Oil and Gas Investor

NO HALF STEPPIN'

Private Equity Takes Midstream All the Way

PRIME PERMIAN

Industry Pushes Production to Pre-Pandemic

CCUS

Texas Wants to Capitalize on Carbon Storage

BUILDING for the FUTURE

Civitas CFO Marianella Foschi Shares Growth Strategy

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DECEMBER 2022

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Co-Manager	Financial Advisor	Joint Bookrunner	Joint Bookrunner	Financial Advisor

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LONESTAR RESOURCES	Cactus	TALOS ENERGY	MARTIN MIDSTREAM PARTNERS	LONESTAR RESOURCES
ACQUIRED BY PENN VIRGINIA CORPORATION	FOLLOW-ON OFFERING	SENIOR SECURED NOTES	HAS SUCCESSFULLY CONSUMMATED ITS DEBT EXCHANGE, FINANCING, AND CASH TENDER	CHAPTER 11 RESTRUCTURING
Fairness Opinion	Co-Manager	Senior Co-Manager	Financial Advisor	Financial Advisor

UNDISCLOSED	$270 MILLION	UNDISCLOSED	UNDISCLOSED	UNDISCLOSED
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Financial Advisor	Financial Advisor	Financial Advisor	Financial Advisor	Financial Advisor

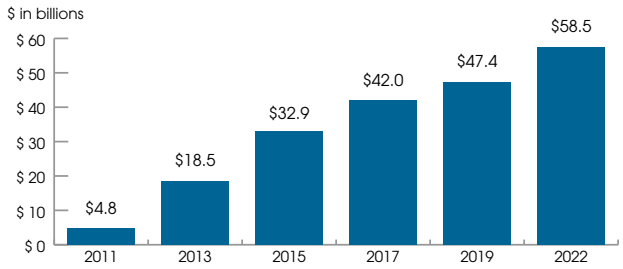
ENERGY GROUP KEY STATISTICS

$58+ Billion
Aggregate Transaction Volume since 2009

$310 Million
Average Transaction Size

189
Transactions Closed since 2009

ENERGY GROUP AGGREGATE TRANSACTION VOLUME



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Oil and Gas Investor
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Oil and Gas Investor

by HARTENERGY

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ENERGY TRANSITION

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ABOUT THE COVER: Photographer Michael Ciaglo spent an afternoon in October at Civitas Resources' Denver headquarters to photograph CFO Marianella Foschi for *Oil and Gas Investor*.

NOG CLOSES DEALS

$3.0 Billion of Deals Signed Since 2018

PERMIAN

50+ Transactions

including:

VERITAS ENERGY, LLC

LAREDO PETROLEUM

$1.2 Billion+

2021-2022

WILLISTON

250+ Transactions

including:

W Energy Partners

PIVOTAL PETROLEUM PARTNERS

FLYWHEEL ENERGY

SALT CREEK OIL+GAS

COMSTOCK RESOURCES

INCLINE ENERGY PARTNERS

$1.1 Billion+

2018-2022

MARCELLUS

Northern Oil

purchased non-operated assets from:

Reliance Marcellus, LLC

$120.9 Million

Closed April 2021

NOG

Northern Oil and Gas, Inc.

Adam Dirlam, *President*
Nicholas O' Grady, *Chief Executive Officer*

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INDUSTRY'S SUPPORT IN UNSEATING DEMOCRATS IS WORKING

RING THE BELL

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Elections easily turn based on issues that candidates have little to zero power to influence. U.S. presidents' ability to influence the price of gasoline is limited, and yet extraordinary fuel costs—whether high or low—generally find a place in campaign materials, and pollsters use it as a guide for turnout.

What's more, voter approval is largely based on personal economy and who is perceived to be in charge.

For most of the past 50 years, the industry's performance when the federal government is in the hands of Republicans and Democrats produces what may be a counterintuitive result. The only exception is two of former President George W. Bush's eight years in office. By and large, oil and gas fares stronger with Democrats in office.

"We're producing a million more barrels of oil a day now than when Joe Biden took office," former U.S. Sen. Byron Dorgan, who represented North Dakota as a Democrat in Congress for 30 years, told Hart Energy. "We use in the United States about 20 million barrels of oil a day, and my sense is that we're going to need to continue using oil and gas for a good number of years."

Philosophically and in practice, Democrats want to limit growth in the oil and gas industry, University of Houston Energy Fellow and economics lecturer Ed Hirs said.

Hirs is also managing director of Hillhouse Resources, an independent E&P that develops acreage along the Texas-Louisiana Gulf Coast.

"If you start limiting things, you tend to actually promote higher prices," he told Hart Energy. "In the oil patch, they can talk all they want about regulatory costs and those items. I'll take $5 a barrel of regulation if I can get my $20 a barrel of revenue back."

But the more things change, the more they stay the same.

A decade ago, industry sentiment toward then-sitting President Barack Obama was best described as "visceral disdain, beyond dislike," the late John Hofmeister, former president of Shell USA, told Steve LeVine at Quartz.

"[Obama is] basically viewed as a know-nothing, empty suit by the industry, using whatever language he needs to so that people think he's engaged and doing something. In meetings with energy executives that I have all the time, it doesn't take much to get people to a level of angst about Obama that some spit and some just curse," Hofmeister said.

During the 2012 election cycle, the industry and its advocates' support for Republican candidates accounted for 89% of the $42.6 million spent that year, according to the Center for Responsive Politics, a watchdog group that has since merged with OpenSecrets.org.

Oil prices increased more than 35% during Obama's tenure. In 2015, his administration—in conjunction with a Republican-controlled Congress—repealed the ban on U.S. oil exports in place for more than 40 years.

Nevertheless, the industry displayed a similar recoil when Obama's former running mate ran for president against businessman Donald Trump, according to polling of Texas Oil and Gas Association members.

Hirs pointed out that in the special interest group's survey, 76% of its membership feared a Joe Biden presidency more than an ongoing oversupply of oil.

And yet, there is this dirty little secret given a voice by longtime energy consultant and investment adviser James Wicklund.

"The oil industry always does better under Democrats than under Republicans," he said during Hart Energy's Energy Capital Conference in Dallas. "They increased the rules and regulations, and they raised the cost, which raises the price and we all make more money."

When Trump took office on Jan. 20, 2017, benchmark WTI oil traded for $52.33/bbl.

At the conclusion of his single, four-year term, the price was 9 cents down, trading for $53.24/bbl on Jan. 20, 2021.

Oil prices popped and dropped between 2017 and 2021. Importantly, his term included the historic collapse on April 19, 2020, when WTI plummeted to minus $37.63/bbl during the early weeks of the COVID-19 pandemic.

As such, it was a global catastrophe that was really calling the shots. The leanings of American politicians were largely irrelevant. OGI

WHAT CAN WE EXPECT FROM DIVIDED GOVERNMENT?

ENERGY POLICY

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CORNERSTONE GOVERNMENT AFFAIRS
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Elections have consequences, especially for U.S. energy and environmental policy, and the recent midterm elections are no exception. While the Republican red wave that many had anticipated did not materialize, the resulting narrow Republican control in the House of Representatives and narrow Democratic control in the Senate will significantly change how policies are developed and implemented.

Perhaps the most important consequence is that the Biden administration will not be able to implement comprehensive legislation like the recently enacted Inflation Reduction Act (IRA) or the Bipartisan Infrastructure Law that was put into place last year.

Additionally, given Congress's obligation to conduct program and budget oversight over federal agencies, the Republican-controlled House can be expected to hold hearings on energy and environmental policy topics with witnesses from entities like the Department of Energy, Department of the Interior, Environmental Protection Agency (EPA) and Federal Energy Regulatory Commission (FERC). The hearings will be quite contentious, focusing on issues like the lack of federal oil and gas leasing, LNG export permitting, pipeline approvals and EPA regulation of methane and ozone.

Republican control of the House also means that Democrats will not be able to impose new windfall profit taxes on the oil and gas industry. Such a tax would have been very difficult even under total Democratic control. Now, it is implausible.

Through the appropriations process, Congress determines how much federal money is spent, what it is spent on and how it is applied to specific activities and programs. Through the power of the purse, Congress can prevent the executive branch from taking certain actions, such as writing or enforcing a rule, or require it to take a certain action, like holding a lease sale. Had the Republicans taken the Senate, Congress could have worked to reverse some administration actions through appropriations legislation. With split control of Congress, the appropriations process will not be as impactful of policy. Appropriators will instead struggle to resolve differing priorities of the two houses of Congress.

As the chief executive, the president still holds great power, even with a dissenting House of Representatives. The Biden administration will therefore continue to push its energy and environmental policy centered on increased agency and environmental regulation as well as investment in clean energy and climate equity projects and climate-related policies despite congressional opposition. In the coming two years, additional executive orders related to energy and the environment can be expected. The administration will also continue to implement and support renewable energy-related elements included in the IRA and Bipartisan Infrastructure Law without significant congressional objection. As it continues to move forward with Securities and Exchange Commission rules regarding climate and ESG disclosure, the House will likely hold oversight hearings but will be unable to stop the rulemakings.

With the president's broad authority over foreign policy, he will continue to make commitments related to climate change and greenhouse emissions. Current U.S. policy on OPEC and foreign trade will not likely change significantly, and Congress would not have had the power to change those policies even if Republicans had taken both houses.

Despite expected additional efforts, it appears highly unlikely that a permitting reform bill previously promised to U.S. Senate Energy and Natural Resources Committee chairman Joe Manchin (D-WV) will be voted on during the "lame duck" session at the end of the current Congress. As such, it can be a starting point for the Senate to work on bipartisan legislation at the beginning of the next Congress.

Sen. John Barrasso (R-WY), who will be the ranking member on the committee, will have some common ground with chairman Manchin in terms of pushing for more domestic fossil energy production in the U.S. and opposing the anti-oil and gas policies of the administration. Manchin recently flexed his muscles by announcing he would not hold confirmation hearings for Federal Energy Regulatory Commission (FERC) chair Richard Glick. This likely reflects Manchin's opposition to recent statements by the President about the demise of coal and opposition to oil and gas drilling as well as FERC scrutiny of natural gas projects.

While a red wave would have put greater pressure on the Biden administration with regard to its energy agenda, the 118th Congress will still yield some positive outcomes for the oil and gas industry. In the next two years, we can expect continued gridlock, which means that there will not be any major policy swings in either direction. Instead of playing offense, as they had hoped, they will instead be playing defense. Given the full range of possibilities, that certainly isn't the worst possible outcome for the oil and gas industry. OGI

Watch the Energy Policy Watch series with Cornerstone's Jack Belcher.

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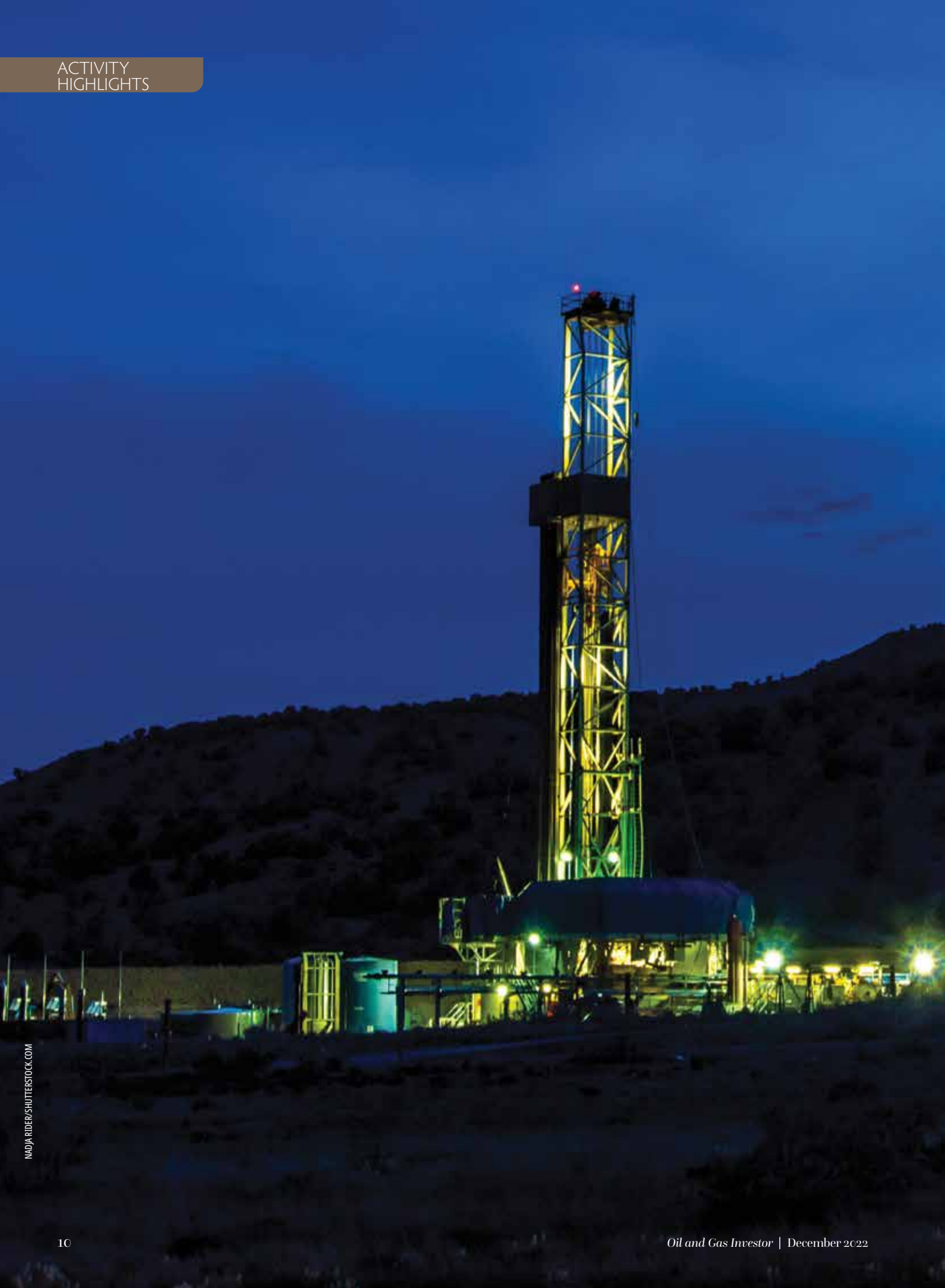

