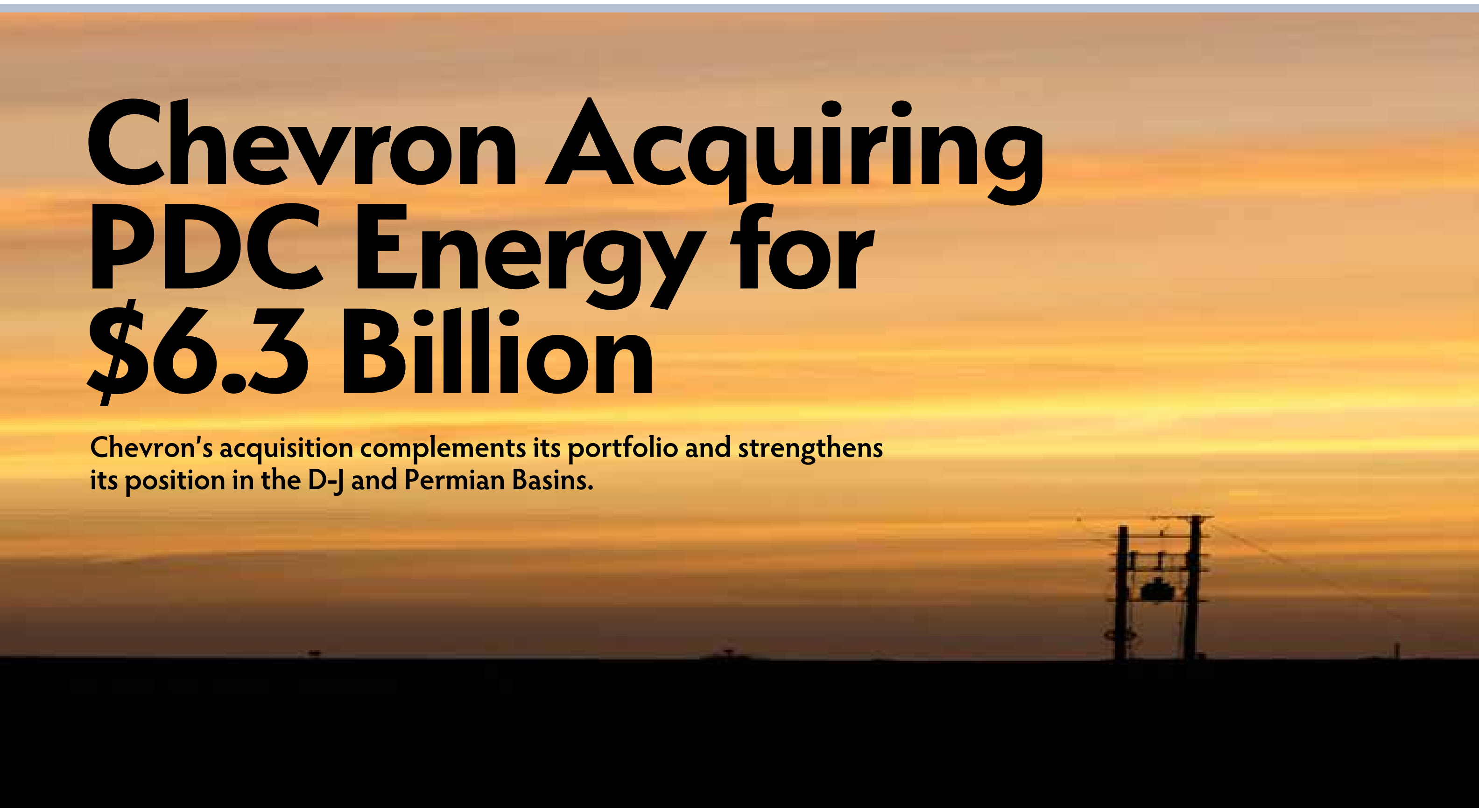
(March 2021-March 2023)



Source: Rextag

Chevron Acquiring PDC Energy for $6.3 Billion

Chevron's acquisition complements its portfolio and strengthens its position in the D-J and Permian Basins.



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Chevron agreed to acquire **PDC Energy** in an all-stock transaction valued at $6.3 billion, or $72/share, adding assets complementary to Chevron's positions in the Denver-Julesburg (D-J) and Permian basins.

The deal will add about 275,000 net acres near Chevron's existing operations in the D-J Basin, boosting the company's proved reserves by over 1 billion boe.

Scooping up PDC also adds about 25,000 net acres in the Permian's Delaware Basin, Chevron said.

PDC shareholders will receive 0.4638 shares of Chevron for each PDC share. Including debt, the transaction's total enterprise value is $7.6 billion.

Given Chevron's recent comments that the D-J Basin contains among their highest well returns, the company's move to acquire PDC isn't terribly surprising, **Truist Securities** Managing Director Neal Dingmann wrote in a May research note.

"What is surprising to us is we do not believe the deal was fully shopped across the industry, which could have potentially enabled an even higher bid for PDCE," Dingmann wrote.

The $72/share acquisition price equates to a 10.6% premium to PDC's May 19 closing price of $65.12/share.

Chevron expects the transaction to deliver about $1 billion in annual free cash flow within the first year of closing, based on Brent crude prices of $70/bbl and Henry Hub natural gas prices of $3.50/Mcf.

The company plans to increase capital spending by around $1 billion per year in conjunction with the PDC acquisition. Chevron raised its spending guidance range to between $14 billion and $16 billion through 2027.

Chevron said it expects to realize around $400 million in capital spending efficiencies after the deal closes.

Truist estimates PDC's current production at around 270,000 boe/d. That's expected to drop to around 260,000 boe/d in the third quarter.

The deal is expected to close during the third quarter.

D-J depth

Focusing on growing in the D-J Basin likely allows Chevron to acquire undeveloped upside at more favorable pricing, **Enverus** Director Andrew Dittmar wrote in a May research note.

"The company looks to have paid less than $5,000 per acre with more than 80% of the total deal value allocated to existing production," Dittmar wrote. "That compares to the Permian Basin, where equity valuations for companies with equivalent inventory tend to be higher and M&A markets more competitive."

Equivalent quality inventory in the Permian


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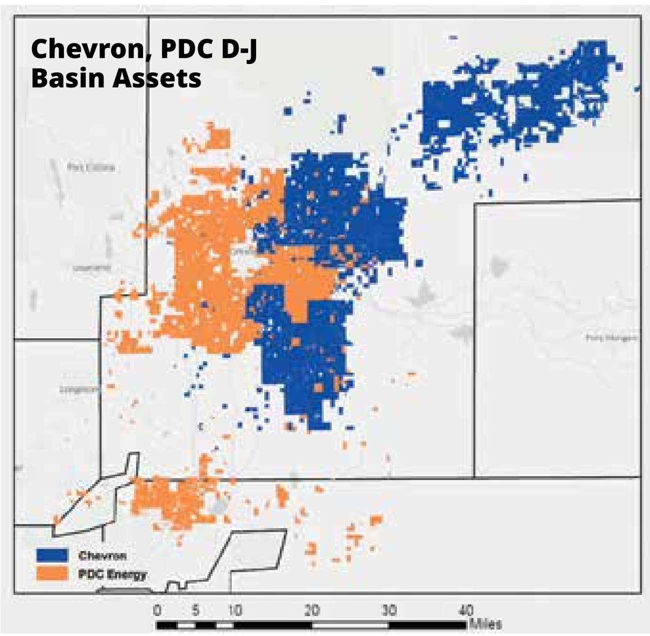
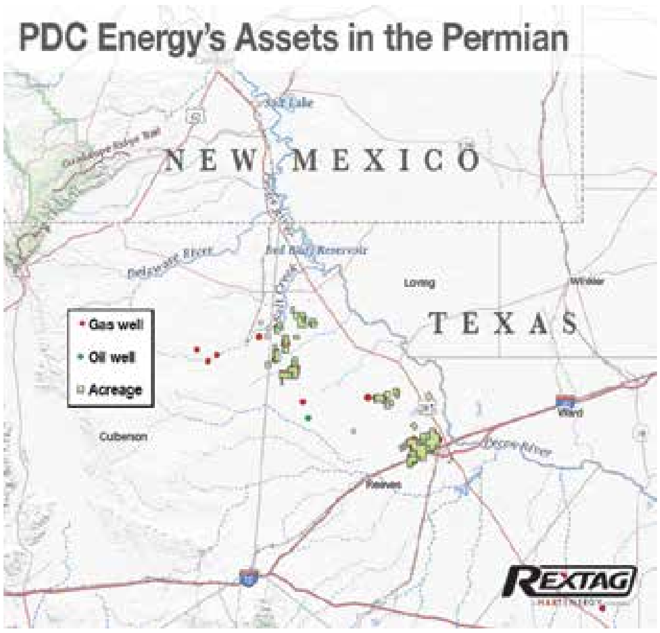


Source: Chevron-PDC investor presentation

Chevron's acquisition of PDC adds about 275,000 net acres in the D-J Basin.



Source: Rextag

PDC Energy's footprint in the Permian Basin

Basin has traded at more than $20,000/acre in recent deals struck in the Midland and Delaware basins, Enverus has reported.

Operating in Colorado does pose some increased regulatory risk to E&Ps compared to other geographies, but companies have been able to successfully secure years of drilling permits for future development, Dittmar said.

In prepared remarks, Chevron said PDC has received regulatory approval to enable development at current levels in Weld County, Colo., into 2028.

Private Investor Group Buys Rockies Gas Producer PureWest in $1.8B Deal

A private consortium of family offices and financial institutions acquired ownership of Wyoming natural gas producer PureWest for $1.8 billion.

In an unusual pure natural gas deal, a private investor group led by family offices has taken ownership of Wyoming-focused **PureWest Energy** in a blockbuster acquisition.

The Rocky Mountain natural gas producer merged with an entity sponsored by the private consortium of investors called PW Consortium in a $1.84 billion cash transaction.

Denver-based PureWest Energy's existing management team and employees will remain in place and the company's board will be reformed with PW Consortium representatives following the closing of the deal.

In a news release, PureWest CEO Chris Valdez said the private investor group's backing will further strengthen the company's natural gas platform in Wyoming's Green River Basin.

"Our team has successfully consolidated operations on the Pinedale Anticline, showcasing a sustainable inventory runway," Valdez said. "Moreover, we have positioned our brand as a prominent market leader in low-methane certified gas and earned recognition as the best workplace in Denver."

PureWest has amassed more than 110,000 net acres in and around the gassy Pinedale and Jonah Fields in Sublette County, Wyo.

As of May 1, PureWest averaged equivalent gross production of 650 MMcf/d from approximately 3,400 operated wells in the Green River Basin, according to the company's website.

Following the merger, PureWest "plans to increase its high-margin production through development," company President and CFO Ty Harrison said.

E&Ps have announced several oil-focused transactions in the Lower 48 this year, but volatility in U.S. natural gas prices has slowed the M&A market for gas-focused deals.

Henry Hub natural gas prices are expected to average $2.66/MMBtu in 2023, down more than 58% from an average of $6.42/MMBtu last year, according to the latest estimates published by the U.S. Energy Information Administration.

Family office interest

Harrison said that the unique capital structure of the deal, which includes family office equity and securitized debt, positions the company for long-term value creation.

The company closed on a third asset-backed securitization as part of the transaction, which included offering and selling $200 million worth of notes through a private placement.

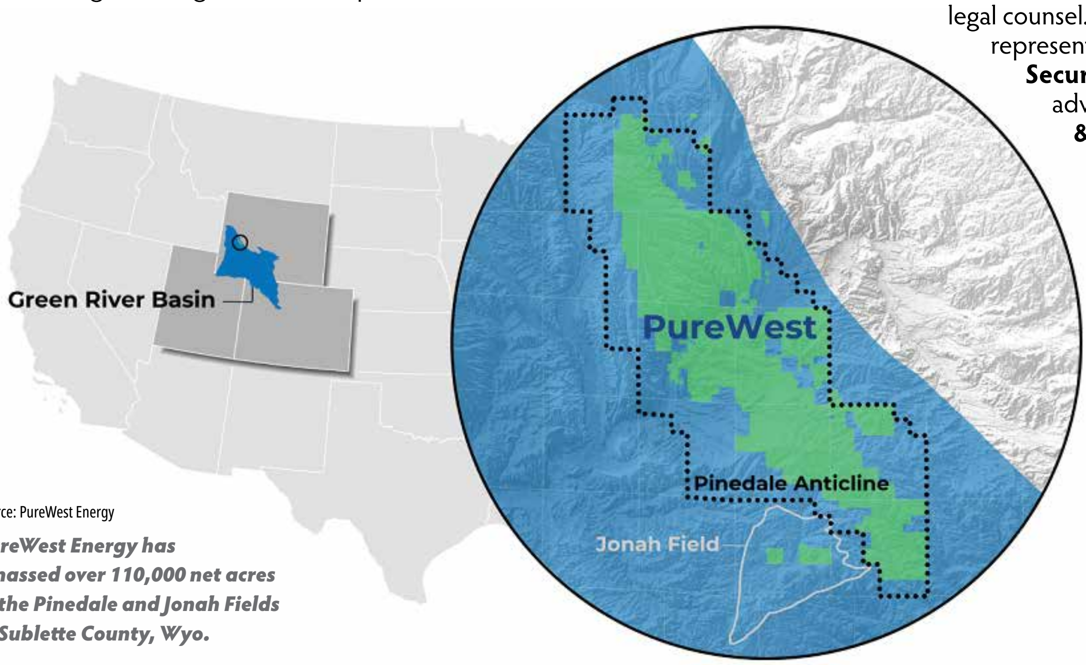
PW Consortium members include **A.G. Hill Partners**, **Cain Capital**, **Eaglebine Capital Partners**, **Fortress Investment Group**, **HF Capital**, **Petro-Hunt** and **Wincoram Asset Management**, according to the release.

PureWest also divested some producing wellbores to investment vehicles managed by Wincoram as part of the deal.

PureWest was represented by **Evercore** as exclusive financial adviser and **Vinson & Elkins** as legal counsel. PW Consortium was represented by **Guggenheim Securities** as sole financial adviser and **O'Melveny & Myers LLP**, **David B. Denechaud PLLC** and **Jackson Walker LLP** as legal counsel.

Guggenheim also served as the sole book-running manager and placement agent for the debt offering.

—Chris Mathews, Senior Editor, Shale/A&D



Source: PureWest Energy

PureWest Energy has amassed over 110,000 net acres in the Pinedale and Jonah Fields in Sublette County, Wyo.

Exclusive: Mesquite Sells Eagle Ford's Catarina Ranch to Private E&P

In a transaction likely worth about $300 million, Mesquite Energy made its second divestiture of Eagle Ford assets in a month following a deal with Crescent Energy.

Shutterstock

Mesquite Energy offloaded more of its acreage in the southern Eagle Ford Shale to a private E&P, Hart Energy has learned.

Fort Worth, Texas-based **Black Mountain Oil & Gas**, along with Houston-based equity backer **Trace Capital Management**, acquired the Catarina Ranch asset from Mesquite Energy at the end of May, Black Mountain told Hart Energy on June 12.

The transaction includes 51,921 net acres spanning Dimmit, Webb and La Salle counties, Texas, which is south of the town of Catarina, Texas, near the Mexican border.

The Catarina Ranch asset is currently averaging production of 12,400 boe/d, according to Black Mountain.

A Black Mountain representative said the company had a roughly 20,000-acre tract largely contiguous with Catarina Ranch prior to its deal with Mesquite.

Financial terms of the deal were not disclosed. The deal's value was likely about $300 million, Andrew Dittmar, director at **Enverus**, told Hart Energy.

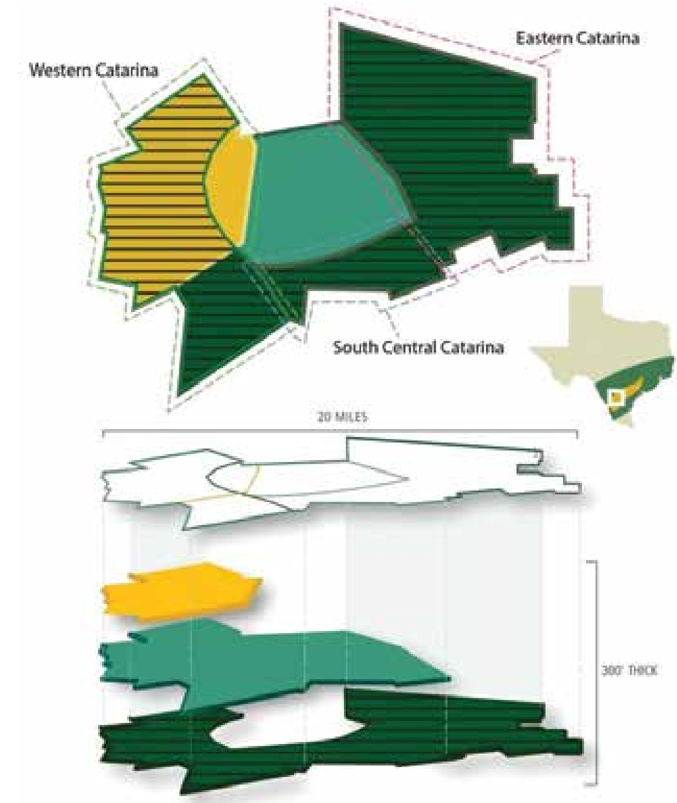
Black Mountain's acquisition keeps alive the Eagle Ford's megadeal streak, with the mature play's M&A generating $5 billion in the first quarter alone. In the past year, companies including Canada's **Baytex Energy**, **Chesapeake Energy**, **Marathon Oil**, **Devon Energy** and others have conducted billions in transactions.

The Catarina Ranch has been a part of Mesquite's portfolio since the company's predecessor, Sanchez Energy, acquired the southern Eagle Ford asset from **Shell** in June 2014.

Sanchez Energy, which developed a sizable position in the Eagle Ford Shale, voluntarily filed for Chapter 11 bankruptcy protection in August 2019, citing the challenging commodity price environment for oil and gas.

The company emerged from bankruptcy as a private op-

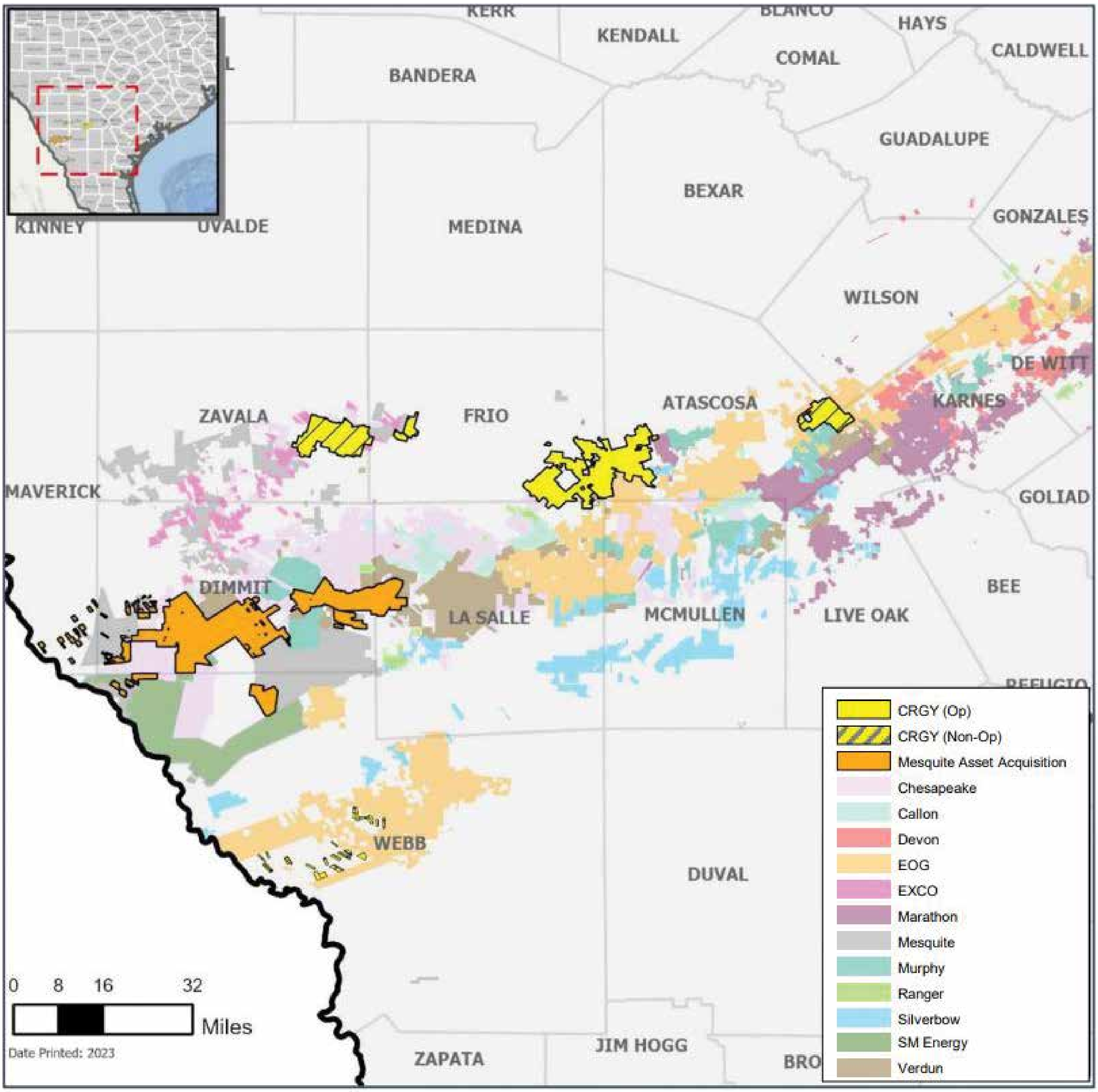
Catarina Ranch Asset



Source: Sanchez Energy 2016 investor presentation

The Catarina Ranch has been part of Mesquite Energy's portfolio since the company's predecessor, Sanchez Energy, bought the asset from Shell for $639 million in 2014.

Southern Eagle Ford Assets



Source: Crescent Energy investor presentation

Crescent Energy is acquiring Mesquite's Comanche assets in the southern Eagle Ford, adjacent to the Catarina Ranch acreage.

erator, Mesquite Energy, in mid-2020, eliminating about $2.3 billion in debt through a court-ordered reorganization.

Catarina Ranch grew into an important part of Sanchez's portfolio prior to the bankruptcy.

The Catarina asset accounted for more than 60% of Sanchez's total natural gas production and 36% of the company's total crude oil production during 2018, according to Securities and Exchange Commission filings.

Mesquite's deal is part of a broader divestiture campaign in the Eagle Ford.

In May, Mesquite entered into an agreement to sell its Comanche assets—adjacent to Catarina Ranch— to **Crescent Energy** for $600 million.

The deal with Crescent included approximately 75,000 contiguous net acres, primarily in Dimmit and Webb counties, and average production of 20,000 boe/d (70% liquids).

Crescent's transaction with Mesquite is expected to close during the third quarter.

Sanchez had acquired the Comanche assets through a $2.1 billion transaction with **Anadarko Petroleum** in 2017.

—Chris Mathews, Senior Editor, Shale/A&D

Chord Energy Divests Permian Assets to Private E&P

Chord Energy is selling non-core acreage and wells, primarily in the Central Basin Platform, to private E&P BCP Resources, which is focused on developing and optimizing legacy assets.

Chord Energy is shedding non-core assets in the Permian Basin as part of a broader divestiture plan to streamline its portfolio.

Chord, formed through the public-public merger of Whiting Petroleum and Oasis Petroleum last year, closed a deal to sell acreage and producing wells in the Permian to private operator **BCP Resources**, the company's CEO told Hart Energy.

The transaction includes 153 producing wells across six counties in Texas, with the majority in Winkler County in the Permian's Central Basin Platform.

The deal also includes non-operated properties and mineral interests in Texas, New Mexico, Oklahoma and Michigan, BCP Resources said.

Private E&P BCP, based in Midland, Texas, said the acquisition adds 1.3 MMboe of net proved developed producing (PDP) reserves (84% liquids) to its portfolio. Financial terms of the transaction were not disclosed.

In an interview, Barry Portman, owner and CEO of BCP Resources, told Hart Energy the acquired assets made up most of the remaining position Whiting Petroleum held in the Permian Basin, with the exception of a few other properties.

Portman, who previously held operational roles at **Pioneer Natural Resources**, **Kinder Morgan** and **Marathon Oil** before launching BCP Resources last year, said the company sees opportunity in scooping up legacy properties—including conventional assets that might not compete for capital in the horizontal drilling plans of larger operators.

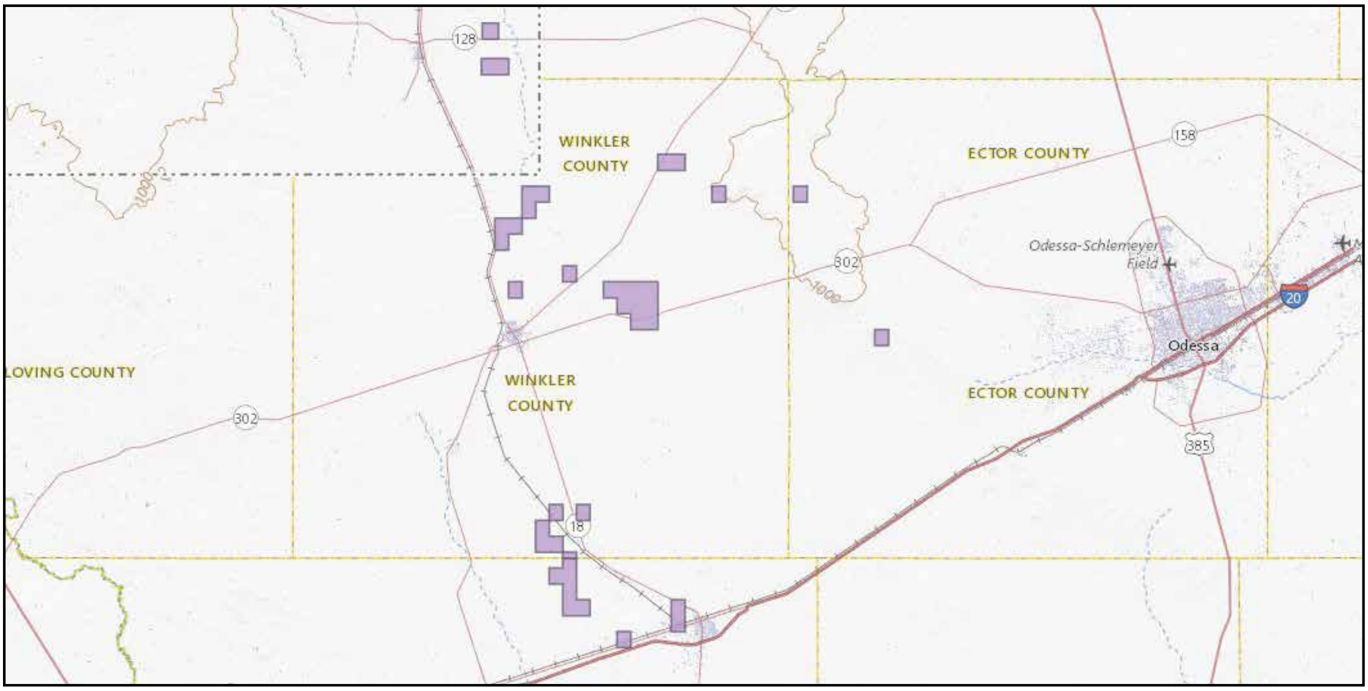
"Your typical 2, 3-mile shale laterals that most of the majors pursue—we want to do everything but that," Portman said.

The deal with Chord scaled BCP Resources' Permian position in a big way. The company grew from 640 Permian acres before the deal to 15,818 acres (100% HBP) after closing, according to data from BCP.

The company also boosted its gross production from 740 boe/d (63% liquids) to 2,280 boe/d (78% liquids) with the Chord transaction.

Over the next year, BCP Resources aims to grow production by optimizing the conventional assets acquired from Chord, he said. The company plans to extend the field by drilling additional vertical wells in the future, as well as using

Whiting Petroleum's Legacy Permian Acreage



Source: Rextag

Whiting Petroleum's legacy acreage position in and around Winkler County, Texas, in the Permian's Central Basin Platform secondary recovery methods including waterflooding and CO_2 flooding.

"We feel like we can boost our production 50% to 100% in the next year," Portman said.

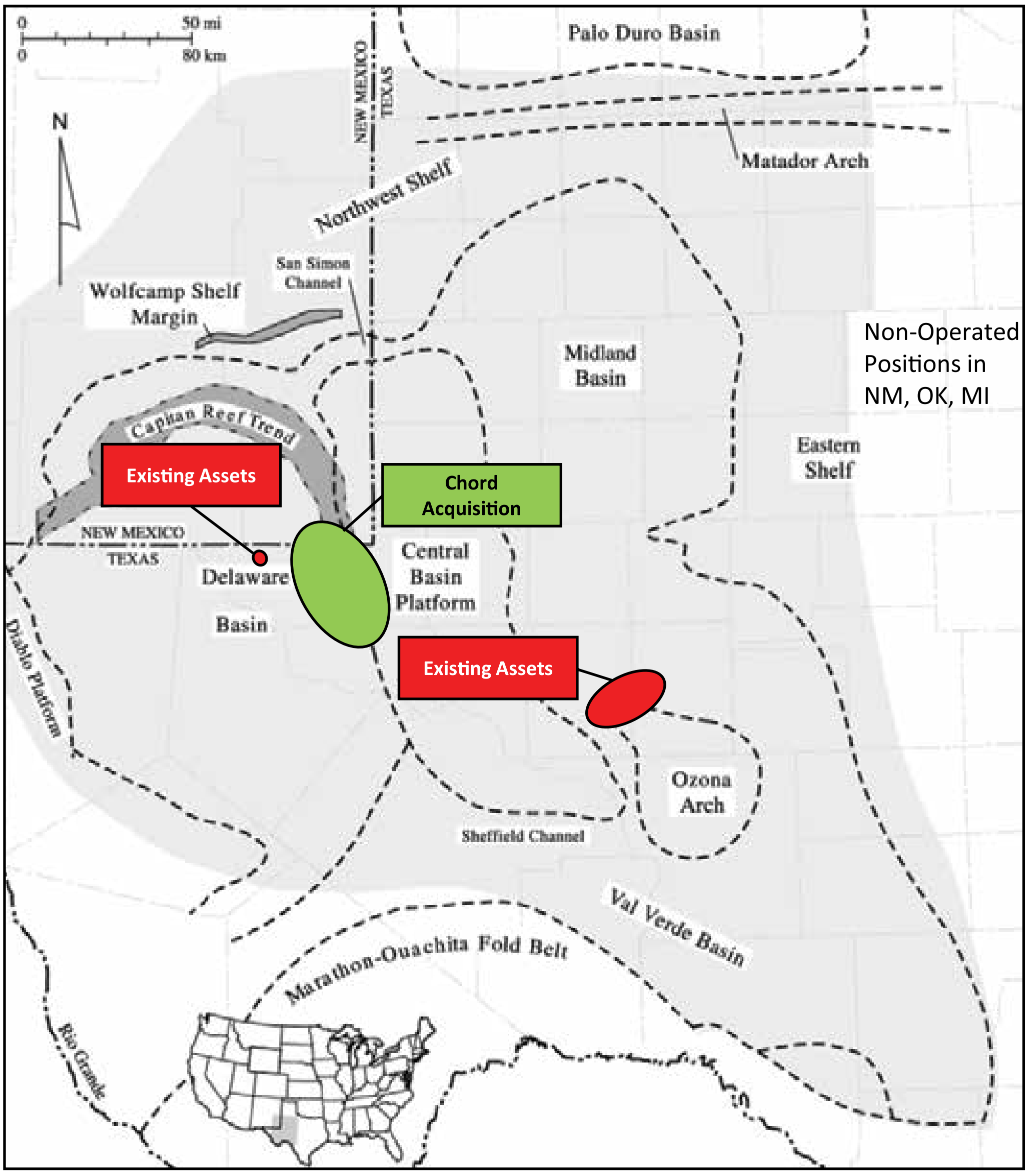
Outside of the Central Basin Platform, BCP Resources also operates wellbore interests in the Permian's Midland Basin.

BCP Resources is the dedicated oilfield operator for **Lodestone Energy Partners II**, which acquired assets in Reagan and Upton counties, Texas, from **Hibernia Resources III** in July 2022.

The deal with Hibernia included 85 conventional and 21 legacy horizontal wellbores and more than 2 MMboe of net PDP reserves (63% liquids).

With financial backing from a group of investors and access to senior bank debt, BCP Resources aims to move on accretive acquisitions in the Permian at least every 12 months, Portman said.

"We know we want to target the legacy properties and we know what we're good at," Portman said. "But we need to find [a deal] that fits our operational background and our expertise, and also fits our bank and our investors."



Source: BCP Resources

BCP-operated assets in the Permian Basin

Community Bank of Midland provided a senior oil and gas debt facility to BCP Resources in connection with the transaction. The company was represented by **Stubbeman, McRae, Sealy, Laughlin & Browder** as legal counsel.

Chord focused on Williston growth

Chord Energy has been deliberately offloading non-core assets located outside of the Williston Basin in North Dakota and Montana.

The company lined up sales for about $35 million of non-core assets outside of the Williston during the first quarter, Chord reported in its May earnings.

During the company's first-quarter earnings call, President and CEO Danny Brown said Chord still had a small amount of non-core assets in the portfolio that could be sold and monetized.

As Chord exits other geographies, the company is searching for opportunities to expand its footprint inside of the Williston.

In late May, Chord announced an agreement to acquire Williston assets from **Exxon Mobil** subsidiary **XTO Energy** and affiliates for $375 million in cash.

The deal included around 62,000 net acres, 77% of which are undeveloped, and more than 100 future drilling locations. Production acquired from XTO averaged more than 6,000 boe/d (62% oil).

Chord has around $590 million of cash on hand held in reserve for Williston Basin M&A opportunities, Chord Senior Vice President of Production Charles Ohlson said during Hart Energy's SUPER DUG conference in May.

—Chris Mathews, Senior Editor, Shale/A&D

Exclusive: VTX Energy Adds More Southern Delaware Acreage

VTX Energy Partners, backed by Swiss energy trader Vitol, is expanding its southern Delaware Basin footprint to 47,000 net acres through a bolt-on acquisition, CEO Gene Shepherd tells Hart Energy.

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VTX Energy Partners is expanding its footprint in the Permian Basin following a major acquisition earlier this year.

VTX agreed to acquire another 12,000 net leasehold acres in the Permian's southern Delaware Basin, the company announced in June, making good on M&A hints dropped at a May Hart Energy conference by CEO Gene Shepherd.

The Delaware assets include daily net production of approximately 4,000 boe/d and associated water infrastructure.

Shepherd told Hart Energy that the latest acquisition in Reeves County, Texas, will significantly increase the company's inventory of undeveloped drilling locations.

"This further solidifies our desire and interest in continuing to focus on the southern Delaware, and I think the same holds for **Vitol**," Shepherd said.

VTX, which is backed by Swiss energy trader Vitol, will grow its position to 47,000 net acres in the southern Delaware Basin when the deal closes. Closing is expected to occur by mid-July, Shepherd said.

The newly acquired acreage is largely contiguous with the Red Bull play VTX purchased from **Delaware Basin Investment Group** (DBIG) earlier this year.

Extending inventory

Shepherd said with the previous DBIG acquisition, a large part of the deal's value was based on the acreage's developed oil and gas production.

The DBIG deal included production of about 32,000 boe/d when the transaction closed in March, Shepherd said during Hart Energy's SUPER DUG conference.

Gene Shepherd

With the latest deal, VTX ascribed much of the transaction's value to the undeveloped acreage of future drilling locations, he said.

"From that standpoint, they complemented each other," Shepherd said.

The newly acquired acreage includes operated ownership within the DBIG block where VTX was previously a non-op partner, Shepherd said.

Most of the remaining acreage VTX picked up through the deal shared a lease line to the northwest of the DBIG block.

It's an area that the VTX team knows well. Shepherd, formerly president and CEO of **Brigham Resources**, said DBIG shares a lease line with the position Brigham sold to **Diamondback Energy** for $2.4 billion in 2017.

Compared to the Permian's competitive Midland Basin, or even the northern part of the Delaware, the southern Delaware remains a more fragmented basin.

E&Ps such as **Continental Resources** and **Permian Resources** have been active in the region. But VTX—with the weighty financial backing of Vitol—also aims to be a buyer in the southern Delaware.

"We think we're well positioned to continue to look for opportunities and be one of the more meaningful consolidators in the southern Delaware," Shepherd said.

Another Vitol-backed Permian E&P, **Vencer Energy**, made a splashy debut in 2021 by **acquiring Hunt Oil's** position in the Midland Basin.

—Chris Mathews, Senior Editor, Shale/A&D

UPSTREAM

• **Ovintiv** closed the previously announced acquisition of core Midland Basin assets in June 12, adding approximately 1,050 net 10,000 ft well locations and 65,000 net acres—mostly undeveloped land adjacent to the company's Permian Basin operations.

The $4.275 billion cash-and-stock transaction includes almost all the leasehold interest and related assets of **EnCap Investments** portfolio companies **Black Swan Oil and Gas**, **PetroLegacy Energy** and **Piedra Resources**.

Ovintiv also closed its previously announced all-cash sale of its Bakken portfolio in the Williston Basin to EnCap portfolio company **Grayson Mill Bakken** for $825 million.

Both transactions will enhance capital efficiency by 15% and increase cash returns per share by more than 25%, the company said.

As part of the transaction, Ovintiv will issue approximately 31.8 million shares of its common stock, down from the 32.6 million shares estimated in the initial announcement of the transaction.

Ovintiv will also be added to the S&P 400 Index effective prior to market open on June 20.

Ovintiv expects to have a total company oil and condensate production of more than 200,000 bbl/d and a total capital investment of $2.1 billion to $2.5 billion in 2024.

• **ConocoPhillips** is boosting its stake in a Canadian oil sands project for around CA$4 billion (US$3 billion).

Houston-based ConocoPhillips is exercising its preemption right to purchase the remaining 50% interest in the Surmont in situ oil sands asset from **TotalEnergies EP Canada**, the company announced in May.

The deal trips up Canadian producer **Suncor Energy**, which in April announced it would acquire TotalEnergies EP Canada, including its interest in the Surmont assets, for US$4.1 billion.

ConocoPhillips currently holds a 50% interest as operator of Surmont. The company will own a 100% interest when the transaction closes, which is expected to occur in the second half of 2023.

ConocoPhillips has operated the Surmont oil sands project in Alberta, Canada, since its launch in 1997. The company had a first right of refusal on TotalEnergies' 50% interest in the project.

The company said it plans to finance the transaction with either cash, short- and medium-term financing, or a combination of both.

The deal is also subject to contingent payments of up to CA$440 million (US$325 million) over a five-year term.

The transaction is expected to add about $600 million in annual free cash flow in 2024, based on WTI prices of $60/bbl.

• **Chord Energy** has strengthened its position in the Williston Basin with an agreement to acquire core acreage from **Exxon Mobil** subsidiary **XTO Energy** and affiliates for $375 million cash.

The nearly one-year-old company, formed by a merger of **Whiting Petroleum** and **Oasis Petroleum** in 2022, will add about 62,000 acres—of which about three-quarters is undeveloped—within or adjacent to its near-term development program, the company said in a news release.

"These low-cost, tier-one assets are highly competitive with our existing portfolio and further extend our inventory runway," Chord CEO Danny Brown said. "Consolidation in the core of the basin supports longer laterals, higher capital and operating efficiencies, strong financial returns and sustainable free cash flow generation."