NADJA RIDER/SHUTTERSTOCK.COM

PRODUCTION IN THE PICEANCE-UINTA BASIN TOTALED 181 MMBOE IN 2021.

PERMITS

Terra Energy Partners LLC, a private equity-backed oil and gas producer operating in the Piceance-Uinta Basin, has garnered plenty of attention this year.

It has been the subject of reports that Kayne Anderson Capital Advisors and Warburg Pincus were exploring a sale of the company for $2.5 billion, including debt. It was also involved in a hearing for an air emissions permit for its wastewater treatment facility in Parachute, Colo.—a hearing that took 13 years to come about because state regulators struggling with an enormous backlog fell behind.

Terra is also the monthly leader in securing permits among all U.S. E&Ps. According to its website, the company operates about 6,800 wells on about 370,000 net acres in the Piceance Basin in Colorado, mostly in the gas-rich Williams Fork Formation.

The leader among counties was not within the borders of Texas this month. Campbell County, Wyo., in the Powder River Basin, led all with 44 permits, just ahead of Midland County, Texas. EOG Resources Inc. is the leading producer in Campbell County, and it ranks among the leading operators in permitted wells with 20.

Permitted Wells By State

State	Well Count
Texas	452
Colorado	119
Wyoming	68
Oklahoma	35
North Dakota	33
Louisiana	29

Permitted Wells By Operator

Operator	Well Count
Terra Energy Partners	38
ENG	38
The Anschutz Corp.	35
Verdad Resources	27
Double Eagle IV	23
EOG	20
Chevron Corp.	16
Blackbeard Operating	16
Pioneer Natural Resources	15

Permitted Wells By County

County	Well Count
Campbell, Wyo.	44
Midland, Texas	42
Loving, Texas	38
Martin, Texas	31
Upton, Texas	31
Reeves, Texas	30
Glasscock, Texas	24
Crane, Texas	21
Howard, Texas	20
Dimmit, Texas	19
Caddo, La.	10
DeSoto, La.	10

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Get a glimpse into who attended DUG Haynesville in the past!

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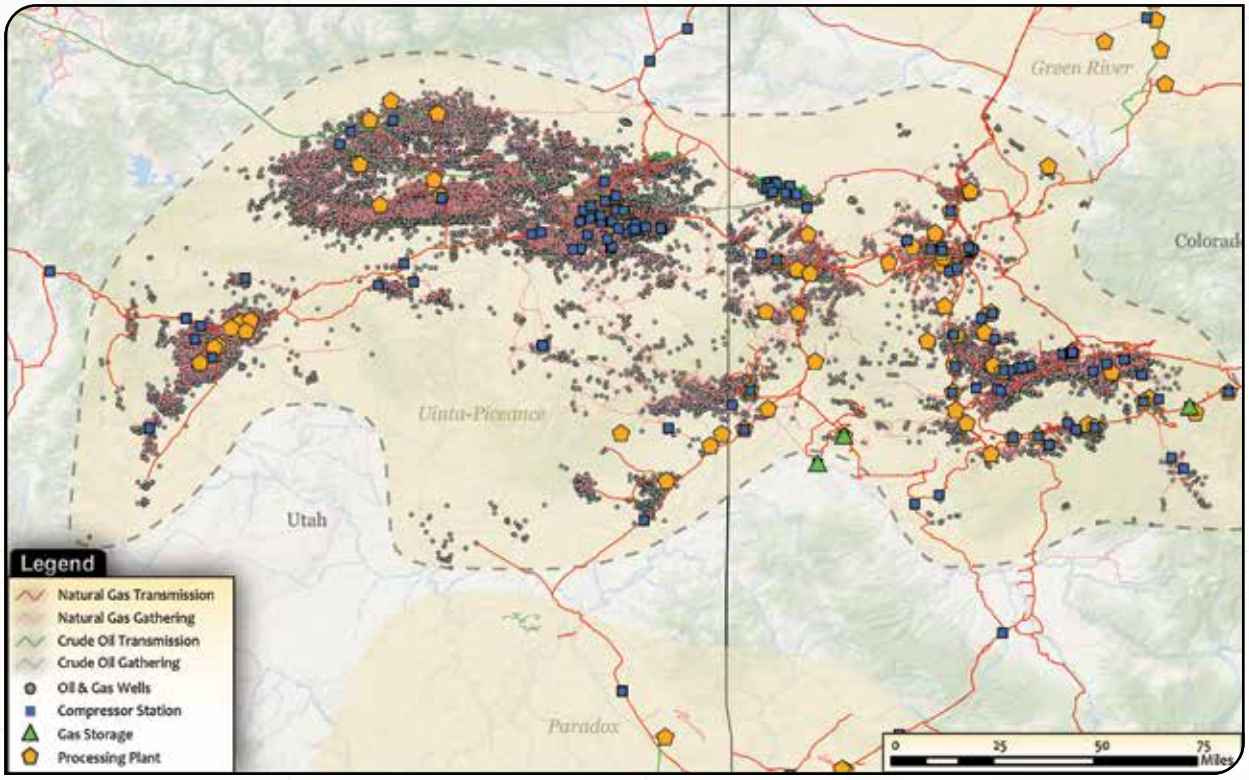
FOCUS ON: PICEANCE-UINTA



Data from Rextag ENERGY DATALINK

The Piceance-Uinta Basin boomed along with the shale revolution. As many as 42 rigs operated in Utah in 2012, and it would not be until after the OPEC-induced downturn of Thanksgiving 2014 that the count would fall below 20 on a given week, according to Baker Hughes data. The pandemic would cut that number to zero, but the region has recovered and between 12 and 14 rigs have operated steadily in the state since February.

The region is now the focus of M&A interest, with leading producers Terra Energy Partners LLC and Caerus Oil and Gas both reportedly available to a buyer willing to pony up $2.5 billion.

Among the region's positives is the $1.4 billion Uinta Basin Railway, a freight system being developed by a public-private partnership, that will connect the area to the national railway network. In July, the U.S. Forest Service moved the project forward by approving a critical right-of-way. Rail is particularly valuable for Piceance-Uinta crude oil because its waxy nature makes it difficult to transport by pipeline without heating the crude, which raises costs.

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ENVERUS

MARATHON, DEVON'S $4.8 BILLION IN DEALS PUTS SPOTLIGHT ON EAGLE FORD

Marathon Oil Corp.'s $3 billion cash deal for **Ensign Natural Resources** earlier this month was another sign that the Eagle Ford's pre-owned market is starting to heat up.

The announcement by Marathon follows the September closing of **Devon Energy Corp.**'s purchase of **Validus Energy** for $1.8 billion. Meanwhile, **Chesapeake Energy Corp.** is shopping its Eagle Ford assets in a deal that **Enverus** said in July could fetch between $4.6 billion and $5.9 billion, based on strip prices at the time.

Dealmakers appear to be excited at the potential sale of several private companies in the Eagle Ford. Possible targets include **BlackBrush Oil & Gas LLC**, **GulfTex Energy LLC**, **1776 Energy Operators LLC** among others.

Still, how actively the assets are being marketed is unclear, although, in June, Reuters reported BlackBrush had placed some of its Eagle Ford and Austin Chalk assets up for sale.

Marathon's is the second deal in the Eagle Ford to potentially set the stage for buyers' willingness to pay more for potential upside. Andrew Dittmar, director at Enverus Intelligence Research, noted **Diamondback Energy Inc.**'s $1.6 billion deal to buy **FireBird Energy LLC** in the Permian Basin also assigned value to undeveloped land.

During Marathon Oil's Nov. 3 earnings call, CEO Lee Tillman said the Ensign deal found a "sweet spot" between immediate cash flow accretion and inventory that competes for capital within the company's portfolio.

"On the value component, when we think about the valuation, I would say in general we would kind of put it almost 50:50 between PDP and future undrilled development opportunities," he said. "That was one of the unique opportunities about the deal."

The Ensign deal in the Eagle Ford addresses a key issue for Marathon: lack of inventory life but with a willingness to pay prices more in line with the Permian Basin, Dittmar said.

"The allocation of value to undeveloped land in the Marathon purchase of Ensign looks more in line with the usual Permian valuation rather than the Eagle Ford where assets tend to trade closer to production value," Dittmar said.

The acquisition of Ensign would add 130,000 net acres (99% operated, 97% working interest) in acreage adjacent to Marathon Oil's existing Eagle Ford position.

Ensign's estimated fourth-quarter production will average 67,000 net boe/d, including 22,000 net bbl/d of oil.

Andrew Dittmar

"We have expected the company to make an acquisition of this type," Dittmar said. "Critically, Marathon was able to extend its inventory runway while keeping the deal accretive to its own key financial multiples of cash flow multiple and free cash flow yield. Adding inventory while keeping the deal accretive to free cash flow has been among the largest challenges for public companies in the current market."

The deal is another example of a public company looking to take advantage of private equity exits to secure inventory and production, he added.

Where is the Eagle Ford's consolidator?

The Eagle Ford stands apart from other mature basins because buyers are so far choosing to add acreage adjacent to their existing footprints while keeping an eye on their balance sheets.

Companies such as Marathon, Devon and **ConocoPhillips Co.** have such strategic core positions that they are more inclined to focus on core bolt-ons rather than aggregating the whole basin, Craig Lande, managing director at **RBC Capital Markets LLC**, said at Hart Energy's A&D Strategies and Opportunities Conference in Dallas in October.

The Eagle Ford is the "only core basin where there is no public consolidator," Lande said.

Look for smaller publics like **SilverBow Resources Inc.** and **Ranger Oil Corp.** to "try and fill that consolidator role by continuing to be acquisitive in the Eagle Ford," he said.

Inventory hunting

As larger public companies continue to hunt for more inventory, the Eagle Ford offers the potential for more deal activity.

Marathon said it estimates the Ensign acquisition will acquire more than 600 undrilled locations, representing an inventory life of more than 15 years.

The acquisition also includes 700 existing wells, most of which were completed before 2015 with early-generation completion designs. Marathon said the locations offer upside redevelopment potential but weren't considered in the company's valuation of the asset or inventory count.

The Eagle Ford, like the Bakken Shale, started to see widespread development more than a decade ago, when drilling activity was dominated by earlier well completions.

"One of the ideas in both plays is that they sort of matured, hit the late innings, is to go back and revisit some of those older laterals with refracs and see what kind of production you can get out of them," Dittmar said.

While refracs are intriguing, most companies are likely to take a conservative approach to underwriting deals based on restimulating legacy wells.

"The Eagle Ford has a pretty interesting rate of change right now," he said.

Craig Lande

E&Ps are familiar with the Eagle Ford's core target zones. But they're also revisiting under completed wells, which have helped revitalize the Austin Chalk.

"You're finding ways to bring some additional inventory life out of what people thought of as a fairly mature play," Dittmar said. "I think that's one thing that's spurring this new interest in M&A in the play."

Some of those legacy positions are now operated by private companies such as BlackBrush, backed by **Bain Capital Specialty**. BlackBrush hired an investment bank to run an auction for more than 30,000 net acres in the Eagle Ford, according to the Reuters report.

Select Eagle Ford Deals, 2022

Value ($MM)	Buyer	Seller	Month
$3,000	Marathon Oil	Ensign Natural Resources	November
$1,800	Devon Energy	Validus Energy	August
$354	SilverBow Resources	Sundance Energy	April
$271	Lime Rock Resources	N/A	January
$122	Andros Capital Partners	N/A	June
$115	Freehold Royalties Ltd.	N/A	July
$87	SilverBow Resources	N/A	October
$71	SilverBow Resources	SandPoint Resources	April
$64	Ranger Oil	N/A	May
$50	SilverBow Resources	N/A	September
$46	Ranger Oil	N/A	June

Source: Hart Energy

According to Texas Railroad Commission data, sizeable Eagle Ford oil producers include:

- GulfTex, which averaged more than 5,000 bbl/d of oil last year;
- BlackBrush, with about 1,300 bbl/d of oil last year; and
- 1776 Energy, with more than 1,200 bbl/d of oil.

"There's going to be a lot of turnover in the Eagle Ford. It's great rock," Lande said. "So, I think a lot of people have seen this as an opportunity since there is no big basin bully necessarily to come in and" consolidate.

Chesapeake Energy's upcoming exit

Chesapeake represents the opposite move: a public company looking to divest from the Eagle Ford as it moves back toward its prowess at producing natural gas.

Dittmar said Chesapeake might be better off splitting its assets into smaller packages.

Chesapeake has a large, more traditional deep South Texas footprint in the Eagle Ford in counties such as LaSalle and Dewitt counties. The company's subsidiary, **Brazos Valley Longhorn LLC**, also manages assets it purchased in 2019 from **WildHorse Resource Development Corp.** for nearly $4 billion.

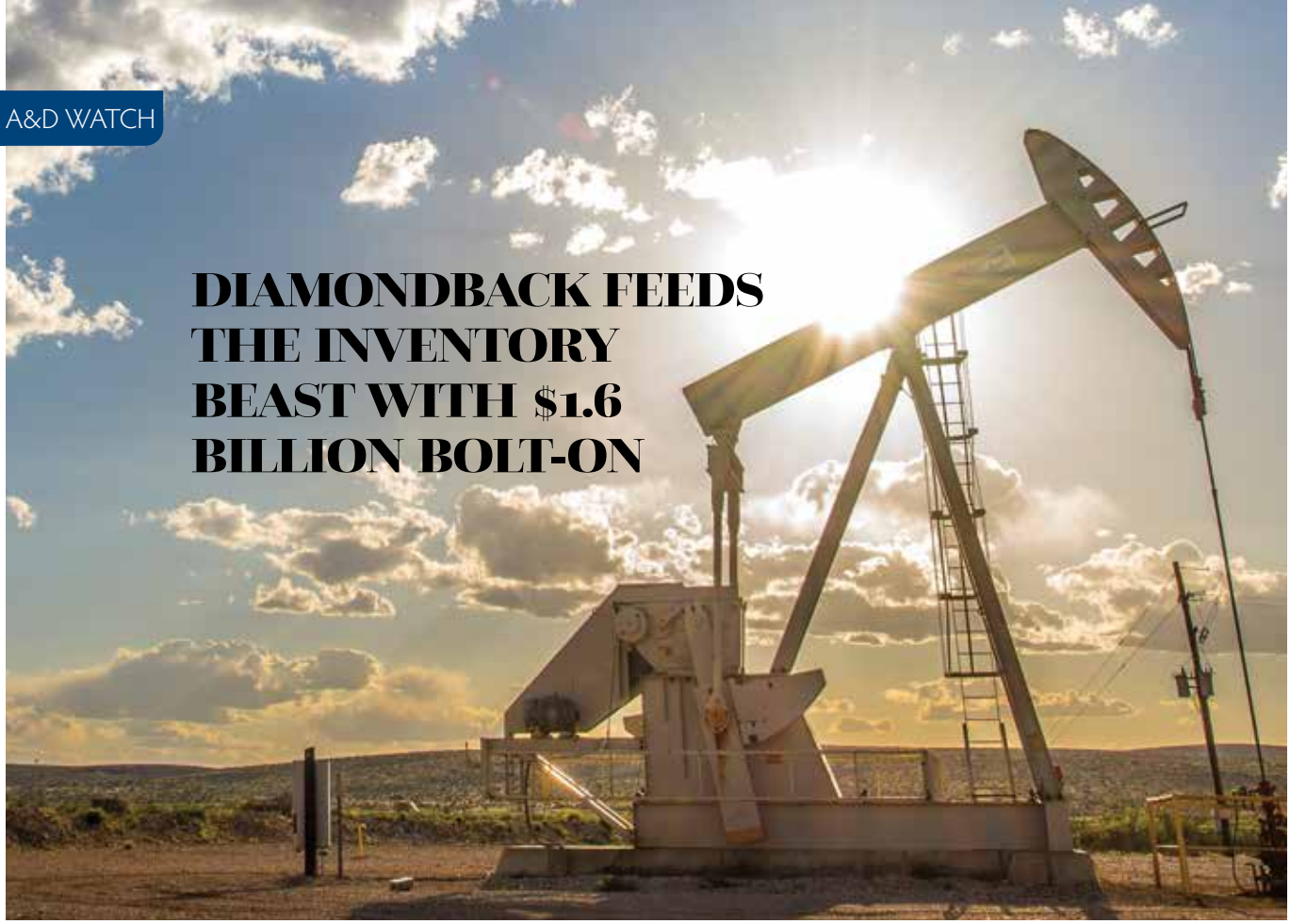
Dittmar said he suspects that were Chesapeake to sell off assets in packages, rather than as a whole, "you're definitely going to have a much larger buyer pool for the assets if you're willing to sell it in multiple pieces.

"Plus, you have two fairly distinct geographic and commodity mixes and different economics between the Brazos Valley and the traditional Eagle Ford pieces," he added.

Such an approach would also enable companies to target areas that are more specifically accretive or bolt-on to their own operations.

"I think that you're going to have a lot better success in the marketplace with a multipack offering for that versus a single deal," he said.

—Darren Barbee



DIAMONDBACK FEEDS THE INVENTORY BEAST WITH $1.6 BILLION BOLT-ON

Diamondback Energy Inc.'s first E&P acquisition since March 2021 is a reminder that even one of the Permian Basin's largest independents—the company was Texas' second-largest oil producer in 2021—is constantly on the lookout for replacement inventory.

On Oct. 11, Diamondback announced a $1.6 billion deal to buy **FireBird Energy LLC**, which is backed by **RedBird Capital** and the **Ontario Teachers' Pension Plan** (OTPP). The deal follows a torrid M&A stretch for Diamondback in which, over two and a half years beginning in 2018, the company paid more than $13.7 billion for rivals **QEP Resources** ($2.2 billion), **Ajax Resources** ($1.2 billion) and **Energen Corp.** ($9.2 billion) among others.

"The challenge for public E&Ps in the M&A market is adding inventory while keeping the valuation on deals in line or less than their own cash flow multiples and free cash flow yields," said Andrew Dittmar, director at **Enverus Intelligence Research**. "Diamondback appears to have just managed that. While the 3.0x 2023 EBITDA multiple and 15% free cash flow yield paid for FireBird aren't as cheap as production-heavy deals outside the Permian, it does keep the deal accretive to Diamondback's own trading multiples."

Mark A. Lear, an analyst at **Piper Sandler**, favorably likened FireBird's assets to Diamondback's Spanish Trail assets. Diamondback is acquiring 68,000 contiguous net acres along the southwestern Midland Basin and southeastern Ector County, Texas.

Diamondback management "suggests that the northern third of the acquired assets is analogous to Spanish Trail and incorporates 40% of the undeveloped inventory," Lear said.

Much of FireBird's development has been concentrated in the southern portion of the acreage position, leaving much of the northern position undeveloped, Lear said. Diamondback expects production of 25,000 boe/d, including 19,000 bbl/d of oil in 2023, and expects to be able to maintain that level of production with a one-rig drilling program.

"We looked at recent vintage performance of FireBird operated horizontal wells, and while there has been some variability, the four Wolfcamp producers that were brought

Diamondback's FireBird Acquisition Key Metrics

Acres (net):	68,000
Valuation ($B):	$1.6
Horizontal locations (net):	316
Cost per location ($MM):	$1.7
Funding (stock):	5.86 million shares
Funding (cash):	$775 MM
Current production, oil (bbl/d):	17,000
Average lateral length (ft):	11,400
Average working interest:	92%
HBP acreage:	84%
Primary formation targets:	Middle/Lower Spraberry; Wolfcamp A/B formations

Source: Diamondback Energy; Cowen

on production in 1H22 have delivered oil volumes in line with our FANG Midland Wolfcamp type curve," he said.

David Deckelbaum, in research published Oct. 12 by **Cowen**, said that well results in southeast Ector County, Texas, have shown oil productivity per foot of 16.5 bbl/ft of lateral in the first 12 months of production and 22.3 bbl/ft in the first 24 months during the past four years, "roughly in line with the respective productivity observed for all of Diamondback's Midland activity" focused in Martin County, Texas.

"We anticipate greater focus on the Spraberry versus Wolfcamp in initial development, but note that adjacent well productivity shows encouraging potential," he said.

A bulk of FireBird Energy's portfolio in the Midland Basin of West Texas was acquired from **Chevron Corp.** around the time of FireBird's founding, according to its website.

But Diamondback will initially stand down two of FireBird's three rigs to preserve the estimated 316 net horizontal locations "in primary development targets" that Stice said are adjacent to Diamondback's current Midland Basin position.

The company expects FireBird's assets to add more than a decade of inventory at their planned development pace, **Goldman Sachs** analyst Neil Mehta wrote in an Oct. 12 report.

The deal was viewed positively by analysts who see FireBird's assets shoring up potential weak spots in Diamondback's portfolio and, based on strip prices, adding cash flow in 2023.

"For Diamondback, the deal looks to be about increasing the development life of its core inventory runway and boosting overall production and scale," Dittmar said. "RedBird brings to the table hundreds of drilling locations that break even with oil prices in just the mid-$30/bbl range. That adds additional quality inventory to Diamondback's portfolio while allowing the company to sustain production from the new asset for more than a decade."

Deckelbaum suggested that Diamondback is conservatively accounting for potential locations and that the deal works out to about $1.7 million per location—"attractively in line with per location values observed over the last six years and well below acreage multiples paid."

"Even overall flowing valuation of $72,000/flowing boe/d is 13% below FANG's last implied valuation, and management estimates they are paying 3x 2023E EBITDA at strip [pricing], taking advantage of FANG's closing valuation at strip at roughly 4.7x 2023E," Deckelbaum said. "In total, the deal should be viewed as a classic, accretive bolt-on for quality acreage with high working interest."

Goldman Sachs noted that Diamondback currently trades at 5x EBITDA with a 15% free cash flow (FCF) yield at strip pricing, Mehta said.

Mehta sees "the potential for incremental cash flow toward capital returns (~75% of FCF) along with further balance sheet improvement."

Diamondback management on Oct. 11 noted the company plans to sell at least $500 million of noncore assets by the end of 2023.