The acquired acreage enables Chord to expand six of its pre-acquisition drilling spacing units from 2 miles to 3 miles. The acreage, which is 100% held by production, has 123 estimated net 10,000-ft equivalent locations, the company said.

"The transaction creates significant accretion for shareholders across all metrics, while maintaining pro forma leverage below our target," Brown added.

With an effective date of April 1, the transaction was expected to close at the end of June.

• Canada's **Baytex Energy** continues to make progress toward closing its acquisition of Eagle Ford E&P **Ranger Oil**.

Baytex reported in May that shareholders had approved the deal, a cash and stock transaction valued at $2.5 billion. Baytex said that the holders of 95.45% of shares voted in favor of the purchase, according to a press release.

The company previously closed a private offering of $800 million in senior unsecured notes to help fund the cash portion of the acquisition.

Under the terms of the agreement, Ranger shareholders will receive a fixed ratio of 7.49 shares of Canada's Baytex and $13.31 in cash for each Ranger share. Upon closing, Baytex shareholders would own approximately 63% of the combined company and Ranger shareholders will own approximately 37%.

Baytex said the merger is expected to close late in second-quarter 2023 or early in the third quarter, subject to the satisfaction of customary closing conditions, including receipt of requisite regulatory approvals and Ranger shareholder approval.

GAS

• **Rice Acquisition Corp.** (RONI) and energy company **NET Power** closed a $2 billion merger in June that will create a new energy company already backed by large independent E&Ps, Asian conglomerates and major oilfield service companies.

The company offers clean energy produced from the combustion of natural gas with pure oxygen to spin turboexpanders, with remnant CO_2 ultimately sequestered.

NET Power said it has an initial enterprise value of approximately $1.5 billion and a market capitalization in excess of $2 billion.

NET Power received gross proceeds of more than $675 million from the combination, consisting of more than $135 million cash from RONI's trust account and approximately $540 million in private investment in public equity (PIPE) capital from strategic and financial investors. A PIPE is a funding mechanism that allows investors to buy stock directly from a company at a reduced price.

Proceeds are expected to "fully fund" NET Power's corporate operations and grow its backlog of utility-scale power plant projects, with plant deliveries expected to begin in 2026.

• **Occidental Petroleum** provided $10 million in interim financing to support NET Power's operations through the closing. In addition to Occidental, NET Power's backers include **Baker Hughes**, **Constellation Energy** and **8 Rivers**, a subsidiary of **SK Group**.

Vicki Hollub, president and CEO of Occidental, said NET Power has a transformative technology that supports the company's net-zero ambitions through its ability to provide "near emissions-free power to our Permian Basin operations and future Direct Air Capture sites."

• **TotalEnergies** will buy a 17.5% stake in U.S. LNG developer **NextDecade** for $219 million, the French group said on June 14, part of a broader deal to enable the Texas company's **Rio Grande LNG** export project to proceed.

NextDecade said it had entered into framework agreements with **Global Infrastructure Partners** and TotalEnergies to facilitate the final investment decision for the Rio Grande LNG project, expected to be confirmed by the end of June.

"Our involvement in this project will add 5.4 million tons per year of LNG to our global portfolio, strengthening our ability to ensure Europe's security of gas supply, and to provide our Asian customers with an alternative fuel to coal," TotalEnergies Chairman and CEO Patrick Pouyanne said.

The French energy major is the world's third-largest LNG player, with a roughly 12% market share and global portfolio of about 50 million tons of LNG per year.

It has said it aims to grow its LNG business 3% annually, and expects natural gas to account for half of all its energy sales by 2030.

MIDSTREAM

• Asset manager **Energy Income Partners**, one of the top shareholders in **Magellan Midstream Partners**, said in June that it intends to vote against pipeline operator **ONEOK's** deal to buy Magellan.

Energy Income said in a letter addressed to the company's board that the taxes paid by its funds and investors will exceed the premium offered by ONEOK and any potential benefits from the merger.

Energy Income is the fourth-largest shareholder in Magellan with a roughly 3% stake.

The asset manager also said it wants Magellan to remain a standalone entity because its returns on invested capital are far superior to ONEOK's.

ONEOK said last month that it would acquire Magellan in a cash-and-stock deal valued at about $18.8 billion.

OTHER TRANSACTIONS

• **Ingersoll Rand** entered into a definitive agreement to acquire **Howden Roots's** compression business from **Chart Industries** in an all-cash deal valued at approximately $300 million.

The sale comes nearly three months after Chart Industries completed the acquisition of industrial toolmaker Howden from **KPS Capital Partners** for $4.4 billion in cash.

Ingersoll said the deal was made at a "low teens" adjusted EBITDA purchase multiple that is expected to be reduced to mid-single digits within three years. Ingersoll, a provider of industrial equipment including oil and gas products, said the deal adds low-pressure compression and vacuum technologies to the company's portfolio.

The Howden Roots business will enhance the company's ability to serve high-growth, sustainable end markets including green steel, the company said.

For Chart Industries, the deal backs up management's commentary that the company will divest $500 million in assets to reduce debt.

Chart Industries provides highly engineered equipment servicing multiple applications in the clean energy and industrial gas markets, according to Jefferies.

• Solar energy provider **Solar Alliance Energy** signed a non-binding letter of intent in May to acquire an unnamed Canadian commercial and utility solar company for $6 million.

The unnamed solar company is based in Alberta with a year-to-date unaudited 2023 fiscal year revenue of $5,801,023 and future contracted projects totaling more than $5.6 million.

"The transaction is expected to significantly increase the scale of Solar Alliance, be immediately accretive to Solar Alliance, provide access to the rapidly expanding Canadian solar market and create operational synergies while positioning the company to be cash flow positive post-transaction," Solar Alliance CEO Myke Clarke said in a May press release.

Solar Alliance's increase in scale will allow for shared engineering, administrative and accounting services, increased buying leverage and decreased bonding and debt facility costs. The combined management, board and insiders will own approximately 54%, Clark said in the press release.

The transaction also comes at a favorable time for Canadian solar due to the introduction of a 30% investment tax credit in the federal budget for renewable energy projects in 2023.

Closing of the transaction remains subject to completion of due diligence, a binding definitive agreement, shareholder approval and approval by **TSX Venture Exchange**, which Solar Alliance has 90 days to complete.

• **Knight Energy Services** has acquired **Platinum Pipe Rentals**, the **Voyager Interests** portfolio company announced in June.

Platinum Pipe Rentals is a drill pipe and tubing rental company in the Permian Basin and Eagle Ford Shale. Its acquisition adds a fleet of downhole rental tools, including drilling jars, tubular handling equipment and over 7 million feet of drill pipe and tubing to Knight's arsenal.

"Today is an extremely exciting day for Knight. Combined with Platinum, we believe Knight has the largest fleet of rental drill pipe and tubing in the nation," said Dwight Gross, CEO and president of Knight. "We have operations in every key basin and as a result of Platinum's presence in the Permian, we are now a real force in the most active oil and gas region in the country."

As part of the deal, founder and president of Platinum, Mickey Padilla will join Knight as a senior executive staff member, shareholder and board member.

Headquartered in Houston, Knight's Permian operations will be consolidated into Platinum's facilities in Odessa. OGI


NOMINATIONS CLOSING SOON
Deadline for submissions is July 14, 2023
40 UNDER FORTY
Oil and Gas Investor is accepting nominations for the 2023 Forty Under 40 in Energy awards. We encourage you to nominate yourself or a colleague who exhibits entrepreneurial spirit, creative energy and intellectual skills that set them apart. Nominees can be in E&P, finance, A&D, oilfield service, or midstream. Help us honor exceptional young professionals in oil and gas.
Honorees will be profiled in a special report that ships with the November issue of Oil and Gas Investor and on HartEnergy.com.
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Family Offices Step Up to Fund Oil and Gas

Insiders say family offices are increasingly willing to take on fossil fuel investment risks as returns skyrocket.

PATRICK McGEE
SENIOR EDITOR, FINANCE
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Family offices are increasingly investing in oil and gas, and some industry analysts and executives say their presence may offset some of the macro deficit created when generalist investors fled the E&P space.

A decade of dismal returns coupled with a rising tide of anti-fossil fuel sentiment drove shareholders away from the sector in recent years. But private family offices may be less distracted by the sector's history, especially as many large producers—flush with free cash flow—are now returning record cash to investors.

For example, in first-quarter 2023 alone, the energy sector's combined yields of dividends and stock buybacks added up to 8.36%. The returns to investors beat every other sector and more than doubled the combined yields of the S&P 500.

A family office is a private company that manages investment and wealth for a wealthy family, typically one with at least $50 million-$100 million in investable assets. The company's goal is to increase the family's wealth and transfer it across generations.

Dallas-based private equity firm Pearl Energy Investments closed a $705 million fund in May to target oil and gas opportunities with heavy participation from unnamed family offices.

PW Consortium, a private investor group largely led by family offices, acquired Wyoming natural gas producer PureWest Energy in a late May cash deal worth $1.84 billion. The buyer entity consisted of A.G. Hill Partners, Cain Capital, Eaglebine Capital Partners, Fortress Investment Group, HF Capital, Petro-Hunt and Wincoram Asset Management.

Joe Flack

Joe Flack, an attorney at Jackson Walker who worked on the deal for Wincoram, said the family offices were attracted to the consortium for its ability to share risk. The new consortium is an example of family offices' greater interest in oil and gas investing.

"I think they're interested in producing assets because they have consistent return relative to other assets they would invest in," Flack said, adding that family offices are using sophisticated financial devices to manage risk and are investing for longer terms than private equity does.

Oil and gas producers may source 12% of their capital from family offices during the next year, according to a Haynes Boone survey of energy executives released in April. This was the survey's greatest increase in expected capital sources; in a survey six months earlier, respondents expected family offices to account for 7% of their capital.

"It's too big to ignore. The oil and gas industry in this country is extremely sophisticated, has tons of ingenuity and has thrived and survived in a variety of market conditions that other industries would not."

—**Mike Vlasic,** ***private investor***

Filling a void

Kraig Grahmann, a partner at Haynes Boone, said family offices are filling part of a newly created void.

"When all of a sudden you saw private equity firms not being as willing to back oil and gas, and you saw commercial banks not be as willing to put as much capital in the space, it created an opening for family offices," he said.

Grahmann and many others said declining returns and ESG concerns were the main drivers pushing investors away from oil and gas. He said private equity firms and publicly traded companies can have constituencies that "are very focused on ESG concerns and whether or not you're putting … their money into oil and gas." Many family offices have fewer ESG concerns and are seen as willing to wait longer for returns.

Private equity pulled back from oil and gas investing when the landscape turned unfavorable to their model, according to Keith Behrens, a managing director of Stephens, a

"The industry has shown greater discipline than it has in the past in terms of controlling its leverage and developing free cash flow that it uses for returns or for growth."

—**Frank Lodzinski,** *executive chairman, Earthstone Energy*

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financial services firm based in New York. As the shale boom began to ebb, private equity portfolio companies could no longer drill a few promising wells and find a public buyer in the "drill and flip" model.

That derailed private equity's fundraising cycle and hindered its ability to circle back to investors for new investments.

'Too big to ignore'

Others said many traditional investors are still sitting out because they were so turned off by the massive capital destruction caused by rampant E&P overspending and tanking commodity prices.

But Mike Vlasic, whose family office has invested profitably in oil and gas for decades, said most people aren't looking at the oil and gas boom-bust cycles in the right way. While many companies faced bankruptcy during the busts, the cycles also showed the industry's resilience. Steep declines in oil and gas prices were blows many other industries probably could not have endured, he told Hart Energy.

Vlasic's family earned its wealth—and household-name status—in the pickle business. The Vlasics turned to wealth building with a family office after selling the business in 1978.

Vlasic said oil and gas has been a profitable part of his family office portfolio since the late 1980s, and he sees more family offices starting to realize the industry's potential.

"It's too big to ignore," he said. "The oil and gas industry in this country is extremely sophisticated, has tons of ingenuity and has thrived and survived in a variety of market conditions that other industries would not."

Among the Vlasics' early partners was Frank Lodzinski of Earthstone Energy who, now at age 74, is executive chairman of the Permian Basin pure play.

Lodzinski said family offices are being won over by management teams' track records or by showing more responsible business practices in the aftermath of profligate spending and down-cycles.

"The industry has shown greater discipline than it has in the past in terms of controlling its leverage and developing free cash flow that it uses for returns or for growth," he said. "The discipline has offset some of the fears of volatility and massive commodity price swings."

Analysts and executives said the family offices' growing presence brings E&P companies many long-term investors, but their investment is unlikely to meet all of the industry's capital demands. Many described the family offices as wanting high returns while keeping a low profile.

Lacking expertise?

As many talked up family offices' increasing presence as positive, one senior investment banking analyst who works with family offices said many such offices don't have the internal expertise to evaluate oil and gas business plans and geology to make sound decisions in these investments. He spoke on the condition his name not be used in order to offer a candid assessment.

Michael Mitchell

That was not a concern for Dallas broker Michael Mitchell, senior management director of Mitchell Energy Advisors. He said if family offices need petroleum expertise, they can outsource it.

Family offices that invest in E&P companies without a private equity team save themselves from paying the firms' management and carried interest fees, Mitchell said.

"I think we will continue to see family offices moving in to fill the gap based on improving industry returns as a result of renewed capital discipline by oil and gas producers," he said. OGI

▸ **FINANCE** & INVESTMENT

E&Ps' Siren Song to Investors: Free Cash Flow

Regaining investor trust—and access to their cash—is on the horizon as the E&P sector returns record profits to investors, a panel of experts said during SUPER DUG.

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FORT WORTH, Texas—Record market performance, billions of dollars' worth of shareholder returns and consistent fiscal discipline are synthesizing into a siren's song luring generalist investors back to the E&P space.

"This industry went through a 10-year period that we wouldn't [have] put our own money into it if we look back on our performance," said Al Carnrite, CEO of The Carnrite Group and managing director of Alvarez & Marsal.

That was during the early days of the so-called "shale gale" when companies spent fast and loose with any cash on hand and borrowed prodigiously to grow their footprint and their production. Returns were dismal. Shareholders called for returns quarter after quarter, but their demands fell on deaf ears.

Amid increasing sentiment on all things ESG-related, many investors gave up on the sector and took their cash elsewhere. Access to capital closed, and that's when the C-suites at public E&Ps of all sizes took notice. Incrementally, companies started buying back shares and increasing distributions. A few, including Pioneer Natural Resources, Devon Energy and ConocoPhillips reintroduced a variable dividend to their shareholder returns strategy.

Now that sector is flush with free cash flow (FCF) and, in some quarters, returning most of it to their investors, the question is how open investors and the capital markets will be to E&Ps.

"I think we're in an environment where it's only going to get better as far as attracting capital, whether that be private or public capital," Carnrite told an audience last month at Hart Energy's SUPER DUG presentation, "Big Bucks: The Money Panel."

"But it's going to take time," he said. "If I'm a long-term investor, I'm saying, 'OK, are you going to keep that discipline?'"

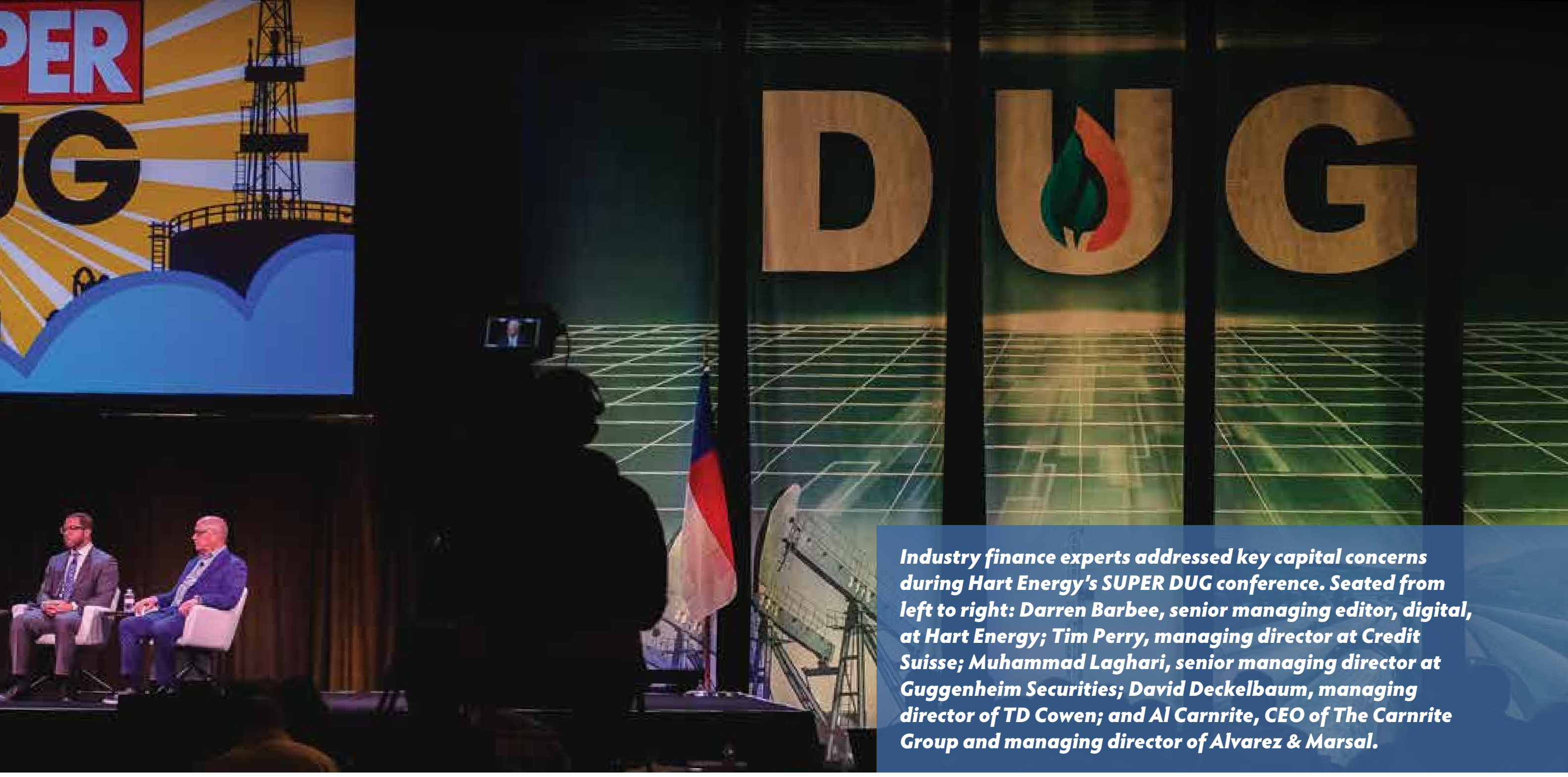
'Super' bull market

When oil prices increase, investment should, too, and that increases costs, said Muhammad Laghari, senior managing director at Guggenheim Securities.

"It's a pretty simple equation," he said.

But while oil prices increased—although they have stabilized this year—and costs based largely on inflation grew, E&P investment remains flat in recent years.

The sector's capital spending is down roughly



Industry finance experts addressed key capital concerns during Hart Energy's SUPER DUG conference. Seated from left to right: Darren Barbee, senior managing editor, digital, at Hart Energy; Tim Perry, managing director at Credit Suisse; Muhammad Laghari, senior managing director at Guggenheim Securities; David Deckelbaum, managing director of TD Cowen; and Al Carnrite, CEO of The Carnrite Group and managing director of Alvarez & Marsal.

Arnaldo Larios/Hart Energy

"It's not hard to draw a line that says we're going to be at some kind of 'super' bull market for crude oil, absent a demand destruction event."

—**Al Carnrite,** *CEO, The Carnirite Group; managing director, Alvarez & Marsal*

33% from five years ago, said Tim Perry, managing director at Credit Suisse. U.S. producers have dropped their production guidance from double-digits to zero in some instances.

Meanwhile, demand dynamics around the world are in flux, he said.

Per capita demand in the U.S. has dropped from 27 bbl/person to 20 bbl/person as a desire to cut carbon has captured the interest of the general public, Perry said.

But in China, where the population of 1.43 billion is quadruple that of the U.S., the opposite consumption trend is happening. Per capita oil consumption has increased from less than 1 bbl/person to 4 bbl/person.

If capital spending continues to diminish—or if it flattens—while the population in China, India and throughout Asia consumes more oil, the long-term supply/demand dynamic is likely to shift, Carnrite said.

"It's not hard to draw a line that says we're going to be at some kind of 'super' bull market for crude oil, absent a demand destruction event," he said. "So, I think we're in an environment where supply is not going to be able to keep up."

'Returns solve everything'

A key indicator of corporate spending is M&A, and deal flow this year is down 33% by value from last year, said David Deckelbaum, managing director at TD Cowen.

Instead, they are using blockbuster profits to shower shareholders with cash. The top Western oil companies paid out a record $110 billion in dividends and share repurchases to investors in 2022.

Between 2008 and 2009, the industry had a dismal track record as measured by the S&P 500, where it offered a 1% return while accounting for up to 13% of trading. FCF was generally in the red.

During the pandemic, the industry's representation on the S&P fell to 2%, but has since rebounded to roughly 5%, Perry said.

At the same time, operators' focus on FCF now puts the E&P sector at the top of the index, generating close to 20%, compared to the total index's 5%.

"It was the worst-performing industry on the S&P 500 to [become] the best performing," he said.

But E&P shares prices remain low, which makes buying back shares more affordable.

Deckelbaum said E&Ps have to decide whether they should buy the shares while they are cheap, further incentivizing investors, or make a deal to grow.

Meanwhile, the industry's access to capital is finally loosening— at least, to some extent, the panelists said.

"I don't think the capital markets are closed at all, but they're more expensive than they should be," Perry said.

Laghari said he is seeing new interest from private equity.

"We do expect quite a few folks to raise money," he said.

Private equity funding will exceed the raises generated in recent years, Deckelbaum said. There may be fewer players, but some of them are newly interested in the space, such as family offices and international players. "The odds of getting the size (of fund raise) that you want are greater" than in recent years, he said.

Financial frameworks have changed, but the panelists said the E&P value proposition via record cash flow and blockbuster shareholder returns makes a strong case for investment by both private equity and public investors.

"I think it's wide open," Carnrite said. "But returns solve everything."

Kissler: Global Demand Dictates Oil Prices

Dennis Kissler of BOK Financial examines the potential net effect of market manipulation.

Market Watchers

DENNIS KISSLER
BOK FINANCIAL SECURITIES

Dennis Kissler is SVP of Trading for BOK Financial Securities. He is based in Oklahoma City.

Faced with a significant drop in crude prices, OPEC+ recently announced it would be extending existing oil production cuts. Although the move was somewhat expected, the degree of cuts certainly wasn't—and its long-term effects remain to be seen.

What did OPEC+ do?

Leading up to OPEC+'s announcement, there was a lot of discussion about what they were going to do. Everybody was looking for them to maintain the existing output cuts of 3.66 MMbbl/d. Then when it became clear that OPEC+ likely would further react to lower oil prices, a lot of people in the industry expected additional cuts to be anywhere from 250,000 bbl/d to 500,000 bbl/d.

Instead, OPEC+ decided to cut production by 1 MMbbl/d. That obviously caught the market by surprise. However, one of the bigger elements of their announcement is that they are going to keep production levels in place to year-end 2024, which I believe has just as much significance to oil pricing as the cuts do.

So, what's going on?

Well, OPEC+ is very, very sensitive to price levels. Candidly, I think \$60/bbl is too low and \$90 is too high—and if prices drop below \$60/bbl, I think you're going to see them continue to react.

However, the more significant issue is that we've seen a structural change. The Baker Hughes rig count marked a loss of another 15 rigs in the first week of June. That's one sign that higher interest rates and inflation are making an impact, as these factors are increasing the cost of production and moving break-even prices higher—and keep in mind that rates are expected to move higher this year. Basically, the higher the interest rates and the lower the crude prices, the more drilling rigs we will see disappear.

On the flipside, I think the Russians are continuing to produce well over what they're stating. Although they're saying that the fuel that's coming into the market is old inventory and that supplies are depleting, a lot of people, myself included, don't fully believe that. Rather, we think they're going to continue to produce, which would offset some of OPEC+'s cuts.

What's the long-term impact?

The long-term impact of these macroeconomic factors will have a lot to do with demand. There was record travel over Memorial Day weekend, so demand is coming back—just at a slower pace globally than we all hoped for.

The fact that Russia is selling fuel to the world in a discounted market, under normal market conditions, takes the U.S. and other countries out of pricing.

But in the long term, despite rig counts dropping, I don't see global demand falling as well. Instead, I foresee demand either continuing at current levels or maybe even clicking a little higher. Plus, if Russia starts to play ball and participates with cuts in production, we could see some higher prices, which is what it will take to get the rig count to really move higher and the Permian shale producers excited again. After all, they want to see that upper-\$70 or lower-\$80 market back into the curve.

That said, I think crude in the \$90 range hurts the world economy. Could we go there for a little while? Sure, but I don't think we can maintain it.

What about refilling the Strategic Petroleum Reserve (SPR)?

Finally, as prices have fallen, there has been some discussion about the U.S. refilling its Strategic Petroleum Reserve (SPR) and whether it would put a floor under crude. We're definitely going to have to refill it, even though we've had the chance to do so at lower prices than this and it did not happen.

So, why now? The SPR is at a 40-plus year low, therefore the need to refill it is growing more important to the American public. Since near-term global demand remains below expectations, the timing could be right this time around to begin the refilling process whenever prices dip.

If the SPR does move onto a refilling mode, I think it does put a floor under oil prices. Unless there is an economic collapse—and I don't foresee that happening—anywhere in the low-\$60/bbl area could be a very fine floor. Some banks still predict Brent crude to be in the \$90 to \$100 range, but that seems unlikely. Instead, it's more likely that Brent will move into the \$80 range for a little while—and that's what it will take to move OPEC+ back into more production. One thing is for sure, look for volatility in prices to remain in Q3 and Q4 of this year. OGI

NOV AND THE NATURE OF REINVENTION

CEO Clay Williams breaks down the energy transition and NOV's role in the industry's evolution.

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The origin story of global oilfield services and technology firm NOV Inc. begins with the oil and gas industry itself—just a few miles down the road in Oil City, Pa., where "Colonel" Edwin Drake drilled the first well with a steam-powered cable tool rig in 1862. The industry has seen its share of ups and downs, and so has NOV. But CEO Clay Williams—Princeton grad, Eagle Scout and bona fide optimist—just sees opportunity ahead.

In an exclusive interview with Deon Daugherty for Oil and Gas Investor, Williams shares his perspective on NOV's future, how the firm attracts talent and where the company fits into the ongoing energy transition.

Q&A

Deon Daugherty: Let's begin by talking about where the industry is in its recovery from the pandemic and the resulting economic shutdown, which you've described as a "wrecking ball." Is the North American energy industry bouncing back?

Clay Williams: It's getting better. That's the good news. Last year taught the world the importance of oil and gas and energy security. And while it brought a lot of hardship to economies and people, I think it was sort of necessary to demonstrate that what we do is important and critical to our standard of living.

But it's been a tough three years with the pandemic and the recovery at the end of eight tough years for an industry that has seen a significant downcycle and arguably one of the toughest in its history with negative oil prices and the lowest rig count recorded going back to World War II.

I think NOV, probably more than other participants in the oil field, was affected by the pandemic and the lockdown impact on the supply chain globally. We're the leading manufacturer in the oil field so we rely on a global supply chain, and it was severely disrupted. We've made a lot of good progress, but we still have ways to go.

DD: It does seem surprising that this lingering effect on the supply chain, whether it's accessing medicine or drill pipe, continues to create issues.

CW: Let me just say, it's a really bad idea to shut down your economy for any reason whatsoever, and I hope our political leaders learn the lesson this time around. It takes a long time to recover, and there's all kinds of weird ripples that run through the economy as a result. We're still dealing with some of those.

Given the breadth of our product offering, what that means is that we have a very broad and highly specified number of parts and metals and special recipes of polymers that we buy globally.

Sometimes there's really only one supplier of that particular recipe. So when that one mill gets shut down, [it slows the process] and a lot of these mills and foundries and casting houses really haven't come back from the pandemic lockdown.

It was very disruptive to our business. A lot of equipment that we make, we can't ship until it's complete. If we're missing one piece or one widget for a particular piece of equipment, then it takes a while to get it out. I think you're seeing that not just in our business, but really across the economy still.

THE OGI INTERVIEW
Watch the video interview here:

Felix Navarro/Hart Energy

DD: How has that impacted your costs?
CW: Well, inevitably they go up. So, we're paying more for the components that we buy, as well as for the sub-assemblies that we buy from suppliers. Things like diesel engines and certain transmissions—we're still wrestling with accessing those because [the shutdown] disrupted everybody's plans and schedules.

In the middle of the energy crisis that we saw last year, it made things doubly frustrating for everybody. But our teams and our suppliers' teams are working hard to get back to normal.

DD: How has the shutdown and the incremental recovery impacted the energy transition dynamic?
CW: I think it injected more realistic thinking into the practicality of pivoting quickly to a different form of energy. We're going to have to move to a lower-carbon source of energy. But the playbook that's been run on people that involves demonizing oil and gas was another really bad idea.

Oil and gas is the industry that powers all other industries, and oil and gas is going to be around for a long time to come, for generations. And this narrative that we're going to pivot quickly to renewables and that we're going to wean ourselves off of oil and gas is misguided. It's not realistic. Our political leaders, I think, haven't been honest with voters about what's required here.

It's not trillions of dollars, it's tens of trillions of dollars that's required in investment in these alternative sources of energy that are fundamentally less efficient. They're more expensive. They face land use problems, intermittency problems—a lot of challenges that we have to overcome.

I'm an optimist. I'm convinced we will overcome those challenges to make these alternative sources of energy more attractive. But in the meantime, we need oil and gas. We need oil and gas to feed humanity. You know, 7 billion people rely on diesel to power tractors to plow fields, power combines to harvest grain and to transport grain to the mills, to the bakeries and to the H-E-B store down the street. It's not a stretch to say this is the industry that powers all other industries and it powers our way of life.

DD: What is NOV's role in the energy transition?
CW: The first plank of our strategy is to invest in ways to reduce the environmental impact of conventional oil and gas operations. The second plank of our strategy has been to invest in actual technologies that can bring about the energy transition with low- or no-carbon technologies: wind, solar, carbon capture and sequestration, biogas, geothermal and nuclear.

DD: It looks like NOV is doing a lot of interesting work with wind. How did that begin?
CW: Well, we made an acquisition several years ago of a company that was engaged in providing technology into offshore wind installation vessels.

If you go to Europe today—flying into the airport in Amsterdam, for instance—offshore, there's a lot of fixed wind towers. These are massive structures with great big blades that are turning and generating a lot of wind power from the North Sea. The vast majority of those were installed using technology from this company along with technology that we developed here at NOV. Specifically, the jacking systems are from the same technology used in offshore jack-up rigs [that] are used in lift boats that are used to install those turbines.

DD: So you're applying oil and gas technology to make wind power work.
CW: Absolutely. It's been a great market for us. Along with the cranes and handling systems, we've done time and motion studies on how to install these fixtures more efficiently.

NOV has carved out a leading position in that space. Today, for instance, there are 15 vessels being constructed around the world to install offshore wind turbines, and 12 of them are utilizing NOV technology and designs in what they're doing.

The vast majority of vessels out there are the same; they use NOV technology that we've developed and applied from the oil field.

What we learned … has shaped our views of further wind development, both onshore as well as in the floating wind space, which is where wind power really benefits from our taller towers.

If you can put up larger turbines, then the longer blades swing through a larger area and capture a larger wind resource and they concentrate into a larger turbine.

But the longer blades require a taller tower. The other good

Financial Snapshot
AS OF JUNE 11, 2023

Market cap	$6.09B
Enterprise value	$7.7B
Profit margin	4.33%
Operating margin	6.50%
Revenue (trailing 12 months / ttm)	$7.65B
Revenue/share	$19.56
Quarterly revenue growth	26.7%
EBITDA	$825M
Total cash (most recent quarter / mrq)	$774M
Total cash/share (mrq)	$1.97
Total debt (mrq)	$2.38B
Total debt/equity (mrq)	44.78
Current ratio (mrq)	2.35
Operating cash flow (ttm)	-$278M
Levered free cash flow	-350.38M
Return on assets	3.15%
Return on equity	6.38%

Share Statistics

Avg. volume (3 months)	5.06M
Shares outstanding	393.72M
Held by insiders	0.66%
Held by institutions	94.48%

Dividends & Splits

Forward annual dividend yield	1.26%
Payout ratio	23.81%

Source: Hart Energy research, U.S. Securities and Exchange Commission

NOV By the Numbers

37,463,356
number of shares owned by BlackRock

160
years in business

A wind turbine in the North Sea is shown under construction along the Dutch and Belgian coast. Most wind turbines in the North Sea were installed using NOV technology.

Shutterstock

thing about going taller is that you access a wind resource that blows steadier and harder. It's a higher quality wind source because the higher up you go, the less affected it is by ground effects. We've learned this offshore, where there really aren't constraints to going higher other than the fleet of installation vessels. That has prompted demand for larger installation vessels with taller cranes that can handle heavier weights to put in these larger towers offshore, that ultimately are far more economically efficient than shorter towers.

DD: Where is this being deployed? Is it in the Gulf of Mexico?

CW: Not yet, but it is coming. We're actually building the first two vessels that are Jones Act-qualified for U.S. waters to start installing wind towers off the Eastern Seaboard as well as the Gulf of Mexico. And we see many more of those to come.

One of other things we're doing now is looking at this taller tower thesis and how it might be applied to onshore wind. The constraints on onshore towers are twofold. The first is, the taller the tower, the larger the diameter of the base. The problem with that is that if you construct a tower here in Houston, Texas, and you want to ship it out to the wind belt in west Texas, there's a lot of interstate overpasses that you've got to get underneath. The diameter of the tower base is right at the ragged edge of what will fit underneath overhead obstructions between here and there. That caps the size of the tower at about 100 meters or so.

And then the second constraint [is,] if you're successful in getting around all the overpasses and traffic lights and bridges between here and there, you have to figure out a way to stand the tower up and, at about 100 meters for conventional crawler cranes, that's about the limit of where they can really work as a practical matter. So, we've got our engineers working on a way … to erect these towers once on site, along with a technology that we've been developing that potentially could manufacture the towers on site.

If you think about it, we could set up a mobile plant that could build a 200-meter tower, along with a proprietary way to erect a 200-meter tower, and then we could put larger turbines higher in the air that would be far more economically efficient than the land wind developments of today.

DD: How far away are we from seeing that come to fruition?

CW: We're actually making tower sections now on site. They're more conventional-sized for one of the big turbine makers, and we're fine-tuning the manufacturing process in our plant in Pampa, Texas.

We're working on finalizing our designs for a crane system to erect the towers once they're in place, but we think that it's still a few years away. But this could be very transformative for the land wind tower space, not just here in the U.S., but globally.

DD: What is it about NOV's work in the energy transition space that most excites you?

CW: Honestly, what I'm most excited about is the passion of the team here for pursuing a lot of ideas. I'm not sure which source

32,307	20	52	19	31%
employees as of spring 2023	capabilities and industries	brands within NOV's portfolio	business units	revenue growth in 2022 compared to 2021

Felix Navarro/Hart Energy

of energy is ultimately going to win, and it'll probably take a variety of them.

A few years ago, we really tried to unleash a lot of the entrepreneurial energy across our organization. We have some fantastic scientists and engineers here that are very skilled in all kinds of industrial pursuits that the oil field pursues globally from lifting and handling, to material sciences, to executing large projects at scale, to managing the supply chain globally. There's a lot of unique skillsets embedded here at NOV that I think are very applicable to this challenge.

DD: How does that work from a practical perspective?
CW: We asked around the organization, "Hey, if you have any ideas around energy transition, let's elevate those and see if we can figure out a way to explore them further," and we've been doing that.

We started with a couple of dozen really good ideas that we've narrowed down now to 10 or 12 that are still very viable business plans that our scientists and engineers are focused on and excited about.

It's that sort of creativity within NOV's culture that I'm most excited about. I'm not sure precisely where it's going to lead, but I would say so far, so good.

DD: There is so much angst within the industry about recruiting and retaining fresh talent, given the competition from alternative energy businesses, but you're offering similar opportunities.
CW: It's something that our senior management team thinks about a lot. We go to the facts. We have a few hundred million dollars of highly accretive revenue that's coming from the energy transition related to wind and other technologies around the globe today. It's a real business, and it's a real high-return business for NOV today.

We foresee playing a very important role in traditional oil and gas as well as in reducing the environmental impact of those operations.

In fact, in our latest sustainability report, we highlight the fact that if you apply technologies that NOV has developed and products in the past few years to conventional oil and gas operations around the world, we can offset our own greenhouse gas footprint by more than 20 times, given widespread adoption. There's a lot of leverage in that. If you actually want to fix the problem of decarbonizing oil and gas, this is the company that can do it.

But the second way that we convince young people to join our organization that I think is equally important, if not more important, is pretty fundamental. Provide a nice place to work, provide a place that you can do things that are meaningful, that you work with people that you respect and enjoy, and you have a little fun along the way.

DD: It's clear that NOV is addressing the "G" part of the ESG equation. There's no increase in salary for named executive officers; you've flattened the long-term incentives; and made the energy transition a key metric in annual incentive bonuses tied to revenue from energy transition technology and services. And then, interestingly, you didn't have any activist shareholder proposals to consider at the annual shareholder meeting.
CW: Ultimately, we have to do what's right for the company. We have a very thoughtful board and a seasoned and, I think, practical management team. We all get the fact that energy transition really is the business plan of the 21st century. And if we crack the code, we would create enormous corporate wealth. To me, it makes good business sense if you have the skill set and you can see your way clear to develop competitive advantage in that space that absolutely, we need to be driving towards that.

The various business plans that we're pursuing across energy transition offer the potential of creating long-term corporate value through competitive advantage in those spaces, given our unique skill sets. All of that ties together. It makes sense and hopefully our investors get that message.

DD: I'm not sure if "ground floor" is the right way to phrase this, but it does seem like NOV is getting in on the ground floor of energy transition technologies. And the company has been around as long as the oil and gas industry, so it follows suit in that sense.

CW: We started as a distribution company, and we've been through dozens of cycles since then in the oil and gas industry. With each one, our company has had to reinvent itself, and I'd like to think that through each upcycle we get better. We reposition ourselves for the opportunities that are out there and that ability to reshape NOV is embedded in our culture.

So, when we asked the organization to find opportunities in the energy transition, I think that really fits our DNA well. In a way, it's how we're reshaping ourselves for the next upcycle in oil and gas along with this huge mega-cycle that's going to be required to transition to lower-carbon energy. I think NOV will play key role in both of those.

I think what's incumbent on management is to try to get better with each iteration—to make it a better, more capable organization to capitalize on the opportunities that the upcycle brings.

DD: When you see the underinvestment in energy in the U.S. and compare it to other countries that don't seem to be pulling back, do you think the U.S. may be at risk of losing its grasp on energy independence if it doesn't start investing?

CW: Absolutely. Without sustained investment here, we definitely will—just like we did for the better part of a generation.

But I'm an optimist. I think, ultimately, smart capital seeks returns. There's really good returns in this space and they're only going to get better.

I think the U.S. will continue to lead in oil and gas technology, and we'll continue to invest in oil and gas. But we're passing through a period here where the equity markets need to somewhat relearn the importance of oil and gas.

I think that began to change last year with the situation in Europe. The market in North America's always been more responsive to commodity prices. And so, coming out of the pandemic as oil prices recovered, I wasn't surprised to see a rapid run-up in the rig count here that moved a lot more quickly and definitively than the rig counts in many of the other major oilfield markets around the world.

DD: Has it shifted more recently, though?