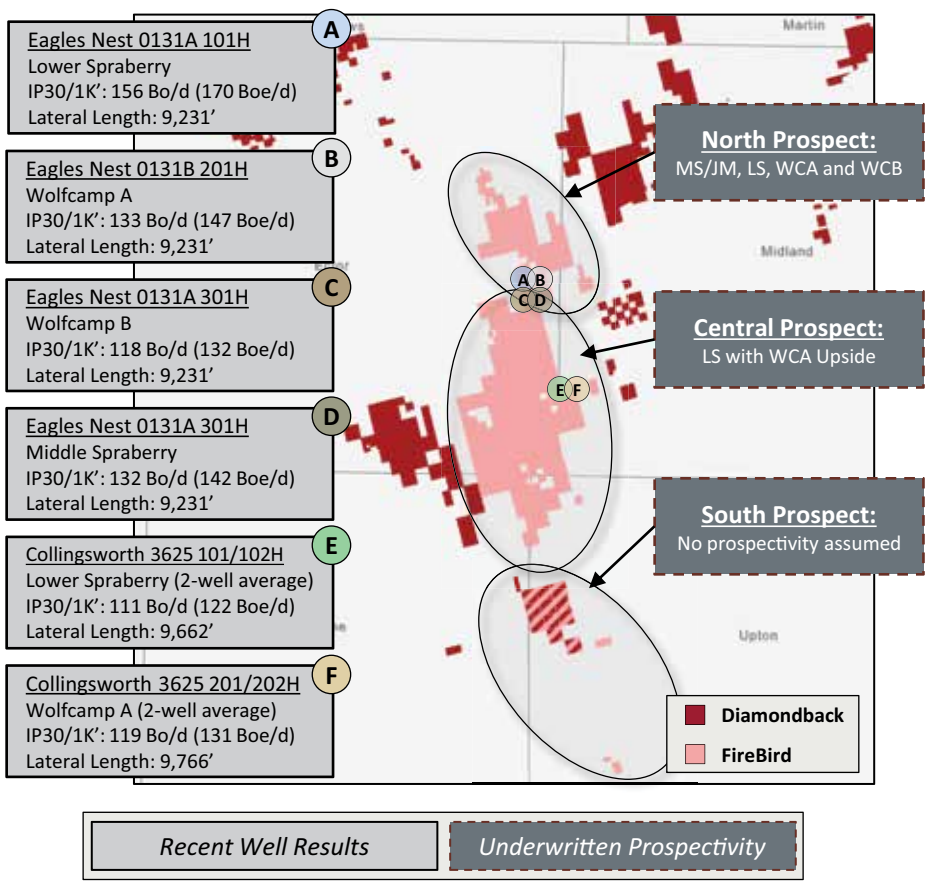
—Darren Barbee

Diamondback Notable E&P Transactions, 2018-2021

Closed	Acquired Entity	Value ($MM)
2018	Energen Corp.	$9,200
2018	Ajax Resources	$1,200
2018	ExL Petroleum	$312.5
2021	Guidon Energy	$862
2021	QEP Resources	$2,200
Total:		**$13,774.5**

Source: Hart Energy

Firebird Acreage Map



Source: Diamondback Energy

CONTINENTAL RESOURCES AGREES TO HAROLD HAMM'S BOOSTED TAKE-PRIVATE OFFER

Continental Resources Inc. agreed to be acquired by its founder, Harold G. Hamm, in a $4.3 billion cash acquisition that would take the U.S. shale giant private.

The Oklahoma City-based company said on Oct. 17 it entered a merger agreement to be acquired by **Omega Acquisition Inc.**, an entity owned by Hamm, for $74.28 per share. The offer price represents a 15% premium to the closing price on June 13—the day before Hamm's family disclosed their initial $70 per share proposal.

Harold G. Hamm

An industry icon who helped lead the charge to lift America's 40-year-old ban on U.S. crude oil exports, Hamm founded Continental Resources in 1967 at the age of 21. Since then, the company has grown into one of the top 10 oil producers in the U.S. Lower 48.

Hamm took Continental public in 2007. The public market, at the time, rewarded companies for both growth and performance, Hamm wrote in his proposal letter in June.

"Times have changed in the public market, particularly since the COVID pandemic. The market response has not been there for the oil and gas industry," wrote Hamm, noting the dwindling number of public E&P companies.

"This diminishing number of public entities is illustrative of a lack of support from the public market, and we believe there is a resulting under-appreciation of Continental," he added.

David Deckelbaum, managing director and senior analyst at **Cowen**, agreed with Hamm's view that Continental does not necessarily need the support of capital markets given its healthy free cash flow (FCF) yield and a leverage-neutral profile in 2023, even taking into account plans to partially finance the transaction through a new term loan facility.

"Even with the proposed incremental leverage from the buyout, CLR would be roughly 0.6x leveraged in 2023, and expected FCF, even before assuming decreased costs from going private (else dividend), would have the term loan repaid in approximately 1.5 years," Deckelbaum wrote in a research note.

As a private company, Continental should have "greater freedom to operate, particularly in areas such as exploration," he added.

Hamm currently serves as chairman of Continental Resources. He and members of his family control 83% of the company's stock.

Based on the shares outstanding as of Oct. 12, the tender offer would be for approximately 58 million shares of common stock, the Continental release on Oct. 17 said.

The tender offer values Continental at roughly $27 billion. The offer price is slightly under **Siebert Williams Shank & Co. LLC**'s $75 price target compares to the consensus price target of $72.86 on FactSet and $71.73 on Bloomberg.

"On the valuation side, the deal is valued at 3.5x 2023 EV/EBITDA, right in line with its peer group," wrote Gabriele Sorbara, managing director of equity research at the firm, in a research note on Oct. 17.

Continental is the largest leaseholder and the largest producer in the nation's premier oil field, the Bakken play of North Dakota and Montana, according to the release. Continental also proclaims to be the largest producer in the Anadarko Basin of Oklahoma. Additionally, the company has newly acquired positions in the Powder River Basin of Wyoming and Permian Basin of West Texas.

The merger transaction agreed to on Oct. 17 does not require a vote by Continental's shareholders and is currently expected to close prior to year-end. Following closing, the remaining public operators in the Bakken, according to Deckelbaum, will include: **Chord Energy Corp.**, **ConocoPhillips Co.**, **Hess Corp.**, **Devon Energy Corp.**, **Northern Oil and Gas Inc.**, **Marathon Oil Corp.**, **Ovintiv Inc.** and **Exxon Mobil Corp.**

Continental's board of directors, acting on the unanimous recommendation of a special committee consisting solely of independent and disinterested directors, has approved the merger agreement and the transactions contemplated thereby and recommended that Continental's shareholders tender their shares of common stock pursuant to the tender offer.

Intrepid Partners LLC is acting as financial adviser, and **Vinson & Elkins LLP** (V&E) is acting as legal counsel to Hamm. **Evercore** is financial adviser, and **Wachtell, Lipton, Rosen & Katz** is providing legal counsel to the special committee of the Continental's board of directors. **Sidley Austin** lawyers Mark Metts and Kayleigh McNelis represented Evercore.

The V&E team consisted of David Oelman, Mike Telle, Steve Gill, David Bumgardner, Markeya Brown, Mary Busse, Michelle Yang, David D'Alessandro, Missy Spohn, Roxy Barbera, James Longhofer, Taylor Daily, John Lynch, Ryan Carney, Keleigh Carver, Larry Pechacek, Michael Kurzer, Marcus Martinez, Michael Holmes, Craig Zieminski, Darren Tucker, Evan Miller and Jing Tong.

—Emily Patsy

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MARATHON OIL TO ACQUIRE ENSIGN IN $3 BILLION EAGLE FORD DEAL

Marathon Oil Corp. agreed to acquire **Ensign Natural Resources** on Nov. 2, nearly doubling the Houston-based company's position in the Eagle Ford Shale in a $3 billion cash deal, Marathon CEO Lee Tillman said.

"This acquisition in the core of the Eagle Ford satisfies every element of our exacting acquisition criteria, uniquely striking the right balance between immediate cash flow accretion and future development opportunity," commented Tillman, who also serves as chairman and president of Marathon Oil.

Based in Houston, Ensign was formed in 2017 in partnership with **Warburg Pincus**, a global growth investor. The company also secured an equity commitment from the Kayne Private Energy Income Funds platform in 2019 as part of an acquisition of **Pioneer Natural Resources Co.**'s Eagle Ford assets.

Ensign later bolstered its Eagle Ford position further with the purchase of **Reliance Eagleford Upstream Holding LP**, a step-down subsidiary of India's **Reliance Industries Ltd.**, for an undisclosed amount. The 2021 deal, which represented an exit from U.S. shale by Reliance, increased Ensign's current ownership to 100% in the leases and wells it acquired from Pioneer in 2019 and **Newpek LLC** in 2020.

Through its acquisition of Ensign, Marathon Oil said it will gain 130,000 net acres (99% operated, 97% working interest). The acreage is adjacent to Marathon Oil's existing Eagle Ford position and spans Live Oak, Bee, Karnes and DeWitt counties in South Texas across the condensate, wet gas and dry gas phase windows of the Eagle Ford, according to a company release on Nov. 2.

In total, the Ensign transaction will materially increase Marathon Oil's scale in the Eagle Ford Shale to 290,000 net acres and contribute to optimized supply chain accessibility and cost control in a tight service market, the company said in the release.

The Ensign inventory in the Eagle Ford Shale is among the most capital efficient in the Lower 48, according to Marathon Oil.

Marathon added in the release the Ensign transaction adds "significant high-return, high-working interest inventory that immediately competes for capital and is accretive to Marathon Oil inventory life." However, the company plans to hold fourth-quarter production flat with approximately one rig and 35 to 40 wells to sales per year.

Estimated production of the Ensign assets for the fourth quarter is 67,000 net boe/d, or 22,000 net bbl/d of oil. The company estimates it is acquiring more than 600 undrilled locations, representing an inventory life greater than 15 years.

Marathon also added its valuation of the asset was based on the maintenance level program and does not include any synergy credits or upside redevelopment opportunity.

The company is planning to fund the transaction with a combination of cash on hand, borrowings on its revolving credit facility and new prepayable debt. As a result, Marathon does not expect the transaction to meaningfully affect its leverage profile.

"Importantly, we expect to execute this transaction while maintaining our investment grade balance sheet and while still delivering on our aggressive return of capital objectives in 2022 and beyond," Tillman noted in the release.

The transaction is subject to customary terms and conditions, including closing adjustments, and is expected to close by year-end 2022.

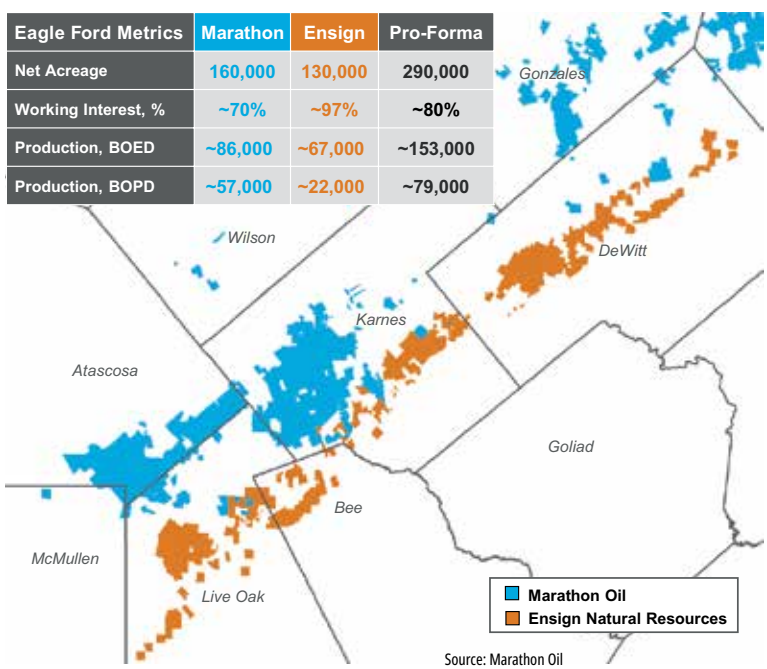
Morgan Stanley is serving as lead financial adviser to Marathon Oil and is providing committed financing to Marathon Oil with respect to a portion of the purchase price. **White & Case LLP** is serving as outside legal counsel for Marathon Oil.

Evercore and **J.P. Morgan Securities LLC** are financial advisers to Ensign, and its principal legal adviser is **Sidley Austin LLP**. The Sidley deal team is led by Tim Chandler and Jim Rice and also includes John Brannan, Jeff Kinney and Sabina Wahl.

—Emily Patsy

Marathon Oil's Eagle Ford Acquisition

Eagle Ford Metrics	Marathon	Ensign	Pro-Forma
Net Acreage	160,000	130,000	290,000
Working Interest, %	~70%	~97%	~80%
Production, BOED	~86,000	~67,000	~153,000
Production, BOPD	~57,000	~22,000	~79,000



Source: Marathon Oil

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NOG CONTINUES A&D TEAR WITH $330 MILLION MIDLAND BASIN ACQUISITION

Northern Oil and Gas Inc. (NOG) continued its acquisition streak on Oct. 19 with another multimillion-dollar buy in the Permian Basin.

"With this transaction, we showcase NOG's expanding capabilities," said CEO Nick O'Grady in a release. "Beyond just a consolidator of nonoperated interests, NOG is proving itself to be an adept and preferred partner for the development of high-quality assets."

In the release, NOG announced an agreement to acquire a 36.7% working interest in the Mascot Project from **Midland-Petro D.C. Partners LLC** (MDPC) for a purchase price of $330 million in cash. The purchase will be funded with cash on hand, operating free cash flow and borrowings.

The Mascot Project is operated by **Permian Deep Rock Oil Co.**, an affiliate of MPDC, which is a David H. Arrington-owned business based in Midland, Texas. NOG expects production from the acquired properties to average roughly 4,400 boe/d in first-quarter 2023 and 6,450 boe/d for full-year 2023 (2-stream, about 80% oil), according to the release.

"Mr. Arrington and his team have dedicated over five years to developing this project, and we would like to thank him and his stellar operating team for the opportunity to help see it through," O'Grady added.

Based in Minnetonka, Minn., NOG aims to be the go-to resource for operators that want to offload nonoperated working interests in leasehold. Originally focused in the Williston Basin, the company has also expanded into the Marcellus Shale and Permian Basin through a series of acquisitions.

NOG has significantly boosted its position in the Permian Basin in 2022. The company's dealmaking this year was jump started in January with the closing of a $406.5 million acquisition of **Veritas Energy**'s nonop position in the Permian, which marked the company's largest acquisition to date.

Since then, NOG has added nearly $400 million worth of additional acquisitions in the Permian Basin.

Transactions have included a bolt-on acquisition of core northern Delaware Basin properties announced in late September for an initial purchase price of $157.5 million and the closing of a $110 million deal for Midland Basin properties from **Laredo Petroleum Inc.** on Oct. 6, plus an additional northern Delaware Basin bolt-on acquisition unveiled by NOG on Oct. 11.

The newly acquired assets announced Oct. 19 are located in Midland County, Texas, and include four all-depth contiguous drilling spacing units developed for long laterals, 12.1 net producing wells, 5.5 net wells-in-process and approximately 17.3 net undeveloped locations. The properties have incurred minimal legacy vertical drilling relative to typical Midland Basin properties, NOG said.

NOG anticipates over $300 million of unlevered free cash flow from the **Mascot Project** properties in Midland County, Texas, from effective date through 2025 at current strip pricing, according to a company investor presentation.

NOG is also acquiring a pro rata interest in the midstream assets and associated infrastructure, which represent approximately $36 million of the allocated value of the transaction.

"This acquisition has unique properties versus almost any prior transaction NOG has done," NOG president Adam Dirlam said in the release. "As typical, it is focused on one of the highest quality regions in the U.S., but what differentiates this transaction is the surety of development timing and returns, with clear line of sight to turning valuable acreage into significant free cash flow, rapidly and efficiently."

The effective date for the transaction is Aug. 1, and NOG expects to close the transaction in January.

Citigroup Global Markets served as NOG's financial adviser. **Kirkland & Ellis LLP** is serving as the company's legal adviser.

Petrie Partners served as MPDC's financial adviser. **Hunton Andrews Kurth LLP** is serving as MPDC's legal adviser.

—Emily Patsy

EOG RESOURCES UNVEILS NEW OHIO UTICA COMBO POSITION

EOG Resources Inc. added a new shale gas position to its multibasin platform, the Houston-based company unveiled on Nov. 3 alongside stellar earnings results.

"EOG is now operating seven significant resource basins with the addition of the Utica Combo in Ohio," Ezra Yacob, chairman and CEO, commented in a company release.

In the release, EOG said it established a new position in the Ohio Utica Combo play for a combined cost of entry of less than $500 million. The company also acquired mineral acreage in the southern portion of its acreage footprint.

The company offered sparse details regarding how it acquired its Utica position. It termed its efforts an "accumulation" without specifying whether it had stepped up leasing efforts in the play or made an asset acquisition from one or more operators in Ohio.

Still, EOG Resources did state that it expects the Utica Combo to be its "next large-scale premium resource play."

"A favorable drilling environment and the opportunity to develop the play with three-mile laterals support cost efficiencies. Combined with strong liquids production rates, EOG expects the Utica Combo to be additive to the overall quality of its premium inventory," the company release said.

In total, EOG accumulated 395,000 net acres and about 135,000 mineral acres in the Ohio Utica Combo play.

One of the largest crude oil and natural gas producers in the U.S., EOG also operates in the Bakken play in the Williston Basin, the Powder River Basin, the Wyoming Denver-Julesburg Basin, the Delaware Basin in the Permian and the Eagle Ford Shale.

Yacob said the company's multibasin footprint, now with the addition of the Utica Combo play, will continue to lower EOG's overall cost of supply.

"EOG continues to get better," he said, noting the importance of its new Utica Shale position and multibasin footprint in the company's future.

"Our growing multibasin portfolio of high-return plays positions EOG for long-term sustainable value creation," he said.

EOG's development of the "high rate-of-return" Utica Combo play is underway with about 20 wells projected for 2023, the company said on Nov. 3.

So far, EOG completed four wells and operates 18 additional legacy wells across a 140-mile trend on the Utica Combo position.

—Emily Patsy

KIMBELL'S LARGEST DEAL IN YEARS ADDS PERMIAN ROYALTY INTERESTS

In its largest deal since 2018, **Kimbell Royalty Partners LP** agreed on Nov. 3 to purchase Permian Basin interests from Austin, Texas-based **Hatch Royalty LLC** for $290 million in cash and units.

Kimbell will pay $150 million in cash and about 7.3 million units of **Kimbell Royalty Operating LLC** valued at $140 million. On Nov. 8, the Fort Worth, Texas-based company announced an upsized $106.5 million follow-on offering led by **Raymond James** to help fund the deal.

The deal is Kimbell's first since it closed a $57 million multibasin deal last December and the company's largest since it acquired **Haymaker Minerals & Royalties LLC** and **Haymaker Resources LP** for about $404 million in cash and stock four years ago. Since 2018, the company has made $900 million in acquisitions.

Hatch is backed by **Ridgemont Equity Partners**. The Hatch assets consist of 889 net royalty acres on 230,000 gross acres located in the Delaware Basin (90%) and Midland Basin (10%), according to a Nov. 3 company news release.

The transaction reestablishes the Permian as the leading basin for Kimbell production, active rig count, DUCs, permits and undrilled inventory. Kimbell estimated the acquired assets average about 2,072 boe/d (1,198 bbl/d of oil, 372 bbl/d of NGL and 3,012 Mcf/d of natural gas). Kimbell estimates 2023 production will increase to an average 2,522 boe/d.

About 98% of the acquired acreage is leased by public and private operators, including **Occidental Petroleum Corp.**, **ConocoPhillips Co.**, **Devon Energy Corp.**, **Coterra Energy Inc.**, **Mewbourne Oil Co.**, **Permian Resources Corp.**, **Diamondback Energy Inc.**, **BPX Energy**, **Exxon Mobil Corp.** and **Callon Petroleum Co.**

As of Oct. 1, there were 11 active rigs on the acreage. The deal strengthens Kimbell's oil weighting from 25% to 29% of daily production mix.

Bob Ravnaas, Kimbell's chairman and CEO, said that the acquisition fits the company's strategy "with an optimal balance of currently accretive cash flow combined with significant remaining proven drilling inventory."

According to Kimbell, the deal adds:

- An estimated 14.7 MMboe in total proved reserves, reflecting a purchase price of approximately $19.80 per total proved boe;
- An average net revenue interest of 0.8% per tract; and
- Line of sight on development of 1.18 net DUCs and 1.06 net permitted locations.

At close, Kimbell is expected to have more than 16 million gross acres, 123,000 gross wells and 90 active rigs on its properties.

Kimbell said it expects the acquisition to be immediately accretive to distributable cash flow per unit. The transaction, with an effective date of Oct. 1, is expected to increase daily production by 14% and decrease cash G&A per boe by 12%.

Citi served as Kimbell's exclusive financial adviser. **White & Case LLP** acted as legal counsel to Kimbell. **TPH & Co.**, the energy business of **Perella Weinberg Partners**, served as exclusive financial adviser and **Kirkland & Ellis LLP** served as legal adviser to Hatch Royalty.

—Darren Barbee

DELAWARE BASIN

Northern Oil and Gas Inc. (NOG) agreed to acquire an additional core northern Delaware Basin bolt-on for $130 million on Oct. 11, marking three back-to-back acquisitions in the Permian Basin since August.

"NOG continues to press its advantage as a well-capitalized, reliable and consistent purchaser of high-quality nonoperated properties. More importantly, NOG's technical team continues to underwrite for returns with precision and focus on the best assets available in the marketplace today," NOG CEO Nick O'Grady commented in a company release.

Based in Minnetonka, Minn., NOG aims to be the go-to resource for operators that want to offload nonoperated working interests in leasehold. Originally focused in the Williston Basin, the company has also expanded into the Marcellus Shale and Permian Basin through a series of acquisitions.

The additional northern Delaware Basin bolt-on acquisition unveiled by NOG on Oct. 11 includes core nonoperated working interest properties in New Mexico's Lea and Eddy counties and Loving and Winkler counties in West Texas. The acquired assets cover roughly 2,100 net acres, 5.3 net producing wells, 2.1 net wells-in-process and approximately 17.2 net undeveloped locations.

NOG said in an investor presentation the Delaware Basin nonop acquisition on Oct. 11 adds over 17 sub-$40 breakeven net locations of Tier 1 inventory in the core zones of the Wolfcamp and Bone Spring formations.

The primary operator of the assets is **Mewbourne Oil Co.**, which NOG described in its release as "one of the most cost-efficient and active operators in the northern Delaware Basin." Other operators include **Coterra Energy Inc.** and **Permian Resources Corp.**

Production of about 2,500 boe/d (68% oil, 2-stream) is expected from the acquired assets for 2023, generating an estimated $55 million of unhedged cash flow in 2023 at strip pricing as of Oct. 10 and resulting in a 2.4x transaction multiple, according to the company release.

NOG agreed to acquire the assets from a private seller for $130 million in cash. The effective date for the transaction is Nov. 1, and NOG expects to close the transaction in December.

Wells Fargo Securities is financial adviser to NOG for the acquisition. **Kirkland & Ellis LLP** is serving as the company's legal adviser. **Tudor, Pickering, Holt & Co.** served as financial adviser to the seller, and **Bracewell LLP** is serving as the seller's legal adviser.

EAGLE FORD

SilverBow Resources Inc. agreed to an Eagle Ford Shale bolt-on acquisition in the Karnes trough for $87 million on Oct. 3.

"This transaction fits our disciplined growth strategy of adding production at attractive valuations and increasing our high-quality inventory across both the Eagle Ford and Austin Chalk formations," SilverBow CEO Sean Woolverton said in a company release.

According to Woolverton, the acquisition on Oct. 3 marks SilverBow's seventh transaction announced since August 2021, and the second strategic bolt-on in SilverBow's liquids-weighted position in the Karnes trough.

According to the release, SilverBow entered the agreement to acquire the bolt-on assets in the Karnes trough from an undisclosed seller for $87 million in cash. The acquisition adds 5,200 net acres in the oil and condensate windows of Dewitt and Gonzales counties in South Texas. June net production was approximately 1,100 boe/d (44% oil).

SilverBow Resources expects the bolt-on acquisition to create a consolidated 13,000 net acre block in the Karnes trough with 100 high rate-of-return drilling locations, according to Business Wire.

Gibson, Dunn & Crutcher LLP is advising SilverBow in the acquisition led by partner Stephen Olson and counsel Adam Whitehouse. The Gibson Dunn corporate team also includes associates Samantha Astrich and Michael Holmes. Partner Michael Cannon is advising on tax aspects.

■ **APA Corp.** is marketing 212,000 net acres of oil and gas producing land in southeast Texas' Eagle Ford and Austin Chalk shale basins, according to a document seen by Reuters.

The sale could fetch APA between $450 million and $500 million, two sources close to the bidding process estimated. However, they cautioned the valuation was susceptible to commodity price volatility and that APA could ultimately retain the asset if it did not receive a suitable offer.

The sources requested anonymity as the sales efforts are confidential. A spokesperson for APA said the company does not respond to market rumors.

The potential sale of the properties, which is being administered by an investment bank and is a small fraction of APA's total U.S. production, comes as the company pivots back to western Texas, where it is beginning to see benefits from its investments in a remote part of the Permian basin.

For November, APA expected oil and gas production of around 15,000 boe/d from the acreage on sale.

OKLAHOMA STACK

Land Run Minerals V LLC (LRM V) recently made its debut with an initial acquisition in the Midcontinent.

The Oklahoma City-based firm, a royalties acquisition and management strategy launched from the **89 Energy** platform, acquired a "unique, large-scale, mature royalties asset" located in the core fairway of the STACK play, according to an Oct. 31 company release.

"This initial acquisition leveraged our extensive experience and understanding of production and development activity in the Midcontinent," John-Mark Beaver, board member of LRM V and president and CEO of 89 Energy, said in the release.