CW: Yes, with the oil price coming down in 2023 and the collapse in gas prices in particular, that's led to lower levels of activity. It fits with historically what the industry's done in North America.

DD: Where do you expect to see growth in the next five to 10 years?

CW: I think internationally and offshore.

It was pretty remarkable, what the U.S. did over the past several years in terms of oil and gas growth and the advancements made in shale technologies. And so, it's a really good testament to the power of entrepreneurial thinking and capitalism here in this country.

But we're hearing that we're starting to find the limits of efficiency gains in shale production. Some of the producers are beginning to see the end of their Tier 1 acreage inventory. So, I don't think we're going to see the kind of explosive growth that we had in U.S. production.

I think higher commodity prices, higher oil prices are giving more conviction to oil companies to develop some of their offshore prospects in a lot of ways that, since 2014 …[has] been missing. And a lot of good work has been done around bringing down costs and making those developments more efficient in the past nine years. And so, I think a lot of more FIDs are coming offshore. I think places like the Middle East, along with a much higher level of offshore activity, is what's in store for the next five, six years.

DD: Much of the new technology discussion across the E&P space is focused on artificial intelligence. Is more AI the story or where does the technology go from here?

CW: It's certainly working for our customers. We have a product called Kaizen that optimizes the drilling process. It's artificial intelligence and machine learning that figures out how to drill rock most efficiently, and then it learns along the way. It's really the same way a human driller does; it just does it a lot faster because it adjusts on a microsecond basis.

We are very focused on driving higher levels of automation in the oil field. There's still a lot of manual processes that are happening.

It's a safety, cost and efficiency opportunity for our customers. One of the other really cool products that I'm pretty excited about that we came out with through the downturn was a way to upgrade rigs using robots on the drill floor that would actually trip the pipe—and trip it safely and as efficiently as humans can. But it gets the humans away from well center, which makes them a lot safer, and it's a very efficient rig.

What's really neat about this is the fact that it's an economical upgrade for a rig. We're utilizing industrial robots that were hardening for the oil field, and we've programmed the end effectors—the robot hands, if you will—to pick up the tools. It offers a way to upgrade the existing rig fleet to make it more capable and safer in a way that's very cost-effective.

DD: Does it displace your workforce?

CW: I think it raises the level of requirements for them, from throwing chains or handling tongs to now maintaining these robots. It's a higher skill set and it's a safer, less repetitive task that I think will offer a better career for people.

DD: We've discussed a lot of things this morning—the supply/demand imbalance, the energy transition, U.S. energy independence and energy security. To bring it full circle, is there a duty of care for the western nations, or perhaps the OECD nations, to help those who live in undeveloped nations with energy poverty—and to do so in a way that raises their standard of living by incorporating the energy transition?

CW: Yes. I think that's the highest priority—lifting people out of poverty. Today, people are cooking with wood and biomass and animal dung in their homes, which is a terrible health hazard.

Step one is: let's feed people, let's lift them out of poverty. But then there's a second duty, which is, let's invest in the technologies that make lower-carbon sources of energy more attractive. Let's address the intermittency problems that they have. Let's address the land use problems that they have. Let's figure out the right way to execute a low-carbon energy transition. And then let's help bring that to these nations that really desperately need more energy. I think there's a very strong moral imperative to accomplish both. OGI

Ring Energy's Conventional Wisdom

The purchase of Stronghold Energy II allows Ring to keep its focus on mature, conventional assets in the Permian's Northwest Shelf and Central Basin Platform.

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Mention drilling in the Permian Basin and unconventional reservoirs immediately come to mind. But Ring Energy focused on conventional assets to set itself apart from the crowded market.

The mid-sized operator is applying shale boom technologies to legacy assets in conventional reservoirs that others viewed as uneconomic, Paul D. McKinney, chairman and CEO of Ring, told Hart Energy.

"What we're finding is, nobody's really competing with us for that," McKinney said.

Ring operates in the Permian Basin's Northwest Shelf and Central Basin Platform. McKinney said the company primarily pursued drilling horizontal oil wells in the San Andres formation across Yoakum and Gaines counties, Texas—a region where operators have to fill in the gaps between mature oil fields developed from the 1940s onward.

But to compete in the prolific Permian Basin, Ring needed greater scale. And in order to grow, the company needed to buy its way into a larger position.

M&A continues to be a key part of Ring's growth strategy, but not all deals can move the needle for the company.

Not only did Ring aim to grow its size and scale in the basin with a deal, the company also needed to strengthen its balance sheet, accelerate its ability to pay down debt and lower its breakeven costs.

Ring found what it was searching for with the acquisition of Stronghold Energy II last year, McKinney said.

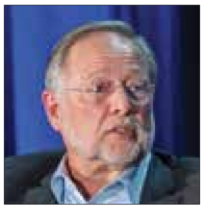
Come together

Stronghold Energy II, majority-owned by private equity firm Warburg Pincus, was founded by Steve and Caleb Weatherl.

The father and son duo brought complementary skills to the table. Steve, who served as Stronghold's CEO, is a geologist who helped pioneer some of the first economically successful horizontal Wolfcamp wells in the Midland Basin.

Caleb, president and CFO, graduated from Harvard Business School and brought his financial background to the Permian operator.

Acknowledging the high-quality rock offered in the Midland and Delaware basins, Stronghold wasn't attracted to the high prices companies were paying for acreage there. Instead, Stronghold focused its efforts on the Permian's Central Basin Platform.



"We believe now is the time to grow the company through acquisitions."

—**Paul D. McKinney,** ***chairman and CEO, Ring Energy***

Since launching in 2017, the company grew its position to approximately 37,000 net acres in the Central Basin Platform—primarily in and around Crane County, Texas.

Stronghold's assets had production of about 9,100 boe/d (54% oil, 75% liquids).

In July 2022, Ring announced plans to acquire Stronghold's Permian position in a cash-and-stock deal valued at up to $465 million.

Scooping up Stronghold checked a lot of boxes for Ring. Adding the private E&P's position in the Central Basin Platform to its portfolio effectively doubled the company's overall production, from around 9,300 boe/d in second-quarter 2022 to a record 18,292 boe/d in first-quarter 2023, according to investor disclosures.

Accretive free cash flow generation from Stronghold assets also helped lower Ring's leverage ratio from 3.5x at the end of 2021 to 1.65x by first-quarter 2023.

"The assets that came along with Stronghold—many of them were very similar in economics, but some of them were actually superior," McKinney said.

"One particular area is the most economic set of opportunities that our company has," he said.

Ultimately, the deal gave Ring better optionality to invest its money in multiple geologies with different rates of return.

"We can make a change in that investment strategy depending on what happens in the marketplace on a dime's notice," he said.

Although the company has the inventory to ramp up production further, Ring plans to keep oil and gas output relatively flat this year amid significant volatility in commodity prices.

Instead of pouring money into drilling, Ring plans to prioritize continuing to lower its leverage ratio and gearing up for its next deal.

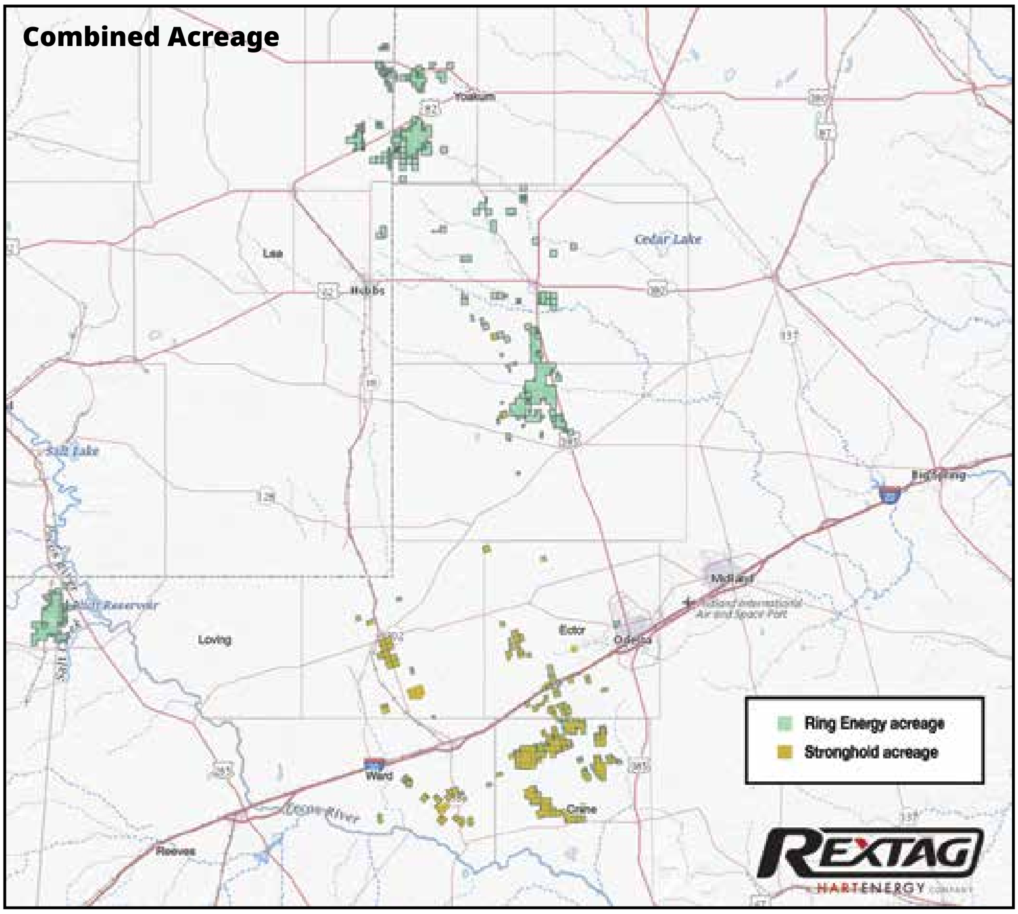
"We believe now is the time to grow the company through acquisitions," McKinney said.

Road map for the future

E&Ps from small independents to publicly traded supermajors are jockeying for inventory runway in the Permian, the top oil-producing basin in the U.S. Lower 48.

Public players including Callon Petroleum, Ovintiv, Matador Resources and Diamondback Energy have pumped billions of dollars into Permian Basin M&A in the past year to expand their positions and inventory.

Operators aren't in a massive hurry to drill up their undeveloped inventory to grow production. With more than a decade of rapid expansion in the books, E&Ps now have line of sight toward peak Permian production and eventual decline.



Ring Energy has operations in the Northwest Shelf and Central Basin Platform in the Permian Basin. The company added about 37,000 net acres in the Permian's Central Basin Platform with the acquisition of Stronghold Energy II in 2022.

"[By] the end of the decade… plus or minus a couple of years, you might see the Permian peak and start plateauing," said Danny Wesson, executive vice president and COO at Diamondback, said during Hart Energy's Super DUG conference in May.

"The longer it takes us to get there, the longer it will plateau and run flat. But the faster we get there, it will decline faster," he said.

Acquiring Stronghold boosted Ring's Permian inventory by another over 200 undeveloped drilling locations set aside for the future.

But despite the runway extension from the Stronghold deal, Ring is still searching for more longevity in the Permian.

"We've got good running room for the short- and medium-term," McKinney said. "Long-term, that's why we're so focused on acquisitions—to ensure that five years and out we want to have a bigger inventory of undeveloped locations."

When it comes to its M&A strategy, Ring is prioritizing adding opportunities with significant undeveloped upside, McKinney said.

The company would consider another deal that was heavy on production, but only at an attractive multiple, he said.

Ring aims to capture synergies with its existing operations in the Northwest Shelf and the Central Basin Platform. But, the company is open to deals outside of the Permian if those assets can compete economically with Ring's existing portfolio.

"We like the Permian Basin. We think our shareholders prefer a Permian Basin focus," McKinney said. "But I'm not necessarily promising that I'll stay in the Permian—I will consider things outside of the basin as long as they have some really attractive aspects that provide a lot of value to my shareholders."

McKinney said the company will consider deals in nearly any of the predominant oil plays where Ring can enter a Tier 1 acreage position at competitive costs.

That includes the Eagle Ford Shale, the Denver-Julesburg Basin, East Texas and portions of the Powder River Basin, he said.

In the meantime, Ring is focusing most of its spending this year on debt reduction.

"If I could significantly improve my balance sheet, I could be lured to go someplace else," McKinney said.

And after selling Stronghold last year, the Weatherls are also back in the Permian searching for deals.

Their new E&P company, Midland-based Garrison Energy Holdings, secured a $500 million line of equity financing from an undisclosed institutional investor to pursue Permian acquisition opportunities.

Caleb Weatherl told Hart Energy that Garrison Energy is still open to deals in the Central Basin Platform, but the company is evaluating potential deals across the Permian, including the Delaware and the Northwest Shelf.

Garrison is fairly agnostic when it comes to the kinds of assets it wants to develop. The company is open to buying horizontal locations, but Garrison is also eyeing opportunities to acquire vertical locations or recompletion wells.

Similar to Stronghold's strategy, the Garrison team is evaluating opportunities to develop a position outside of expensive core-of-the-core Permian plays.

"We're certainly not afraid to take some technical risk, go into an area that is maybe not quite as proven as the core-of-the-core and apply our geology and engineering expertise to help de-risk an area," Weatherl said. OGI

▸ REGULATORY

How the Debt Bill Rescues MVP and Speeds Up Permitting

The Fiscal Responsibility Act did more than avert economic disaster—it allowed a critical gas pipeline to be completed and for future projects to gain approval faster.

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In the end, it took nothing less than an extraordinary act of a Congress desperate to avert a catastrophic unraveling of the global economy to rescue the Mountain Valley Pipeline (MVP).

But rescued it is.

Late in the evening of June 1, the Senate voted 63-36 to pass debt ceiling legislation that included provisions to clear the way to build MVP, as well as amend the National Environmental Policy Act (NEPA) to streamline the permitting process for infrastructure. President Joe Biden signed it into law two days later.

"Passing this budget agreement was critical," Biden said in an address from the Oval Office. "The stakes could not have been higher."

He was referring to the bipartisan agreement, known as the Fiscal Responsibility Act of 2023, to limit growth of the nation's $31.4 trillion debt. Failure would have resulted in default and potentially catastrophic consequences for the U.S. and global economies.

The stakes were also pretty high for MVP and other energy infrastructure projects. Wasting no time, Equitrans Midstream, lead partner in the Mountain Valley Pipeline LLC joint venture, said soon after the bill was signed that it aims to complete construction of the project by the end of the year.

"The Independent Petroleum Association of America (IPAA) is pleased Congress and the Biden Administration have developed a bipartisan agreement on the debt ceiling that includes important elements of reforming our nation's onerous process for permitting energy projects," said C. Jeffrey Eshelman II, president and CEO of the trade group, in a statement to Hart Energy. "Although the agreement does not address many of the key issues surrounding permitting reform for oil, natural gas and other energy projects, it is a good first step in that process."

Passage did not come easy. Sen. Tim Kaine (D-Va.) ultimately voted yes, but not before submitting a failed amendment to delete aspects relating to the pipeline. Hard left Sens. Bernie Sanders (I-Vt.) and Elizabeth Warren (D-Mass.) found themselves in an unusual alliance with hard right Sens. Ted Cruz (R-Texas) and Rand Paul (R-Ky.) in opposition.

Democrats, who hold a majority in the Senate, voted 44-4 in favor of the bill, along with two of the chamber's three independents. Among Republicans voting, 31 of 48 defied Minority Leader Mitch McConnell (R-Ky.) and voted against. Sen. Bill Hagerty (R-Tenn.) did not vote.

NEPA reforms

"The vote in the Senate is significant, not only because it guarantees passage of the package, which includes NEPA reforms and approval of the Mountain Valley Pipeline, but because you have had a bipartisan vote in both houses of Congress in support of the reforms and MVP," Jack Belcher, principal at Cornerstone Government Affairs, told Hart Energy.

The compromise struck by Biden and House Speaker Kevin McCarthy (R-Calif.) on the House bill turned out to be significant not just for MVP, but for other energy infrastructure projects in the future.

"For years, NEPA reform has been off the table, with environmental advocates opposing any attempt to touch it," Belcher said. "Originally passed in 1969, the last time it was significantly altered was in the early 1980s."

The reforms are not inconsequential, he said, and they streamline the permitting process in a number of ways:

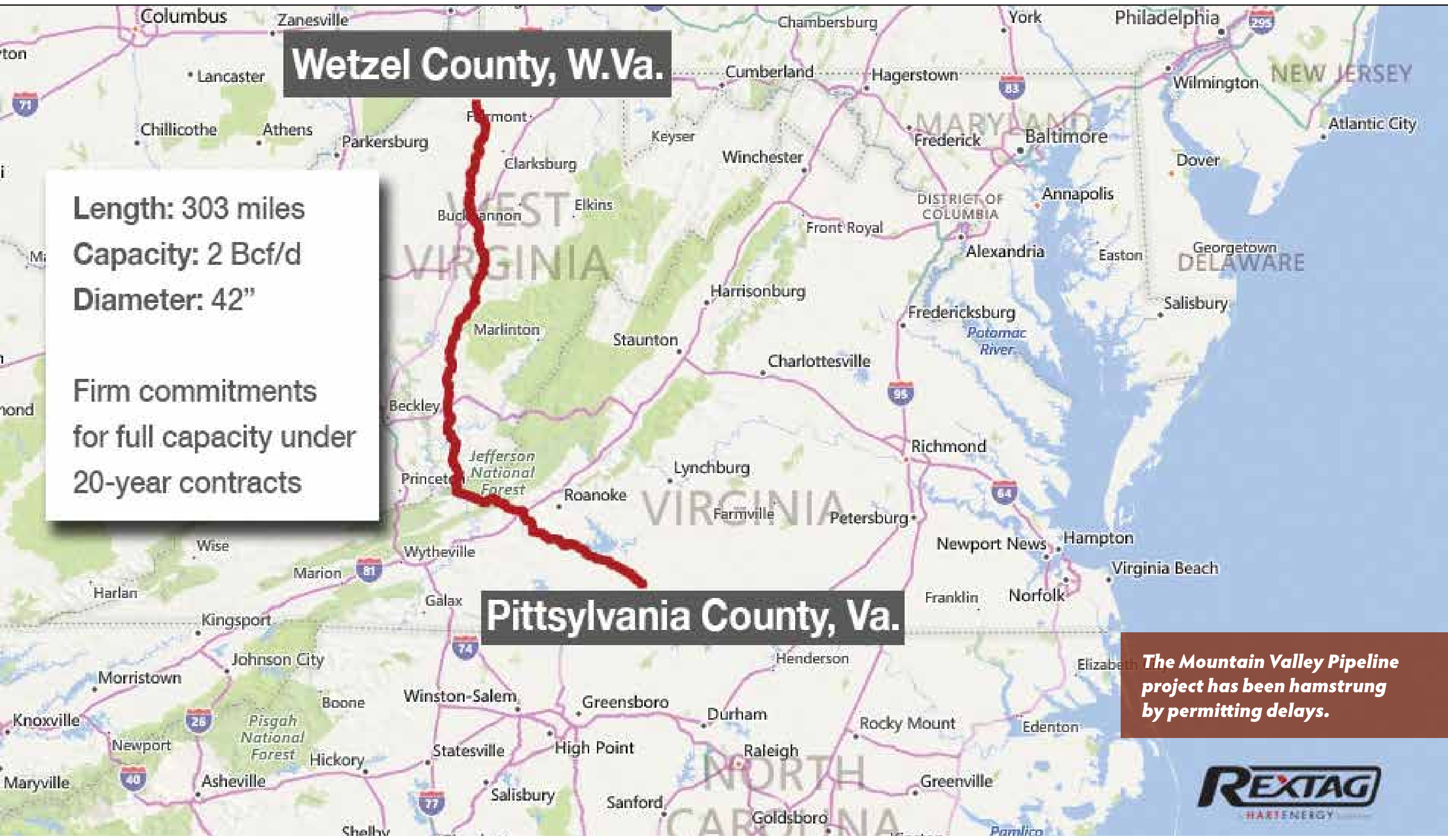
- Codifying the "reasonably foreseeable standard";
- Eliminating delays and confusion over determining the lead federal agency;
- Relegating environmental impacts to a single document;
- Creating a "shot clock" for environmental impact statements and environmental assessments; and
- Making categorical exclusions easier to put in place.

These changes will make federal permitting easier, quicker and, in some ways, less contentious, he said.

"It is also important because it creates momentum for more changes in a possible reform package that might move through Congress later in the year," Belcher added.

That momentum will face resistance. The bill's provision to divest the courts of jurisdiction to review agency actions on approvals for MVP's construction and operation angered opponents of the project.

Mountain Valley Pipeline



The Mountain Valley Pipeline project has been hamstrung by permitting delays.

Source: Hart Energy

The Institute for Energy Economics and Financial Analysis was unsparing in its criticism.

"The ill-advised plan to override the MVP public permit process and the right to judicial review undermines U.S. government principles," wrote Suzanne Mattei, an energy policy analyst with the organization. "It's a bad way to make decisions on a gas project."

Critical need

Equitrans Midstream's stock shot up 57% following announcement of the deal struck by Biden and McCarthy. The $6.6 billion project that began construction in 2018 has been caught in legal limbo for several years, but its completion comes just in time for Marcellus and Utica producers.

Low natural gas prices and expected flat production for 2023 have provided some near-term spare capacity in Appalachia, Zach Krause of East Daley Analytics said in a research note. But the region will need more pipeline capacity when LNG demand rises after 2026.

"MVP will be critical during this period to allow the Northeast industry to participate in future market expansions," he said.

Provisions in the bill that set MVP, a project at serious risk for years, on a trajectory to ultimate completion have a profound impact, he said.

"The language virtually ensures that it will be built by immediately approving the permit and taking the ability to challenge it out of the 4th Circuit and into the D.C. Circuit, which will not likely allow any more delays," he said.

EQT Corp., a key producer in the Appalachian region, also hailed the agreement.

"The completion of MVP is critical to addressing increasingly unaffordable and insufficient electricity in the Southeastern United States, in alignment with feasible climate goals," CEO Toby Rice said on his LinkedIn account. "Its inclusion in this bill shows that permitting reform is not a political bargaining chip but, instead, a necessity recognized by a bipartisan government acting for the good of all Americans."

Still, frustration over the Herculean effort required to clear the way for MVP's completion lingers in the oil and gas industry.

"Our current system for reviewing the infrastructure projects that fuel our economy and support our way of life did not become an endless gauntlet of bureaucratic hurdles overnight, and it will take more than one step to develop a workable process," said API President and CEO Mike Sommers.

To Belcher, the law's passage says a great deal about how government functions when it comes to approving energy projects.

"We actually live in a time when it takes an act of Congress and the White House to permit and build an interstate pipeline and also to hold a Gulf of Mexico lease sale," he said.

Anne Bradbury, CEO of the American Exploration and Production Council, echoed those sentiments.

"It should not take an act of Congress to approve a pipeline in America," Bradbury said. "We encourage Congress to continue to work toward modernizing our permitting system and addressing more of the underlying issues that have been hurting America's ability to build." OGI

Equitrans CEO: MVP's Approval Can Be 'Canary in the Coal Mine'

Tom Karam said he's thrilled with the definitive approval of Mountain Valley Pipeline, which could lead to further reform of U.S. permitting regulations.

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Hart Energy Editorial Director Jordan Blum conducted an exclusive interview with Equitrans Midstream CEO Tom Karam on June 5 following passage of the Fiscal Responsibility Act, the debt ceiling compromise legislation which specifically includes the authorization and expediting of the 303-mile, 2 Bcf/d Mountain Valley Pipeline (MVP) from northern West Virginia to southern Virginia.

Jordan Blum: I'll start off broad. Just how big a deal is this legislation now that we have a compromise and the president's signature?
Tom Karam: I think that the importance and significance of MVP being included in the debt ceiling legislation goes far beyond MVP. I think that it's symptomatic and shines a light on the fact that we should not have to rely on an act of Congress to construct—in a timely manner—infrastructure that is critical to continue our economic and energy growth and security.

So, my takeaway is both narrow and broad. The narrow takeaway is, we're thrilled and grateful as a company and as a partnership that MVP was deliberately and definitively determined by Congress and the White House to be a piece of infrastructure that is critical to our national security and our national energy. So that, then, will result in an efficient completion of the project sometime around the end of the year or early 2024.

On a more broad scope, I hope and expect that there will be some wind at the backs of our elected officials to see the need for comprehensive permitting reform, which is agnostic as to whether it's fossil fuel—meaning natural gas infrastructure—or whether it's renewable wind, solar, hydrogen or other. You have to be able to attract the capital on a risk-adjusted basis that can then be deployed to construct this infrastructure that we need in a timely manner, but also consistent with the appropriate and necessary environmental review and protection. So, I hope that MVP turns out to be the canary in the coal mine of what needs to be done to fix our permitting regulation in this country.

JB: In the debt ceiling legislation, there's broader language about bigger permitting reform, but I'm assuming you think that's not nearly enough of what needs to be done?
TK: I think it's a good start. I've heard it referred to as "permitting light." I would call it more directional than definitive. I think what was included in the debt ceiling legislation directionally is a good step in the right direction. But you need definitive rules of engagement with the state and federal agencies with very well-defined time limits and thresholds. And then you need rules of engagement with the court system so that there are timelines, and you can't continue to be in a loop where there's never-ending litigation. I think those things have to be included and contemplated in what I would define as the more broad and comprehensive permitting reform that we so desperately need.

JB: Is there optimism that that might end up being a part of another broader congressional compromise package? I know it's hard to do it as standalone legislation.
TK: I don't know that I can handicap that. I think everything I've heard from Sen. [Joe] Manchin (D-W.Va.), from Sen. [Shelley Moore] Capito (R-W.Va.), from [House] Speaker [Kevin] McCarthy (D-Calif.) is that there is an appetite and desire to roll up their sleeves and see if they can't put together a comprehensive piece of permitting legislation.

Right now, we're the hot spot in terms of natural gas infrastructure, but if you step back and think about it over the long term, the transmission grid needs permitting reform every bit as much, if not more than we in the natural gas infrastructure business need it. The transmission grid has to be, first of all, upgraded and, secondly, enlarged significantly if there's any hope to deploy and get the penetration of renewable power sources that the transition is talking about.

JB: When it comes to MVP, was it surprising that enough Democrats got on board with it, including the president?
TK: No. I think it's a watershed event for our

Equitrans CEO Tom Karam said he's thrilled with the definitive approval of Mountain Valley Pipeline, which could lead to further reform of U.S. permitting regulations.

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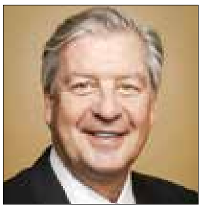

"It's amazing to me that you cannot build a pipeline into the Northeast and into New England to ease their supply concerns and their cost impact. Instead, they will import LNG and import natural gas from Canada and use heating oil."

—Tom Karam, CEO, *Equitrans Midstream*

dual-path strategy. What I mean is, we, as a company and as a partnership, have consistently maintained that we were going to travel two paths at once. The first path is the regular way permitted in order to have durable permits issued by state and federal agencies, and to finally get through the [U.S. Court of Appeals for the] Fourth Circuit panel that has so consistently been antagonistic toward us. And then the other path was to continue to educate and to communicate with both parties to include the White House, to discuss and explain why MVP is so important to our energy security. The watershed event for me was when—through the administration— [U.S. Energy] Secretary [Jennifer] Granholm issued that public letter of support stating that the administration deemed MVP to be a critical piece of infrastructure for national security. I think that confirmed for a lot of Democrats, as well as Republicans, that they were actually all on the same page specifically with MVP. I think that opened the door for continued conversations to allow us to get the result we did in the legislation.

JB: Obviously, this legislation is a huge deal, but can you talk about just kind of what MVP roadblocks and next steps remain in terms of any issues with lawsuits or permitting?

TK: We feel very good that the legislation as written will both withstand challenges to its constitutionality as well as very clearly lays out a plan … that the remaining permits shall be issued and deemed ratified immediately upon issuance by Congress. So, we see a path for us to be fully mobilized by early to mid-July to complete construction.

JB: But there will still be some litigation hurdles, even though you're confident they'll be overcome?

TK: Look, our opponents are very well financed and sophisticated, and they are not simply going to give up. They will continue to challenge us in the courts, and I would think specifically in the [U.S. Court of Appeals for the] D.C. Circuit as it relates to the constitutionality of the act. And we expect to prevail there.

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Activists gather in September 2022 at the Capitol protest against the Mountain Valley Pipeline regulations.

JB: How onerous has this whole process been? Construction started more than five years ago, the planning was years before then. And now there's only 20 or so miles left of pipeline with water crossings mostly.

TK: Yeah, that's correct. It's been a very painful process. Both the federal and state agencies have had to issue multiple permits … and been forced to jump through hoops that they've never had to jump through before. Each time the Fourth Circuit would either vacate or stay a federal permit, they would at the same time confirm the fact that we did successfully show the need for the project, that we were successful in showing the appropriate scope of the project and that they never challenged the route of the project. So, the three main pillars of any regulatory oversight were confirmed, even while at the same time they would remand or vacate the permit either on ancillary issues or issues of not enough explanation. That was the most frustrating for us. But I don't want to go down the rabbit hole of trying to argue the case. I'd much prefer to look forward. We're fortunate that we had an act of Congress mandate that MVP be completed. Now, we have to take that win and we have to expand it to the broader permitting reform.

JB: I think we're still calling this a $6.6 billion project (MVP started at less than $4 billion), but is that going to be revised up in total capex at some point?

TK: I don't think you're going to see any major revisions. I think we're going to try to come in close to the $6.6 billion—that is our guidance. I will tell you that we may change our work schedule and flow a little bit in the four or five months of construction we have remaining. One area that I'm very concerned about is the safety of our right of way and the safety of our contractors as we mobilize to begin construction again. We've had many, many instances in prior construction periods where the opposition and activists would intrude upon the right of way, putting themselves at risk and in danger, and putting our contractors and our employees at risk and in danger. We're concerned that, given the fact that the opposition has now lost, that they will raise their activism even further. So, we are going to take significant extra steps through the Virginia State Police and local law enforcement and West Virginia State Police and law enforcement, as well as our own initiatives with security to do everything we can to protect the right of way, our contractors, as well as our opponents. They have every right to free speech; they just don't have a right to create safety or risk hazards for our right of way or our employees.

JB: If this is completed by year end or early 2024, about how long will it take to really ramp up to full capacity?

TK: We will start operating at full capacity immediately. What will happen is we'll mechanically complete the pipeline, then we'll do all of the hydrostatic testing to ensure that it's fit for service. And then we will start to receive nominations for the 2 Bcf/d.

JB: Big picture again, can you talk about just how big a deal this is for overall Appalachian Basin production with all the bottlenecks that have existed?

TK: That's an excellent point. There is no shortage of producers in the Appalachian Basin that will tell you that they are capacity constrained with takeaway capacity coming out of the basin. That has two impacts. It has the impacts on how much they can produce and grow their production over time, but it also has a significant pricing impact. What we're hoping MVP can do, in the short term, is have a beneficial impact on pricing almost immediately. Over time, we fully expect to have a positive impact on the ability for producers—within their own financial forecast—to grow their production. From there, that may lead to additional projects out of the basin, which could further enhance the energy security and affordability. We haven't talked about affordability yet, but MVP clearly is a tool and a pipeline that will help to keep natural gas from Virginia and south on a much more affordable footing.

JB: This applies more to future projects, but how will this impact the ongoing issues with getting pipelines up into those highly populated East Coast areas?

TK: It's amazing to me that you cannot build a pipeline into the Northeast and into New England to ease their supply concerns and their cost impact. Instead, they will import LNG and import natural gas from Canada and use heating oil. It's just incongruous to me that we should not be able to construct natural gas pipelines when you have the proximity of the largest natural gas reserve on the planet—the Marcellus Shale and Utica Shale—just a couple hundred miles from where it could be delivered and provide pricing relief and reliability and security to a very significant number of consumers. OGI

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Elon Musk: Permitting is Holding America Back

The serial entrepreneur covered a wide range of topics, including EVs, the battery supply chain and the need for permitting reforms during the EEI 2023 conference.

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Tesla CEO Elon Musk has something in common with the energy industry: concern about permitting and siting reform for infrastructure.

"We are, like, practically making construction illegal in this country, especially in California," Musk said during a keynote address at the June EEI 2023 conference in Austin, Texas. Each regulation is not so bad by itself; however, the multitude of regulations creates an analogy to "Gulliver's Travels."

"It's 1,000, 10,000 little strings holding the giant of America down from a regulatory standpoint," he said.

Permitting reform is among the issues faced by energy players working to transition the world to lower-carbon energy sources. The recent passage of debt-ceiling legislation brought a win, streamlining some parts of the permitting process for infrastructure with amendments to the National Environmental Policy Act. However, more is needed, experts say, amid a strong electrification drive calling for improved grids to meet higher expected energy demand.

To Musk, also CEO of aerospace company SpaceX and chairman of Twitter, just about everything will be electric someday. Speaking before the crowd of Edison Electric Institute (EEI) members, Musk continuously stressed the need for more electricity as the company expands production with new gigafactories.

"Demand for electricity is going to be extremely high. I hope that's good news," Musk told the audience of electricity utility providers. "We need to roughly triple electricity to get to a fully electric economy.… It's really going to take a tremendous effort to address this. This is sort of, I think, very good news for those producing electricity, but also entails a tremendous amount of work ahead and new production capacity."

Megapacks are the way to go, he said, when it comes to energy storage to help stabilize the grid. They essentially charge up when there is excess power production and release it when there is insufficient power production. Stationary storage is the fastest growing part of Tesla's business, he said, growing 300% per year—far outpacing the company's electric vehicle (EV) business.

On electric vehicles

Tesla, a manufacturer of EVs, saw explosive growth in the last few years. The Austin-based company delivered about 50,000 cars in 2015. By 2022, the count surpassed more than 1.4 million.

"It means that we should expect electrification of transport, especially passenger vehicles, quite quickly," Musk said. "Electric vehicles are growing exponentially."

However, it will take time for EVs to outnumber the more than 2 billion cars and trucks on the road today and about 100 million new vehicles. Even if 100% of those vehicles were EVs, it would take 20 years to replace the fleet, he said. "I think we're moving quickly to the point where probably half of all new vehicles made will be electric."

Several states—including Oregon, Washington and California—have established programs mandating that all new cars, trucks and SUVs be electric, aiming to reduce emissions to slow global warming. Some states are also planning to ban the sale of new gasoline-powered vehicles.

On battery supply chain

While low U.S. supplies of EV battery materials such as cobalt, graphite, lithium, nickel and manganese are seen as a concern, Musk doesn't see it as a problem for Tesla.

"Demand for electricity is going to be extremely high ... We need to roughly triple electricity to get to a fully electric economy ... It's really going to take a tremendous effort to address this."

—Elon Musk, *CEO, Tesla, SpaceX; chairman, Twitter*

Tesla CEO Elon Musk speaks with Pedro Pizarro, president and CEO of Edison International, at EEI 2023 in June.

Velda Addison/Hart Energy

"Raw materials are not really an issue here, especially when you consider iron-based cathodes," Musk said, adding most of the batteries will be made with iron—the most common element on Earth by mass.

"We're not going to run out of iron, that's for sure—especially for stationary storage where massive volumes are not that important," Musk said before turning to lithium-ion cells. "Lithium is like the salt on a salad, it's not the salad itself," Musk said, as it makes up a small amount of the battery's mass.

The higher energy chemistry is on nickel, and the lower energy chemistry is on iron, he explained. "We use nickel for long-range stuff where mass and volume really matter. We use iron where it is less important, so medium-range cars; whereas, nickel would be used for long-range vehicles and aircraft."

On artificial intelligence

Artificial intelligence (AI) is also moving deeper into the energy and power industries. Session moderator Pedro Pizarro, president and CEO of Edison International, pointed out how the company used an AI-enabled tool to select images captured by drones as part of nearly 200,000 asset inspections in areas where wildfire risk is high.

"There's no way humans could process all those images," Pizarro said, before asking Musk about his thoughts on AI.

"I am worried about AI on the downside," Musk said, calling it a powerful technology that needs government oversight so companies don't do "super dangerous things."

Musk recently launched X.AI Corp., a Nevada-based AI company, according to media reports. OGI

"I think we're moving quickly to the point where probably half of all new vehicles made will be electric."

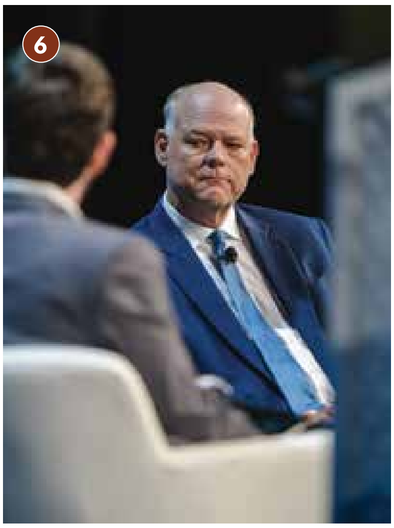
—**Elon Musk**, *CEO, Tesla, SpaceX; chairman, Twitter*

▸ SUPER DUG

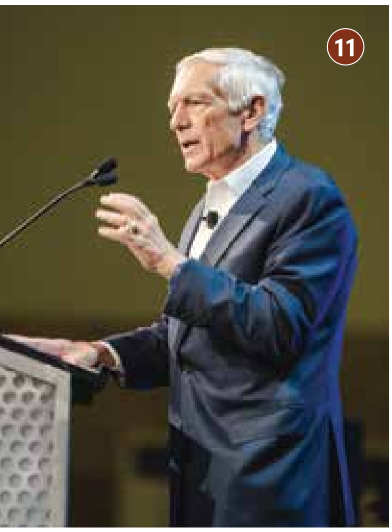
SUPER IS AN UNDERSTATEMENT

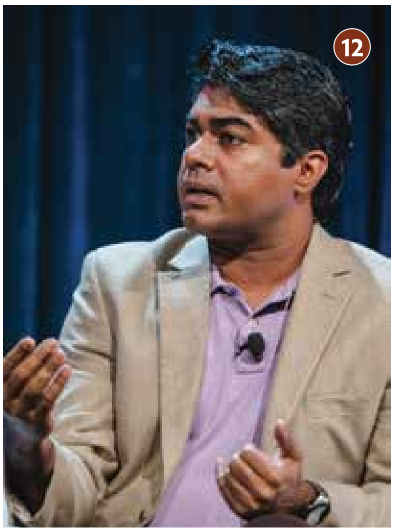
For three days in May, more than 2,000 attendees packed the Fort Worth Convention Center at SUPER DUG to network, learned the top names in the energy field and had a ton of fun.

All Photos by Arnaldo Larios/Hart Energy



1) All eyes on the oilfield services panel. 2) Clay Gaspar, executive vice president and COO of Devon Energy, with Nissa Darbonne, Hart Energy's executive editor-at-large. 3) Daniel Palmer (left), commercialization director for OGCI Climate Investments speaks on a panel with Joe Quoyeser (center), chief commercial officer with LongPath Tecnologies, and Nick Rakic (right), solutions director at Welltec. 4) Indigo Carroll with Harnham Inc. on the exhibit floor. 5) Wil VanLoh, founder and CEO of Quantum Energy Partners. 6) Joe Quoyeser, chief commercial officer of LongPath Technologies Inc. 7) Amrita Sen, co-founder and director of research at Energy Aspects.





8) Darren Barbee, HartEnergy.com's senior managing editor, moderates the "Big Bucks" panel with Timothy E. Perry, managing director, Credit Suisse; Muhammad Laghari, senior managing director, Guggenheim Securities; David Deckelbaum, managing director, TD Cowen; and Al Carnrite, CEO, The Carnrite Group and managing director, Alvarez & Marsal. 9) Super DUG exhibit floor. 10) Reckless Kelly performs at the after party at the River Ranch Stockyards. 11) Retired Army Gen. Wesley K. Clark, CEO of Wesley K. Clark & Associates and former Supreme Allied Commander of NATO. 12) Siddharth Misra, associate professor at Texas A&M University. 13) Gbenga Onadeko, senior vice president at Welltec. 14) Samantha Holroyd, chief commercial officer at ZeroSix.