The transaction comprises 55,000 net royalty acres (normalized to one-eighth) and 1,715 wells with an average net revenue interest of 1.6%.

Acquired entities include **Rumble Minerals LLC**, **Fortis Sooner Trend Minerals LLC**, **Sooner Trend Minerals LLC**, **FMII STM LLC** and **Phenom Minerals LLC**, according to the company website.

The assets included in the acquisition, mostly located in Oklahoma's Kingfisher, Canadian and Blaine counties, have net production of 4,500 boe/d.

LRM V funded the acquisition with equity and debt financings. The equity financing was provided by the new commitments from **Kayne Energy Private Equity**. The debt financing was provided by a new credit facility led by **Wells Fargo Securities LLC** and **TCBI Securities Inc.**

Wells Fargo Securities and TCBI Securities also acted as joint lead arrangers and bookrunners on syndication efforts. **Wells Fargo Bank NA** will serve as administrative agent.

Baker Botts LLP and **Porter Hedges LLP** served as legal advisers to LRM V. **McDermott Will & Emery** served as legal adviser to Kayne Energy.

UTICA SHALE

Peregrine Energy Partners has for the second time this year added the Utica Shale to its portfolio. On Nov. 1, the Dallas-based firm said it had agreed to acquire producing and nonproducing oil and gas royalty interests in Carroll, Columbiana and Jefferson counties, Ohio, from multiple sellers. At least some of the assets are apparently operated by **Encino Energy**, which entered the Utica in 2018 via an acquisition with **Chesapeake Energy Corp.** for $2 billion.

Although the press release doesn't specify any operators directly, C.J. Tibbs, Peregrine's co-founder, said that the company purchased royalties under "best-in-class operators, and Encino certainly fits that bill." Tibbs also noted that Encino is the largest oil producer in the Utica, the second largest gas producer in the Appalachian Basin and a top 25 natural gas producer in North America.

In March, Peregrine purchased Marcellus and Utica interests, including overriding royalty interests in 340,000 acres from **EnverVest Ltd.** and affiliates. Since 2020, the company has also purchased assets in the Permian and Appalachian basins from **Caerus Oil & Gas LLC** and in Colorado's Piceance Basin, Alaska's North Slope and in Florida.

Peregrine doesn't typically disclose purchase prices, and the announced Nov.1 deal didn't include any additional financial details. The acquisition spans dozens of producing wells and encompasses over 520 net mineral acres, adding to Peregrine's total position in the Utica, which spans more than 360,000 gross acres.

CANADA

Enerplus Corp. is bidding Canada farewell. The Calgary, Alberta-based company announced the sale of its remaining Canadian assets located in Alberta and Saskatchewan to **Surge Energy Inc.** on Nov. 2 for total consideration of CA$245 million (US$180 million).

Peters & Co. Ltd. and **National Bank Financial Inc.** are financial advisers to Surge on the acquisition. **ATB Capital Markets** was appointed as Surge's strategic advisers also for the acquisition. **McCarthy Tétrault LLP** is legal adviser to Surge with respect to the acquisition and an equity offering that will be used to partially fund the acquisition.

TPH & Co. and **Scotiabank** acted as financial advisers to Enerplus with respect to the transaction. The effective date of the transaction is May 1, 2022.

G&P RATES – UNLOCKING MIDSTREAM'S VAULT TO CAPTURE VALUE

Shutterstock/ImageFlow

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EAST DALEY ANALYTICS
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Rob Wilson is vice president of analytics at East Daley where he manages a team of energy analysts covering commodity markets and their impact on midstream asset financial performance.

Market Watchers

After a long hiatus, investors are returning once again to the midstream sector. In a difficult year for markets, the Alerian Midstream Index (AMNA) in 2022 was up 32.9% as of Oct. 31, compared to a 17.7% decline in the S&P 500 over the same period. The gains follow years of underperformance by midstream. But turbulent macroeconomic conditions, including soaring inflation and a hawkish Federal Reserve, have investors looking for safe havens. In many respects, midstream fits the bill. Just look at the average 6.07% yield for companies in the AMNA index, more than triple the return demanded by investors in the typical S&P 500 company (see Figure 2).

Midstream is the focus of East Daley Analytics, and we see exciting opportunities on the horizon. The Russia-Ukraine war has boosted global demand for U.S. energy products while helping solidify political consensus around the primacy of energy security. Midstream also has a critical role to play in the energy transition; infrastructure will be needed to move products such as hydrogen and renewable fuels or to capture and transport CO_2 emissions for burial underground.

Yet viewed a different way, the relatively high yield for midstream companies also reflects hesitation by investors. Recent market history likely colors their perception. Midstream overbuilt through prior commodity cycles, leaving companies highly levered when oil prices fell in 2015 to 2016 and 2020. This debt has dragged on sector performance when commodity prices have rebounded. While we see a growth story ahead for midstream, the market seems to lack conviction.

Another factor that potentially inhibits investment is the complexity of the midstream business. Something as simple as the rates that companies charge for services can be complicated by a high degree of opaqueness.

While investors can readily follow fluctuations in commodity prices, these price changes often don't correspond to the rates charged by midstream operators. Gathering and processing (G&P) assets in particular are a locked vault when investors try to assess future cash flow. Since most G&P systems don't cross state lines, they aren't subject to federal oversight. This results in fewer disclosures on volumes, rates and performance compared to other assets, such as interstate pipelines. G&P system operators also rely on bilateral contracting with producers and use varied structures to set rates. These factors make apples-to-apples comparisons of assets difficult.

"Rising oil and gas prices is good for midstream" is a common investor axiom, yet only certain G&P systems directly

benefit from higher commodity prices via percent-of-proceeds (POP) or percent-of-liquids (POL) contracts. Lower confidence in future cash flow results in a higher discount demanded by investors for capital provided to midstream companies.

Wide variance in service rates

To bring greater transparency to markets, East Daley Analytics is undertaking a broad study of G&P system rates. We maintain asset-level financial models for over 1,000 assets owned by public companies. From this asset pool, we've identified 200-plus G&P systems for which we can confidently assess rates. We've created a G&P rate methodology based off our balanced public asset models. Using first-quarter 2022 (1Q22) results, we can calculate an average G&P rate for these systems.

Gross margin/volume = blended rate ($/Mcf)

Our investigation finds wide variance in the G&P rates assessed from basin to basin. Figure 3 presents estimated 1Q22 G&P rates in basins targeted for liquids. On the high side is the Denver-Julesburg (D-J) Basin, where operators received an average of $2.59/Mcf for G&P services in 1Q22. On the low side is the Anadarko Basin, where we calculate an average $0.74/Mcf rate for G&P services. In other words, producers in the D-J in eastern Colorado paid 250% more on average for midstream services than their counterparts in Oklahoma, just one state over.

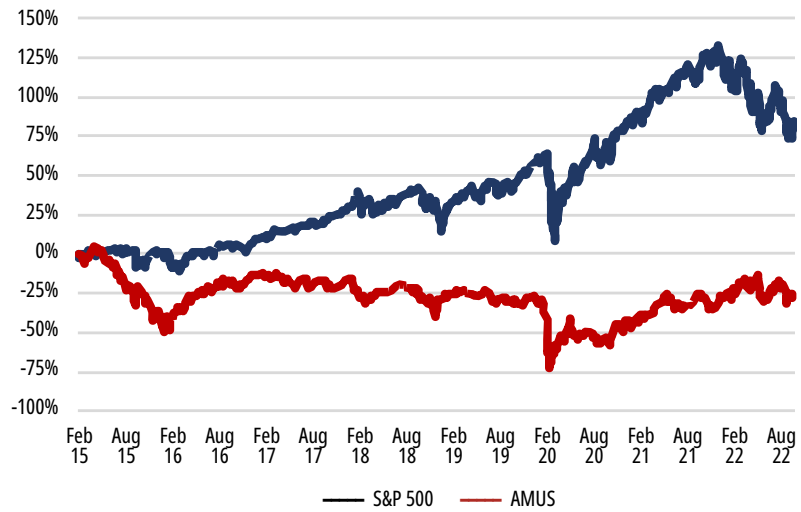
What can explain these huge differences in midstream service costs? Several factors influence G&P rates. Barriers to entry is one factor that can limit the amount of competition for midstream services within a basin. In the D-J Basin, two companies, DCP Midstream and Western Midstream, are the dominant providers of G&P services, while basins such as the Permian and Anadarko have dozens of companies competing for business.

A second factor is the relative sophistication of producer counterparties. If midstream service costs trend too high in a basin, well-capitalized operators (ie, majors and large independents) may opt to build their own gathering systems.

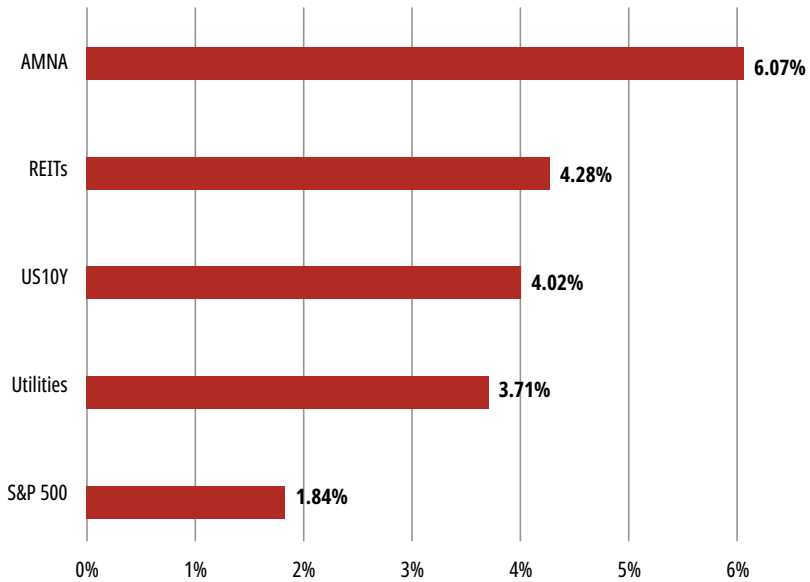
A third factor is the dominant contract structures (ie, postage rates versus POP contracts) used in a basin, which can influence G&P rates when commodity prices are unusually high or low.

Nevertheless, it is easy to see why investors would need to tread carefully when putting money to work in Midstream. Picking the winners while avoiding the landmines can be hard work given the limited information in the public domain. OGI

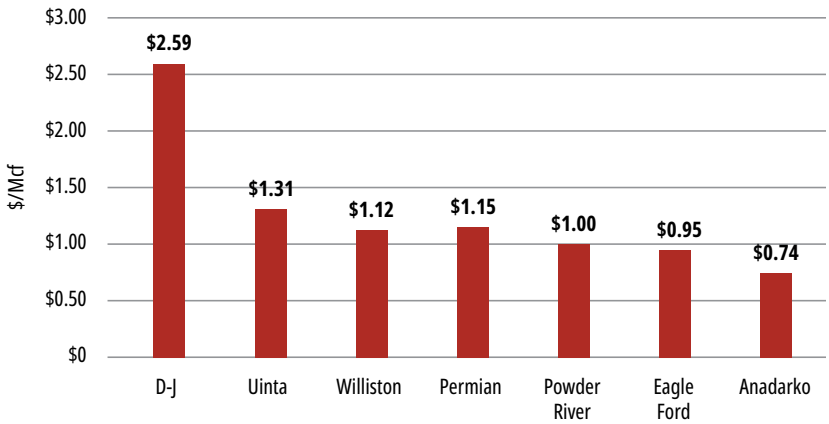
Alerian Midstream Vs. S&P 500
(Figure 1)



Yields On Various Investments (Oct. 30, 2022)
(Figure 2)



Liquids Basins - 1Q22 G&P Rates
(Figure 3)



Source: East Daley Analytics

PERMIAN, HAYNESVILLE KEY TO RISING US PRODUCTION

U.S. crude oil and natural gas production are expected to both rise slightly in November compared to the prior month aided mainly by the Permian Basin and Haynesville Shale.

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U.S. oil and gas production is forecast by the Energy Information Administration (EIA) to rise thanks primarily to higher volumes from the Permian and Haynesville basins.

Combined oil and gas production from seven key U.S. basins—Anadarko, Appalachia, Bakken, Eagle Ford, Haynesville, Niobrara and Permian—will rise slightly in November compared to October. Oil production in the U.S. is expected to average 9.1 MMbbl/d in November while gas production is expected to average 95.1 Bcf/d, the EIA revealed Oct. 17 in its monthly drilling productivity report.