▸ SUPER DUG

Gen. Clark: Oil and Gas Key to Winning the 'Next Battle'

"Oil and gas production is U.S. national security—it's that simple," retired four-star Gen. Wesley Clark told SUPER DUG conference attendees.

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China and Russia each pose "great danger" to the U.S. as a global superpower, and the way to shore up the country's national security is more cooperation from the federal government and the domestic oil and gas industry, said retired U.S. Army Gen. Wesley Clark.

"Today, we're in a really tough international situation, a multipolar competition with two nuclear superpowers," Clark told a packed house at the Fort Worth Convention Center at Hart Energy's SUPER DUG conference in May.

"And I don't [know] if the politicians will tell you—I'm not wearing a tie; I'm not a politician—but I'm going to tell you the United States is in great danger."

The precarious current position of the U.S. is much of its own making, Clark said, adding that beginning in 1991, the country promoted the "rise of China."

"We started educating its students, giving away critical technologies, opening markets.… We permitted the theft of billions of dollars' worth of technologies, including [those of] the oil business," he said.

The idea at the time was that China would become increasingly democratic, more open and more engaged with the world.

But it didn't work out that way.

Instead, two decades of U.S. fumbles opened the door for both China and, tangentially, Russia to gain power—so much so that Russia now believes "it can take back Eastern Europe by force," the general said.

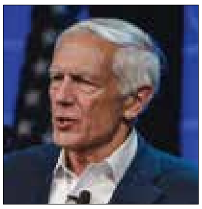
On the 'bubble'

The months following Russia's February 2022 war on Ukraine have demonstrated the limits of American power, he said.

"Russia hasn't conquered Ukraine, but neither has its economy collapsed under sanctions," Clark said. "This war's a long way from being done, and Europe's energy situation is a long way from getting resolved in Ukraine."

Russia's weaponization of energy in its battle for Ukraine put in full view its stranglehold on the European Union's gas supply. The net effect has disrupted global markets, spiking inflation that now permeates commodities markets around the world.

"We need to get Gazprom out of Europe.



"This is the strongest, most vibrant, longest-lasting industry in America. There's no replacement for it. You're on the front line of American national security. Let's win this next battle."

—Retired Army Gen. Wesley Clark

We're missing the bubble on this," he said.

"We've become more and more stay-at-home," Clark said, adding that both China and Russia are developing resources around the world.

The 'hard way'

Isolationist practices originating from OPEC's 1970's oil embargo still infect some policies.

"We learned the hard way then that the U.S. must move toward energy independence," Clark said. "Oil and gas production is U.S. national security. It's that simple. It's been that way for a long time and it's not going to change anytime soon."

Former U.S. allies are distancing themselves. Rival nations led by Russia and China are "coalescing into a rival power center," working against U.S. interests and seeking a foothold in key parts of Africa.

Meanwhile, "we Americans are at each other in a bitter rivalry not seen since the American Civil War."

This discord makes it more difficult for the federal government to work with the energy industry to promote its interests, develop resources and secure the country, he said.

And then, there's another problem.

"Our government can't make up its mind," Clark said.

The Biden administration wants more oil and gas but refuses to engage domestic producers.

"Do we think we can give up on domestic production of energy and just focus on renewables, rely on friends like OPEC+? If so, we'd be dead wrong again."

The 'enemy right now'

But the industry needs "stronger U.S. governmental support" to develop international resources.

"We've got to understand, China wants to take over the world. This is good for us; we need a challenge," Clark said, adding it would be good for "humanity" for the U.S. to work with China on resources and other issues.

"We're still getting job operations, we're still getting economic growth. We look pretty darn good," Clark said. "That's what China's afraid of—that and our technology."

Moreover, the U.S. must restore China's respect by helping Ukraine beat back its invaders, he said.

"With Russia, they're the enemy right now. And we've got to take the risks to give Ukraine what they need to win," he said. "This is not the American security environment of 30 years ago; it's not the environment [in] which most of you entered the oil business."

Clark laid out a roadmap for bringing domestic industry and the federal government together in a way that puts this complex geopolitical environment in order for business:

- Streamlining permitting in recognition of the domestic oil and gas production that is fundamental to both the U.S. economy and global stability;
- More investment for new technologies that locate and recover, refine and transport oil; and
- Encouraging oil companies to be more active abroad—"not pulling back, but rather being out there seeking new sources," Clark said.

"We need a new partnership between the oil industry and the U.S. government," that will allow the domestic industry to roll back efforts by China and Russia to gain a foothold in Africa's energy industry, he said.

Such an effort is key to shifting Europe's energy supply from Russia and the Middle East to the U.S. and Canada, Clark said.

Moreover, the U.S. needs to work with China on LNG and crude exports to diminish its dependence on Russia.

"And we need to do all we can while we're doing all this to decarbonize our continuing efforts, minimize our environmental footprint. We need to capture and monetize methane emissions, sequester carbon dioxide," he said.

That's a mountain of tasks ahead, he said.

"But oil and gas is not going away. We need them as the fundamental underpinnings of the United States energy system, the United States economy, and really, global economic stability," Clark said.

The oil and gas industry is not just a business that is about making money; rather, it's fundamentally about U.S. national security, Clark said.

"This is the strongest, most vibrant, longest-lasting industry in America. There's no replacement for it. You're on the front line of American national security. Let's win this next battle." OGI

Liberty CEO Pearson's 'Gas-Rich Huff and Puff' EOR Program

To get more Bakken oil, Liberty Resources reinjected Bakken gas into a well and pumped up productivity by 25%.

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At the SUPER DUG conference in Fort Worth, Texas, Liberty Resources CEO C. Mark Pearson sat down with Hart Energy Editorial Director Jordan Blum to discuss his company's usage of Bakken-produced gas and EOR in the Bakken.

Jordan Blum: We're talking about enhanced oil recovery in the Bakken. This is a process you all started almost five years ago. I guess with a—what do you call it, a gas-rich huff and puff program? Can you take me through the timeline and where we are now?

Mark Pearson: Sure. In our primary production of our wells in unconventional fields, we're typically only recovering 10% to 15% of the oil in place. And so, that's just a lot of resource that's being left behind. So, we've been studying this for several years now. What can we do and go about learning in the field as well as in the laboratory and running reservoir simulation? So, we've actually conducted two phases of field tests with different types of… just a gas injection and then a water and gas injection. And our last test, which was our phase two first-stage project, was admissible gas, which is… So it's basically our Bakken-produced gas, which is 70% methane, 20% ethane, 10% propane. Just taking that, reinjecting it in pressure and alternating it with produced water or fresh water with a surfactant to basically go in and just mobilize oil that's left in place to increase the productivity coming out of the wells. And after a year and a half of production, we've averaged about a 25% increase over the past year, just in that one well. And in an offset well, a 20% increase in that offset well. So pretty encouraging first steps. And we're going to be doing a second phase test, or the second part of our phase two test this summer.

JB: Very good. And it's basically cheaper and more efficient to use the produced gas at the source?

MP: Right. We're not having to buy CO_2. We're not having to pipe that line in. We're not having to change out our tubulars or anything for corrosion issues. We're not having to separate out CO_2 from the sales gas immediately when that well turns 'round back on production. We're able to sell all the oil, all the gas, because it's the produced gas that was reinjected as part of the miscibility process. So, very cost-effective way to go about increasing recovery and something which could be 15% to 25% boost in recovery for our wells, so something that's very exciting. And we're also excited that other operators are catching on as three of the larger operators in the Bakken that are all planning their first EOR projects this year, and I think it's something that we're going to see a lot more of in our industry.

JB: Does it factor in much with natural gas prices being lower now?

MP: Yeah, well, it certainly helps because when we look at the full cost of it, we actually purchase the produced gas. It's coming off a pipeline, so we've got to pay the producers or the owners of the wells that it came from. So, in terms of a cost standpoint, the last pilot we've averaged, we think about a 3.6 Mcf per barrel of oil. So obviously if we're having to pay \$2, \$3 an M versus \$8 or \$10, there's a significant difference in the cost-benefit equation.

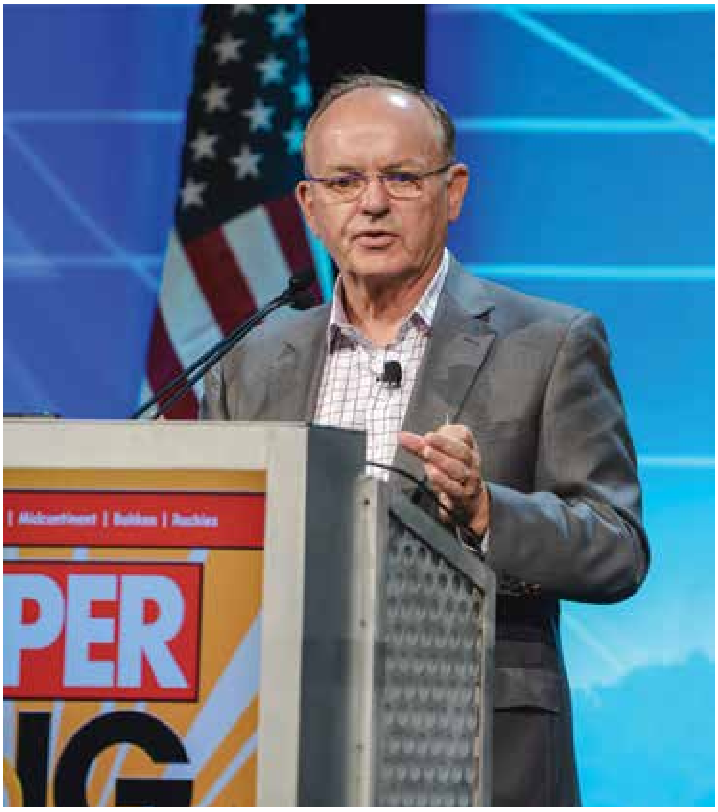
JB: Very good. And can you elaborate, too, on just how all this plays into like you were talking about the Bakken activity kind of moving north of the core, so to speak?

MP: Well, anything you can do to increase productivity with time. So, whether it's from drilling along the laterals I talked about in my talk, moving a big chunk of our program to three-mile laterals, that's something that the North Dakota Industrial Commission is really behind. [It] sees the potential for maybe 15,000 three-mile lateral wells in the Bakken. And so, basically, we're moving from what was the traditional core of the Bakken to what we call the Northern Extension Core.

Basically, it's in the same depot center of the basin, but it's just a little bit lower pressure, a little bit lower, a little bit higher water cut, but by running longer laterals, intense completions… And if we can add some added recovery from EOR, it makes performance as good, if not better than traditional core wells.

JB: Mostly about being more creative and technologically savvy as we get out of the core.
MP: Absolutely. It's that we're all learning as an industry, we're learning as we go, and learning to be more efficient, learning to get more out of the ground than what comes out on the initial first gush.

JB: So, this makes you pretty bullish for the long term?
MP: Well, I think it just talks about how technological our industry is and that it's not just a matter of sticking a hole in the ground and suddenly oil comes out, which is what my father, who was a refrigeration engineer, assumed it was and couldn't understand what all this completion technology was about. But it really is the application of technology, which is what petroleum engineering is to the subsurface. And we're recovering more hydrocarbons out. We've gone into unconventionals in the last 15, 20 years in a much greater way, and now we're finding out how to get more of that unconventional oil out of the ground. OGI



Liberty Resources CEO C. Mark Pearson is excited about EOR projects in the Bakken, including Liberty's own that have averaged a 25% increased production in just one well this past year.

Devon Energy's Long-Term Approach

COO Clay Gaspar said he is looking at the future of Devon Energy with "a 2030 and a 2040 mindset."

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Clay Gaspar, COO of Devon Energy, sat down for an exclusive interview with Nissa Darbonne, Hart Energy executive editor-at-large, during SUPER DUG 2023. He discussed Devon's near-term goals for improving well efficiencies and driving environmental improvements, as well as the company's goals to keep thinking generations ahead of the rest of the industry. The following Q&A has been edited for clarity.

ND: Your refracs in the Eagle Ford … you have a somewhat accelerated program there. You're having great success. You have 30 wells online so far, and doing more this year and plans for additional [wells]. What are you seeing in terms of production and EUR uplift?

CG: It's a really exciting program both for the Eagle Ford and specifically for Devon, but even for the broader industry. We also have programs in North Dakota. We have programs going on in the Midcontinent. I think there's just a ton of opportunity to go back and redo some of the barrels that we've left behind before, go enhance those wells and really extract more and more value. When we look at the economics of the wells that we're delivering today, the original well economics are actually on a rate of return similar to these new refracs. The EURs are roughly about half. They can be as much as half of the original reserves. So, the economics with using existing wellbores are really strongly compelling.

ND: And then also, as history goes, Devon Energy, back to the 1980s … The NEBU development in New Mexico was an incredible platform, and it was pure wildcatting. Devon was built upon that. So in the past 40 years, Devon has somewhat demonstrated where Devon goes, eventually, so does the industry. It's just been somewhat patient and incredible foresight. So, based on that track record, where is Devon going, therefore suggestive of, where is the industry going?

CG: [I] appreciate those compliments. There are real benefits [to] working for a company that's been around for more than 50 years, understanding some of the things that we've learned along the way and have that experience of cycle upon cycle as our industry does. We look at it through an interesting lens. There are two versions of it. One lens is in a 0-5-year look. How do we continue to get better at what we do? How do we drill wells more efficiently, think about the completion, stimulate more rock, extract just a little bit more of those hydrocarbons that we're after? How do we do it in a more cost-effective manner? How do we do it in a safer manner? And very importantly today, how do we continue to drive environmental improvement around emissions, water recycling and so many other important categories?

All of this is really focused on how do we do what we do with a continuous mindset of improvement. And that really drives a rolling five-year approach. But we also have some teams that are freed up from delivering this week's production, this month's returns, this quarter's results. They have a little bit more of a blue sky, an exploration kind of mindset to say, "What is it beyond what we're doing today?" Certainly, enhancing what we're doing today, extending the runway of what we're doing, but also thinking about adjacent businesses, maybe up the value chain or down the value chain, thinking about really creative opportunities in this world of transition … We recently made an investment in a geothermal company that in a 0-5 year lens may not look material, but when you really open it up to that longer-term approach, it could be a material way that energy is created going forward. We always are looking to think about

Clay Gaspar, COO of Devon Energy, speaks with Nissa Darbonne, Hart Energy executive editor-at-large, about the company's challenges and opportunities in the Lower 48 and how it is planning for a sustainable future in oil and gas at SUPER DUG.

> *"We would certainly love to have a really clean acquisition that fits right into our footprint, bought for the right price that enhances our absolute business model and makes us a better version of ourselves, but you usually don't get all of those things to line up."*
>
> —Clay Gaspar, *COO, Devon Energy*

Devon in a 2030 and a 2040 mindset and really making sure that we are generations ahead in some cases.

ND: Speaking of carbon … clearly oil and gas is going to be crucial and essential to energy in the future for a long time going. But, carbon footprint, carbon credibility, looks like it's going to define the oil and gas operators that exist in the future versus the oil and gas operations of the past. In terms of M&A … I would gather that there are merger and acquisition candidates—just like all operators are always considering and looking at—that you would kind of lean towards wanting to acquire and merge with one with a very good low-carbon program. How does that work for you?

CG: I think it's an important consideration, but it's no more important than the base fundamentals of the E&P assets that they have. Do they enhance the footprint that we have today? Are there other things that they bring, maybe some breakthrough technology or a mindset that is really beneficial to and incremental to what we're already doing? We would certainly love to have a really clean acquisition that fits right into our footprint, bought for the right price that enhances our absolute business model and makes us a better version of ourselves, but you usually don't get all of those things to line up. So if we acquired a company that did not have the highest standards as we have, we're fine with going in and retrofitting. In fact, one of the deals that we did last year, part of the acquisition cost in our minds was making sure that we had the opportunity to rebuild a lot of facilities and run things in a little bit different manner with a longer-term view. And that's been very beneficial and it's beneficial from an economic standpoint, from our operations standpoint, and for Devon's continued credit with how we operate. It's fundamentally important. OGI

Quantum Energy's VanLoh Talks Inflation and Innovation

The CEO "never will bet against human innovation," but neither is he all in on geothermal.

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Wil VanLoh, founder and CEO of Quantum Energy Partners, discussed the ways the Inflation Reduction Act will stimulate inflation in some parts of the economy, how U.S. consumers will likely pay more for electrical power in coming years and why he is doubtful about a rapid scale-up of geothermal energy. VanLoh spoke with Nissa Darbonne, Hart Energy's Executive Editor-at-Large, at SUPER DUG. The following Q&A has been edited for clarity.

Nissa Darbonne: I wanted to ask about something that you described as the "Inflation Stimulus Act." What do you mean by that?

Wil VanLoh: Well, it was when we were talking about the Inflation Reduction Act, and I was just making a comment that it's actually going to be very inflationary, right? I mean, clearly a lot of good things came out of that and will come out of that in terms of stimulating a lot of investment in lots of things for the energy transition, including carbon capture and storage and other things that will benefit the oil and gas industry. But it's going to be inflationary, not deflationary. It's not going to reduce inflation because it's going to massively increase spending on a lot of things … that we're in short supply of. So that's going to drive prices up.

ND: Well, how do we reconcile that, though, when the Fed is pulling on the reins to beat back inflation, but you have the entity that the Fed is part of—the government—that's, not dumping … that would be unfair to say, but just dropping billions and billions of dollars into the economy on top of what it already spends. How do we reconcile this in the short term?

WVL: Well, I'm not sure we will (laughs).

I think that the perceived need to significantly increase our spending … in particular … the vast majority of the benefits of the Inflation Reduction Act are going towards the renewable power space, right? For wind and solar and battery storage. And so, in those particular areas of the economy, I think we're going to see significant inflation. And it's … got this kind of dual challenge in front of us of trying to tackle the increasing levels of CO_2 in the atmosphere. And I think the government's kind of making a value assessment of it's more important, even if we have some inflation. I don't think they were so much thinking about it that it would be inflationary. I don't think they really cared. I think they said that the issue of reducing CO_2 emissions from the United States is of paramount importance, and this will help speed up our transition to these low-carbon technologies.

ND: And, to be clear, Quantum Energy Partners is an investor in alternative energy in addition to oil and gas, so Wil is speaking from the perspective having looked at the economics of everything.

And speaking of the economics of everything, wind and solar in particular, you said that that was not largely born from, but it was encouraged early on by the incredibly cheap cost of money, but money's not cheap anymore. Money is expensive and increasingly more expensive, and you described wind and solar will be increasingly challenged from an economics point of view. What is your outlook, then, for additional wind and solar?

WVL: Well, I think we'll continue to increase. You know, we did have a big issue last year with getting solar panels from China. And so, the installed solar capacity in the U.S. was down about 75% from what it was going to be. Had we not had this—basically, you know, they blocked the import of panels from China if they couldn't be certified that there was no Uyghur labor in them, right? But I think, overall, we're going to have a lot more solar and wind built in the U.S. and I think the point I would just make is, while over the last

"The Inflation Reduction Act is going to be inflationary, not deflationary, it's not going to reduce inflation because it's going to massively increase spending on a lot of things, and on a lot of things that we're in short supply of."

—Wil VanLoh, *founder and CEO, Quantum Energy Partners*

decade, the cost of that power has fallen 75%, 80%-plus, likely over the next decade, it's going to be going up. The PPAs—the power purchase agreements—that our wind and solar companies are entering into today are, in a lot of cases, double what they were two to three years ago. And the reason they're double is because we have to have that much higher price for the power we're producing because our capital cost went up so much. So, to earn the same rate of return, we have to charge a lot more for that power. So, I do think what this massive buildout of wind and solar domestically is going to create is much higher over the next decade, probably much higher power prices for consumers, not lower power prices.

ND: Speaking of the PPA—the power purchase agreement of offsetting your carbon … Google has relied on PPAs in the past, and I saw just this past week how their next gen now is kind of hoping that, instead of them generating carbon offsets for their own carbon footprint, that if they grow a geothermal business, they won't need to purchase carbon offsets. In terms of geothermal as a tack, how do you like geothermal?

WVL: Well the interesting thing is, geothermal is kind of a cousin of the oil and gas space, right? Because you're having to drill these wells using the same kind of technology we've developed in the oil and gas space … We've spent some time looking at geothermal. Some of the technologies we've looked at, in our opinion today, are pretty expensive. Could that cost come down? Sure. I mean, I think one of the things that we've learned is, you know, be careful betting against innovation in this country. You know, we saw it, what it did in the shale revolution. I mean, everybody said the oil and gas industry in the United States was dead and we were building LNG import terminals in the early 2000s, and now we're one of the largest exporters of natural gas and oil in the world.

And so, I never will bet against human innovation, especially in America. I think there is some merit for geothermal today. I don't think a case can be made that it's going to supply a significant portion of our electricity domestically. But in select cases, I think there's certain geographies that companies like Google may choose to pay more for their power. And, at least when they do that, they're truly offsets.

I'm very circumspect [because] a lot of these offsets are being sold multiple times. There's not a great market out there for policing, if you will, regulating the offset market, which I think we have to develop if we're going to truly do that. But I also don't necessarily know if offsets … I think it makes people feel good, to say, "well we're not going to cut down this forest in Brazil and we're going to just sell these offsets." Well, they probably weren't going to cut down that forest, anyway. Did that really help the environment? And I think that's what executives at some of these companies are starting to realize: If we're really serious about climate change, then let's actually truly reduce our carbon footprint. Don't just buy offsets that arguably may or may not really be reducing, in aggregate, the amount of carbon going into the atmosphere every year.

ND: To resolve the question of whether it is a real carbon offset or not, is the tokenization of carbon offsets the solution? Or do we need a … NYMEX-type trading house instead?

WVL: I think we need something like an S&P or a Moody's that truly rates carbon emissions and ensures that emissions are being abated and what the actual measurements are—that they're factual, accurate estimates and that that offset's not being sold more than once. OGI

Wil VanLoh, founder and CEO of Quantum Energy Partners

Bigger Than Shale: The Coming Boom of Electric Natural Gas

Green molecules and green electrons, such as electric natural gas, present a potential investment opportunity in the U.S. that promises to be three to four times that of the shale revolution, says the CEO of TES Americas.

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Efforts to convert green hydrogen to a synthetic natural gas called electric natural gas (e-NG) are underway as Belgium-based hydrogen startup Tree Energy Solutions (TES) partners with TotalEnergies to bring a large-scale e-NG production unit to Texas.

The move comes as parts of the world struggle to meet energy needs while reducing reliance on carbon-intensive forms of energy. TES is on a mission to accelerate global decarbonization by combining CO_2 with green hydrogen and moving the produced e-NG into global markets using existing infrastructure.

Pending a final investment decision in 2024, the project in Texas will utilize a 1-gigawatt (GW) electrolyzer to produce hydrogen powered by about 2 GW of wind and solar energy to produce up to 200,000 metric tons (mt) of e-NG. The project will likely source biogenic CO_2 from high-emitting regions such as the Gulf Coast, where reporting facilities in Houston alone reported to the U.S. Environmental Protection Agency more than 52 MMmt of CO_2e in 2021.

Cynthia Walker, CEO of TES Americas, spoke to Hart Energy about e-NG, the company's latest project and how the renewable energy source can play a major role in the clean energy revolution. This interview was edited for length and clarity.

Velda Addison: What are some of the benefits of e-NG and how does it compare to fossil natural gas and renewable natural gas (RNG) such as from landfill waste?

Cynthia Walker: We think e-NG has a lot of benefits. There are many initiatives around the world to bring green molecules to market. One of the green molecules that there's a lot of focus on is hydrogen. But we see hydrogen as a molecule in a way that is fairly illiquid because it's used in a pretty narrow market today, primarily as a refinery feedstock and in the fertilizer value chain. We allow hydrogen to access multiple markets by transforming it into a natural gas molecule that can be used by anyone that uses natural gas today, and it can be transported through any existing natural gas infrastructure. So, we think the big benefit is it can be used today: no new infrastructure, no new plant equipment.

When you think of all the derivatives of hydrogen, one of the things that we think is unique about our derivative of e-NG is that there's already an established premium market for green natural gas. That is the renewable natural gas market that you know of here in the U.S. … Our process is simply another way of producing a green molecule that has a similar carbon intensity reduction benefit and is price competitive with RNG today. We see it as renewable natural gas but better because we can do it more at scale and more in a manufacturing type of way.

VA: How do the production costs compare?

CW: There's quite a bit of a range on renewable natural gas, as you may be aware—anywhere from the teens to even the $40s [per MMBtu], or we've heard some numbers closer to the $50s. We haven't disclosed specifically what our production costs are going to be, but we do believe that our molecule competes within that very broad range. We think it will be cost competitive. But to put more specificity around the cost, overall, the biggest cost for us is our feedstock, and we really have two major feedstocks. One is the renewable electricity, and renewable electricity to produce the hydrogen is about 70% of the overall cost structure. Then, we have CO_2, an essential feedstock. Depending on the quality of that CO_2 and its location, it's about 7% to 10% of the overall cost of our molecule.

We are at the height of the cost curve right now for hydrogen, therefore, as a derivative for e-NG. We expect costs can come down probably by at least 50% simply with the maturing of the supply chain and using advanced manufacturing for electrolyzers. One of the fantastic things about the IRA (Inflation Reduction Act) is it's going to move those supply chains all to the U.S. We're going to invest in advanced automation, and the cost of electrolyzers will come down easily by half.

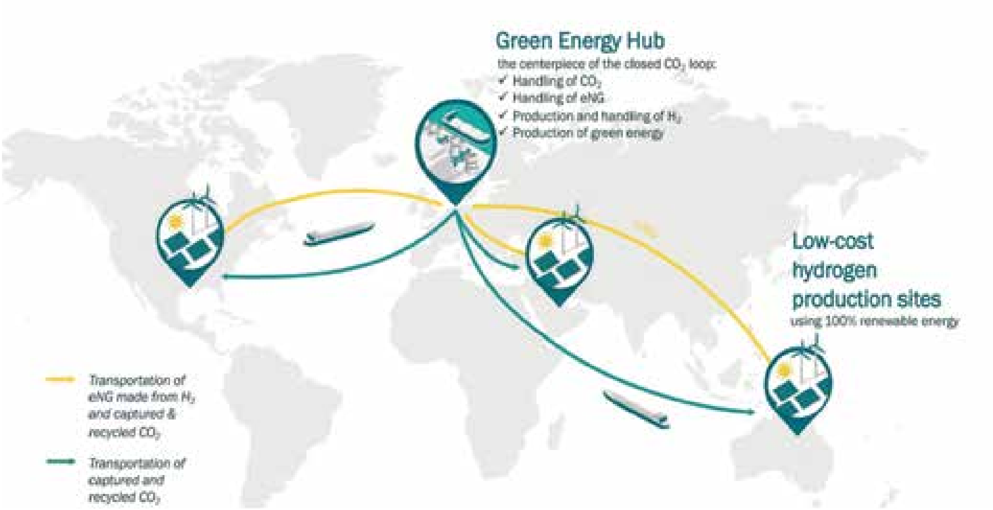
VA: You mentioned that the process or the technology behind e-NG has been around for decades. So why haven't we heard more about e-NG?

CW: There are multiple methods actually for methanization. The process that we use is called the Sabatier process. It was discovered by a French scientist back in 1912. He won the Nobel Prize in chemistry. It has been used by NASA, actually, to produce water on the space station. Water … for us, is a byproduct; for NASA, it was

Renewables and Hydrogen Costs Prediction

Year	$/MWh renewable cost	$/MWh hydrogen cost
2010	360	600
2021	30-45	100-140
+5 years	20-35	45-70
+10 years	15-27	35-55
Large-scale option	10-13	22-28

Source: TES



an essential life support mechanism for astronauts on the space station. But other than that, the sheer concept of needing to use CO_2 to produce something was not something that society was focused on.

Essentially, if you think about our process, what we do is we recycle CO_2. We follow the nature cycle, right? Trees, nature, takes in CO_2. It recycles it into useful materials. That's really what the whole process of producing e-NG does. It recycles CO_2 into a useful molecule. As a society, we were focused on other forms of energy—traditional fossil fuels—so [we] didn't need it.

VA: Has TES moved e-NG through an existing natural gas pipeline system here in Texas before, or is that part of the preliminary study process?

CW: The study will be about the design of the plant. There won't be physical movements of anything. We don't see barriers because it's chemically, essentially, equivalent to natural gas that is produced via the drill bit. So, we don't see any showstoppers in that regard.

VA: Have you lined up power purchase agreements yet for the hydrogen? Do you also have to line up like similar agreements for the biogenic CO_2? How does all of that work?

CW: We've had lots of conversations with renewable developers, renewable electricity providers. In our partnership with Total, it will be their responsibility to bring the renewables. They're a very large, capable developer of renewables. We're excited to partner with them. On the CO_2 front, we'll need to contract for the CO_2. We've had lots of conversations with biogenic CO_2 emitters, and we will continue to advance those discussions formally. Think of it as just like a feedstock. Just like a refinery or a chemical plant, we need to ensure in order to make that final investment decision that we have a firm long-term contract to support us building the plant.

VA: Do you see direct air capture being used as part of this process?

CW: Direct air capture is an interesting and promising technology from an overall climate perspective and certainly for the prospects of our e-NG development going forward. We could put a plant anywhere. Our biggest constraint right now is being close to a CO_2 source and direct air capture just changes that dynamic.

However, direct air capture is in extremely early stages. My former employer, Occidental [Petroleum], is the only one that I'm aware of in the U.S. that has a project underway out in West Texas. They actually just broke ground recently. We don't see direct air capture being a solution for this first [e-NG] project. But we would love to see [direct air capture] become a lot more economic and be a part of our future plans either in the U.S. or anywhere else around the globe.

VA: What are some of the markets you envision e-NG being used in?

CW: For this first project, we are targeting primarily the European market. The Asian market is also a possibility as well. We are producing a premium green molecule, so we will be looking for customers who value decarbonization the most. In Japan, they've set a target of filling their entire city gas natural gas distribution system, like our CenterPoint [Energy] here in the U.S., with 90% … e-NG. They've put mandates in place. Similarly, Europe has put some quotas and mandates around e-fuels being a requirement for the transportation industry. There are other mandates going in place. So, there's lots of support to develop demand in the European and Asian markets.

In the U.S. what we see is pretty significant demand for renewable natural gas and a market that's really undersupplied right now. We think our e-NG can fit right into that market as well. Here in the U.S., the majority of the RNG goes into transportation fuels. But there's a growing piece of the pie that is going into natural gas utilities, again like a CenterPoint here in Houston. There are good markets everywhere but [demand is] really driven internationally by some of those quotas and mandates around green molecules.

VA: How do you see the market evolving over the next five to 10 years?

CW: TES has a big ambition. We would like to produce in 2030, a million tons a year of CH_4 [methane] of green e-NG. What we just announced is about 20% of that target. I think actually a lot if not all of that production potentially could come from the U.S. and then we've got tremendous opportunity abroad as well. So, ultimately, we have a longer-term target at being much bigger than a million tons a year. Of course, we always remind ourselves it starts with just one project, so we need to just get one online.

I would leave you with this. The United States has been a major force of change for the global energy system, and it started 15-20 years ago with the shale revolution, which you've reported on undoubtedly for a very long period of time. But I think the shale revolution is beginning to sunset; it's beginning to mature. I think the U.S. has an opportunity now to step in and demonstrate huge leadership on the next revolution, which is around green molecules and green electrons. The opportunity to invest and the opportunity for the U.S. to play a massive role is multiples of the shale revolution. It's three or four times. It's a huge market. TES and e- NG hope to play a very big role in it, but we're going to start with just one.

Carbon Capture Remains Up in the Air

Permitting sites, pipelines and getting projects profitable remain conundrums as CCUS projects work to cross the finish line.

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Getting the economics and technology right to make carbon capture, utilization and storage (CCUS) projects a reality requires managing risks, having honest conversations and aligning objectives among government agencies, a trio of energy experts said.

As with all things energy, the funding, politics and permitting remain roadblocks—particularly for the emerging CCUS industry.

As one expert remarked during Hart Energy's SUPER DUG conference, "CO_2 is not new, but it's new."

CCUS technologies are expected to play a crucial role in driving down emissions, whether it's pulling carbon from fossil fuel-burning power plants for use or storage underground, or using technologies alongside the production of blue hydrogen.

Assessing injectivity performance, potential seismic activity and plume monitoring, and ensuring containment of CO_2—along with preventing groundwater contamination—are among the technical risks that must be managed to get projects across the finish line, according to conference panelist Siddharth Misra, an associate professor of petroleum engineering at Texas A&M University.

"For these four risks, we need to have very good geophysical monitoring … It starts from monitoring the plume, monitoring the reservoir, monitoring the wellbore, the seal, the above-zone formation," Misra said. "If we monitor all these things, we can ensure there's no risk, and all these projects will end up with a good outcome."

The U.S. alone has an estimated storage capacity of about 3,000 gigatons; however, the problem lies in the number of active CO_2 storage sites, Misra said.

The U.S. operates just seven active sites—all deep saline aquifers—that store about 10 megatons of carbon per year, he said. Though 11 sites are under construction with 130 more in development for 200 megatons/year, storage will still be needed for nearly 1 gigaton/year of carbon, according to Misra.

"That will require us to develop one megaton-scale project every week till 2040. That's a pretty daunting task," he said, adding the U.S. Department of Energy's National Laboratories, oil and gas companies and storage companies have been working to develop technology to help reach objectives.

Storing CO_2 safely in depleted oil and gas reservoirs has been getting interest.

"These depleted oil and gas reserves have stored gas for more than a million years. So, if they can store gas, it can also store CO_2," Misra said. "This is a relatively new front. There's not a lot of active sites focused on depleted oil gas reservoirs, and that's where I see a lot of new innovations coming."

A balanced approach

Looking aboveground, Summit Carbon Solutions' COO James Powell pointed out the need for alignment among federal agencies as well as with state and local governments.

"A lot of states are trying to get primacy around storage of CO_2 and that will help, but it's that misalignment at the federal level, at the state level, and at the local level."

Summit Carbon Solutions has undertaken a massive $5.5 billion project that aims to capture emissions from 32 ethanol plants in five states. Plans include building more than 2,000 miles of CO_2 pipelines to gather the emissions from point sources and transport them to sequestration sites in North Dakota.

So far, about 80% of the rights of way have been acquired for transportation infrastructure with more than 130,000 acres of pore space leased for sequestration.

"If you ask me what is really needed is an honest, fact-based conversation, which allows for real decisions and real choices to be made."

—**Nikhil Ati**, *partner, McKinsey & Co.*

Getting the economics and technology right to make carbon capture, utilization and storage projects a reality requires managing risks, having honest conversations and aligning objectives among government agencies, a trio of energy experts say.

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Projects need support from local, state and federal governments, and the projects must be attractive for each of them, according to Powell.

"You've got to convince these folks that [the project] makes sense for them," he said, adding the dilemma is in trying to align goals and objectives in an emerging market. "Some people just don't see the need."

Called the Midwest Carbon Express, Summit's project spans some 82 counties. That can be a challenge.

Speaking to a public official or at a public meeting in Minnesota has a much different political climate than South Dakota, Nebraska or North Dakota.

"Just think about it politically. ... Our message has to be tailored," Powell said. "The facts are the facts, but how we present it makes a difference."

A handful of counties have passed moratoriums for ordinances restricting the construction of pipelines, he added, noting Summit spends a lot of time educating county officials.

"I've had many landowners say, well, I've got a natural gas pipeline running across my property. It's been there for 30 years. I don't care about that, but I'm scared about this. So, it's educating the public and landowners about what is CO_2."

Decarbonization economics

Honest conversations need to take place around CCUS and decarbonization, added Nikhil Ati, partner for McKinsey & Co., given what has happened in energy markets in recent years.

"The change in energy markets today, I think, really brings to bear the need for investments in all types of energy," and continued investment in infrastructure, Ati said. "If you ask me, what is really needed is an honest, fact-based conversation which allows for real decisions and real choices to be made."

Speaking on the economics of decarbonization, Ati said a balanced approach is needed for energy security and energy affordability. While some companies have set decarbonization targets between 30% and 50%, others are still figuring out how to make it work from an investor and shareholder perspective.

Some decarbonization projects are not yet profitable.

"If you look across sectors, we would say about 20% to 30% emissions reduction is in the money today. These are typically actions associated with operational efficiency, capturing fugitive emissions, a bit of electrification," Ati said, excluding what he called more needle mover items like carbon capture, switching to hydrogen as a fuel and large electrification projects.

About 20% of emissions from the petrochemical sector, for example, can be abated economically, Ati said; however, the rest of the emissions require a carbon price of about $130. "And we are far away from that."

Federal incentives such as 45V hydrogen credits and 45Q CO_2 credits are moving the needle, but are inefficient at closing the economic equation, he said.

"We think bigger incentives are needed in the use cases to actually make things happen." OGI

Exxon Mobil, Steelmaker Nucor Sign CCS Deal

Exxon Mobil plans to capture, transport and store up to 800,000 metric tons per year of CO_2 from Nucor's direct-reduced iron manufacturing plant in Convent, La.

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Exxon Mobil said in June it has sealed a carbon capture and storage agreement (CCS) with U.S. steel company Nucor marking the energy company's third such contract and the first in what is considered a hard-to-abate industry.

Starting in 2026, Exxon plans to capture, transport and store up to 800,000 metric tons per year (mt/year) of CO_2 from Nucor's direct-reduced iron manufacturing plant in Convent, La. The project will utilize the same transportation and storage infrastructure as Exxon's CCS project with fertilizer maker CF Industries, Exxon said.

The CCS agreement will be integrated into the existing CO_2 transportation framework with EnLink Midstream, analysts at Tudor, Pickering, Holt & Co. (TPH) said.

Exxon holds firm commitments for 3.2 million tons per annum (mtpa) of transportation capacity with EnLink. The midstream company is in the process of converting a legacy, large-diameter natural gas pipeline and building a greenfield, supercritical phase CO_2 line for downstream connectivity to Exxon's sequestration field in Vermilion Parish.

With the Nucor agreement, Exxon has 2.8 mtpa of emissions to be shipped across the EnLink system, which comprises nearly 90% of Exxon's initial commitment, TPH said.

"Our agreement with Nucor is the latest example of how we're delivering on our mission to help accelerate the world's path to net zero and build a compelling new business," Dan Ammann, president of Exxon Mobil Low Carbon Solutions, said in a news release. "Momentum is building as customers recognize our ability to solve emission challenges at scale."

The deal comes as companies of all types and sizes work to reduce emissions to combat climate change. On average, the energy-intense steel industry released 1.891 mt of CO_2 into the atmosphere for every tonne of steel produced in 2020, according to the World Steel Association (WSA). With a total global production of 1,860 MMmt produced that year, the WSA put total direct emissions from the sector that year at an estimated 2.6 Bmt, equivalent to about 8% of global anthropogenic CO_2 emissions.

Nucor sees CCS as a key part of its decarbonization strategy.

"We are taking a multi-faceted approach to decarbonization, and this partnership builds on previous investments we have made in a carbon-free iron start-up, renewable energy generation and the development of small modular nuclear reactor technology," Nucor CEO Leon Topalian said.

The direct-reduced iron process, which removes oxygen from iron ore with carbon monoxide and hydrogen instead of melting in a blast furnace, has lower CO_2 emissions than other methods. Nucor, which remelts recycled scrap in electric arc furnaces, also said its steel mills generate about two-thirds less than the CO_2 of extractive blast furnace steelmaking plants.

With the deal, Exxon brings its CCS customers—which also includes industrial gas company Linde—up to 5 million metric tons per year (mt/year). The company is tapping into part of the CCS, hydrogen and biofuels "molecules" market it believes could reach $6 trillion by 2050.

Exxon did not disclose the value of the Nucor agreement, saying the company is "not publicly discussing certain aspects of the deal for competitive reasons."

However, the company anticipates "revenue from our first CCS projects could begin as soon as 2025," Exxon spokesperson Chevalier Gray told Hart Energy in a statement.

The company believes policies such as the Inflation Reduction Act and technology deployed at scale are needed to grow CCS.

"Exponential growth [in CCS] will be enabled by significant technology innovation to bring costs down for CCS, hydrogen and biofuels by 30%-70% to make the business returns viable at scale," Gray said. "There is a small, addressable market today that is willing to pay the premium—as policy and carbon price take hold, and the infrastructure develops and technology brings the cost of CO_2 abatement down, [that] market will develop."

The energy company isn't alone in its pursuit of growing CCS. In 2022, more than 60 new CCS facilities were announced worldwide, bringing the total number of facilities to nearly 200, according to the Global CCS Institute.

Exxon and its partners—including Air Liquide, BASF and Shell—are also currently working to advance large-scale CCS in the Houston area. Their efforts could capture and store about 5 million mt/year of carbon by 2030, the company has said. OGI

Transition in Focus

ENERGY STORAGE

Toyota Plans Auto Battery Lab at Michigan R&D Headquarters

Toyota Motor North America is gearing up to build a $50 million lab facility to evaluate batteries for electric vehicles at its R&D headquarters in Michigan.

The focus will be on ensuring batteries meet performance, quality and durability requirements, the company said. Charging and connectivity to power sources and infrastructure will also be among the planned R&D activities.

"By adding these critical evaluation capabilities around automotive batteries, our team is positioned to better serve the needs of our customers, including Toyota Battery Manufacturing, North Carolina; and Toyota Motor Manufacturing, Kentucky; the latter of which will soon be assembling the recently announced all-new, three-row, battery electric SUV," said Shinichi Yasui, executive vice president of Toyota Motor North America, R&D.

The company said it will also work with other suppliers in North America to incorporate battery parts and materials produced locally to its products as the company aims to lower carbon emissions.

HYDROGEN

Perenco Taps Bloom Energy for Fuel Cells in Europe

Bloom Energy

The Bloom Energy Server platform will be installed at Wytch Farm in Dorset, England.

U.K. oil producer Perenco plans to install 2.5 megawatts (MW) of Bloom Energy's solid oxide fuel cells at the Wytch Farm oil field in western Europe as the operator moves to further lower emissions.

Bloom said the agreement will mark the first U.K. deployment of its fuel cell technology. The company plans to deliver its Bloom Energy Server platform in late 2023. The technology will be used to support Perenco's baseload requirements, Bloom said.

"This is an important step that will demonstrate how our solid oxide fuel cell technology supports the resilience and sustainability goals of our energy-intensive clients," said Tim Schweikert, senior managing director of international business development for Bloom.

The company describes its server platform as "a distributed generation platform that provides always-on power."

Oman Ramps Up Hydrogen Push With $20B in Agreements

Oman took a giant leap toward establishing itself as a global hydrogen hub, sealing three agreements for a combined total investment of more than $20 billion.

The agreements for three projects were signed by Energy Development Oman's Hydrom with BP Oman, Green Energy Oman and Amnah. The projects could lead to total production capacity of 500,000 tonnes of green hydrogen per annum from more than 12 gigawatts (GW) of installed renewable energy capacity, according to Oman's Foreign Ministry.

Each area covers about 320 sq km in the Al Wusta Governorate and is part of Oman's first green hydrogen blocks. The public auction process was launched last year.

"Today, with the completion of the regulatory framework, sector structure, first investment opportunities, and block awarding mechanisms, the Sultanate of Oman is at the forefront of taking its first serious steps towards green hydrogen production among other nations," Oman Energy Minister Salim Al Aufi said in a news release. "In the coming years, Oman is poised to become one of the leading countries in green hydrogen production."

Plug Power Moves to Boost Hydrogen

Plug Power

Plug Power has announced plans for three green hydrogen production facilities in Kokkola, Kristinestad and Porvoo, Finland.

New York-headquartered Plug Power said it plans to develop three green hydrogen production plants in Finland costing about $6.5 billion, eyeing exports to strengthen Europe's energy security.

The plants—which will be located in Kokkola, Kristinestad and Porvoo, Finland—are expected to produce 850 tons of green hydrogen per day using Plug Power's PEM electrolyzer and liquefaction technology. The combined electrolyzer capacity for the three plants, 2.2 GW by the end of the decade, accounts for 5% of the RePower EU plan, Plug Power said.

"Plug is happy to be making this investment in Finland—especially as seen with the three land agreements," Plug Power CEO Andy Marsh told Hart Energy in a statement. "We are about to put ample resources into the country to allow us to get to FID [final investment decision] by 2025-2026."

Based on Plug Power's experience building a green hydrogen plant at the Port of Antwerp, Marsh said the plants would cost about 2.5 million euros to 3 million euros per megawatt (MW). At 2.2 GW, that's equivalent to about US$6 billion to US$7 billion.

The company said it has started talks with financial investors and debt providers as well as industrial partners to seal offtake agreements. Like other renewable asset financing, Plug said it anticipates the capital structure will mostly comprise non-recourse debt.

SOLAR

US Achieves Quarterly Record for Solar Installations

Alleviated supply challenges helped push U.S. solar energy installations to a record 6.1 GW during first-quarter 2023, up 47% from a year earlier, according to a joint report released by the Solar Energy Industries Association and Wood Mackenzie

The growth came as delayed utility-scale solar projects came online and the Biden administration continued efforts to strengthen the sector with incentives, including those from the Inflation Reduction Act (IRA).

"Each segment had a record-setting first quarter, except for community solar, which faced interconnection and siting challenges in several key state markets," the report states. "The residential segment set a first-quarter record and would have likely set another overall quarterly record had it not been for intense rainstorms that hampered installation crews."

With 1.46 MW of utility-scale solar installed during the first quarter, Florida was the top solar market, the report showed. The amount installed was 72% more than the second-ranked state, California.

The report pointed out that overall installations were down, including for utility-scale solar, compared to fourth-quarter 2022; however, first quarters are typically slower than the end-of-the-year rush to install projects.

Wood Mackenzie forecasts installed solar capacity to rise to 378 GW by 2028, tripling in size.

WIND

TotalEnergies, Kazakhstan Sign PPA for $1.4B Wind Project

Kazakhstan has signed its largest power purchase agreement to date with TotalEnergies—a 25-year agreement for the 1-GW Mirny onshore wind project, the energy company said.

The $1.4 billion project, which will include a 600 megawatt-hour battery energy storage system and about 200 turbines, will be located in the Zhambyl region of north Kazakhstan. All electricity produced, enough for an estimated 1 million people, will be sold to Kazakhstan's Financial Settlement Center of Renewable Energy.

TotalEnergies CEO Patrick Pouyanné said the project is a significant milestone for the company's multi-energy strategy.

"As a global energy leader, TotalEnergies is proud to drive the energy transition in Kazakhstan through such an innovative project as Mirny," said Pouyanné. "This wind and battery project will contribute to the supply and security of the Kazakh power grid."

TotalEnergies said it is developing the wind project in partnership with National Wealth Fund Samruk-Kazyna and the National Company KazMunayGas. The project is expected to avoid about 3.5 million tons of CO_2 emissions annually during the 25-year PPA.

BOEM Completes Environmental Review of GoM Wind

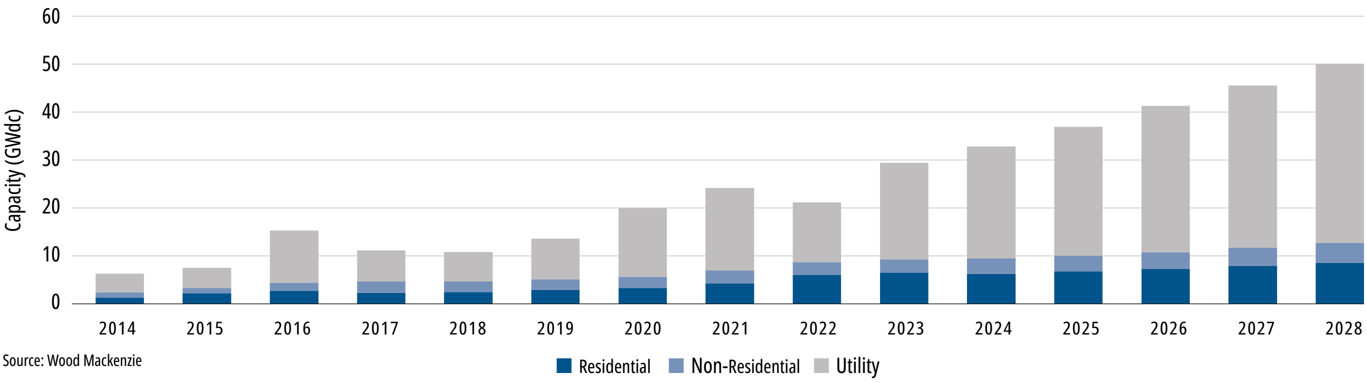
The U.S. Bureau of Ocean Energy Management has found no significant impacts to environmental resources in its analysis of offshore wind leasing in the Gulf of Mexico (GoM).

"The completion of our environmental review is an important step forward to advance clean energy development in a responsible manner while promoting economic vitality and well-paying jobs in the Gulf of Mexico region," said BOEM Director Liz Klein. "We will continue to work closely with our task force members, ocean users and others to ensure that any development in the region is done responsibly and in a way that avoids, reduces, or mitigates potential impacts to ocean users and the marine environment."

In February, the Interior Department proposed its first-ever offshore wind lease sale in the GoM as it continues efforts to deploy 30 GW of offshore wind by 2030.

The proposed wind lease sale in the GoM, home to vast oil and gas production, would open 102,480 acres offshore Lake Charles, La., and two areas offshore Galveston, Texas—one for 102,480 acres and the other for 96,786 acres—for wind development. Combined, the areas could power nearly 1.3 million homes with clean energy, according to the Interior Department. OGI

US solar PV installations and forecasts by segment, 2014-2028



Source: Wood Mackenzie

For Argentina, LNG Exporting Glory is the Gooooaaallll!

After achieving a World Cup triumph, the country now chases a natural gas victory as it looks to monetize the massive Vaca Muerta formation—but much-needed foreign investment remains a challenge.

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NEUQUEN, Argentina—Argentina's plans for a 25 million tonnes per annum (mtpa) liquefaction facility could convert the country into the second-largest LNG exporter in the Latin American and Caribbean region and fourth in the Americas when the U.S. and Canada are included, according to Rystad Energy data compiled by Hart Energy.

The first stage of the facility will have an installed capacity of 5 mtpa, with subsequent stages to add 20 mtpa, according to state-owned YPF. But to get there, Argentina first needs to attract capital from wary foreign investors—something the country is trying to rectify through changes to Argentina's laws.

YPF and partner Petronas, the Malaysian energy giant, look to have the first module installed by 2028, YPF CEO Pablo Iuliano told Hart Energy in May. Iuliano said the estimated cost of the completed facility is between $1,100 and $1,200 per tonne, or between $27.5 billion and $30 billion excluding additional infrastructure investments.

Argentina is home to the largest shale operations outside North America. YPF believes Argentina has sufficient gas resources to become a sizable LNG exporter, and from 2028 to 2050 looks to maximize monetization of the country's Vaca Muerta or "Dead Cow" shale gas in the form of LNG.

The Argentine facility will allow the companies to meet global gas demand and replace dirty energy with cleaner sources and reduce CO_2 emissions. Importantly, it will allow Argentina to reduce its dependence on costly LNG imports in winter months, boost its energy security and subsequently become a major LNG exporter.

As it stands, the proposed facility would be on par in size and price with the 27.6 mtpa Driftwood LNG LLC facility under construction in Lake Charles, La. That facility, being developed by Tellurian, carries a price tag of $1,300/tonne, or roughly $36 billion.

But it's never been easy-peasy for Argentina financially, economically or politically to get anything done in a seemingly straightforward manner. Like its national football team, the country might have to suffer before being able to claim LNG exporting glory.

The future of the project hinges on an LNG bill submitted to Congress guaranteeing investments and legal security, Iuliano said.

Argentina's Energy Secretariat

Argentina's economic minister Sergio Massa (left) and the country's energy secretary Flavia Royón (right) talk with Argentina's President Alberto Fernández (seen on screen) about the completion of the President Néstor Kirchner Gas Pipeline (GPNK).

"The law is necessary to carry out the project; it's what generates the conditions for it to be feasible and executable. In the meantime, we're investing in engineering and initial studies. Once the law is approved, we'll be ready to make an investment decision, which [we plan to make in] 2024."

YPF and Petronas signed a memorandum of understanding (MOU) on Sep. 1, 2022, to start feasibility studies for a liquefaction facility. And approximately 1,500 hectares have been reserved for a port at Bahía Blanca near Buenos Aires province with access to the Atlantic Ocean, YPF revealed in a corporate presentation on its website.

But YPF confronts headwinds on various fronts. Financially, it has $6 billion in net debt with a busy principal and interest payment schedule over the next five years. As such, the facility is reliant on foreign direct investment—and more of it—to move Argentina's LNG plans forward.

On the macro level, financial analysts expect Argentina to register triple-digit inflation this year (it was 8.4% in April). Argentina's currency remains overvalued and capital controls are constant, limiting foreign companies' ability to move money out of the country.

Argentine presidential elections are in October. Polls from consultants such as D'Alessio-IROL/Berensztein or Jorge Giaccobe point to a shift in the political landscape from

Argentine workers wave the country's flag as they celebrate completion of work on the President Néstor Kirchner Gas Pipeline (GPNK).

Argentina's Energy Secretariat

statist policies toward a more pro-market orientation. Despite a potential ideological shift, major course corrections are not expected.

These uncertainties across the board will test Petronas' nerves and other companies watching the LNG developments in Argentina, but still somewhat trigger-shy about making multi-billion-dollar investments.

Legal security in question

As an exporter, Argentina is just learning to walk. Its first step will be to supply gas to Chile and Bolivia, Gas Energy Latin America director Álvaro Ríos Roca told Hart Energy in May. According to Ríos Roca, it could take at least seven years before the first Argentine LNG cargoes reach international markets.

"The big problem for Argentina is legal security. Long-term contracts of 20 years must be signed, and Argentina has contracting problems in Chile, so the long term will cost even more," Ríos Roca said. "Countries in the region tend not to comply with contracts. We have to see if this LNG law attracts that investment. But outside the law, we have to see who dares to bring in $5 billion or $10 billion to structure a dedicated gas pipeline and LNG plant when companies are still not allowed to take out their profits.… a law by itself is not enough."

Ríos Roca, who also served as Bolivia's hydrocarbon minister from 2003 to 2004, estimates the Argentine liquefaction facility could function with a $10/MMBtu price in a stable market before deducting $2 for transportation and $3 for liquefaction.

Argentina's regional market is limited, and to fully develop Vaca Muerta, terminals need to be developed, Consultora Economía y Energía Director Nicolas Arceo told Hart Energy.

Arceo said the Argentine liquefaction project, which may have three trains, could take eight to 10 years to complete.

"[That's possible], if there is an appropriate legal framework and favorable conditions. In concrete terms, the only thing signed, and which is very preliminary, is the MOU with Petronas. The rest doesn't exist," said Arceo, who worked briefly with YPF and Argentina's economic and planning ministry.

"The commercial outlet is through the Atlantic. It's logical, and the transport costs from Bahía Blanca or San Antonio Oeste to Southeast Asia in particular, aren't higher than those of the Gulf of Mexico, mainly because you aren't crossing the Panama Canal," Arceo said. "Therefore, there isn't a serious location problem."

"Petronas will provide the technology and floating liquefaction terminals in a first stage, then collaborate investments for the development of onshore facilities. This implies buying gas from other producers since it's difficult for YPF alone to guarantee the total volumes required," Arceo said.

Massive shale gas potential

Argentina's push for LNG export glory will compete for investors in Mexico, which is looking to bring to market almost 45 mtpa by 2030. Brazil with its pre-salt resources and Guyana, which has recently found oil and associated gas, are seemingly years away from developing their gas resources, but eying the potential.

Argentina has technically recoverable shale gas resources of 802 Tcf, according to the U.S. Energy Information Administration second only to China with 1,115 Tcf. Argentina's Neuquén Province, home to the Vaca Muerta formation, holds 308 Tcf.

Connection work along the GPNK

Argentina's Energy Secretariat

As such, the Vaca Muerta contains 53% of Neuquén's shale resources or 38% of Argentina's total shale resources.

These figures put the Vaca Muerta on par with the Permian, which holds around 297 Tcf, according to Rystad Energy.

Average oil production in Neuquén could reach 750,000 bbl/d in 2030 compared to around 380,000 bbl/d in 2022, according to Argentina's Tecpetrol. Gas production in 2030 could reach 5 Bcf/d compared to around 3.3 Bcf/d in 2022.

But getting there will not be easy. Neuquén province governor Omar Gutierrez has said recently that industrial development of the Vaca Muerta needs to reach 25% (compared to below 10% now) to reach 2030 goals.

Argentina also needs to address its regulatory framework and fiscal conditions, foreign exchange and macro-economic predictability, as well as create clear and sustainable rules, argue executives from Shell, Chevron, TotalEnergies and Exxon Mobil, all active in the Vaca Muerta.

LNG infrastructure and doubt

Steps to close the infrastructure gap, a major headwind in Argentina's path to becoming a major LNG exporting hub, continue to move forward.

Argentina supposedly completed the first 573-km tranche of the President Néstor Kirchner Gas Pipeline (GPNK), which in its initial stage extends from Tratatayén, the heart of Vaca Muerta, to the town of Salliqueló in the province of Buenos Aires. Investment in the segment was nearly $2 billion, according to a statement in May by Flavia Royón, Argentina's energy secretary.

Technical workers involved in the project tell Hart Energy differently.

"Right now, we are finishing the first stage, and the reversal of the North Gas Pipeline will be added, allowing gas from Vaca Muerta to reach the northern region of the country," Royón said. "Afterwards, a bidding process will be initiated for the second stage of the GPNK, which will extend from Salliqueló to San Nicolas in the province of Santa Fe."

Completion of the GPNK could allow Argentina to satisfy domestic gas demand without depending on Bolivian gas, which is declining and will stop flowing when a contract ends in 2024. Additionally, Argentina can start to supply gas to neighboring countries, particularly Brazil, which currently relies on Bolivian gas and LNG imports.

Many in the global LNG sector are following the developments in Argentina since gas from the Vaca Muerta formation competes head-to-head with the U.S. Permian Basin on several levels, according to a report by McKinsey & Co. On other levels, the Vaca Muerta is even superior, according to Tecpetrol.

In theory, Argentine shale should compete with U.S. shale, Poten & Partners senior adviser Gordon Shearer told Hart Energy. But it has one major headwind.

"I think the problem there is it's politically challenging," said Shearer, co-author of the book "LNG: After the Pandemic," who added that the idea around exporting Vaca Muerta gas has been around for more than 25 years.

"Argentina has had a very erratic history. I'm not sure I've seen anything political that tells me that's changed," Shearer said. OGI

Pitts: Can LatAm Really Change its LNG Import Mentality?

The Latin America and Caribbean region has the potential—in theory—to change its dependency on LNG imports amid rising production and bilateral trade.

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The Latin America and Caribbean (LAC) region is primarily geared up to import LNG, not export it. The two exceptions are Peru with its Peru LNG facility and twin island Trinidad and Tobago with its Atlantic LNG facility. But, in theory, proposed liquefaction projects could revert the LAC region's import reality. To what extent it materializes in practice is another question.

Currently, the LAC region has regasification capacity of around 72 million tonnes per annum (mtpa), according to the Gas Exporting Countries Forum (GECF). And the countries with the largest populations and economies are home to the bulk of the LAC region's regasification capacity. Brazil accounts for around 40% of this capacity; Mexico, 24%; and Argentina, 12%.

And at least 15 mtpa of regasification capacity is under construction, with 12 mtpa alone located in Brazil, according to the GECF. This, despite exploration successes in recent years in the prolific pre-salt region offshore. At most, Brazil needs to hedge its bets until it can build-up its domestic gas infrastructure. In the meantime, it needs assurance it can import gas if need be.

Despite this massive regasification capacity, actual and planned, the LAC region's utilization capacity averaged around 25% in 2021, according to the GECF. The reasons vary across the LAC region's big economies.

Argentina is boosting oil and gas production from its Vaca Muerta ("Dead Cow") shale formation, albeit slowly due to infrastructure bottlenecks. Likewise, Brazil's import dependency falls drastically when the country doesn't experience drought conditions and its dams are sufficient to produce energy and reduce the need to import LNG. Brazil also still has access to piped-gas from Bolivia and potentially Argentina. Mexico is better located geographically, which affords it the easy access to cheap piped-gas from the U.S. Permian Basin.

Major headwinds

All told, LNG exporters face the threat of losing market share as LAC transitions from a LNG importing region to an exporting region.

But getting there will not be easy. Investors across Argentina, Brazil and Mexico will face political headwinds with changing governments and ideology-driven priorities, as well as economic and financial headwinds that encompass subsidies, overvalued currencies and repatriation of funds.

Another major consideration: international oil companies active in the LAC region are also changing priorities in response to the energy transition and the push to net-zero emissions.

Enter Argentina and Mexico with plans that could, in theory, anchor the LAC region's emergence as an LNG exporter over the near-to-medium term.

Plans floated by Argentina's state oil company YPF, in partnership with Malaysia's Petronas, to move forward an LNG export project could see the country add 25 mtpa of liquefaction capacity. Beyond the political, economic and financial constraints that confront Argentina's national oil companies, the biggest below-surface headwind is a lack of infrastructure to move the country's massive shale production to the coast for export.

Plans in Mexico to export LNG could see the country add 32 mtpa of liquefaction capacity, according to Rystad Energy, or up to 45 mtpa, according to BTU Analytics.

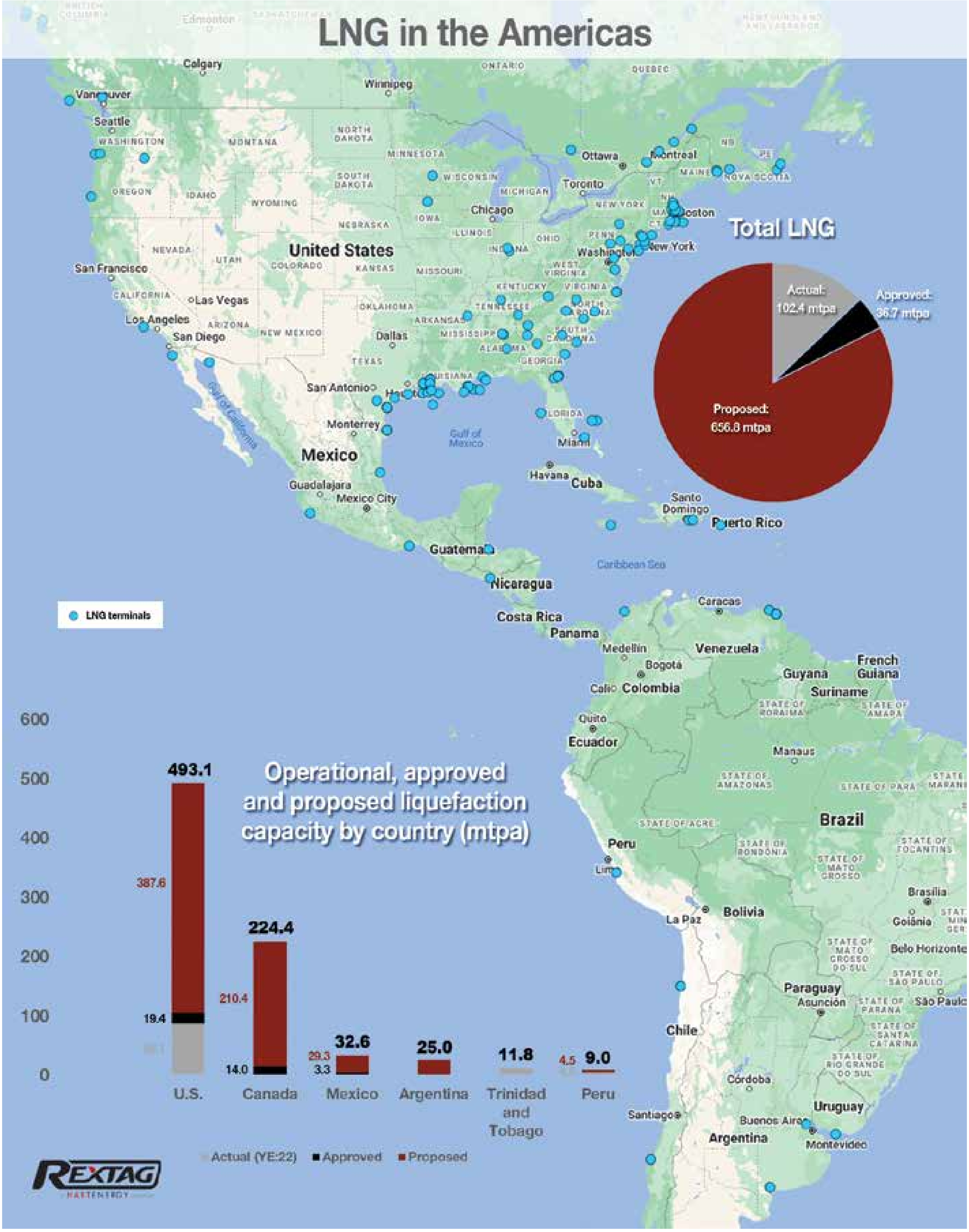
But unlike Argentina, Mexico has an advantage on two fronts.

First, the planned liquefaction projects have been proposed by private companies with foreign capital, a factor that boosts the potential of many of them to get across the finish line since that would reduce the burden on state-owned Petroleos Mexicanos (Pemex) to fund infrastructure projects.

Second, the planned projects will source gas from the prolific U.S. Permian Basin, thus further reducing Pemex-related funding pressures to increase production to feed the projects.

But lurking in the region are Guyana and Suriname, neighboring countries in northern South America with plans to add significant liquefaction capacity in the future.

The potential to add liquefaction capacity in the LAC region is real. While Argentina



Source: International Gas Union, Hart Energy

and Mexico are seemingly moving the fastest with mega-liquefaction potential, Brazil is not far behind. Then, there's always the sleeping giant in the region, Venezuela, home to massive non-associated gas reserves but hampered by political stalemate, U.S. sanctions and all-around investor uncertainties.

So, what's the likelihood that Argentina and Mexico achieve their goals?

It depends on the risk factor applied. My risk adjusted figures: 50% for Mexico and 30% for Argentina. OGI

Driftwood LNG's Got it All ... Except Customers

Tellurian's proposed 27.6 mtpa LNG export project is pursuing $2 billion in financing but, as a Poten & Partners executive says, "in the absence of customers, you don't have a project."

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Tellurian's Driftwood LNG project in Lake Charles, La., has one fundamental problem that is holding back its development, Poten & Partners senior advisor Gordon Shearer said.

In a word: clientele.

"It doesn't have enough customers to underwrite the investment, and in the absence of customers, you don't have a project. And that's true for a lot of U.S. projects—they don't have enough customers," Shearer told attendees at a May forum in Houston.

Driftwood is seeking up to $2 billion in financing from equity partners to move the project forward, Tellurian Executive Chairman Charif Souki reiterated in late April.

Driftwood LNG is being developed in two phases. Phase I could provide 11 million tonnes per annum (mtpa) by early 2026 and Phase II could add another 16.6 mtpa. The estimated cost for Phase I is around $14.5 billion, Tellurian revealed in May 2023 in a corporation presentation.

"None of the North American projects are going to be financed on somebody's balance sheet 100% with corporate funding; it just doesn't happen," Shearer said.

The executive said Golden Pass could be an exception since it's being backed by Qatar Petroleum and Exxon Mobil.

"And for them, project financing is probably an option, but for everybody else project financing is a necessity, not an option," Shearer said.

Shearer said the problem with LNG relates to commoditization since there was no real commodity market.

"If it was an oil product project, and it met the oil price criteria, it'd be easy to finance because everybody is familiar with oil pricing—it's liquid, it's transparent. [On the other hand], it's LNG. It doesn't have liquidity, it doesn't have transparency. You build it, they may not come—or if you export it, they may not get unloaded."

Michael D. Tusiani, Poten & Partners chairman emeritus, was optimistic about U.S. LNG projects. During the forum, he said the model was great and suffered from an "insurance problem" more than anything.

"You're a long-term buyer of LNG, no minimum requirement. You pay a fee to the insurance premium, right? So, I think that when buyers look at that, they look at the U.S. very favorably because you have something that's very unique," Tusiani said.

Mexico and the Permian

Shearer fielded questions about the global LNG industry and Mexico, and its plans to use U.S. piped-gas imports to supply a number of Mexican LNG export facilities.

Robust production from shale gas has helped anchor higher U.S. LNG exports to Europe amid a supply glut caused by the Russia-Ukraine conflict. Shale producers near the U.S.-Mexican border, especially in the Permian Basin, have also benefited from steady gas demand south of the border.

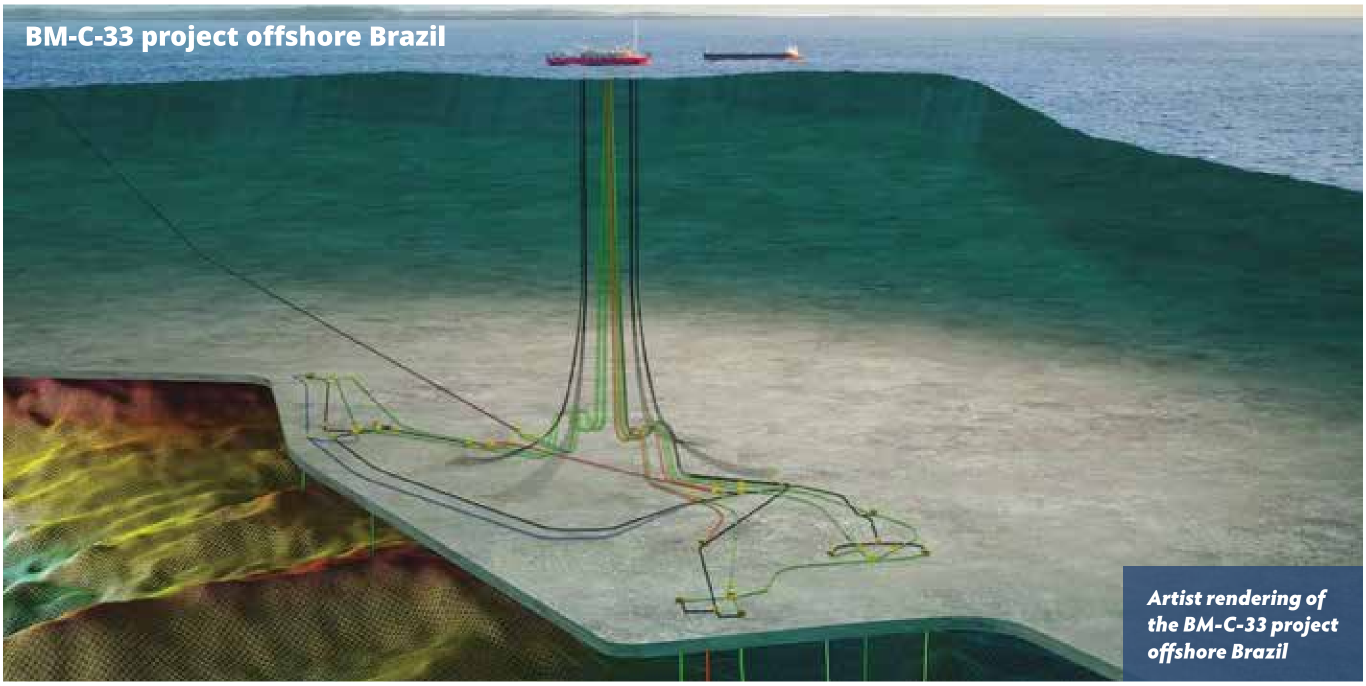
There, U.S. piped-gas exports to Mexico averaged around 5 Bcf/d in April of 2023, according to data from the Energy Information Administration. There's potential for that figure to rise by about 6.1 Bcf/d to feed planned Mexican LNG export facilities, according to a recent study by BTU Analytics.

At least four facilities are planned for Mexico's Pacific Coast. These facilities are advantaged since their cargos would bypass the Panama Canal, which has become a bottleneck for U.S. LNG exporters, Shearer said in response to a question by Hart Energy.

"So, exports off the West Coast of Mexico do make sense. You've got to get the gas there, which is not always trivial and means you've got to go through Mexican permitting as well as U.S. permitting," Shearer said.

"And, frankly those projects are going to be Asia-focused. They're not going to have that option really of supplying Europe … they're not going to be competitive," he said. "So, they are going to be 100% Asia-focused projects, just like LNG Canada is or any other British Columbia project. Are there enough locations in Mexico to support big industry? That's an open question. And that's Permian gas and that's almost more a function of what the Permian does, too." OGI

Around the World



Artist rendering of the BM-C-33 project offshore Brazil

Source: Equinor

BRAZIL

Equinor, Repsol and Petrobras Reveal $9B FID Offshore Brazil

Norway's Equinor along with partners Repsol Sinopec Brasil and Petrobras announced a $9 billion FID to develop the BM-C-33 project offshore Brazil.

The project, slated to start up in 2028, will utilize an FPSO with a production capacity of 16 MMcm/d with expected average exports of 14 MMcm/d, Equinor said in a press release in early May.

"BM-C-33 is one of the main projects in the country to bring new supplies of domestic gas, being a key contributor to the further development of the Brazilian gas market," Equinor Brazil country manager Veronica Coelho said in the release. "Gas exported from the project could represent 15% of the total Brazilian gas demand at start-up."

BM-C-33 is located in the Campos Basin and comprises three different pre-salt discoveries—Pão de Açúcar, Gávea and Seat. Combined, the discoveries contain recoverable reserves in excess of 1 billion boe.

Enauta Adds to Atlanta Reserves

Enauta Participações confirmed oil through the 9-ATL-8DP well in a new reservoir section, the Atlanta NE accumulation, offshore Brazil.

Atlanta NE is in the larger Atlanta Field, which is under development. Enauta estimates resources in place exceed 230 MMbbl, the company announced late May. Drilling and logging of the well are complete, and more studies are planned.

Enauta is developing the Atlanta Field with an FPSO in water depth of 1,500 m. The six wells connected to the *FPSO Atlanta* are expected to produce up to 50,000 bbl/d, with Phase 1 first oil expected in mid-2024.

Petrobras Brings Búzios 5 FPSO Onstream

Petrobras brought the fifth of 11 planned FPSOs online in its massive pre-salt Búzios Field offshore Brazil.

Petrobras and field partner CNOOC announced late May that the development in the Santos Basin in water depth of 1,900 m to 2,200 m had begun production to the *FPSO Almirante Barroso*, chartered from MODEC. The FPSO has storage capacity for 1.4 MMbbl. It was converted in China and arrived at the oilfield in February.

The P-74, P-75, P-76 and P-77 FPSOs in the Búzios, the world's largest deepwater field, are jointly producing 600,000 bbl/d. Búzios 5 has five production and five injector wells, which will produce up to 150,000 bbl/d, 6 MMcm/d and inject 220,000 bbl/d of water, according to CNOOC.

The *Almirante Tamandare* is expected to begin production in 2024, the P-78 and P-79 in 2025, the P-80 and P-82 in 2026 and P-83 in 2027.

"By 2025, when the Almirante Barroso FPSO will be close to its maximum capacity and we will have the entry of other units, the field's production should reach close to the 700,000 bbl/d mark," Petrobras CEO Jean Paul Prates said in a press release.

Petrobras Hits Hydrocarbons in Aram Block

Petrobras found hydrocarbons in a pre-salt appraisal well in the Aram Block of the Santos Basin offshore Brazil.

Well 3-BRSA-1387D-SPS, in water depth of 1,979 m, was still in progress at the time of the announcement, Petrobras revealed in mid-May. Petrobras said the oil-bearing interval was verified through wireline logging and fluid samples, which will be further characterized through laboratory analyses. The data will enable evaluation of the area's potential and help direct exploratory activities in the area, according to Petrobras.

The discovery augments the possibilities of expanding the accumulation discovered by the wildcat well 1-BRSA-1381-SPS in the block, according to Petrobras.

Petrobras operates the block with 80% interest on behalf of partner CNPC with 20%.

FSO Pargo Moored in Campos Basin

Perenco Brazil said that hook-up of the FSO vessel for the Pargo project in the Campos Basin is complete.

The hook-up included the connection of nine mooring lines and the new production line from the Pargo platform, Petrobras announced. The lines will connect to the new turret, which was integrated in Dubai as a key part of the FSO conversion. The *FSO PARGO*, which has 750,000 bbl of storage capacity, will serve the Pargo Cluster offshore Brazil.

Perenco said it will next submit its documents to Brazilian regulatory authorities for the FSO's operations license.

COLOMBIA

Report: Colombia's Oil, Gas Reserves Running Out

Colombia will run out of gas in 7.2 years and oil in 7.5 years, according to new data revealed by the country's National Hydrocarbon Agency (ANH).

The alarming figures come as Colombia struggles to boost reserves and production owing to a lack of conventional resources and incentives to entice investors. Colombia has significant non-conventional resources, but hydraulic fracturing is not an option under the government of President Gustavo Petro.

Unless Colombia can attract investments to boost its oil and gas reserves or dramatically boost production of renewable energy sources, the country will be forced to rely increasingly on imported energy.

Colombia currently imports LNG via a terminal in Cartagena on its Caribbean coast. Another terminal slated for Buenaventura on its Pacific Coast could be tapped in the future.

Colombia's proved gas reserves reached 2.82 Tcf in 2022, while production was 392 MMcf. In 2021, reserves were 3.16 Tcf and production was 395 MMcf. Colombia's gas R/P ratio of 7.2 years in 2022 slipped from the 8.0 years registered in 2021. In 2015, the figure was 9.9 years.

On the oil side, reserves reached 2.07 Bbbl in 2022, while production was 275 MMbbl. In 2021, reserves were 2.04 Bbbl and production, 269 MMbbl. Colombia's oil R/P ratio of 7.5 years fell from 7.6 years in 2021. In 2015, the figure was 5.5 years, according to ANH data.

GUYANA

Trendsetter Tapped for Guyana Connectors

Trendsetter Engineering won a contract to provide Esso Exploration and Production Guyana with TC11 Connection Systems for the gas-to-energy project in Guyana.

The contract includes Trendsetter's TCS subsea connectors, hubs and an assortment of pressure caps and tooling, the company announced in May. The contract also includes subsea valves, sourced from Advanced Technology Valve (ATV) in Italy. The equipment is slated for delivery in mid-2023.

Uaru Umbilical Goes to Aker Solutions

Exxon Mobil awarded Aker Solutions the contract for the dynamic and static subsea umbilical for the Uaru project offshore Guyana.

Under the contract, Aker Solutions will deliver three dynamic and seven static umbilicals totaling more than 52 km in length, the company said in May. Project execution, engineering and manufacturing will take place at the Aker Solutions facility in Mobile, Ala. The work begins immediately, with delivery planned for first-quarter 2026.

Previously, Aker Solutions received the umbilical awards for the Payara and Yellowtail projects.

MEXICO

Pemex Eyes Production from Macuil #201 Exploration Well

Mexico's state oil company Petróleos Mexicanos (Pemex) expects to ramp up light oil production from its recent Macuil #201 exploration well later this year.