U.S. gas production from the key seven basins—with Appalachia and the Permian Basin leading the push—continue to support rising U.S. LNG exports as well as piped gas exports to south of the border neighbor Mexico.

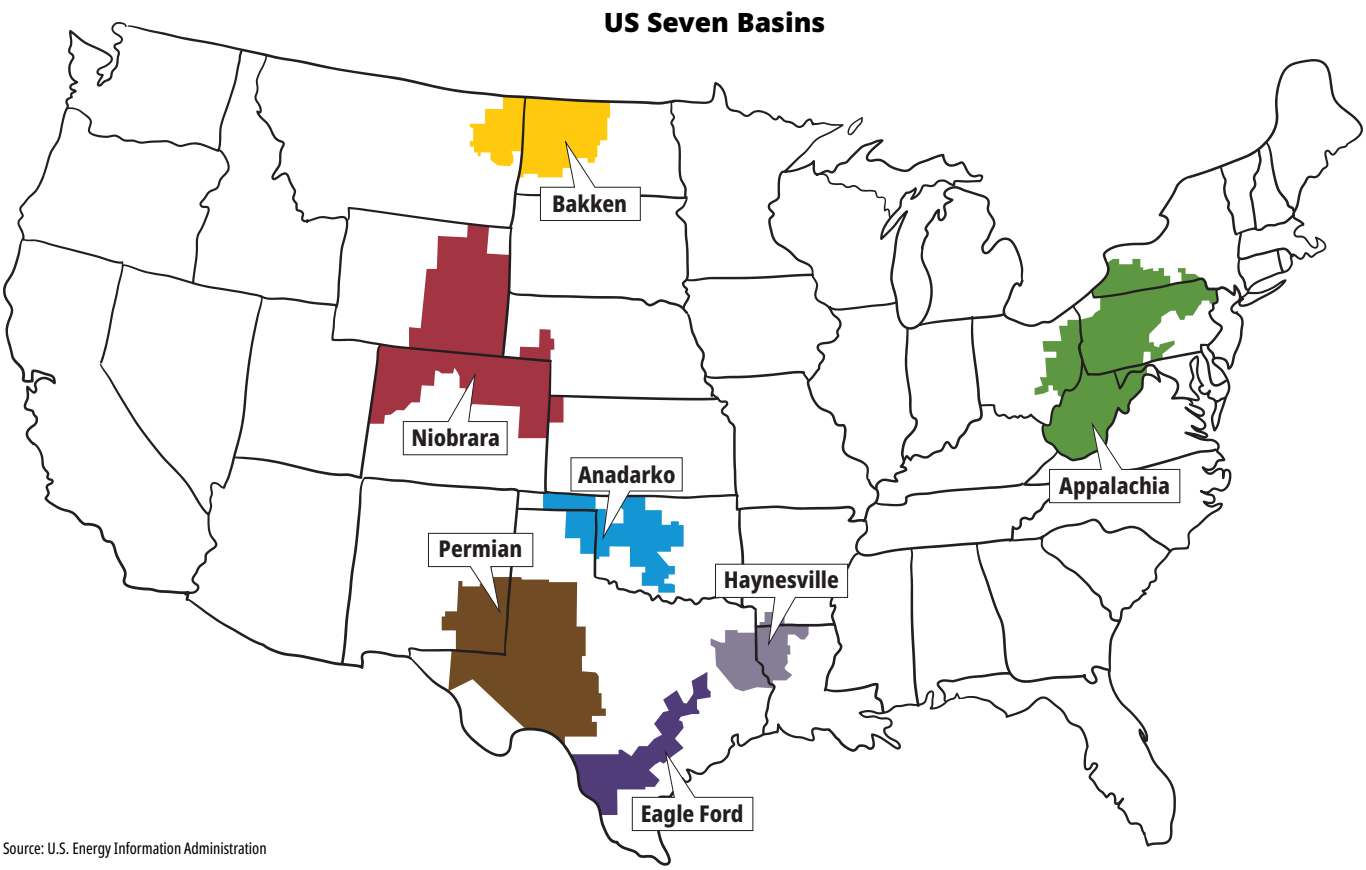
Russia's invasion of Ukraine has negatively impacted global gas supplies and flows, especially into Europe. The continent's urgent need to procure gas from countries other than Russia has pushed up its demand for U.S. produced LNG and helped convert the North American country into the world's leading LNG exporter.

Europe's demand for U.S. LNG is only expected to continue to rise this winter and next, many energy sector executives and pundits argued earlier this month at an energy forum in London.

Oil growth

U.S. oil production growth will primarily be driven by rising volumes in the

US Seven Basins



Source: U.S. Energy Information Administration

The EIA expected oil rigs in West Texas in the Permian Basin to account for 60% of the U.S.'s total monthly oil production in November.

SHUTTERSTOCK/MIKE IRVIN

Permian Basin followed by the Bakken and Eagle Ford, the EIA said.

Oil production from the Permian Basin is expected to average 5.5 MMbbl/d in November, accounting for 60% of the U.S.'s total monthly production. Production from the Bakken and Eagle Ford will kick in for 13% each with the remaining 14% coming from the other basins.

However, higher oil production is not likely to be that beneficial to the U.S. refining industry and ultimately fuel consumers, according to Wells Fargo equity analyst Roger D. Read.

"We believe policy risks have substantially increased as seasonally stronger winter demand approaches amid record low inventories … We see little the U.S. refining industry can do to deliver more refined products given the U.S. refining system is already running at high levels of utilization and production," Read wrote Oct. 16 in a research note to clients.

"We do not believe an export ban would ultimately be effective, and it might well be counterproductive," he added.

Gas growth

U.S. gas production growth will primarily be driven by rising volumes in the Haynesville and then the Permian Basin and Eagle Ford.

Despite Haynesville leading the production rise next month, Appalachia and Permian are the basins that are the largest in terms of total U.S. production. Gas production from the Haynesville was expected to average 16.1 Bcf/d in November, accounting for just 17% of the U.S.'s total monthly production.

In November, gas production from Appalachia and Permian was expected to average 35.7 Bcf/d and 21.1 Bcf/d respectively, according to EIA data, and account for 38% and 22% of the U.S.'s total monthly production.

Gas production from the Eagle Ford will average 7.3 Bcf/d and account for 8% of total monthly production. The remaining 15% of projected gas production in the U.S. comes from other basins.

More gas, higher bills

While just around 20% of U.S. gas production is exported to Mexico as piped gas and to other countries as LNG, the North American country's rising gas production profile will do little to shelter U.S. households from higher bills this winter.

Many U.S. households across the country are likely to spend more on energy this winter compared to recent winters, the EIA announced Oct. 12 in its "Winter Fuels Outlook" report.

"Higher forecast energy expenditures are the result of higher fuel prices, combined with higher heating demand because of a forecast of slightly colder weather than last winter," the U.S. agency said.

U.S. households that "primarily use natural gas for space heating will spend an average of $931 on heating this winter (October through March), which is $206, or 28%, more than last year," the EIA report said.

Approximately 47% of U.S. homes utilize natural gas as their primary heating fuel, according to the U.S. Census Bureau's 2021 American Community Survey. OGJ

OIL AND GAS COULD OVERCOME UNDERINVESTMENT

Oil and gas executives are focusing on balance sheets and clean energy, according to Deloitte's outlook for 2023.

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The oil and gas industry entering 2022 could have been described as cautiously optimistic, and that phrase holds true as the industry nears 2023.

Deloitte's "2023 Oil and Gas Industry Outlook" sees an industry that is flush with cash exercising capital discipline as it works to produce more energy while heading toward a lower carbon future.

Just a year ago, the industry was starting to emerge from the pandemic and was cautiously optimistic about the future. Now, Kate Hardin, executive director of Deloitte's Research Center for Energy and Industrials, said the industry is "still cautiously optimistic, but they're cautious about different factors."

She said the most recent outlook shows interesting trends across the different segments of the oil and gas industry.

One of the trends is that while free cash flow is projected to be 70% higher than 2021 levels, the expectation is that capex will rise by only 30% over 2021 spend, she said. At the same time, production is up.

"Even with lower capital expenditures, we're getting the production increase," she said. "It's a real efficiency play and an automation play that is contributing."

According to the outlook, the oil and gas industry will likely enter 2023 with its healthiest balance sheet yet. With continued capital discipline, companies could overcome underinvestment of recent years and help accelerate the energy transition.

The results of the 2023 outlook survey show that 93% of respondents remain positive or cautiously positive about the industry in the coming year. Years of underinvestment, rapid recovery in demand and geopolitical developments have driven oil prices to 2014 highs and upstream cash flows to record levels, the outlook noted.

Hardin said 40% of the 100 executives surveyed for the annual outlook indicated that balance sheet strength was one of their immediate priorities. She said some of that focus reaches back to "what 2014 and 2015 taught us and what 2020 taught us." As a result, companies are focused on paying down debt.

One of the upsides of that, Hardin said, is that "their spending is not surpassing what they have on their balance sheet" so they may be able to pursue M&A activity with less reliance on outside funding and debt than in the past. "That may open up some interesting opportunities," she continued.

> "Even with lower capital expenditures, we're getting the production increase."
>
> —Kate Hardin, *Deloitte*

Clean energy future

As the world focuses on moving toward a lower carbon future, companies are seeking ways to be part of the solution. In the survey, Hardin said, nearly a quarter of respondents indicated an interest in investing in emission abatement technology or increasing investment in clean energy sources.

Clean energy investment by oil and gas companies has risen by an average of 12% each year since 2020, according to the outlook. In 2022, clean energy investment is expected to account for an estimated 5% of total oil and gas capex spending, up from less than 2% in 2020.

While the outlook expects investment to continue increasing in 2023, 30% of survey respondents indicated higher demand for low-carbon clean energies, and 24% selected more scalable and economical low-carbon use cases that would enable increased investment in clean energy.

However, following Russia's invasion of Ukraine earlier this year, energy policy in the U.S. and Europe began to pivot. Momentum is now shifting away from phasing out natural gas to reducing emissions from natural gas while cleaner alternatives are developed and deployed, the outlook noted.

"Clearly we're seeing a short-term increased reliance on natural gas" related to Russia's invasion of Ukraine, Hardin said.

While the longer-term focus will be on reducing emissions and transitioning to those clean energy sources, natural gas is viewed as a bridge fuel to the future, she said.

Natural gas markets, according to the outlook, are expected to remain tight in 2023 with European and Asian demand absorbing incremental LNG export volumes coming online.

The outlook suggests potentially increasing investment in the natural gas market.

For example, in 2022, North American LNG developers signed nearly 34 million tons per annum of long-term LNG contracts, a 68% increase over 2021. Most of the contracts are anchoring new or expanded liquefaction projects expected to reach financial investment decisions in late 2022 and 2023.

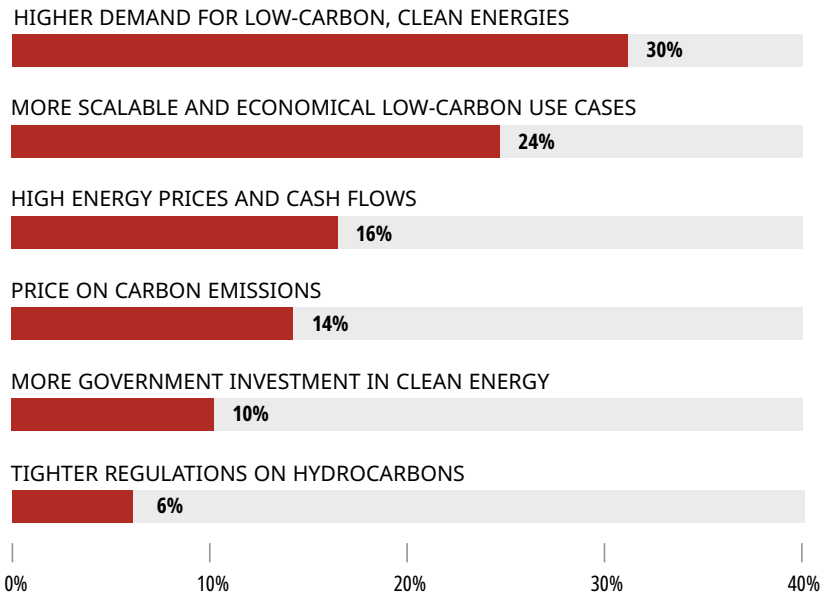
Further, natural gas exporting countries such as Qatar and Israel have announced plans to boost production, and in the U.S., natural gas-directed rigs are at their highest level since September 2019, the report stated.

Additionally, eight floating storage regasification units are expected to become operational in late 2022 through 2023. The outlook said this increases total European import capacity by more than 20%. More than 103 LNG vessels were ordered globally during the first seven months of 2022, the report stated.