"This is where we are applying our early production strategy … and working on construction of a pipeline that will allow [us] to bring production online from the well in December" 2023, Leonardo Enrique Aguilera Gómez, Pemex exploration sub-director, said in June.

"Seismic processing, applying state-of-the-art algorithms and technological concepts have allowed the company to improve underground images and strengthen the portfolio of exploratory opportunities in the Tabasco coastal region," Aguilera said.

The Macuil #201 exploratory well was drilled in a record 40 days without setbacks or problems, Pemex operations engineer David Salas Santos said.

Pemex didn't provide details or production estimates for the well. Its media department team didn't immediately reply to a request for seeking details.

However, initial production from the nearby Macuil #101 exploration well was 457 bbl/d, according to details in Pemex's first-quarter 2023 operational report on its website. Pemex's oil production, including condensates, was 1.85 MMbbl/d in the first quarter.

In the Tabasco region, Pemex has identified 44 exploration possibilities with a prospective resource base of around 2 Bboe, which "could translate into work and production for many more years," Pemex CEO Octavio Romero Oropeza said in the video.

SURINAME

TotalEnergies Signs PSCs for Suriname Blocks

TotalEnergies and its partners have signed PSCs for Block 6 and Block 8 with state-owned Staatsolie Maatschappij Suriname.

The two blocks were awarded to TotalEnergies in the Suriname Shallow Offshore Bid Round 2020-2021, the French company announced in May. TotalEnergies will operate the two blocks with a 40% interest on behalf of QatarEnergy with 20%, and Staatsolie subsidiary Paradise Oil with 40%.

The blocks are located in the southern part of offshore Suriname, close to the border with Guyana in water depths of 30 m to 50 m. The blocks are adjacent to the operated Block 58 where several discoveries have been made and appraisal drilling is ongoing, TotalEnergies said. OGI

▸ TECHNOLOGY

EQT Walks the Walk in Mission to Curb Emissions

Promotion of natural gas as a low-carbon energy transition fuel has focused the company on delivering fully auditable net-zero products to its customers by 2025.

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EQT, with its aggressive promotion of natural gas to fuel the energy transition, is taking a multi-faceted approach to meet its goal of achieving net-zero emissions status in 2025.

The company says it has made significant progress since making its pledge in 2021 and has picked up some third-party certifications. But because it also wants long-term trust from its customers, EQT is working on ways to accurately and transparently quantify its carbon emissions—and its offsets.

Rob Wingo, EQT's executive vice president of corporate ventures, told Hart Energy that the company is working on a number of decarbonization initiatives, including carbon capture, utilization and sequestration, carbon credits and offsets.

When the company made its pledge in 2021, Wingo said, it was very early in the life cycle of the decarbonization effort.

"At the time, we had spent some time and capital to decarbonize," he said. "But as soon as we made that pledge, we immediately ramped up our efforts to decarbonize our operations, and then we started working on plans to generate offsets to get us to net zero."

EQT has certified 3.3 Bcf/d of its natural gas under both Equitable Origin's EO100 Standard for Responsible Energy Development and non-profit MiQ's methane standard.

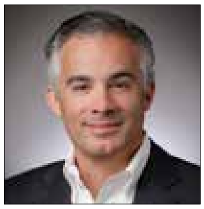
The company says it can deliver net-zero products to its customers and do so transparently.

"Right now, the biggest problem as we see it, is that customers don't trust that nature-based carbon offset projects are actually removing carbon from the atmosphere," he said. "So what we want to do is actually give them measurements, quantify it in a way that they can come in and evaluate it and see exactly what we're doing."

Because emissions occur at many places from the wellhead to the end-user, Wingo said the only way to calculate the carbon intensity is by gathering the emissions data "from everybody who touched it along the way."

Emissions and context

Initially, EQT considered building a system that would track that information, but around the same time, the company became aware of Context Labs, which has a software platform that gathers emissions data from multiple sources to calculate path-specific carbon intensity.



"Right now, the biggest problem as we see it, is that customers don't trust that nature-based carbon offset projects are actually removing carbon from the atmosphere."

—**Rob Wingo**, *executive vice president of corporate ventures, EQT*

EQT announced in early April it was partnering with Context Labs to advance the commercialization of verified low-carbon intensity natural gas products and carbon credits.

"It would be impossible for us to create something that would be better, and it would take us years to get there," he said. "They already had this up and going."

The company has begun implementing Context Labs' decarbonization-as-a-service platform across its asset footprint, he said.

Plus, he added, it has the benefit of being a third party, which "brings a veracity to the data."

"If we can calculate our carbon intensity transparently in a way that can be audited by third parties, and we can bundle our low-carbon intensity gas and our other low-carbon energy products that we manufacture with carbon offsets to get the carbon intensity down, we think we can deliver net-zero products to customers to the extent there's demand for that in a way that's fully auditable, fully transparent, and we think there will be huge demand for that," Wingo said.

With transparent carbon intensity calculations, EQT can bundle those metrics with its natural gas products and its carbon offsets to reach the adjusted carbon intensity and retire those particular offsets, he said.

"When you take credit for an offset, you have to make sure that offset gets retired. You need

EQT

EQT's first nature-based project was Wheeling Park in West Virginia, where EQT did invasive species removal and planted trees.

EQT

Nearly 9,000 pneumatic controllers were replaced or retrofitted with primarily electric actuators and air compressor installations on all EQT production locations and compressor stations.

EQT

The soil probes from Teralytic can continuously measure phosphorus, potassium, carbon and other nutrients in soil and remotely communicate that data at 15-minute intervals for nature-based carbon offset projects.

a system to make sure you're not double counting," he said.

Context Labs' dashboard allows end-users to select the least carbon-intense products, he added.

One of the major steps EQT took after targeting net-zero emissions by 2025 was to change out all of its natural-gas driven pneumatic devices, replacing them with air- or electric-operated equipment. That $29 million project, announced in June 2021 and lasting through year-end 2022, replaced nearly 9,000 devices. The company credits the change out with reducing its annual carbon footprint by the equivalent of more than 300,000 metric tons of CO_2.

EQT's natural carbon offsets

One way EQT expects to reach net-zero emissions by 2025 is by generating carbon offsets.

"We're doing everything we can to decrease our operational emissions," Wingo said. "But like most industries, there's only so much we can do operationally. So we want to supplement that with nature-based projects to get us to net zero."

EQT's first nature-based project was Wheeling Park in West Virginia, where EQT removed invasive species and planted trees.

But doing the work is only part of the company's efforts. EQT is using probes from soil health firm Teralytic to measure nutrients and carbon in the soil in real time.

"Our plan is to use those probes in our carbon credit generation projects to empirically measure how much carbon we're actually taking out of the atmosphere" through the nature-based projects.

The role of CCS

Carbon capture and storage (CCS) "is where a big part of our focus is going right now," Wingo said. "That's going to underpin everything else we're doing energy transition-wise."

He said the company is using its subsurface expertise to find places to store CO_2.

"The technologies exist to make that happen," he said. "It's really just finding the right rock, and getting the permitting in place."

And use has its role as well.

"Any use cases probably won't be big enough to take all of the CO_2 that we would be generating," he said. "But if we can decrease how much we have to sequester, we would prefer to do that. But ultimately, you're going to have to have a place to store the CO_2 for a long duration."

Wingo said he views the carbon sequestration question as being similar to exploration for oil and gas.

"We're always going to be looking for new places to store CO_2 because we're always going to be producing it and filling up what we know about. So we're going to need constant development, constant finding of new places to put CO_2," he said.

"It's going to be an ongoing effort." OGI

▸ TECHNOLOGY

From Siloed to Optimized: How Exxon Mobil Juiced Its Technology Approach

One year after integrating technology and engineering functions, the supermajor's EMTEC encourages collaboration and improves problem solving.

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What happens when you put a bunch of engineers and scientists together? Technology development "on steroids."

One year after the supermajor integrated its technology and engineering functions to create the Exxon Mobil Technology and Engineering Co. (EMTEC), new and existing solutions are helping to optimize drilling and production operations, help the operator along its low-carbon path and solve technology challenges in the company's other business units.

EMTEC president Linda DuCharme told Hart Energy that the fresh approach has excited the technology and engineering specialists within the company. "We had a technology organization that supported our chemicals organization, another one for fuels and lubricants, another one for the upstream, another one that did research into new forms of energy," she said. "The idea was, let's put all of that together, and let's also take all of our engineering capabilities and put that all together."

The question was how to effectively bring all those different disciplines together, she said.

"The reason we had things separated in the past was because of that intimacy you get between the technical organization and the business itself," she said.

Technical people were focused on technology for a business outcome—but balance was needed to manage the company's technical capabilities more centrally.

"We've built … a bit of a matrix organization in order to achieve that," she said.

A year later, she said, one of the most exciting things about EMTEC, which has an annual $1 billion R&D budget, was that the approach worked.

"You spend so much time designing an organization, and you have so much ambition for not just what you can achieve through the organization, but what the organization is going to be able to achieve," DuCharme said.

The first year has paid off more than the designers could imagine, jumpstarting Exxon Mobil's technology efforts.

"The opportunities that we have when you put a bunch of engineers and researchers all together is they collaborate and they help each other with challenges" rather than operating in silos, she said.

In one example, scientists were struggling with friction on a hydrogen-related technology. A similar problem had been observed in drilling operations.

"We were able to take people from our drilling organization and put them together with people in our process engineering organization, and they figured out how to solve the problem," she said.

Collaborative efforts are now commonplace within EMTEC.

"If somebody has a problem, they can post it on our internal intranet chat board and say, 'Has anybody ever seen something that looks like this?'" DuCharme said. "One of the things you find about engineers and scientists is they love problem solving."

EMTEC: always on

DuCharme is based in the Houston EMTEC facility, but company scientists and engineers are spread out globally: from Kuala Lumpur and Bangalore to Brussels and Shanghai. In addition, EMTEC collaborates with universities, energy centers and national labs around the world, she said.

And at the beginning of May, Exxon's IT organization folded into EMTEC.

"We have over 10,000 scientists, engineers and project managers across a range of disciplines, all over the globe, with a big footprint in Houston," she said.

EMTEC teams have also been able to help better organize data to take advantage of advanced data sciences and machine learning to optimize production. They also use surveillance techniques that take data from the technical support centers around the world.

"We can have people working on that data 24/7 to identify where there are

EMTEC

Linda DuCharme at Exxon Mobil's Europe Technology Center in Brussels, Belgium

EMTEC

Exxon Mobil's Center for Operations & Methane Emissions Tracking (COMET) monitors methane emissions from initial field locations. This project is on track to be one of the most robust continuous methane monitoring programs in the Permian at this scale, the supermajor said.

EMTEC

Liza Unity *is one of two FPSOs vessels currently operating offshore Guyana for Exxon Mobil. Collectively, the two FPSOs are producing an average of 375,000 bbl/d.*

opportunities to optimize production," she said. "We do the same thing in the upstream with our drilling data."

For example, she said, the 24/7 data center looks at all the drilling data coming in from Exxon Mobil drilling operations—from the Permian Basin to offshore Guyana—to identify roadblocks to improving efficiency.

Exxon worldwide

When Exxon started developing its series of projects offshore Guyana, the supermajor committed to ensuring data would be accessible, she said.

"We put in high-speed fiber to all of our FPSOs that allow us to bring 4G and LTE services, not just to our assets, but even to the drillships and the support vessels in the area in Guyana," she said. "Getting all of that data, we can take that data all the way to our tech center in Bangalore so that they can be looking at those data inputs and using some of that technology I talked about in order to optimize production and optimize recovery."

In the past, data was "locked" in multiple applications, which hindered the industry's use of the information.

"Now that we've been able to expose that data and put it in a common platform, we're now able to pull more insights out of that data that are helping us optimize production," DuCharme said.

That effort, she said, was achieved through a combination of collaboration with external partners and some proprietary optimization engines developed by Exxon.

"One of the best values in our organization is actually keeping all the assets that we have in the world operating and operating efficiently," she said.

In the past year, attention has been placed on upstream optimizing production drilling efforts, she said. EMTEC has focused on well spacing, development plans and drilling rates.

"Elsewhere in the upstream, the other focus area has been continuing to reduce our emissions," she said.

Exxon has targeted 2030 to reach net-zero emissions in its Permian operations.

"We've had a lot of innovations and applications of technology that help us make sure that we understand where our emissions are coming from," she said.

Exxon uses a combination of satellite technology and sensor networks to identify methane emissions.

"That's been a big focus for us, figuring out how to make sure that we have a very complete network of those sensors," DuCharme said. OGI

Simonelli Hails 'Unsung Hero' of the Energy Transition

Efficiency will drive the transformation and digital enablement can drive efficiency, said Baker Hughes Chairman and CEO Lorenzo Simonelli, calling for increased collaboration and investment in tech.

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Affordability, sustainability and security of supply: that's the trilemma facing the energy industry as it navigates the energy transition.

Investment in digital technologies is key to driving the efficiency necessary for a successful energy transition—a concept emphasized by industry leaders at the Amazon Web Services (AWS) Energy Symposium.

"Efficiency is the unsung hero of the energy transition. And digital can play a key role in driving that efficiency," Baker Hughes Chairman and CEO Lorenzo Simonelli said.

The International Energy Agency has stated that a 10% efficiency increase in oil and gas operations could reduce CO_2 emissions by 500,000 tons, he said.

"Now, that is significant," he said. "And it's with the capability of digital enablement."

Digital enablement, he said, starts with measuring and analyzing the data. Actions can be taken based on interpreting the information, and the process can be iterative, he said.

"It's often said that knowledge is power. I believe that's only a half-truth. It is applied knowledge that is power, applying the knowledge that you can obtain through the digital enablement of operations to drive better efficiencies as we go forward," Simonelli said.

But, he said, it will take a "mix of lots of different technologies," including digital enablement, to create efficiencies. Some of those will require upgrades or new capabilities, he added.

"One thing that isn't going to change is the demand for energy," he said. "How can we ensure that we can meet the energy trilemma of affordability, sustainability and security as we deploy all of this technology? Collaboration is key."

Baker Hughes has established a number of partnerships. One with AWS resulted in the Leucipa product, which can automate field production solutions on the cloud.

From the 'hamster wheel' to the cloud

Woodside Energy's digital innovation journey with cloud computing started with a simple goal of reducing repetition of tedious tasks, said Daniel Kalms, executive vice president and chief technology officer at Woodside.

For many years, Woodside backed up its seismic data on tape every four years.

"After finishing backing up the seismic data, we had to start again," he said. "We saw moving the storage of our seismic to the cloud was a way to avoid this hamster wheel activity that we did every four years. So we committed to that in 2015 and discontinued tape backups."

The result was a significant reduction in the manual handling of data.

"We now have over 20 petabytes of seismic data stored in AWS," he said. One petabyte is 1,024 terabytes.

The operator's digital journey included other steps, including seismic processing in the cloud.

That "led to the breakthrough in our understanding of Scarborough," a gas field offshore Australia, he said.

"We were able to interpret, visualize and model the reservoir, and we increased the resource from 7.3 Tcf to 11.1 Tcf of gas. Now that's a 52% increase," he said, and it led to a final investment decision on the field.

In 2019, Woodside went "all in" on the cloud and moved all of its subsurface computing to the cloud, Kalms said.

Shell collaborated with AWS through the Open Subsurface Data Universe (OSDU) forum.

Now that the OSDU exists, other oil and gas companies can put their data into AWS in a standardized way, said Jay Crotts, Shell's CIO and executive vice president.

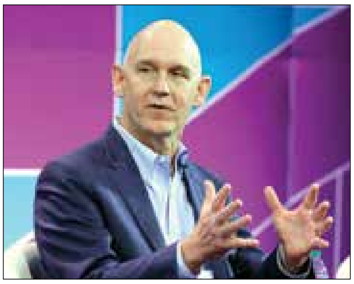
"Now all the applications that are being built by Baker Hughes or others can actually use that same data structure," he said.

Ben Wilson, director of product and solutions, energy, at AWS, called the OSDU forum a "major step forward for breaking down silos of data, proprietary data formats and schema."

Shell is also using AWS for high-performance computing to improve efficiencies.

"With the partnership of Amazon, we can use burst capacity in the cloud and actually look at the earth better than we've ever done before. What does that do? It makes us more efficient. We drill in the right spots, we produce in the right spots, reducing our overall carbon footprint," he said, noting it also is speeding up simulations.

Rather than spending weeks or months on each trial, Shell can now run simulations on Amazon's high-performance computing capacity



"It's often said that knowledge is power. I believe that's only a half-truth. It is applied knowledge that is power."

—**Lorenzo Simonelli**, *chairman and CEO, Baker Hughes*

and "produce better catalysts that make us more efficient in the way that we are producing our hydrogen, which is going to make hydrogen more affordable," Crotts said.

Knowing when to geek out

And while the technology enables companies such as Shell to be more efficient, he said it's not the critical success factor.

"Everyone of us here, everyone on the planet has the technology available. AWS provides it, and we can use it tomorrow. Then why are some of these successful and others are not? It starts with maybe the two bookends that are important for this: cooperation and collaboration," he said.

And as much as he likes to geek out on the technology, Crotts said it's vital to remember to tie the tech to the value the tech enables.

"You'll know we're successful when we celebrate the business outcome more than the technology we bring. Now that doesn't mean I don't love technology, but when we're all geeking out as the technology people, let's do it," he said. "Let's make sure that we're focused on that outcome."

Right now, he said, generative artificial intelligence (AI) is a huge buzzword.

"The challenge is that…[AI] will change the way the world operates. The problem is when will it change and how will it change?" Crotts said.

"A lot of people are comparing it to the early days of the internet," he said.

While the internet has changed a lot in 30 years, he said, the change with generative AI is "happening about five times" as fast.

"Part of that is the accelerated compute [power] that's available in the cloud to enable this," he said. "That transformation is going to affect many industries."

Some people, he said, are simply avoiding generative AI out of fear.

"People should be thinking more about what it can do and err on the side of trying it out, than being afraid to use it," he said. "Now is the time to give it a shot and say, 'Hey, what could it do?'"

Generative AI Speeds Seismic Imaging Workflow

Computer vision is generating subsurface images using a tiny fraction of the seismic shot data that has traditionally been required.

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Generative artificial intelligence (AI) can draft marriage vows and create pictures of penguins playing soccer. It's also useful in the energy sector—capable of generating subsurface images using far less data than previously required.

While massive amounts of computing power are still required for subsurface image generation, machine learning, deep neural networks and computer vision have made it possible to significantly speed up the seismic imaging workflow.

For two years, SparkCognition and Shell have worked together to accelerate seismic imaging using computer vision.

"To their credit, Shell realized this was an open-ended research problem," Bruce Porter, chief science officer at SparkCognition, told Hart Energy. "They brought it to us as outsiders from the oil and gas industry. We're not oil and gas experts. We are machine learning experts. They wanted to see whether this partnership—with our machine learning and their geoscience—whether that could crack the nut."

According to Porter, it did. The result is the SparkCognition Oil & Gas Exploration Advisor software.

SparkCognition holds seven patents on the technologies developed to accelerate seismic imaging workflow. Most of those patents are from the "de-noising" migration process, which clarifies the seismic phase imagery.

How long the seismic interpretation workflow takes largely depends on how much shot data needs to be processed, and SparkCognition's new technology uses between 1% and 3% of the shot data that has historically been used.

"Given a properly trained neural net, if you prime it with some data points—in this case shot data—the neural net can fill in for all of the missing shot data, the other 99% to 97% of the shot data that goes unseen and unprocessed," he said. "The result is these neural nets are able to do what's called the inference step, which is to generate the seismic image. It can do that in a matter of seconds to minutes, filling in for all of these unseen shot data."

The upshot is that the vast majority of data that's been collected does not have to be processed, he said.

"Whether that leads to a next-generation product in which the acquisition of shot data is reduced, that's another matter," he added.

But picking the shots to include takes on more importance when you're using less than 3% of the shots acquired.

As Porter put it, "There are so few of them, the ones you use matter. You can't just choose randomly."

SparkCognition developed a solution to enable the neural networks to select the 1%-3% of shot data that carries the most information and will have the greatest impact in generating an accurate subsurface image. While algorithms run the automated shot selection process, the system is not a complete black box, he said.

Being able to see into the process is important, particularly in light of how wildly off-track some generative AI, such as ChatGPT, have reportedly gone.

Porter said the software generates confidence levels alongside its geological subsurface images, and interpreters can add more shot points and allow it to iterate the new subsurface images with corresponding changes in confidence levels of the image.

"You need the right answer. You need to get the geological substructure correct," he said. "It's important that they not be black boxish. It needs to be one that the human has trust in and can understand where the neural net is being creative in elucidating the geological subsurface and when it's quite certain of its output."

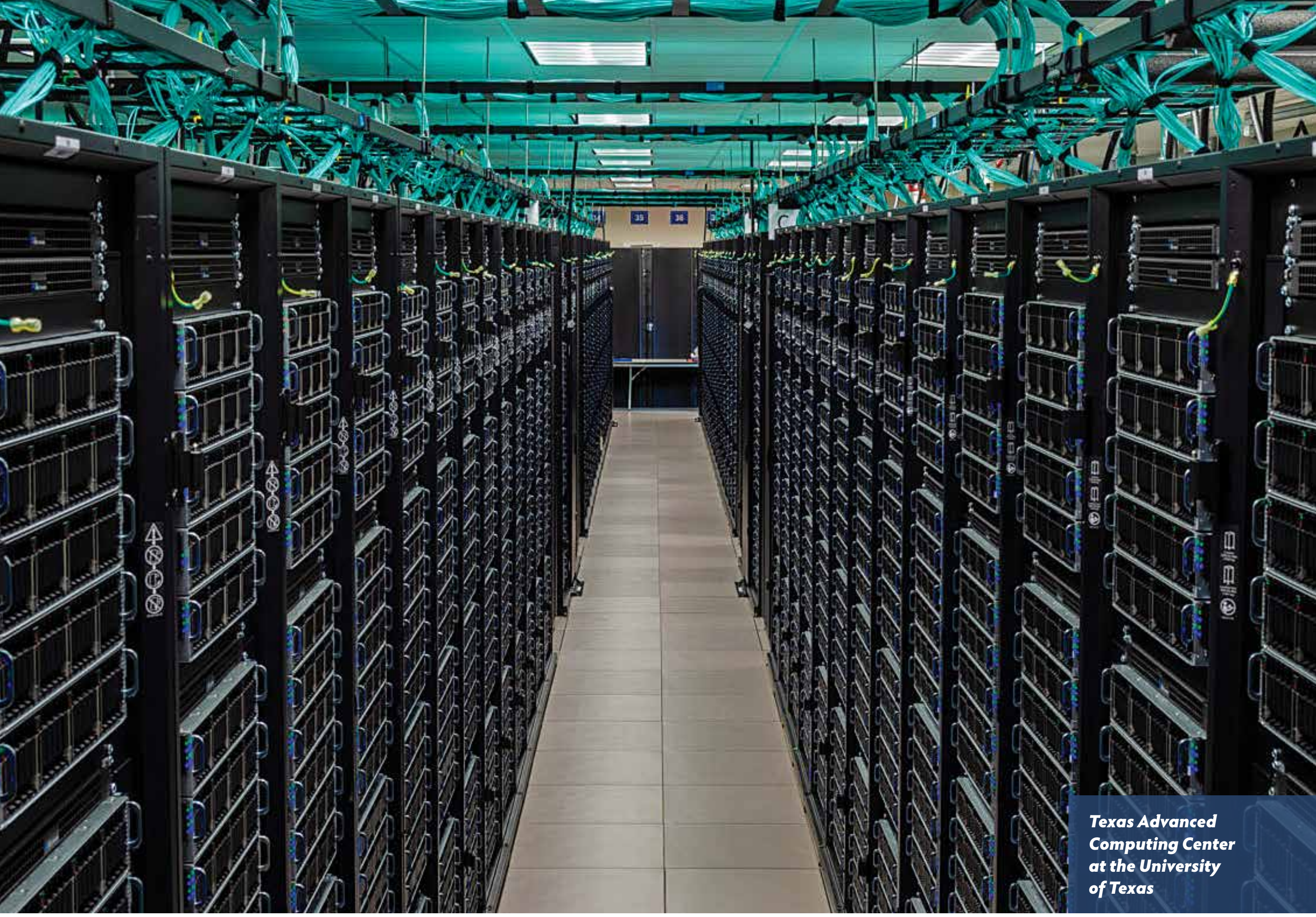
Combined approaches

Machine learning is a big field, and many techniques were potential solutions for this particular computer vision problem, Porter said.

"We tried probably 10 to 12 different families of approaches, not just individual algorithms, but whole classes of approaches to the problem, before we settled on the one that did the best," he said.

But on its own, a generative solution wasn't enough.

"The machine learning, the AI field has



Texas Advanced Computing Center at the University of Texas

University of Texas at Austin

"We're not oil and gas experts. We are machine learning experts. [Shell] wanted to see whether this partnership—with our machine learning and their geoscience—whether that could crack the nut."

—**Bruce Porter,** ***chief science officer, SparkCognition***

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learned over the recent decades that if you approach a problem as complicated as this one using only data, you hit a glass ceiling—and the results aren't great," he said.

Getting through that glass ceiling called for some creativity and finding a way to bring physics—or geoscience—into the solution, he said.

"A hardcore machine learning person is going to say, 'No, I don't want to have anything to do with physics. I'm just going to use the data. I'm going to focus on the data, and my algorithms will derive the right answer,'" Porter said. "Uh, no, I don't think that works. We have to have a way of marrying, combining the influence of geoscience into the neural net so that the neural net is drawing inferences. It's creating images that are geologically plausible, and not only plausible, but correct."

During the companies' collaboration on the de-noising solution, SparkCognition had access to the Texas Advanced Computing Center at the University of Texas.

"Shell has their own supercomputers," he said. "But for our research phase, we depended on TACC."

The technology has been proven on real data from Shell, Porter said.

"We've gotten verification from Shell that the results are very promising, and we are now hardening the software so that it can be released to Shell as a product for deployment," he said.

The SparkCognition Oil & Gas Exploration Advisor will also be made available to other operators, as well. OGI

▸ TECHNOLOGY

E&Ps Push AI, But Will AI Push Back?

From quicker data processing and predictive maintenance to the end of humanity, panelists at SUPER DUG discussed oil and gas developments using AI and machine learning.

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Among the giddy proponents of artificial intelligence (AI)—and the doomsayers—the oil and gas industry increasingly embraces the technology used to process vast caches of data, increase safety and even increase well performance.

As with other innovations, E&Ps have once again joined some of the early adopters to see what it can do. One key benefit: it's a time-saver in an industry drowning in data.

"One of the [philosophies] behind using AI and ML [machine learning] is, any task that requires a lot of human effort, any task that requires a lot of computational effort … can be reduced a lot," said Siddharth Misra, associate professor of petroleum engineering at Texas A&M University, in a panel at Hart Energy's SUPER DUG conference.

That includes some necessary but mundane tasks, such as sorting through terabytes of data.

Data—raw, structured and unstructured—is being captured all the time in the industry, said Ali Raza, chief digital officer at ChampionX. Data analytics can refine the information to increase productivity and monitor a company's assets, including compressors and engines.

The data is so voluminous that it's "too much for [a] human to work … through," said Thomas Johnston, COO at ShearFRAC. So, the company employs a real-time fracture guidance technology known formally as FracBRAIN, and the AI component behind it is nicknamed Shear-i. Johnston later told Hart Energy that the FracBRAIN technology "measures pressure patterns and interprets how the rock is fracturing," and the implementation of Shear-i offers change suggestions to the "rate, proppant concentration and viscosity to more efficiently and effectively fracture the rock."

The technology is expected to have practical applications in the field. During the panel, Johnston said that the utilization of the FracBRAIN technology, in conjunction with the Shear-i AI, could, in time, increase production by an estimated 5%.

Misra added that AI constructs can help to manage the "large volume of data" that is "coming from multiple data position sources."

"That's where a bot can take all the data, it can help [with] data reprocessing, data visualization, data entry," Misra said. "Bots are really good at information retrieval."

Learning machines

Performing even regular maintenance on the equipment that keeps the oil patch pumping can be dangerous—moreso if the workers are relying on incomplete or incorrect information. Predictive analytics and predictive maintenance go hand-in-hand. If workers can—with the help of AI constructs and past data—predict when failures might occur, some dangerous tasks can be mitigated.

"Every time something happens, the [AI] model keeps learning," said Raza, who noted that ChampionX promotes continuous and positive learning for its AI until it is able to recall past events with an accuracy of 97%-98%.

Johnston illustrated machine learning with a more practical example, recalling a visit to the Houston Botanical Gardens. He noticed that sprinklers started watering the gardens after a rain shower. Intelligent usage of AI could reduce such a "pointless" waste of water, he said.

Johnston acknowledged that the current automated process does utilize AI in some capacity—a timer is set up that simply waters the plants at regular intervals—but it could be approached differently.

"You can have a look at—did it rain one inch in the last hour? OK, therefore, don't water," Johnston said. "And then you get even more intelligent and say 'hey, in the next hour, what's the prediction that it's going to rain?' and you can keep getting more and more and more [specific]."

Rise of the machines

Sebastian Gass, CTO of Quantum Energy Partners, offered a cautionary note: be careful what you share with an AI.

As ChatGPT gains traction and acceptance, though with decidedly mixed results, Gass emphasized the contrast between private AI engines and public ones.

"Make sure that you do not feed data into an AI engine that you don't want to feed into the AI engine," he said during the panel.

"I think all of us need to be very mindful" about the negative aspects of AI, Gass said.

And for all of the upsides of deploying AI in the oil patch, there's also a nagging worry.

"I think every technology has unintended consequences," Gass said. "If you listen to … smart people out there, the statistics [showed] 50% of AI experts believe there's a 10% chance that AI will wipe out humanity." OGI

Automatic for the People: Drillers Chase Consistency

Panelists at Hart Energy's SUPER DUG conference emphasized automation's ability to bring about much-needed reliability and consistency in the drilling space.

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Reliability and consistency—conditions craved by both the employer and the employee in every business. For oilfield workers, the future may mean trading in coveralls for business casual.

The driver is automation. Automated processes hold the key for the drilling and completions space, panelists said during Hart Energy's SUPER DUG.

"We've seen the workforce change over the years, and it's very dynamic. There's a lot of churn in the service space," Jeff Beach, vice president of Universal Pressure Pumping, told audience members. "Automation can help smooth out some of that competency as we see folks come in and out of oilfield services. Bringing some stability to our industry is a driver for us as well."

The future of drilling might see the typical floorhand, roughneck or driller replaced with a technician to help keep automation components operational, Jim Jacobson, drilling engineering manager at IPT Well Solutions, said.

"We just want to leverage that technology and then use as much of our own database and our own data to automate the way that we write AFEs [authorization for expenditures], the way that we program our wells and the way that we design the wells," Jacobson said.

Justin Kuchta, director of business development for Liberty Power Innovations (LPI), said another benefit of automation is the ability to vertically integrate workflow. LPI facilitates the conversion to cleaner fuel using compressed natural gas. He said vertical integration allows LPI to "kind of control [its] own destiny" and provide a reliable fuel supply product and service to customers from start to finish.

Catalyst Energy Services achieves consistency and reliability through the use of automation in its VortexPrime hydraulic fracturing fleet.

"The creation of that control software was really paramount to the success of the overall project," Seth Moore, co-founder, COO and executive vice president of Catalyst Energy Services said during the panel. "You have to have utmost reliability 365 days, because stuff obviously is going to happen nights, weekends and whatever…The electronic side, the control side was where we spent a lot of our effort to ensure that reliability and that efficiency was where we wanted."

Threading the digital needle

While each company on the panel used automation to take a different approach toward consistency and reliability, they each agreed on the next step they should take to further their innovations: predictive analytics and condition-based monitoring.

"Our end goal is true predictive analytics, but it's proven to be very challenging to thread that digital needle to truly predict failures," Beach said. "So, a big portion of our emphasis today is just on condition-based maintenance and monitoring through a variety of our control systems and instrumentation there."

Condition-based monitoring will allow companies to monitor wells and other assets with much less work, as they won't always need around-the-clock supervision from a human. It will also allow issues with equipment to be addressed before they even pop up due to predictive analytics.

"You can use bots and computing power to actually take in a ton of inputs and spit out outputs that you need. You still need a human interface there [to] say, 'OK, make sure that it's dispatching,' but you can have your software tell you where you need to go and when, and that helps drive that efficiency into that system," Kuchta said.

But even with all the positives that automation and artificial intelligence brings, panelists agree value remains in good old fashioned, face-to-face communication.

To achieve the best wellbore and completion and have those assets work in tandem to reach peak productivity, clear communication is needed on set-up, spending and job descriptions. While it may make the process a little lengthier, Jacobson compared it to building a house, saying "you don't build a house and just put up the frame and then go live in it. You have to build all of it."

Moore took the analogy a step further.

"You have to build a house that completions has to decorate and production has to live in it, right? Without the right house, we don't know where to hang the pictures, and then production doesn't like it," Moore said. "We've seen wells where we couldn't conduct the optimal completion because we had restrictions with specs on casing or other parts of the well. Some of that could have been solved up front much easier than what the fix is. And sometimes [the problem] is just not having everyone in the same room." OGI

▸ TECHNOLOGY

Solving the Sludge Problem

Greentech company Envorem's new waste management technology offers sustainable and cheap sludge solutions.

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What do jewelers, pistol shrimp and Envorem's new sludge treatment technology have in common?

Each use a process called cavitation, which is the formation of partial vacuums in a liquid by a swiftly moving solid body or by high-intensity sound waves. Envorem CEO Mark Batt-Rawden provides a simpler definition, describing cavitation as what "happens when you move something so fast through a liquid that you vaporize the liquid within itself and it forms these kind of vacuous bubbles that implode really fast."

Jewelers use this process to clean jewelry, pistol shrimp to defend themselves by creating shockwaves and Envorem to treat waste and recover oil left behind by producers and operators.

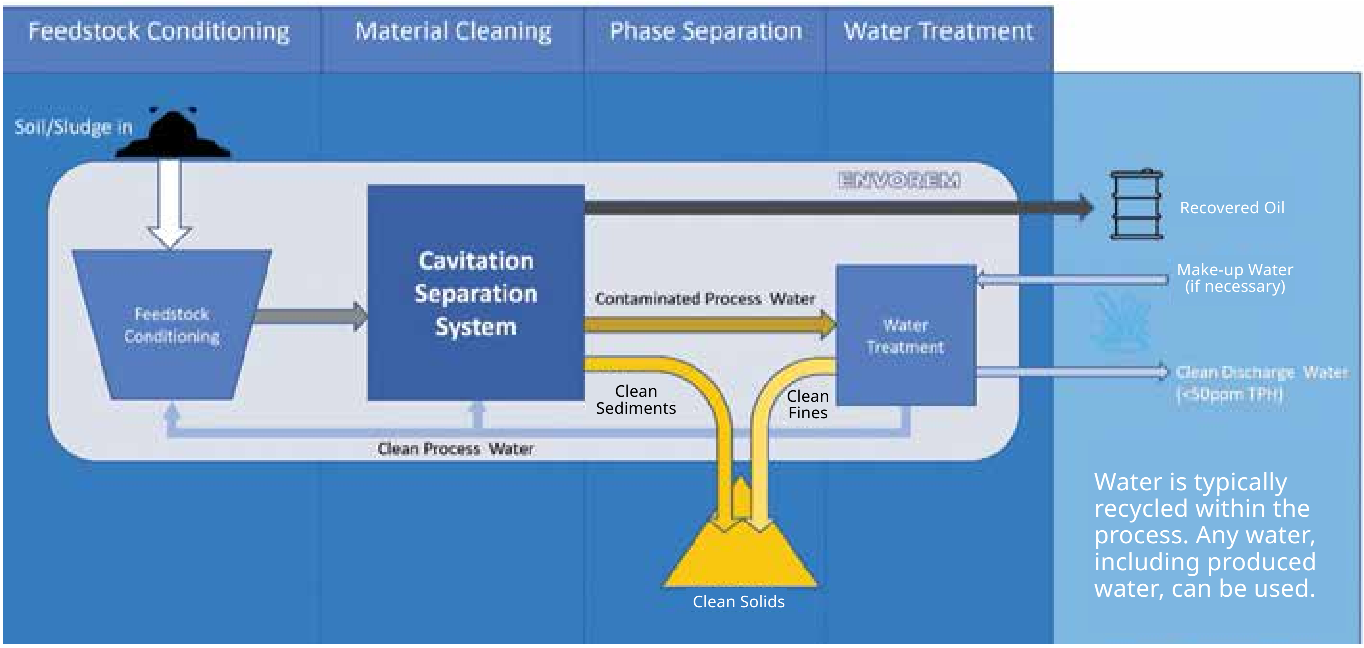
"What we're doing is, we're harnessing the power of those bubbles to rip the contamination out of the materials that we're trying to clean off the surfaces of the particles and into the water," Batt-Rawden told Hart Energy.

Normally, processes such as thermal desorption and incineration are used to clean left-behind sludge, but they come with significant disadvantages. Desorption requires the contaminated area to first be excavated, which is quite costly, and only works up to a certain depth. Incineration is not only costly, but can also add dangerous pollutants to the air. Cavitation is both efficient and inexpensive, as it exploits a technique copied from the natural world.

"There's some great examples out of Kuwait where they've got a massive amount of contamination they've been trying to clean up. They tried thermal desorption as a solution and found that the best they could get through a large thermal desorption machine was around five tonnes of material per hour [mt/hour]," Batt-Rawden said. "In comparison, we've already trialed our technology running at 50 tonnes an hour, so 10 times as fast. And our equipment would be about half the footprint of a thermal desorber to achieve that kind of throughput. And we'd use about 5% of the energy that a thermal system would use for our process."

Envorem's new process also has the ability to recover the oil it cleans, allowing it to be reused, as it doesn't change the chemical characteristics of oil in any way. Batt-Rawden was especially keen on this application of their process because it saves money and fits into

Soil and Sludge Treatment System



Source: Envorem

Sludge forms because of the incompatibility of certain native crude oils and strong inorganic acids used in well treatments.

Envorem

"I think the industry is perhaps a little bit cautious because ... there have been a lot of false dawns with technologies to do this job in the past. Loads and loads of companies have claimed they can do it, and every time they have tried to do it, they have failed."

—**Mark Batt-Rawden,** ***CEO, Envorem***

United Nations' sustainable development goals by recycling waste back into usable product.

"We can operate at about 40% less than the costs of thermal methods for treating these wastes, and with scale, probably less as well. But the added benefit is that our process recovers the oil for recycling, so that further offsets the cost. In some scenarios, it's even potentially that cleaning up the mess could be a profitable business as opposed to a cost," Batt-Rawden said.

Last March, Envorem completed a highly successful pilot of its sludge removal technology for the largest oil and gas producer in Oman, the state-owned Petroleum Development Oman (PDO). The trial was a resounding success for both Envorem and Oman, and received "big ticks in all the boxes," said Batt-Rawden. Not only was the contaminated area cleaned to a better standard than expected, but more oil was recovered than expected as well, he said.

Despite the successful trial in Oman and other research to back up how beneficial Envorem's sludge solution would be to operators and producers, the industry as a whole seems reluctant to adopt this new technology.

"I think the industry is perhaps a little bit cautious because … there have been a lot of false dawns with technologies to do this job in the past," Batt-Rawden said. "Loads and loads of companies have claimed they can do it, and every time they have tried to do it, they have failed. The industry is kind of jaundiced and they're going to want to see something really, really working before they open up their doors."

Currently the product is in TRL 7, with Envorem in talks with multiple classified companies to be used in their fields. Envorem has received funding from the U.K. government to speculatively build a production scale system as a demonstration of its product's abilities. Batt-Rowden said the system will process 100 mt/hour of sludge and 25 mt/hour of solids, and looks to be finished in November. OGI

▸ TECHNOLOGY

New Bit Fills Need for Drilling Speed, While Tool Brings MPD Onshore

A faster bit and an integrated MPD system aim to improve onshore drilling.

PAUL WISEMAN
CONTRIBUTING EDITOR

With drilling costs and return on investment expectations both rising, drilling companies are continually searching for more speed and better process management. Two new tools close to hitting the market— a dual-diameter bit from NOV subsidiary ReedHycalog and a managed pressure drilling (MPD) system from Patterson-UTI—offer solutions.

Bit increases ROP rates

Recent years have seen ROP rates rise in oil and gas drilling, and NOV's new bit is designed to extend the upper limit. Named Pegasus after the mythical flying horse, the bit aims to improve on existing dual-diameter designs by shortening the distance between the bit's pilot and reamer sections to improve both stability and cuttings removal rates.

Once a bit penetrates the formation, the stress state around the bit and drilled well is significantly lowered, said Alex Benson, NOV's product line director of drill bits.

"Conventional single diameter polycrystalline diamond compact (PDC) drill bits are not capable of taking advantage of this reduced effective rock strength," he said.

Pegasus is a PDC bit, but it differs from the conventional model.

"The concentric, dual-diameter design lowers the effective rock strength encountered by the critical shoulder-to-gauge area of the bit's cutting structure. The smaller pilot section of the bit design drills a pilot hole, which reduces the confinement and, thus, strength of the rock drilled by the larger reamer section," he said. "The reamer section utilizes the bedded pilot bit for stabilization to offset the greater forces associated with larger-diameter drilling. The offset blade configuration of the bits also offers increased contact with the borehole and helps deliver a gun-barrel hole quality."

While the dual diameter concept is not new, Benson noted that earlier versions in the marketplace had a 2-in. joiner between the pilot and the reamer. Pegasus reduces that interval, improving stability and steerability with the same number of cutters, he said.

Previous methods of improving stability relied on increasing blade counts from the standard six to seven or more. Adding contact points reduces vibrations that can damage the bit and other equipment, leading to downhole trips for repairs or replacements. But it also restricts the flow area for cuttings removal, which slows the instantaneous ROP. Lower blade counts penetrate faster for a higher instantaneous rate, but reduce the average ROP, which measures the time required from start to finish. The ROP drop was due to drilling halts required by downhole trips.

NOV

NOV is rolling out its Pegasus dual-diameter bit soon.

Pegasus can operate with any number of blades, Benson said.

"Its speed is similar to a six-bladed bit but with the stability of a seven-bladed bit," without the seven-blade's lower cuttings removal rate, he said.

The future of Pegasus

Pegasus is nearing release after almost a year of field trials. So far, it has been tested in onshore applications, including geothermal and oil and gas. Benson says it is designed for "inter-bedded formations or high-vibration environments where you want the bit to be stable drilling and you're trying to reduce torque fluctuations in a heterogeneous formation."

Tests have involved a six-bladed option "in what would otherwise be seven-bladed applications," he said. "This has delivered higher ROP and stability over similar intervals."

Succeeding with MPD onshore

MPD has been an important tool for drillers for many years, said Adam Keith, MPD product champion for Patterson-UTI.

He describes MPD as "an adaptive drilling technique that allows for more exact management of the annular pressure profile of the wellbore. We're applying pressure back to the well in order to control what's happening downhole."

The Society of Petroleum Engineers' website observes that "MPD … reduces several drilling problems that cost time and money, and increases safety of drilling operations."

As powerful as MPD is, the significant costs and manpower requirements of a full MPD deployment have meant it was usually only economical in high-producing environments, Keith said. Oversimplified onshore MPD versions that gained some traction around 2014 "often led to compromises in both technical capability and operational safety," Keith said.

In 2020, Patterson-UTI devised a way to use advancing technology to improve performance and reduce required manpower, allowing it to perform better and at a lower cost than previous systems. These updates would make it as powerful on land as it had been offshore, he noted.

Most MPD systems are completely standalone, limiting their potential benefits. Patterson-UTI created greater efficiency by integrating fit-for-purpose MPD equipment into its Tier 1 Super Spec AC land rigs.

"We integrated not only the hardware to the rig, but also the controls," Keith said.

To further streamline the operation, the company installed an electrically actuated choke manifold on the rig floor, among other hardware updates.

"Because our system is on the rig floor, the rig can pad-drill without having to rig anything down and up between wells, saving a lot of time" on a rig that costs thousands of dollars per day, Keith said. It also improves safety by cutting back on the need to rig up, he added.

Integrating the controls with this proprietary system streamlines data connections. Rather than the driller operating the MPD system with a separate control panel, or human-machine interface (HMI), Keith said, "we've integrated it into the existing drilling HMI." This has made it user-friendly for the driller and has eliminated the need for outside personnel to operate the system.

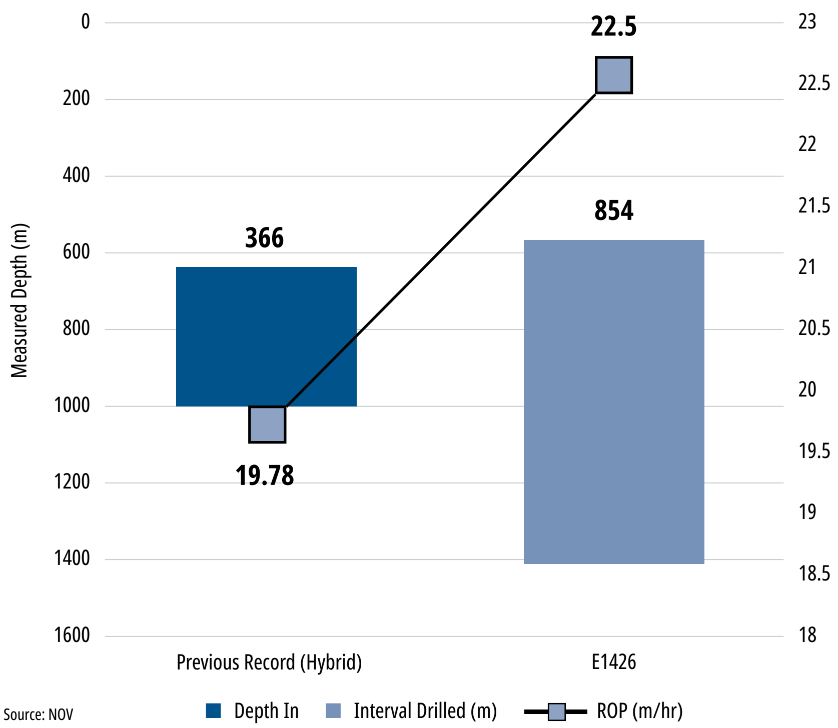
That integration also allows the rig's own automation system to read and respond to the MPD status, Keith said. For example, for a separate MPD system to know and respond to the mud pumps' stroke rates, that information must be separately collected by the MPD system. Patterson-UTI's version, known as the CORTEX Regulator, "knows the RPM of the VFD (variable frequency drive) of the mud pumps," he said.

By comparing that to the pumps' set point as created by the driller, the CORTEX Regulator system can make proactive choke adjustments for greater pressure control, and automate the pumps for MPD connections.

"That has made a big difference in the performance of the MPD system," Keith said.

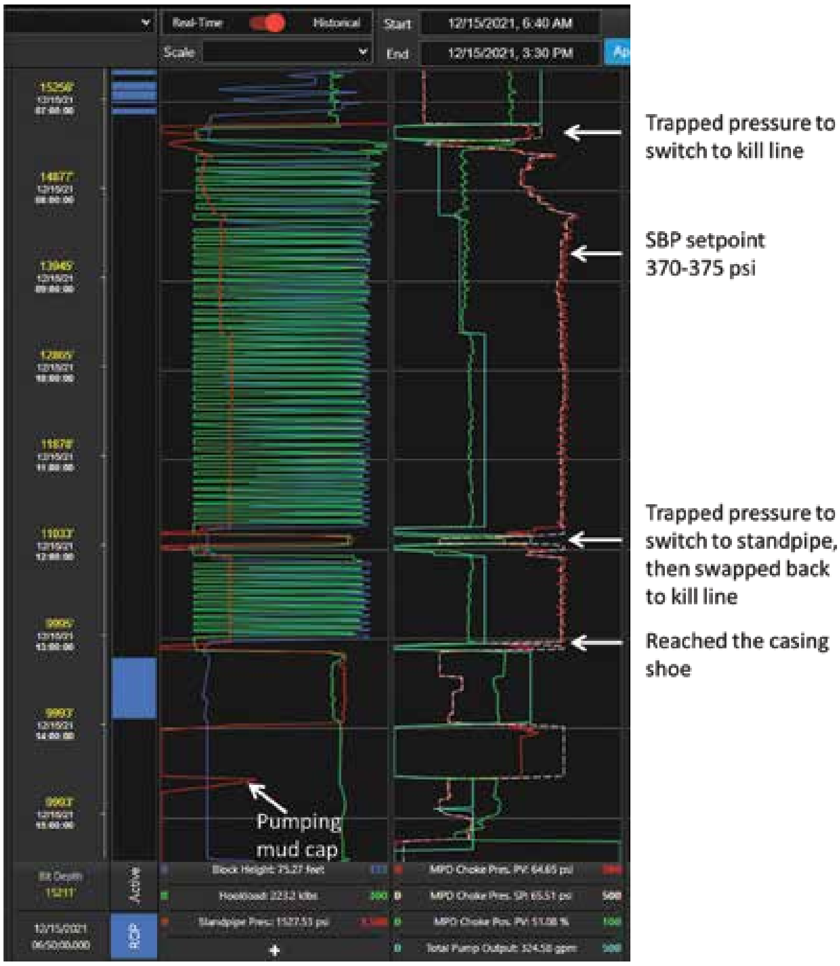
NOV's Pegasus rollout is coming soon, and Patterson-UTI began field operations with CORTEX in late 2022. While both could be considered incremental rather than revolutionary, they are important steps forward. OGI

New Field ROP Record by NOV RH 16" E1426



Source: NOV

MPD Use Downhole



Source: Patterson-UTI

Patterson-UTI's managed pressure drilling (MPD) system, CORTEX, integrates data from multiple sources and allows the rig's own automation system to read and respond to the MPD status.

Produced Water Producing Results

After years of skepticism surrounding the reuse of produced water, experts say it's a new day and age for the water midstream sector.

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It is a well-known and scientifically proven fact that oil and water don't mix, but it's increasingly clear they can coexist.

Experts discussed how the water market has evolved alongside the shale revolution and the benefits of recycling and reusing produced water in May at Hart Energy's SUPER DUG conference in Fort Worth, Texas.

"Speaking globally, reuse is the way to go, whether it's just reuse back into the process for recovery or whether it's reuse and diverting somewhere else," Gerard Cooke, CEO of Belfast, Northern Ireland-based Inov8 Systems, told audience members during the panel. "We're hearing every day that water is a resource. It's not a waste [product], it's a resource, and we need to use it."

The reuse of produced water has long been a point of contention when it comes to water-handling, but the four panelists agreed that reuse is something that should be widely adopted within the water midstream industry.

Even with the positives that recycling produced water brings, many in the industry remain skeptical about reusing the water. John Durand, vice chairman and chief sustainability officer at XRI Holdings, attempted to allay those concerns. He said that nowadays there are fewer and fewer anomalies in produced water and operators are becoming more comfortable using water that fits within regulations.

Detailing the process that produced water goes through, Durand said that once custody of the water is transferred, "we'll take that same barrel of water back, we'll enter into a contract for [a] takeaway agreement to then treat that water, recycle it, give it back to any one of a number of operators and then keep that process going."

This process leads to great economies of scale and cost efficiencies, while also delivering from a quality standpoint. Durand said that each bit of water is analyzed thoroughly, which prevents it from "falling out of spec" and enables the water to be safely reused.

"It's great for the industry because every barrel that's reused is a barrel that's not taken from fresh" water sources, said Robert Rubey, Goodnight Midstream co-founder and chief commercial officer. "Every time that I can provide a barrel for reuse, I don't have to pay a chemical expense, I don't have to pay electricity to move it and I don't have to pay royalties either to put it through a pipe or put it down the hole."

Despite recycling's ability to cut water

"Every time that I can provide a barrel for reuse I don't have to pay a chemical expense, I don't have to pay electricity to move it and I don't have to pay royalties either to put it through a pipe or put it down the hole."

—**Robert Rubey,** *co-founder and chief commercial officer, Goodnight Midstream*

management companies' costs, Rubey still lamented that the cheapest way to get rid of produced water is by putting it back downhole, which can result in a plethora of issues on its own, such as earthquakes.

"If you look at reuse in the Permian, it works because it's cheaper than the alternative. But people don't reuse in North Dakota because it's not cheaper," Rubey said in response to a question about further evolutions in water-handling and how to combat issues that still remain. "People aren't going to [recycle produced water] out of the goodness of their hearts unless it's cheaper or unless they're forced to from a regulatory standpoint."

But panelists offered some solutions to the dilemma Rubey posed.

Among the many innovations in water-handling discussed during the panel, artificial intelligence (AI) was by far the most notable. Duane Germenis, president of Intelligent Water Solutions, said AI could revolutionize the water midstream sector. Capturing data on various wells and feeding it into an AI system could enable the software to learn about different qualities of water. The AI would be able to handle and adapt to situations as they arise.

"I see that as a very big positive because so many things change in an instant," Germenis said. "For instance, in the slugs that come through the pipelines, we don't know when they're coming but if we can detect it and say, 'here comes the slug' and understand that, then the data is going to be fairly accurate, which will benefit all the engineering support." OGI

Tech Bytes

Halliburton

Lab personnel in Halliburton Multi-Chem's new Odessa, Texas, facility

Halliburton Adds Odessa Lab

Halliburton has opened a regional laboratory in Odessa, Texas, to serve Multi-Chem customers in the Permian Basin region, the company said in May.

The facility includes a team of scientists and lab personnel who can analyze oilfield samples and deliver data-driven insights to technical and field teams, Halliburton said.

"We are also working to link this lab system with customers' databases to enhance insights, assess risks and drive program performance," said Jacob Hardy, Halliburton's North America land region manager.

University Offers Apps for MMP, Viscosity Calculations

A team of University of Houston researchers has developed a series of digital applications to make energy industry processes more efficient. The team announced in May that the three online calculators—the most recent being the UH Hydrocarbon Gas Minimum Miscibility Pressure (MMP) Calculator—are available to industry professionals for free.

The new calculators for hydrocarbon MMP, carbon dioxide MMP and viscosity, can help engineers in the field save time, resources and funds by enabling faster screenings and calculations, the team said. The team is comprised of Birol Dindoruk, the American Association of Drilling Engineers Endowed Professor in petroleum, chemical and biomolecular engineering at UH; Mohamed Soliman, chairman of the UH Department of Petroleum Engineering; and Utkarsh Sinha, who earned a master's degree in petroleum engineering from UH in 2018.

"We don't want our ideas and findings to just exist on paper," Dindoruk said. "We want our tools and techniques to be deployed and used by others to improve the efficiency of these processes."

By making the apps freely available, the researchers hope to learn from users' feedback to make improvements and develop new applications.

The UH Viscosity Calculator app calculates the thickness of crude in its natural state, also known as dead oil, needing very little information. It is a full-range method, which can measure a wide range of oil viscosity—from a fraction of centipoise (cp), a unit measurement of viscosity, to 1 million cp.

The UH Carbon Dioxide MMP Calculator considers the composition and temperature of the oil as input parameters. The proposed hybrid model performs better than existing correlations and machine-learning methods, covering a wide range of MMP values, Dindoruk said.

The UH Hydrocarbon MMP Calculator uses a model called light gradient boost to estimate the MMP for hydrocarbon gas injection. The team also determined the minimum amount of heavier hydrocarbon gas needed to reach the target MMP.

"This helps achieve the desired pressure without needing expensive compressors or risking damage to the reservoir," Dindoruk said.

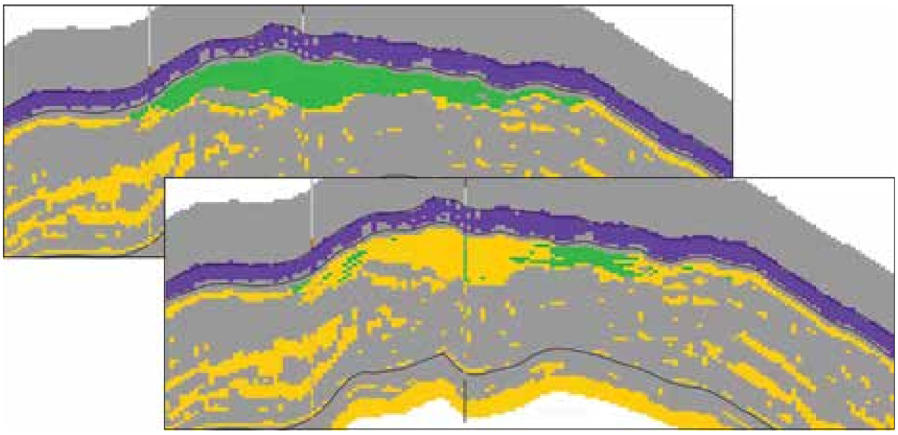
Halliburton Buys Resoptima

Halliburton announced in early June it had acquired Resoptima AS, a Norwegian technology company specializing in data-driven reservoir management. Halliburton said the acquisition will allow integration of the reservoir modeling and predictive analytics of Resoptima into the Halliburton Landmark DecisionSpace 365 suite.

Resoptima, used on more than 130 active fields around the world, provides technology solutions that enhance reservoir understanding to improve oil extraction, resource management and risk mitigation.

Launched in 2013 and developed with input from dozens of customers, Resoptima's software helps increase reservoir recovery factors and deliver cost savings on reservoir intervention projects by preventing costly mistakes such as underperforming well drilling and unnecessary injection volumes. Atila Mellilo, the former CEO of Resoptima, will join the Halliburton Landmark leadership team.

DecisionSpace 365 and Resoptima solutions provide open architectures and interoperability with third-party software. The combined portfolio will maintain these features, enhancing existing and future customers' ability to capitalize on previous investments.



Source: Ikon Science

Inverted facies in production environment: Impermeable and permeable reservoir facies held the same across vintages, while allowing fluid states to change.

Ikon Releases Updates

Ikon Science announced in early June it has introduced a 4D inversion technology tool as part of RokDoc 2023.3 and had released cloud-native subsurface knowledge management solution Curate 2023.3.

Ikon said its Time-Lapse Ji-Fi app offers complete 4D fluid tracking capabilities for production and injection scenarios and is applicable in most hydrocarbon production campaigns, as well as carbon capture utilization and storage efforts.

Curate is a cloud-native subsurface knowledge management solution and the new release streamlines subsurface data workflows. Curate's new capabilities improve performance and scalability, providing the ability to handle large well datasets of over 1 million wells and quick overviews of well data availability as well as key project details.

2H Launches Wellhead Fatigue JIP Phase 2

2H Offshore announced in May it was launching the second phase of its measurement-based wellhead fatigue joint industry project (JIP).

The JIP aims to improve riser, wellhead and conductor fatigue estimates and make drilling operations more reliable and efficient.

In Phase 1 of the project, 2H collaborated with nine major operators to gather and analyze field measurements from 10 drilling campaigns in the Gulf of Mexico and the North Sea. The data covered a range of environments, water depths, soil characteristics, riser and wellhead configurations and vessel types. Findings from the analysis verified that industry assumptions for wave and vortex-induced vibration fatigue assessments are conservative. Remaining fatigue life tends to be higher than determined by typical design methods. A more accurate prediction of remaining fatigue life can eliminate the need for costly mitigation methods or unnecessary upgrades and downtime during severe events.

In the second phase, the field data analyzed in Phase 1 will be used to explain uncertainties identified in the riser, wellhead and conductor fatigue analysis. The findings are expected to further improve the accuracy of future wellhead fatigue assessments and provide an industry consensus on design methodology, 2H said.

Hovering AUV Designed for OBN Placement

A next-generation ocean bottom node (OBN) handling system uses a hovering autonomous underwater vehicle to speed up precision placement of OBNs.

PXGEO in June said it developed MantaRay based on Saab's Sabertooth platform in collaboration with Saab, which is capable of operating in water depths of 4 m to 3,000 m. MantaRay has a fully electrical design and requires no umbilicals or tethers.

PXGEO CEO Tony Bowman said the expectation is to have the initial fleet of MantaRays in full operation by the end of the year.

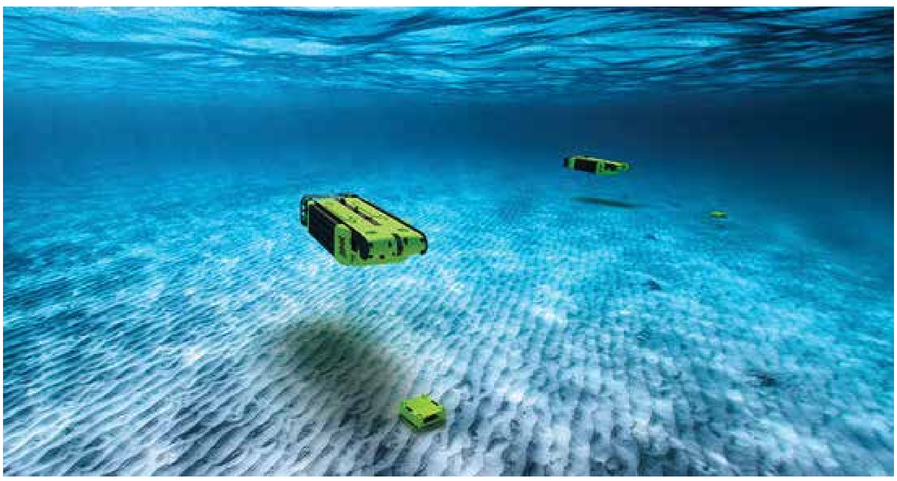
DNV Qualifies Saipem Monitoring Technology

Saipem announced at the end of May that DNV had qualified its Integrated Acoustic Unit (IAU) technology for the monitoring of subsea pipelines during laying operations.

Saipem developed the IAU digital instrument, which is based on acoustic technology, to enable non-intrusive, remote offshore pipeline integrity monitoring during laying activities. It can locate obstructions, pipe deformations and water ingress up to several kilometers away in real time. It can also classify and quantify detected anomalies and send the data to an operator.

The system will be used on Woodside Energy's Scarborough project offshore Australia. Saipem will install the export trunkline of the pipeline that will connect the Scarborough gas field to the onshore plant, subject to the receipt of relevant regulatory approvals.

Saipem has deployed several IAU prototypes onboard its *Castorone* and *Saipem 7000* vessels, and a years-long field test campaign has validated their performances, the company said. OGI



PXGEO

PXGEO developed the MantaRay hovering autonomous underwater vehicle in collaboration with Saab.

Waves of North American Gas Infrastructure Needed for New Supplies and Planned LNG

Long-haul pipe coming on this year and next will meet current needs, but a new wave of LNG export terminals will require significant further investment.

GREGORY MORRIS
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Midstream companies will spend $50 billion this year and next to keep up with surging volumes of natural gas from prime shale basins. Nevertheless, another round of investment is likely to be needed before the end of the decade as the next generation of LNG export terminals are built in the U.S., Canada and Mexico.

"It's all about timing," Ryan Smith, vice president of advisory services at East Daley, told Hart Energy. "Infrastructure is not currently a constraint, but six to eight months ago you could not get gas from Texas to Louisiana. There was a $2 discount at the Houston Ship Channel. That has now gone away."

Ryan Smith

Several major long-haul gas pipeline projects are expected to alleviate tightness in midstream capacity in North America when they come into service in 2022-2023. Gas storage, however, is emerging as a potential area of interest as the sheer volume of gas produced, consumed, and exported grows dramatically.

The next round of LNG investments is expected to be operational in or around 2029, taking total gas demand for LNG to about 33 Bcf/d. So far, infrastructure investment has been able to keep pace. From 2016 to 2021, U.S. LNG export nameplate capacity went from essentially zero to 10 Bcf/d. In another six years, that total will rise to 20 Bcf/d.

How much new infrastructure will be needed by 2029, and how much it will cost, are not yet clear. Given the long lead times for permitting and equipment fabrication for liquefaction trains, midstream companies and the investors that back them are awaiting final investment decisions on the projects under development before deciding to put new steel into the ditch. When that time comes, there is widespread confidence that both public and private equity will be eager to underwrite the necessary investments.

ConocoPhillips has already put skin in the infrastructure game to support its natural gas production growth. Late last year, the company purchased a 30% stake in Sempra's Port Arthur, Texas, LNG development, and signed a 20-year offtake agreement.

"Port Arthur LNG will benefit from intrastrate pipelines out of the Permian Basin," said Bill Bullock, executive vice president and CFO at ConocoPhillips, during its April analyst presentation.

Bill Bullock

Independent producers seem to have a similar sentiment. UpCurve Energy, a portfolio producer of Post Oak Capital, operates in the Delaware Basin. "We have had one rig running for several years," said Zach Fenton, co-founder and president. "It is a nice measured development. At the beginning of 2022 we were at about 20 MMcf/d, and now we are close to 50 MMcf/d."

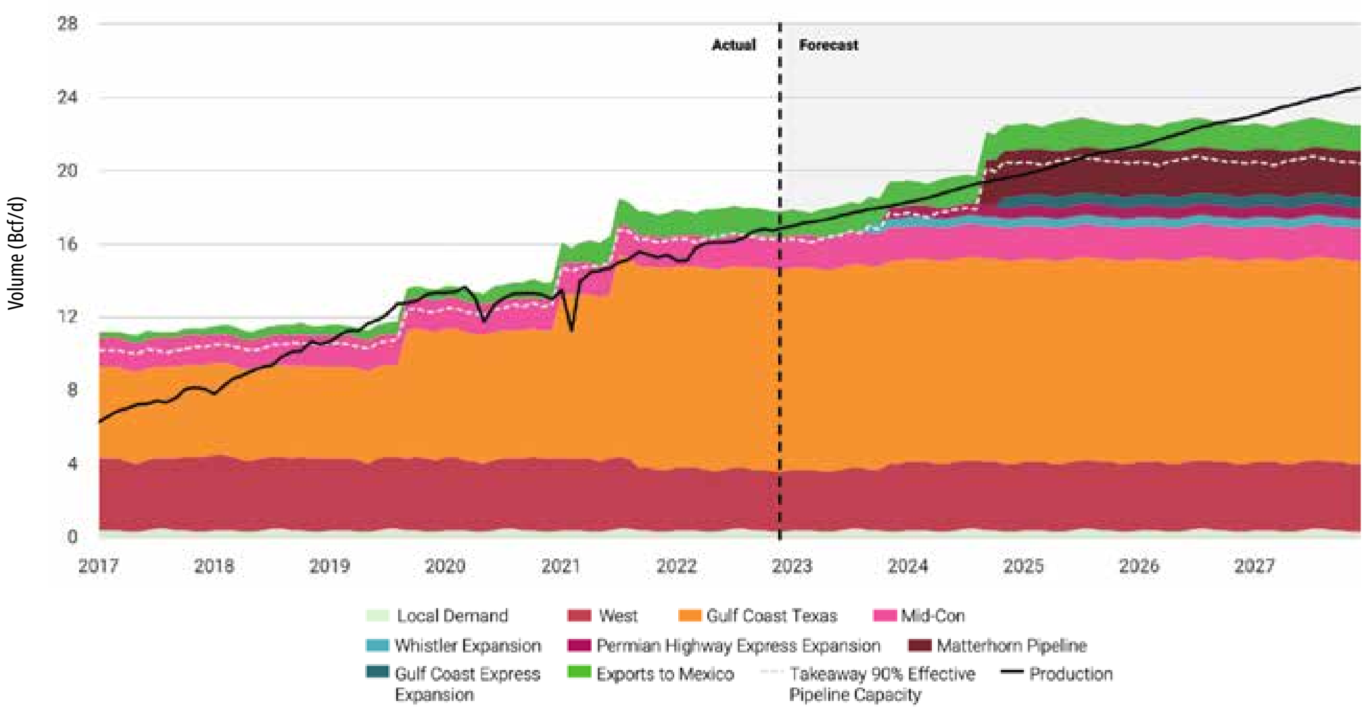
UpCurve works with the larger midstream operators and has secured firm capacity, Fenton said. "Things are tight, especially for producers that do not have firm service. If you have interruptible service, you are going to get interrupted. It has happened, and will continue to happen."

He also noted that differentials indicate the market expects tightness to continue in the near term. "There is a lot of progress on new capacity," Fenton said. "All the big midstream groups are working. The investment is taking place, but the new capacity will come on in blocky chunks, so the tightness will continue intermittently. That will especially be the case in the Permian because operator economics is driven by crude and there is a lot of associated gas."

Frost W. Cochran

In both the Delaware and Haynesville, "gas has been crushed," said Frost W. Cochran, managing director at Post Oak Capital. "There has been significant cash price degradation in the Delaware Basin but oil production is still driving activity." Post Oak is primarily upstream, but also has some midstream operations, which gives Cochran and his colleagues good insight into both sectors.

Gas Takeaway by Market



Source: Enverus Intelligence Research, Bloomberg, company disclosures

Midstream Investment

Company	2023 CapEx $million	2024 CapEx $million
Enbridge	5,199	4,467
TC Energy	4,030	3,340
Enterprise Products	2,334	1,926
Williams Cos	2,125	1,695
Energy Transfer	1,986	2,270
Kinder Morgan	1,949	1,161
Targa Resources	1,520	965
ONEOK	1,183	779
Pembina	737	613
MPLX	695	498
Equitrans	644	282
Kinetik	518	116
Genesis Energy	461	331
Plains All American	426	485
EnLink	341	387
Western	319	473
Antero	306	248
DT Midstream	296	139
Magellan	207	214
NuStar	169	93
Crestwood	143	89
Summit Midstream	52	51
Total	**25,638**	**20,620**

Source: Enverus Intelligence Research, Bloomberg, company disclosures

The tightest infrastructure capacity for the major U.S. horizontal plays is in the Haynesville, according to Cochran. "We have primarily seen tightness manifest itself in slightly higher line pressures. That means that wells are fighting to get on and it's impacting production. I keep expecting more tightness in the Permian, but we have not experienced it yet in the primary revenue generating commodity, oil."

He also noted that midstream operators seem to be adding gathering and processing just as new wells are being brought into production. "That is mostly because of their own supply-chain issues with equipment and construction, but it means that the timing is tight."

The oil side is "no big deal," in terms of transportation, Cochran said. "We have our strong connections to the Oryx system in the Delaware, so there are minimal oil takeaway issues there, or in the Midcontinent." Post Oak was a founding investor in Oryx before selling it to Stonepeak.

Enough LNG tankers?

The numbers support the assertions that midstream investment is taking place. East Daley forecasts capex and EBITDA for 22 of the largest midstream companies. East Daley expects the group to spend $25.6 billion in capex in 2023, decreasing to $20.6 billion in 2024. Enbridge and TransCanada are the top companies with capex spending in 2023, which include large-scale pipeline expansions in Canada.

Midstream companies have been busy building "a runway of new pipe through 2025," Smith said. "But by 2028, there will be 18 Bcf/d of new LNG export demand—4.2 Bcf/d in Texas and 13.8 Bcf/d in Louisiana—and only about half that capacity of new pipe." He noted that some LNG operators, but certainly not all, make it a point to contract capacity all the way back to the supply basin.

"The due diligence for an LNG project is based on global demand and funding for the project," Smith explained. "The long lead times are for permitting and larger components. The need for new pipe is more of an opportunity than a problem. There is plenty of time."

He also noted two other infrastructure elements that bear watching. The order book for new LNG tankers is full, so there could be some short-term disruptions in actual loading and sailing if there are not sufficient vessels at any time.

That variable, along with spikes and dips in demand driven by heat waves or severe storms, mean that storage will matter more than ever. "Storage capacity becomes very important in volatile markets," Smith said. "Midstream is clued in to this already, and some large operators have been investing in buying storage capacity." As far back as 2021, Kinder Morgan purchased Stagecoach Gas Services for $1.23 billion.

"The big area of focus has been gas takeaway from the Permian," said Hinds Howard, portfolio manager at CBRE Investment Management. Noting that there have been both expansions and greenfield development, he added, "capacity is not the current constraint there," but there are some pinches starting to show in other basins.

"The Haynesville has a lot of projects under development," Howard explained. "Overall, it's about 85% full, but going south is a constraint, which is actually where the gas wants to go. The major players, the ones with the big footprints already, are the ones adding capacity."

Bakken gas takeaway is also constrained. "Producers are recovering more ethane to free capacity," Howard said. "As we approach BTU limits we may need more of that." Next steps would include reconfiguring existing infrastructure. For example, TC Energy is considering options for the Bison Pipeline that connects the Powder River Basin in Wyoming to the Northern Border system in North Dakota.

The Appalachian has long been the most constrained basin, and that is expected to remain the case. "Existing infrastructure is at about 90% of capacity. Most expectations are for that to hold steady on, with normal incremental increases," Howard said.

Equitrans is sticking to its projection of having the $6.6-billion Mountain Valley Pipeline development completed by the end of the year, but the embattled project remains vexed by permitting and litigation hurdles.

Macroeconomic shift

In all the examination of specific basins and individual projects, it is important to bear in mind the broader context, noted Kate Hardin, executive director of Deloitte's Research Center for Energy and Industrials. "We are seeing gas production at more than 100 Bcf/d. That is significant production in response to real demand, especially in power generation and LNG."

Kate Hardin

That is a major success story, but a very recent one. "If you look at infrastructure in the Permian, we are at about 90% utilization for gas but only about 70% for oil," said Hardin. "Looking ahead to 2026, gas takeaway is expected to be at 80% to 100% of capacity, with oil at plus or minus 60%. So, it is clear to see where the infrastructure investment has been to this point."

Permian production is still strong, Hardin acknowledged, "but as decline rates set in, the gas-to-oil ratio will shift. At the same time, the market for gas is changing. And producers are starting to understand that. There is more attention to gas than ever before. In 2022, about 82% of upstream deals included gas assets."

The macroeconomic shift is the U.S. becoming a major gas exporter worldwide, not just to Europe, explained Amy Chronis, vice chair, U.S. oil, gas and chemicals leader at Deloitte. "A lot of the U.S. LNG contracts have no destination clauses," she added, noting how that flexibility came to the fore through the pandemic and the embargoes on Russian gas as cargoes were traded globally. "The highlight here is gas transport," Chronis stated emphatically.

Amy Chronis

Transportation capacity is more complex than just solving for the production volumes out of a basin, said Baran Tekkora, a partner at Riverstone Holdings. "The demand locations for natural gas are also changing. As the energy transition continues to gain attention, demand in historically high areas of consumption is leveling off and may decline. At the same time, demand in U.S. export areas is on the rise, as LNG is a growing global energy source. That change in demand location is driving the continued transportation infrastructure needs just as much as the overall demand growth for natural gas."

Tekkora made a point to dispel a common misperception across the industry about how much infrastructure has been completed. "Midstream went through a very disciplined capital deployment period during the pandemic, but infrastructure did not catch up as much as might be expected. Long-haul infrastructure projects in execution phases continued, but some key operators put the development of additional projects on hold due to lack of demand for capacity from both the supply and market side."

That, in turn, "created a pinch coming out of the pandemic, which caused the pricing spread between high-production basins and the market to widen significantly," he continued. "While that began to come back into balance, now that production numbers are back on the rise, the phenomenon will continue."

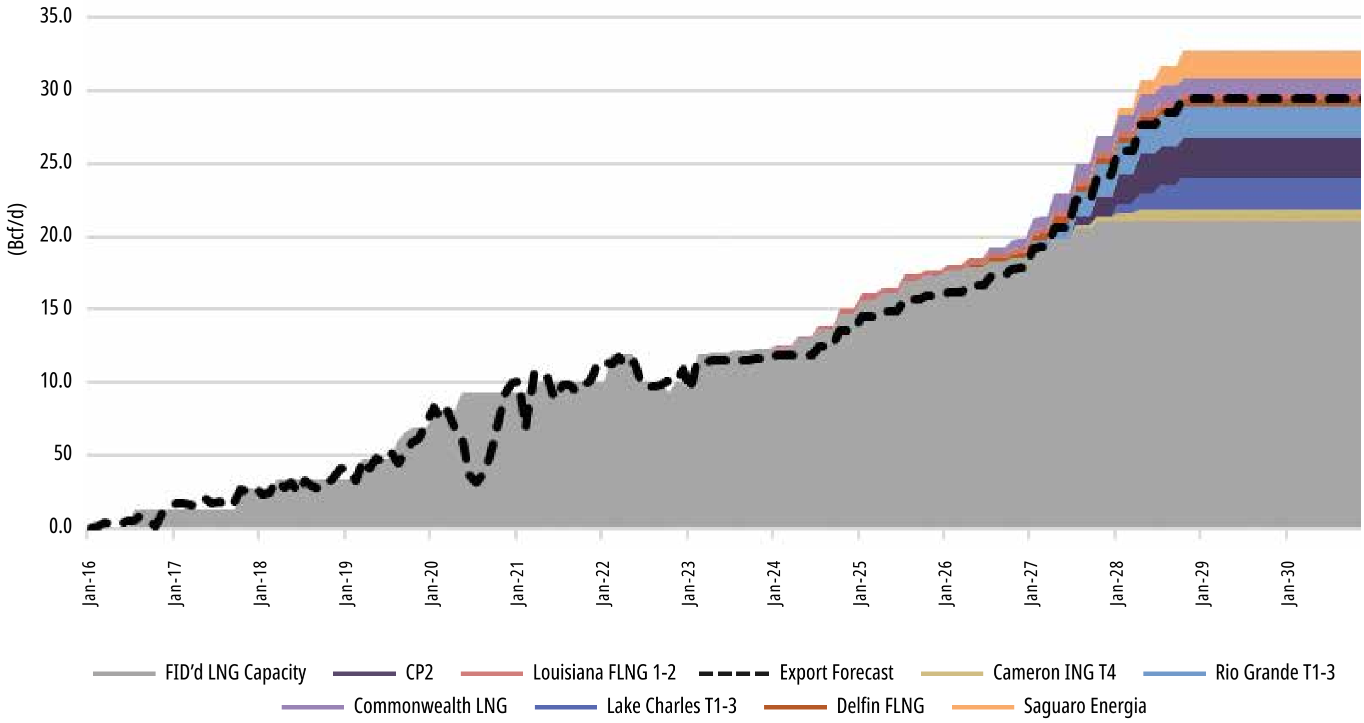
'Catch-up mode'

Broadly speaking, "the industry has been able to maintain capital discipline through volatile prices in the last few years, primarily due to investors rewarding such capital discipline, but also other factors including supply-chain issues and dearth of available skilled labor," said Amol Joshi, vice president and senior credit officer at Moody's Investors Service. "All that has kept a lid on production growth as well as [has] available oilfield-services capacity."

So, there is little surprise that long-haul gas transportation in the Permian "is in catch-up mode," Joshi added, "caused by associated gas growth and rising gas/oil ratio in mature areas, and there have been routine price dislocations and basis blowouts such as at the Waha Hub. New gas takeaway capacity is being added to mitigate this, with projects such as the Permian Highway expansion and the greenfield Matterhorn pipeline project." Crude oil takeaway does not face this issue yet in the Permian, he added.

"We see the need for a massive amount of transmission pipeline infrastructure to be built out in the Haynesville and Permian to support the next wave of LNG projects coming online in the second half of the decade," said Jon Snyder, vice president of intelligence at Enverus. "For the Haynesville, we see almost 5 Bcf/d of new north-to-south Louisiana takeaway coming online by the end of the 2025. For the Permian [we see] nearly 4 Bcf/d by the end of 2024. Even after this Permian buildout, we see the basin needing a new 2 Bcf/d pipe every 18 to 24 months to support continued oil production growth."

U.S. LNG FID'd vs. Projected Capacity (expected)



Source: East Daley Analytics

The slowdown in Permian development in 2020 did help provide some relief to the basin, "but as production has recovered the basin has started to bump up against available takeaway," Snyder said, "and needs expansion projects to come on line at the end of the year to help support continued growth. The decrease in activity in the Haynesville also provided temporary relief, but new north-to-south Louisiana projects are needed to supply more gas to third-wave LNG projects. Those projects are under construction."

Ben Dell

The fundamental challenge in the midstream is that the economics always favor bigger pipes and compressors, said Ben Dell, co-founder and managing partner at Kimmeridge Energy Management. "The midstream is dependent on the upstream to deliver volumes, but the upstream is dependent on price. If a producer could commit to $5 gas for 10 years, any midstream operator would be happy to invest in as much capacity as they could ship."

As big as pipes can get, LNG trains are even more chunky in terms of capacity. Each standard liquefaction terminal of 4.2 million metric tons/day needs about 600 MMcf/d.

"That is a lot of demand coming on in a relatively short time," said Dell. "There is about 25 million tons a year on LNG coming on in the next few years just in Texas. Across the industry, it could be as much as 50 million tons. So, gas is going to be firming in 2025-26-27. Every producer wants to develop its assets into that. We are just in a bit of an air pocket this year and perhaps into next year."

Infrastructure for crude has plenty of capacity relative to production with the possible exception of long-haul pipeline to Corpus Christi, Texas, said Stephen Ellis, energy strategist at Morningstar. In contrast, gas gathering, processing and transportation face an inflection from ample capacity now, to tight in the medium term, to balanced in the longer view.

"The oil side is a bit easier," said Ellis. "It's oversupplied with transportation. Some pipes are going from very under capacity to only a bit under capacity. Maybe we need more transportation into Corpus, or maybe carriers can shift volumes to Houston where there is more capacity. There are discussions about moving things around."

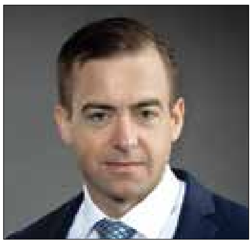
On the gas side, "there is an undersupply," of transport "at least in the next few years: 2024 and '25, maybe into '26, Ellis said. "For the rest of this year there is actually an oversupply in transportation. That is because the European Union did not end up needing as much LNG as was thought it would need going into this winter. Gas production in North America has gone up, consumption has gone down, and so gas in storage has increased."

Looking south, Ellis noted significant improvements in gas exports to Mexico. "There has been good progress in Mexico. TC Energy came to some agreements with Mexican utilities on financial terms. The permitting and the infrastructure on this side of the border are mostly in place. What is needed now is for the Mexican midstream to connect. ONEOK is also planning Mexican pipelines. There is definitely a lot of progress, which is good after years of low volumes of as low as 10% or 20% of capacity."

Balance is always temporary, reiterated Riverstone's Tekkora. "I believe the next imbalance or bottleneck is likely to occur in natural gas liquids fractionation and infrastructure. The sector was arguably overbuilt in 2019 and 2020, but the industry has done a good job of filling that same capacity. I believe there's likely to be some tightness in 2024 and 2025 ahead of new infrastructure and fractionation capacity coming available."

Processors will have some flexibility in NGL production if the tightness comes sooner by switching to ethane rejection mode, Tekkora suggested. "However, that same molecule taken out of the NGL supply chain finds its way into the natural-gas transportation infrastructure and further complicates the congestion there." OGI

Howard: Midstream Investors Say 'Don't Tread on MMP'



HINDS HOWARD
CBRE INVESTMENT MANAGEMENT

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

In a merger slightly less surprising than the recently announced LIV/PGA merger, midstream corporation ONEOK (OKE) announced the $18.8 billion acquisition of Magellan Midstream Partners (MMP), a prominent publicly traded partnership (or MLP). The deal between two titans of Tulsa, Okla., has certainly made waves in a space that has few remaining large companies.

The OKE/MMP merger process looks to be the primary drama for a sector that has largely lacked drama during the last few years. There's potential for investor pushback, issues with proxy services recommendations, potential alternative bidders, recutting of the deal between the parties, and the eventual unitholder vote sometime in the fall if the current deal stays on track.

Origins: WMB to WEG to MMP to OKE

Magellan is the seventh-oldest MLP currently trading. It began its life in 2001 as Williams Energy Partners (WEG), which went public in a 2001 IPO. It was the original dropdown MLP, spun out of Tulsa-based Williams Cos. (WMB), which then used WEG to acquire the Williams Pipe Line (refined products pipeline system) from WMB for $1 billion in 2002. The dropdown story was a short one, however, because in 2003, WEG became one of the original orphaned MLPs when a financially distressed WMB sold its general partner stake to private equity firms Madison Dearborn and Carlyle/Riverstone and changed its name to Magellan Midstream.

MMP was also in the first wave of general partner IPOs. In 2006, the new sponsors took the general partner stake public as an entity called Magellan Midstream Holdings (MGG) in a $539 million IPO. Shortly after, it was the second MLP to simplify when it merged MGG into MMP at the start of a wave of simplification deals in 2008-2010 in the fallout from the global financial crisis.

After that first decade of chaos, MMP settled down and established itself as one of the most stable, best-run partnerships in the sector. While other MLPs issued massive amounts of equity and did splashy M&A, Magellan was disciplined with CEO Mike Mears at the helm. The big success that decade was MMP's acquisition and reversal of the Longhorn Pipeline, which had taken refined products from El Paso to Houston but in 2013 began shipping crude oil in the other direction.

That capital discipline led to a pristine balance sheet and a premium valuation. That balance sheet and lack of growth capital made MMP attractive for a corporation like OKE. Free cash flow accretion and avoiding corporate taxes for a few more years are good reasons for OKE to get involved, even if there is no significant overlap of assets that would drive commercial synergies.

Investor pushback

Soon after the OKE/MMP merger was announced, MMP's fourth-largest investor (but with only a 3% stake), Energy Income Partners, published its intention to vote against the merger, explaining that it believes the taxes paid by MMP investors as a result of the sale will exceed the premium offered and potential growth from the combined company. Also, the letter noted that midstream investors would prefer to make up their own minds as to how much MMP vs. OKE they own, rather than be forced to own the combined entity. This last argument speaks to the desperation of active midstream investors looking around the space and seeing few remaining names from which to choose.

Proxy firms will make their recommendation on the deal, and that recommendation could go either way. The campaign on both sides will intensify. Because of its corporate history, MMP has limited insider ownership, unlike most MLPs, which typically have large sponsor or founder stakes that help push deals like this through. That will make the voting more interesting than normal. A simple majority of the MMP units outstanding is all that is needed.

The guidance from management on timing of a vote is in the third quarter, so maybe the fireworks happen in September. The S-4 should be out soon (or may be out by publication of this column), which will have more detail on the process and any other potential bidders that were involved. With a break fee on the deal of $275 million, it is possible MMP could receive and take a superior bid without much pain, but no obvious alternative bidder exists.

Buckeye (BPL) and its buyout by IFM in 2019 is maybe something of a comparison, but that included a large premium and it was all cash in a time when MLP stock prices were struggling. In that transaction, 55% of the unitholders voted for the deal, 2% voted against. Back in 2014, TRGP bought Atlas Pipeline Partners, but the insider ownership was much chunkier there, so not much of a comparison. In that transaction, the deal was approved by 53%. The challenge, depending on how the proxy firms lean, will be to find retail unitholders and make sure they vote.

Expect more drama, including more letters from investors and replies from management, and maybe more fireworks in the form of additional bids. But the deal is probably not going to work accretion-wise for a tax-friendly bidder (another MLP), because MMP already trades at a high valuation relative to other MLPs. For me, any of those outcomes are fine—I'm just happy to have something to talk about. OGI

Earnings Grow, Projects Push Forward ... Investors Shrug

Midstream companies continue to post strong earnings combined with steady stock buybacks, yet fears of a gas production slump keep a lid on share prices.

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After a strong, and in some cases record-breaking, opening quarter for earnings, the midstream sector continued expansion projects in the booming Permian Basin.

Otherwise, companies showed caution in a market with softening natural gas prices. In 2022, according to the U.S. Energy Information Administration, the Permian Basin reached an annual record high of 22 Bcf/d, 14% above the 2021 average.

High gas and crude production translate into high earnings for midstream companies, which earn fees from shipments.

Analysts said a substantial supply of cash does not automatically translate into capital spending but does allow companies to build where it is needed.

"… [The] relationship between good earnings and management teams focusing on building more infrastructure is not really one-to-one," said Hinds Howard, a portfolio manager at CBRE Investment Management. "Midstream operators build new infrastructure based on utilization of their infrastructure being very high and their customers needing more capacity to process, transport or store hydrocarbons."

As production in the Permian Basin continues to grow, midstream companies with a large footprint in the area will continue to meet the need to process and ship the product to the Gulf Coast, Howard said. America's busiest oil and gas-producing region will remain the primary area of infrastructure development for now.

New plants continue to open in the region to meet the needs for capacity. Targa Resources plans to open six new natural gas plants in the basin, and Enterprise Products Partners is building two. Enterprise also announced the completion of its Acadian Haynesville Extension natural gas pipeline in Texas and Louisiana, increasing its capacity to around 2.5 Bcf/d.

On the coast, Kinder Morgan announced a plan to expand working gas storage capacity at the Markham, Texas, salt dome between Houston and Corpus Christi. The company will lease an additional cavern and add more than 6 Bcf of incremental working gas storage capacity and 650 MMcf/d of incremental withdrawal capacity on its Texas intrastate pipeline system.

'Temporary glut'

However, the high natural gas production numbers have not translated into a surge in stock prices for midstream companies. As the increase in supply over the past year has led to a collapse in gas prices, investors have been holding down the price of midstream stocks because they expect production to tail off in response in the coming months. On June 7, the benchmark Henry Hub natural gas spot price had fallen to $1.95/MMBtu from a high of $9.43/MMBtu one year ago.

The expectation is for an eventual slowdown in natural gas production, though not immediately in the Permian.

"A mismatch between natural gas supply and demand growth in 2023 is likely to create a temporary glut of gas supply, which we believe will continue to pressure natural gas prices," Wells Fargo reported in its Midstream Monthly Outlook for June. The company expected production to slow primarily in the Haynesville and Midcontinent areas generally.

As any production cuts eventually affect midstream earnings, stock prices over the first quarter reflected the marketplace's caution in the gas market.

In the first quarter, the stocks of midstream companies with a heavier stake in natural gas infrastructure did not perform as well as those emphasizing oil transport. Enterprise, Cheniere Energy and Energy Transfer all posted stock price gains of over 5%. Magellan Midstream gained 8% on its stock price in the first quarter, rising to $55.41. (After the announcement of its acquisition by ONEOK in mid-May, the price reached $60.18 by June 15.

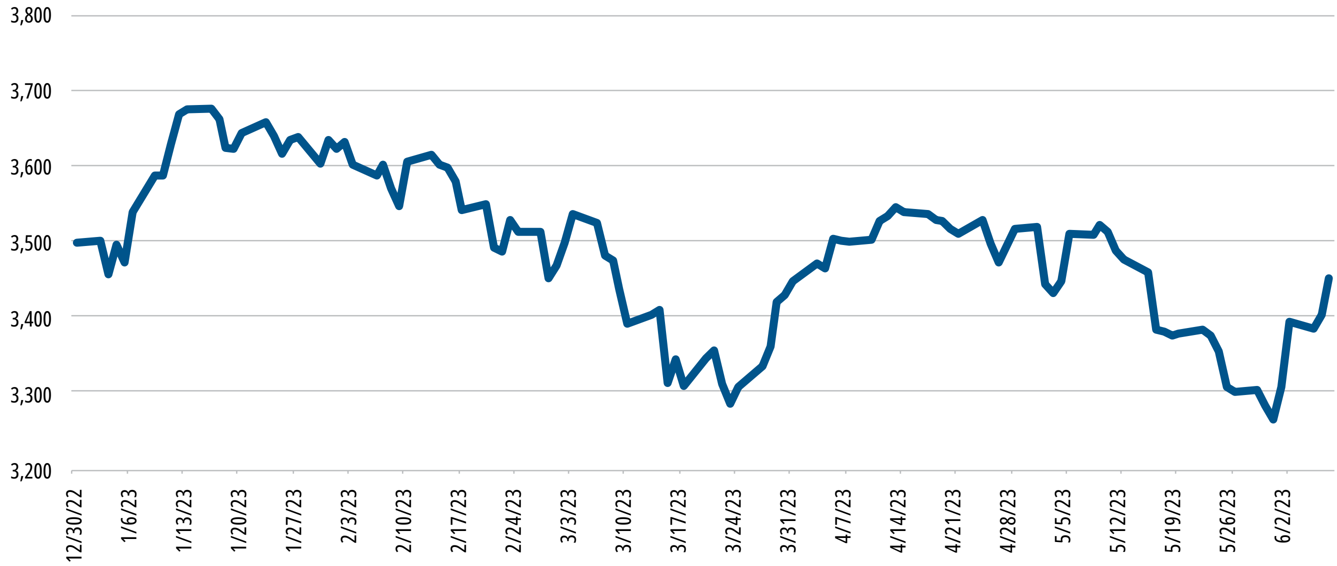
Equity repurchases slow

Meanwhile, natural gas-heavy Targa, Enbridge and Kinder Morgan saw their stock prices drop slightly. Several investors saw ONEOK's purchase of Magellan as a move into oil.

"Most of the (gathering and processing) players highlighted continued activity by crude-focused (exploration and production) in the liquid basins despite recent softness in oil prices, as the current price range still allows economic drilling. For gas, some curtailment in activity is expected in the dry gas basins, and midstream players are hoping for some firming up in gas prices for activity levels to resume,"

Middling Midstream Stock Performance

The Dow Jones Brookfield Oil and Gas Storage & Transportation Infrastructure Index, which tracks global companies, was down 1.4% as of June 7. U.S. companies constitute 49.9% of the weighted index's value.



Source: S&P Dow Jones Indices

Seaport Research said.

While commodity prices fell, the strong demand for their services has generally allowed infrastructure companies to keep sharing solid-to-excellent earnings with their investors, though equity repurchases slowed in the year's first quarter.

About three-quarters of the Alerian Midstream Energy Index (AMNA) companies had buyback authorizations in place at the end of May. Led by Cheniere, eight of those companies spent a combined $780 million on buybacks in the first quarter, according to industry analyst VettaFi. At $450 million, Cheniere outspent all others combined, while Kinder Morgan spent $113 million.

The purchases showed a steady, if slowing, rate of equity purchases in the market. Over the three prior quarters, buyback expenditures had averaged $1.4 billion with the same companies.

The slowdown showed that, while buybacks will continue to be essential to returning money to investors, companies with a more opportunistic approach will be less active, VettaFi said.

Projects' progress

Companies with large stakes outside of the Permian otherwise moved to shore up their share of the marketplace or move important projects forward.

Enbridge currently moves the majority of Canadian crude through the U.S., and at the start of June, the company began slashing its shipment rates in anticipation of new competition coming online next year.

The long-delayed and embattled Trans Mountain Pipeline received $2.25 billion in loan guarantees at the end of May from the Canadian government, which owns the line. Once open, the project will move an additional 590,000 bbl/d of crude from Alberta to the coast of British Columbia.

Enbridge will implement a rate cut in July of about 12%, to $28.80/cu. m, to move oil from its Hardisty, Alberta, hub along its Mainline to Flanagan, Ill., Enbridge reported in a regulatory filing. Enbridge officials said the move was a way to shore up its customer base well before the opening of the Trans Mountain project, which has been hit with cost overruns and has been a political football for the Canadian government.

In the U.S., Energy Transfer moved forward with a government appeal to the Department of Energy. The company's Lake Charles, La., LNG project ran into difficulties in April, when the DOE refused to grant an extension to start exporting beyond 2025.

The government said Lake Charles LNG had not shown good cause for "an unprecedented second extension" beyond 2025.

However, according to Citi, Energy Transfer made a "strong appeal" on June 7, which put the company on a 30-day "positive catalyst watch."

In its appeal, Energy Transfer outlined that it had already spent $350 million on the project and expected to sign an engineering, procurement and construction contract by July.

Also in June, Williams Cos.' CEO Alan Armstrong said the first phase of the expansion of the Regional Energy Access pipeline would be complete in the fourth quarter. The expansion will provide an addition 830 MMcf/d to customers in New Jersey, Pennsylvania and Maryland. The second phase of the $1 billion project is scheduled to enter service in late 2024.

Another Williams project, the Louisiana Energy Gateway pipeline, is on track for completion in fourth-quarter 2024. The 1.8 Bcf/d project will connect Haynesville Shale producers to LNG facilities on the Gulf Coast.

Overall, midstream companies continued with a cautious approach. The demand for infrastructure remains high and natural gas continues to have high demand overseas, but the high production rates of natural gas are expected to drop, following the trend in prices.

"… The lower commodity prices we've experienced this year will have midstream operators being cautious when it comes to their outlook for pipeline volumes and for new project developments that depend on growing volumes," Howard said. "Midstream companies have been much more disciplined when it comes to deploying capital lately and I would expect them to stay disciplined in light of weaker commodity prices." OGI

Patton: Shall We Dance?

Water management and ESG goals move in tandem across the Permian, Eagle Ford, Bakken and Appalachian regions.

BY PATRICK PATTON
PRODUCT MANAGER,
B3 INSIGHT

The oil and gas industry must make its way through an intricate choreography to effectively bridge the water management challenges of the past with the climate change responses of the present.

But there is no tap dancing around a fundamental question: Can the industry transition from precious ground and surface water resources to rely solely on produced water for completions?

Each U.S. oil and gas basin presents unique characteristics—geological, climatic, topographic, political—that influence how water is managed. These distinct factors not only dictate the financial aspects of water management but also the challenges faced in achieving ESG goals.

Permian Basin's Texas two-step

The Permian Basin produces more water than other U.S. basins due to its high water-to-oil ratio and intensive drilling. In contrast, the Eagle Ford, Bakken and Appalachian regions require less water for completions, largely driven by their drilling routines.

Impressively, recycled water usage has grown from an estimated 10% in 2018 to over 30% today. B3 Insight predicts that by 2030, over 65% of completion fluid will come from produced water, further reducing reliance on groundwater aquifers.

In theory, the Permian Basin could run on 100% recycled water for completions, eliminating the need for groundwater sources. However, this lofty goal requires industrywide collaboration and a robust marketplace for water trading. And while the Permian is a shining example of progress, its template isn't a one-size-fits-all solution for other basins.

Appalachian Basin's ballet of efficiency

The Appalachian Basin presents a different story. Although often touted as recycling nearly 100% of its produced water, our estimates show that only around 65% of produced water in this region is recycled. The discrepancy can be attributed to the basin's challenging geography and numerous landowners complicating water transportation and leading to a reliance on trucking for water transport.

Still, the Appalachian Basin's performance is impressive. Despite its challenges, this basin outperforms its peers in water usage per barrel of oil equivalent. Altogether, the Appalachian Basin requires 83% less water for completions while producing only 35% less hydrocarbons than the Permian, earning it a spotlight on the industry stage.

Bakken's different beat

The Bakken Shale, straddling western North Dakota, eastern Montana and southern Saskatchewan in Canada, is unique, as well. It requires significantly less water per completion, roughly half the requirement of the Appalachian and Permian Basins. But it faces its own set of challenges.

Utilizing 100% recycled water is feasible in the Bakken, but the region's rugged terrain and harsh winters can wreak havoc with pipeline hydraulics and impoundment management. Nevertheless, the industry has learned to adapt.

Eagle Ford's resilient rumba

The Eagle Ford Shale is resilient, despite a slowdown in activity since 2018. The water-to-oil ratio is less than 1:1, and operators must navigate extreme temperatures, landowner logistics and ensuring that water is in the right place at the right time.

Even though daily water production nearly matches the source water requirement, recycling in the Eagle Ford is not as simple as in other regions. Ensuring that 100% of completion water is recycled isn't economically feasible there because of the produced water's chemical composition. That creates the complication of sourcing from nearby groundwater wells to meet specific completion fluid requirements.

Finding harmony with ESG goals

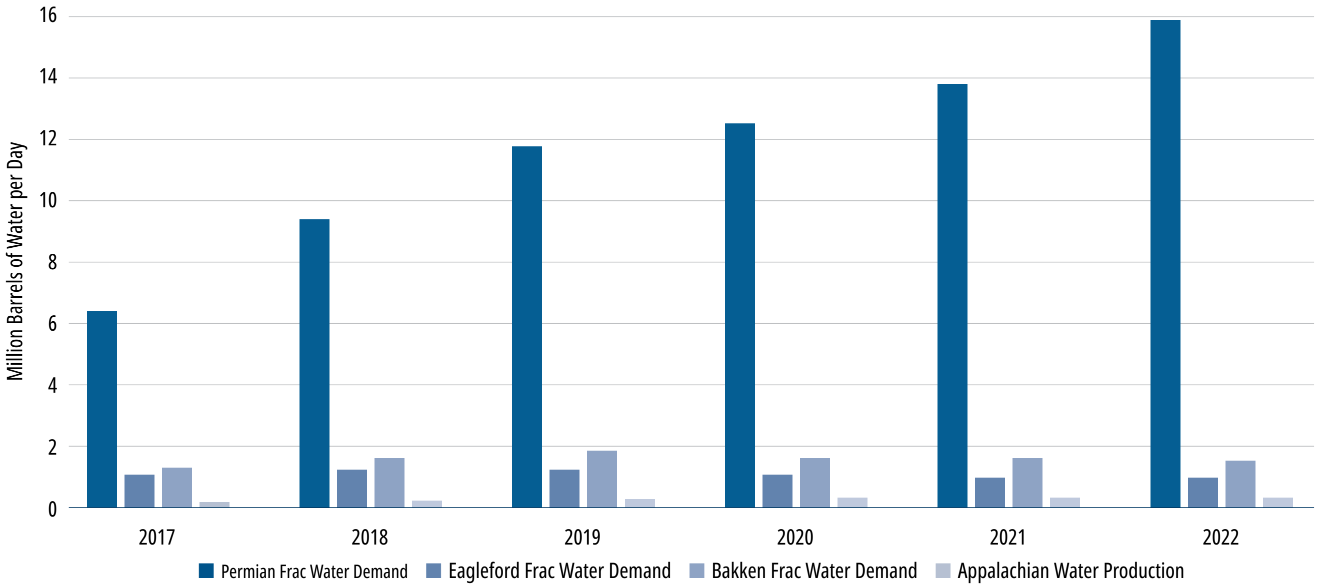
ESG investors demand that the industry dance to a different tune, one in which it must adapt to the demands of climate change and water resource conservation, and recognize that in some regions, reliance on freshwater resources may be inevitable.

Concerns about water resources haven't fallen on deaf ears. Operators are walking a fine line, balancing their responsibility to shareholders with the need for responsible water management.

In the Appalachian Basin, the benefits of gas production—from an energy-per-impact standpoint—outweigh the costs of water resources. However, in basins like the Permian, there's opportunity to conserve billions of barrels of water by using produced water for completions. Despite the growth in produced water utilization, there's room for even more. OGI

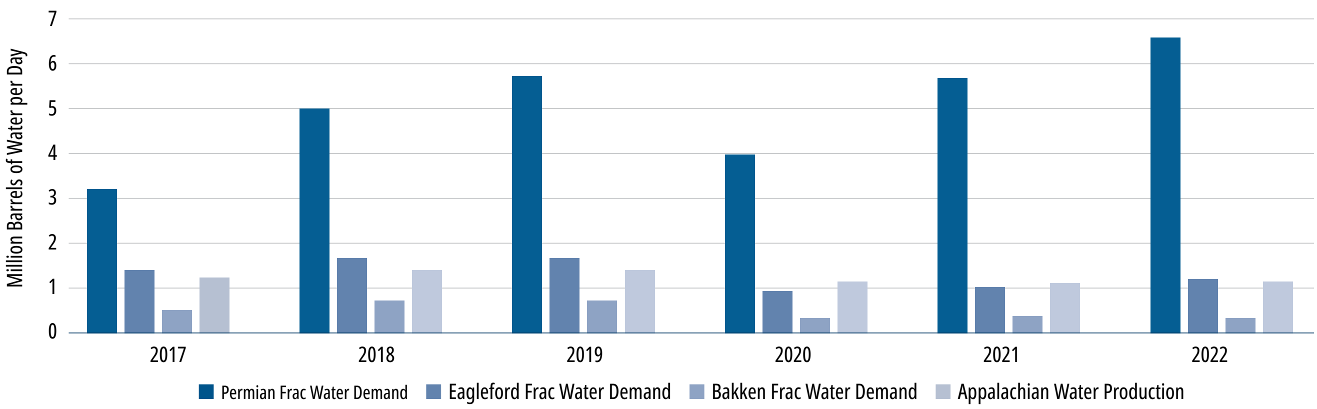
Regional Water Management Performance

Water Production



Annual water production estimates and reported figures across the Permian Basin, Eagle Ford Shale, Bakken Shale and Appalachian Basin during 2017-2022. This data includes Midland and Delaware sub-basins for the Permian; Pennsylvania, Ohio and West Virginia for the Appalachian; and North Dakota for the Bakken. For the Eagle Ford, the region considered extends from the Texas-Mexico border northeast toward Houston.

Source Water Demand



Annual source water demand for the Permian Basin, Eagle Ford, Bakken and Appalachian Basin from 2017-2022. This graph represents the total volume of water needed daily for horizontal completions, highlighting the Permian Basin's significant fracking water needs.

Source: B3 Insight's "2022 Annual Produced Water Forecast"

Carlson: To Flare or Not to Flare?

Permian midstream mismatch has consequences for ESG-minded industry.

JUSTIN CARLSON
EAST DALEY ANALYTICS

Justin Carlson is co-founder and chief commercial officer for East Daley Analytics.

Are oil and gas producers able to turn the page on natural gas flaring practices?

Operators in the Permian Basin face hard decisions over the next 12 months due to a mismatch between production capacity and midstream infrastructure, according to a new study by East Daley Analytics and Validere.

East Daley collaborated with Validere, a measurement, reporting, and verification SaaS company, to quantify the environmental consequences of a shortfall in gas pipeline takeaway from the Permian. For over a year, our "Permian Supply and Demand Forecast" has pointed to bottlenecks starting in early 2023 as a result of rapid supply growth. Low and sometimes negative Permian gas prices since fourth-quarter 2022 confirm egress pipelines are not adequate for current production levels.

The study, "Emissions Critical: Flaring, Methane, and the Cost of Looming Permian Gas Takeaway Constraints," considers several market outcomes for the Permian. In our base case, excess gas production averages 200 MMcf/d over 17 months and peaks at about 500 MMcf/d in May 2024. We also looked at a scenario with flat Permian rigs (rigs decline in our base case given the backwardated WTI price curve) and a third scenario assuming delays in new pipeline projects.

According to Validere, each 100 MMcf/d of flaring adds 2.2 million tons of CO_2 emissions per year and methane emissions contribute an additional 1 million tons of CO_2 equivalent emissions per year, based on a 20-year greenhouse gas impact at 98% combustion efficiency. In the base case, we estimate excess gas averages 146 MMcf/d in 2023; if all this gas were flared, the Permian midstream bottleneck would generate about 4.7 million tons of CO_2e.

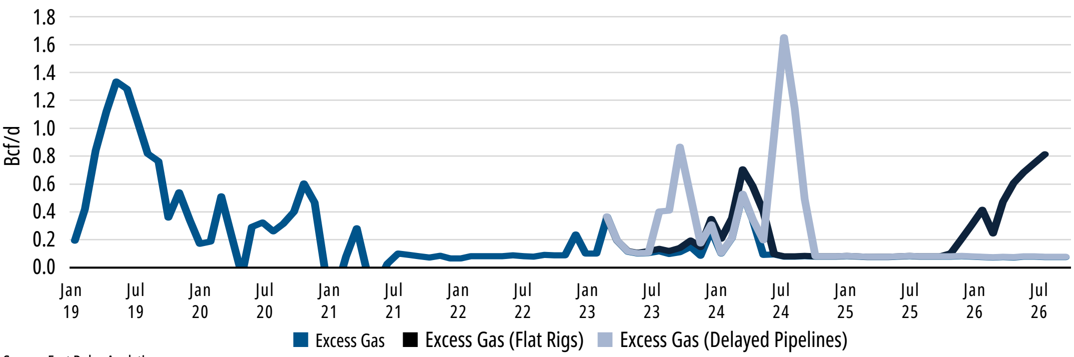
The excess gas problem grows worse if Permian rig counts are higher than we assume or if new pipeline projects are delayed. Under any scenario, the start of the 2.5 Bcf/d Matterhorn Express Pipeline in mid-2024 will be critical to realigning the gas supply chain. Compressor expansions planned on Permian Highway and Whistler pipelines in the back half of fourth-quarter 2023 will add 1 Bcf/d to help alleviate the bottleneck.

In the "Delayed Pipeline" scenario, we assume the two compressor expansions are delayed by three months while the more complex Matterhorn is delayed by six months. The scenario is salient, given the industry is already seeing some slippage in construction timelines. On its first-quarter 2023 earnings call, Kinder Morgan guided to a one-month delay for the Permian Highway expansion to December 2023, citing supply chain issues in procuring equipment and materials. Assuming producers do not further reduce drilling in response, excess gas production in the "Delayed Pipeline" scenario would spike to over 800 MMcf/d at year-end 2023 and 1.6 Bcf/d at year-end 2024, or double the base case.

Of course, flaring isn't the only option for producers; they could opt to slow drilling, defer completions or shut in wells. The industry saw a similar scenario play out in 2019, the last time infrastructure failed to keep pace with Permian supply growth. The associated surge in Permian flaring rates brought increased environmental scrutiny and new commitments by industry to curtail or end flaring as part of ESG frameworks.

Given the recent history, it is unclear whether producers can lean on flaring once again to manage through the pipeline bottleneck and keep oil flowing. In mid-2024, when East Daley estimates the excess gas problem to be at its worst, producers would need to take the equivalent of 200,000 bbl/d of oil production offline to avoid flaring. If they need to flare, producers should focus on managing their operation to ensure they keep the flare lit and combustion efficiency high, because vented methane is a far worse outcome. OGI

Permian Flaring Scenarios



Source: East Daley Analytics

Events Calendar

The following events present investment and networking opportunities for industry executives and financiers.

Scan me

EVENT	DATE	CITY	VENUE	CONTACT
2023				
LNG2023	July 10-13	Vancouver, British Columbia	Vancouver Convention Center	lng2023.org
US Offshore Wind 2023	July 11-12	Boston	Hynes Convention Center	reutersevents.com
IAEE European Conference	July 24-27	Milan, Italy	Bocconi University	aiee.it/iaee_2023
KIOGA Annual Convention & Expo	Aug. 20-22	Wichita, Kan.	Hyatt Regency	kioga.org
Texas Energy Forum 2023	Aug. 23-24	Houston	Petroleum Club of Houston	usenergystreamforums.com
2023 OGA Annual Conference	Aug. 28	Norman, Okla.	Norman Hotel & Conference Center	okgas.org
SEG/AAPG IMAGE Conference	Aug. 28-Sept. 1	Houston	George R. Brown Conv. Ctr.	imageevent.org/2023
Carbon & ESG Strategies 2023	**Aug. 30-31**	**Houston**	**Norris Centers**	**hartenergy.com/events**
SPE Offshore Europe Conference & Exhibition	Sept. 5-8	Aberdeen, Scotland	P&J Live	offshore-europe.co.uk
Solar Power International	Sept. 11-14	Las Vegas	The Venetian Conv. & Expo Ctr.	re-plus.com
GPA Midstream Convention	Sept. 17-20	San Antonio	Marriott Rivercenter on the River Walk	gpamidstreamconvention.org
World Petroleum Conference	Sept. 17-21	Calgary, Alberta	BMO Centre, Stampede Park	24wpc.com
America's Natural Gas Conference	**Sept. 27**	**Houston**	**Westin Galleria**	**hartenergy.com/events**
Energy Capital Conference	**Oct. 2**	**Dallas**	**Statler Hotel**	**hartenergy.com/events**
A&D Strategies & Opportunities	**Oct. 3**	**Dallas**	**Statler Hotel**	**hartenergy.com/events**
Offshore WINDPOWER Conference & Exhibition	Oct. 3-4	Boston	Hynes Convention Center	cleanpower.org
Clean Energy Technology	**Oct. 23-24**	**San Antonio**	**Marriott Rivercenter on the River Walk**	**hartenergy.com/events**
OTC Brasil	Oct. 24-26	Rio de Janeiro	Centro de Convenções SulAmérica	otcbrasil.org
39th USAEE/IAEE North American Conference	Oct. 23-26	Houston	Omni Hotel	usaeeconference.com
WEA Wildcatter of the Year	Nov. 4	Denver	Sheraton Denver Downtown	westernenergyalliance.org
Louisiana Energy Golf Open	Nov. 6	Lafayette, La.	Oakbourne Country Club	loga.la
Energy Transition North America 2023	Nov. 7-8	Houston	TBD	reutersevents.com
IPAA Annual Meeting	Nov 6-8	San Antonio	JW Marriott San Antonio Hill Country	ipaa.org
Rice Energy Finance Summit	Nov. 10	Houston	Rice University	business.rice.edu
OK Petroleum Alliance Fall Conference	Nov. 15-16	Oklahoma City	The National Hotel	thepetroleumalliance.com
Executive Oil Conference & Exhibition	**Nov. 15-16**	**Midland, Texas**	**Midland County Horseshoe Arena**	**hartenergy.com/events**
DUG Appalachia Conference & Exhibition	**Nov. 29-30**	**Pittsburgh**	**David L. Lawrence Convention Center**	**hartenergy.com/events**
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Tuesday, odd mos.	Fort Worth, Texas	Petroleum Club of Fort Worth	adamenergyfortworth.org
ADAM-Greater East Texas	First Wed., odd mos.	Tyler, Texas	Willow Brook Country Club	etxadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.org
ADAM-Permian	Bi-monthly	Midland, Texas	Petroleum Club of Midland	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.org
ADAM-Rockies	Second Thurs./ Quarterly	Denver	University Club	adamrockies.org
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.

▸ PERSPECTIVES

Voices

If there was a topic important to oil and gas professionals, speakers at SUPER DUG had plenty to say about it.

"Core Bakken and (Fort Berthold Indian Reservation) and Little Knife are very competitive among North American oil plays in terms of returns and breakevens."

—**Wade Hutchings,** *COO, Enerplus*

"How can we reduce the emissions with respect to the actual drilling activity—not the well as our focus, but the powering of that rig? So, electrification is a huge push, but not just electrification, but also when we can't electrify ... bringing in power from another source."

—**James Hall,** *senior director for energy transition solutions, Nabors Industries*

"Capex is going towards oil, but maybe the longer-term opportunity [is] in gas."

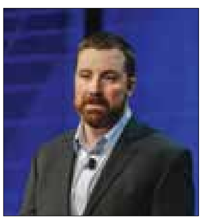
—**Robert Clarke,** *vice president of upstream research, Wood Mackenzie*

"[The 62,000-acre acquisition from Exxon Mobil] was a fun little base hit for us. We were able to block up some things and pick up some additional three-mile laterals."

—**Charles Ohlson,** *senior vice president for production, Chord Energy*

"We should be ashamed as an industry about the very puny recovery factors we have."

—**Clay Gaspar,** *executive vice president and COO, Devon Energy*



"We think [the Uinta] is one of the most economic areas in the Lower 48. By being willing to go ... off the beaten path, we've been able to amass pretty significant undeveloped inventory."

—**Mark Graeve,** *executive vice president of reservoir and development, XCL Resources*

'We Love the Harkey'

The Delaware Basin's Harkey Mills sandstone is producing on a par with neighbors Bone Spring and Wolfcamp.

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The Harkey Mills sandstone is adding new-well inventory to northern Delaware Basin operators' portfolios, showing production just as prolific as its stratigraphic neighbors, the Bone Spring and Wolfcamp.

Sitting between the second and third Bone Spring, overlying the Wolfcamp, the "low-stand submarine fan deposit" has seen laterals dating back more than a decade, according to Marshall D. Davis, whose master's thesis in 2014 was based on the Harkey.

"We love the Harkey," Tom Jorden, Coterra Energy chairman, CEO and president, told securities analysts this spring. The development approach to it in its Culberson County, Texas, leasehold is "variable," he added. "It's not a 'one size fits all.' So, around the basin, it's going to vary.

"But in a lot of our position, it competes very nicely with Wolfcamp."

Coterra is landing Harkey wells as it continues to examine how to develop it. "We've got a lot of Harkey in our program," he said. "I think we'll continue with that. And it depends on where you are. There are places where it's right on top of the Wolfcamp; there are places where it's a little lower than the Wolfcamp.

"But it's one of the best landing zones in the basin. I'll say that flat out."

Davis wrote his thesis, "Petroleum Geology of the Leonardian Age, Harkey Mills Sandstone: A New Horizontal Target in the Permian Bone Spring Formation, Eddy and Lea Counties, Southeast New Mexico," while studying at the University of Texas at Arlington. He was working at the Bass family's Bopco at the time and cited its data in his research. Exxon Mobil purchased Bopco for $6.6 billion in cash and stock in 2017, gaining 275,000 acres, with 250,000 of those in the Permian.

Davis reported that four horizontals in the Harkey in Eddy County produced 176,000 bbl of oil and 708 Mcf combined during three years online.

As to interference, Jorden told analysts in other, recent calls that "when it comes to the Wolfcamp and Harkey, we generally see that as one petroleum system."

Thus, there will be some communication. "But we do not see that as a factor that degrades overall well productivity."

Findings to date are that "having the two landing zones does not interrupt or impede your overall recovery out of that drilling spacing unit. So, we don't see that as a significant issue for the Wolfcamp/Harkey."

Erin Faulkner, an Enverus analyst, reported in April that Coterra's 2022 Harkey/Wolfcamp test consisted of four in Harkey on 1,320-foot spacing with eight in the upper Wolfcamp on 700-foot spacing.

> ***"The Harkey is excellent compared to the Wolfcamp. I mean, they're neck and neck."***
>
> —**Tom Jorden,** ***chairman, CEO and president, Coterra Energy***

"The company was pleased with the results and anticipates that future Wolfcamp/Harkey co-developments with 10,100-foot laterals will pay out in six months at $75 [oil] and $3.50 [gas]."

A Coterra test that's expected to come online later this year consists of nine Wolfcamp wells and four Harkey, she added.

Jorden told analysts that "the Harkey is excellent compared to the Wolfcamp. I mean, they're neck and neck."

He added, "If you had to choose between really great Wolfcamp A or Harkey, it'd be like asking which one of your kids you like best. It's a really tough choice."

Overall, the Harkey may add about five years to Coterra's top-tier inventory. "Harkey is terrific," Jorden said. "… Harkey stands shoulder to shoulder with the best of our landing zones. And we think we have a lot to do in the upcoming years."

Earthstone Energy is also landing in Harkey, it reported. Two wells in Lea County, N.M., averaged some 1,600 boe/d each, 87% oil, in their first 24 days online from 7,500-foot laterals. It expected payout within four months from first production.

Randy Nickerson, Caza Petroleum's COO, told Hart Energy in 2019 that Eddy County's Harkey "is a little more highly oil saturated than the other [zones].

"I think you're going to see that's going to be a new bench out there that people are going to start building. There are some older wells on it that maybe discourage people, but it's a pretty good zone."

Davis' analysis of 625 old, vertical wells found "the best reservoir rock occurs within the apex of turbidite channel deposits proximal to the slope fan." Net thickness is up to 80 feet; porosity, at least 8%. OGI