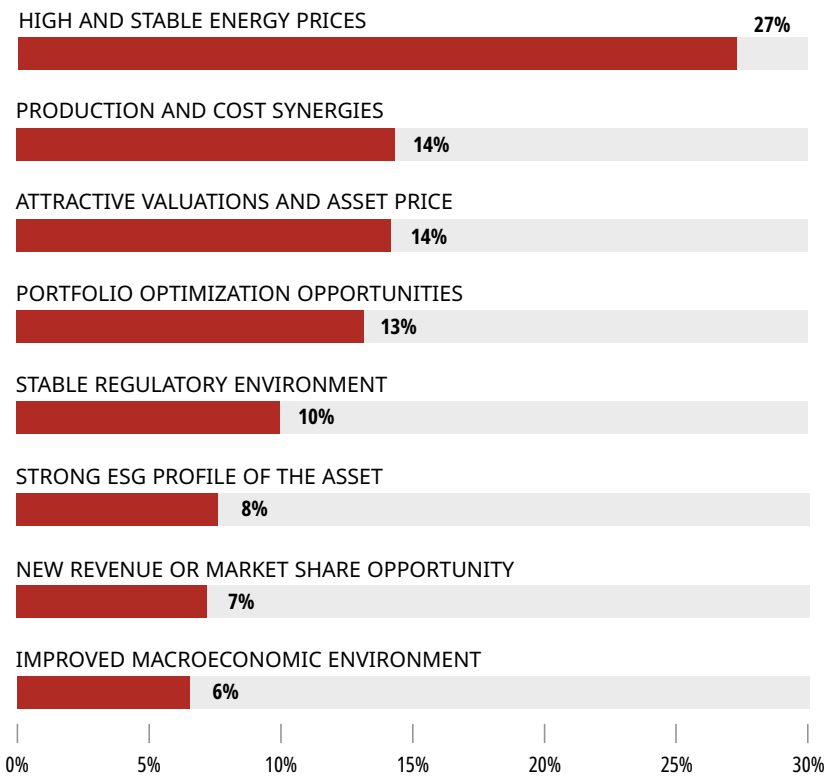
And with all that demand for natural gas, there is an expectation the market will seek to meet those needs. The question, Hardin said, is whether regulatory hurdles will ease.

"Do we have a sense that it may become easier for the permitting for us to do an LNG project?" she asked. It's possible that increased demand for natural gas "may play out with policy decisions," she added. OGI

Factors That Could Accelerate Respondents' Oil And Gas Investment In Clean Energy



Factors Respondents Expect To Drive Oil And Gas M&A Momentum In 2023



Source: Deloitte

NEW FINANCINGS

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount ($MM)	Comments
Northern Oil and Gas Inc.	NYSE: NOG	Minneapolis, Ind.	$51.5	Declared cash dividend 20% increase from prior quarter on common stock for $0.30 per share, payable to stockholders on Jan. 31, 2023. Repurchased 1.37 million shares of common stock and 1.81 million in total year-to-date. Stock price in the third quarter averaged $28.34 per share, and year-to-date price averaged $28.42 per share, totaling $51.5 million. The company still has $98.5 million remaining available on existing common stock repurchase authorization.
Civeo Corp.	NYSE: CVEO	Houston, Calgary	$30.6	Repurchase 40% of outstanding Class A Series 1 preferred shares for $30.58 per share. Company will fund the repurchase through its existing bank revolver. Shares are convertible into approximately 999,000 common shares (6% of the company's fully diluted common shares outstanding) in April 2023. Ten percent of the company's fully diluted common shares outstanding will have been repurchased since August 2021 after repurchase closes on Nov. 1, 2022.
San Juan Basin Royalty Trust	NYSE: SJT	Houston	~$16.3	Declared monthly cash distribution to unitholders on record as of Oct. 31, 2022, of units of beneficial interest of $0.349121 per unit. **PNC Bank National Association** is the trustee, **Hilcorp San Juan LP** own the subject interests and **Hilcorp Energy Co.** is the operator of the subject interests. Hilcorp reported trust net profits of approximately $21.8 million and approximately $26 million in total revenue from the subject interests, both for the month of August 2022. Distribution is payable Nov. 15, 2022.
Exelon Corp.	NASDAQ: EXC	Chicago	N/A	Announced quarterly dividend on common stock of $0.3375 per share payable on Dec. 9, 2022, to shareholders on record as of Nov. 15, 2022.
New Fortress Energy Inc.	NASDAQ: NFE	New York	N/A	Indirect subsidiary **Golar LNG Partners LP** announced cash distribution of 8.75% Series A cumulative redeemable preferred units of $0.546875 payable on Nov. 15, 2022, to Series A preferred unitholders on record as of Nov. 7, 2022. Distribution for the period of Aug. 15, 2022, through Nov. 14, 2022.
Valero Energy Corp.	NYSE: VLO	San Antonio	N/A	Declared quarterly cash dividend of $0.98 per share of common stock to holders on record as of Nov. 17, 2022. Dividend payable on Dec. 8, 2022.

DEBT

Company	Exchange/ Symbol	Headquarters	Amount ($MM)	Comments
Murphy Oil Corp.	NYSE: MUR	Houston	$200	Redeem aggregate principal amount of 5.75% senior notes due 2025. Notes price called for redemption will be equal to 101.438% of the principal amount in addition to accrued and unpaid interest. Notes will be selected along the Depository Trust Co. guidelines, with interest to cease accrual on and after the redemption date of Nov. 30, 2022.
Northern Oil and Gas Inc.	NYSE: NOG	Minneapolis, Ind.	$23.4	Retired $23.4 million of 8.125% senior unsecured notes. Price averaged 96.7% of par value with $26.6 million remaining available on existing notes repurchase authorization.
United Energy Corp.	OTCMKTS: UNRG	Plano, Texas	$5	Entered securities purchase agreement and convertible debt financings, completing Stage 1 financing plan to develop Cherokee Basin oil and gas assets and related projects. Secured financing is through a senior secured convertible note to be convertible into company common stock if elected at a conversion price of $0.10 per share. Shares will accrue interest at a rate equal to prime rate with an additional 9% per annum and a minimum rate of 15% per annum to be paid monthly. Additionally, agreement includes two series of warrants exercisable at $0.20 and $0.30 a share.

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Hart Energy's Oil and Gas Investor holds its 2023 Women in Energy luncheon on February 7th at the Hilton Americas- Houston downtown. The gala lunch will showcase the accomplishments of 25 distinguished women who have influenced all aspects of the oil and gas industry, rising to the top of the industry.

Mark your calendar and join us as we raise a glass and toast these amazing women.

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UK FRACKING BAN MIRED IN UNCERTAINTY

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To frack or not to frack is undoubtedly a topical question in the U.K., especially as new Prime Minister Rishi Sunak, who took office on Oct. 25, is poised to resurrect a previous ban on fracking that was briefly lifted by short-term former Prime Minister Liz Truss.

Sunak in just his first week in office has already proclaimed in parliament to stand by a 2019 manifesto commitment to ban fracking.

The resource-short U.K. has limited options to procure additional domestic energy supply, but many groups there remain steadfast against fracking. Opponents there claim it can cause earth tremors, contaminate groundwater supplies and negatively impact air quality.

"Even if the central government were to allow fracking, the local opposition would be massive. The U.K. is not the wide-open spaces of North Dakota or Texas, and all the massive logistics (i.e. huge trucks) crushing their way through Lancashire villages is, in my view, a non-starter," Andy Parums, a consultant with Energy Strategy International Consultant in London, told Hart Energy.

"So, it's just political posturing until and unless a system is created whereby local communities get direct royalties from any gas produced or other very tangible benefits in kind."

Parums said many local communities across the U.K. can't see a connection between fracking and lower gas bills. He argued that a "bigger, faster impact in practice would come from enhanced licensing and permitting of offshore gas (and oil) in U.K. waters."

Just three years ago, "The Conservative and Unionist Party Manifesto 2019," published by former Prime Minister Boris Johnson, revealed the minister's plans to ban fracking, the result of his audience with local communities. Johnson said at the time that the technique would only be supported if "the science shows categorically that it can be done safely."

Fast forward to February 2022 and Russia President Vladimir Putin's decision to invade Ukraine. The move has jeopardized energy supply flows into the U.K. and mainland Europe and forced leaders there to pivot fast to replace lower supply flowing from sanctioned Russia.

Fast forward again to September 2022, and the U.K.'s fracking ban was briefly lifted under the brief tenure of Truss. She resigned on Oct. 20, after only 45 days of leading the government, leaving the status of U.K. fracking uncertain.

U.K.'s underlying problem is that it's a net importer of oil and, more so, gas, according to bp Plc's "Statistical Review of World Energy" report.

As such, the U.K. relies on Norway and other countries to cover almost half of its gas needs and a third of its oil demand, according to the industry group Offshore Energies U.K. Prior to the start of Putin's war in Ukraine, the U.K. relied on Qatar, the U.S. and Russia for 87% of its LNG imports, according to bp.

No surprise then that the U.K. is caught in a quagmire related to fracking, energy supply and energy security.

"While fracking may not produce results for several years, the banning of the technology eliminates one way to diversify the U.K.'s energy sources," Andy Lipow, president of Lipow Associates, told Hart Energy. "In an era where consumers are demanding more—and affordable—energy, the U.K. will continue to rely on LNG imports for many years. With the U.S. increasing its LNG export capacity by over 40% in the next three years, U.S. natural gas producers can benefit."

Domestically, and further out in the future, the U.K. could rely on production that could come from 898 blocks recently offered in its 33rd U.K. Offshore licensing round, which is part of the North Sea Transition Authority's "ongoing work with industry to ensure security of supply."

"Even when the Ukraine crisis is resolved, there is going to be lingering sentiment to avoid importing hydrocarbons from Russia into Europe for a long time," Steve Hendrickson, president of Ralph E. Davis Associates, told Hart Energy.

"So, I think it's appropriate for them to start thinking about longer-term solutions because there probably will be a longer-term problem, and LNG [especially from the U.S.] probably plays a pretty big role in that for them."

The only thing certain in the U.K. is uncertainty on a host of key topics: the current energy crisis, whether or not to frack, the staying power of the current government—and the crucial question of England's chance of making the finals in the 2022 World Cup in Qatar, where it could earn another star for its football team jersey. OGI

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Hart Energy events provide attendees, sponsors and exhibitors with unrivaled content and networking opportunities across the upstream oil and gas industry. They are designed to facilitate interaction with industry leaders, policymakers and experts in a professional environment.

Please keep these opportunities top-of-mind when you plan your 2023 calendar.

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Norris Centers
Houston, TX

SHALE
DUG HAYNESVILLE
March 28-29
Shreveport Convention Center
Shreveport, LA

SHALE
DUG PREMIUM
May 22-24
Fort Worth Convention Center
Fort Worth, TX

SHALE
EXECUTIVE OIL Conference & Exhibition
Nov. 16
Midland County Horseshoe Arena
Midland, TX

SHALE
DUG EAST
Nov. 29-30
David L. Lawrence Convention Center
Pittsburgh, PA

NATURAL GAS
AMERICA'S NATURAL GAS Conference
Sept. 6-7
Hobby Center
Houston, TX

ESG
25 INFLUENTIAL WOMEN IN ENERGY
Feb. 7
Hilton Americas-Houston
Houston, TX

ESG
CARBON MANAGEMENT Conference
Aug. 30
Norris Centers
Houston, TX

ESG
ENERGY ESG Conference
Sept. 19
Hobby Center
Houston, TX

INVESTMENT
ENERGY CAPITAL Conference
Oct. 2
Statler Hotel
Dallas, TX

INVESTMENT
A&D STRATEGIES & OPPORTUNITIES Conference
Oct. 3
Statler Hotel
Dallas, TX

NEW TECHNOLOGY
ENERGY INFRASTRUCTURE & TECHNOLOGY Conference
April 12-13
Norris Centers
Houston, TX

NEW TECHNOLOGY
CYBERSECURITY IN ENERGY Conference
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LATIN AMERICA CAN'T SOLVE EUROPE'S ENERGY CRISIS IN THE SHORT-TERM

Europe's current energy crisis is not likely to be solved by additional oil or gas to flow from Latin America or the Caribbean over the short term.

SHUTTERSTOCK/CORONA BOREALIS STUDIO

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Resource-rich Latin America, especially Argentina, Brazil, Guyana and Venezuela, will not be able to provide short-term, urgent solutions to Europe's energy crisis, energy experts concurred during a webinar hosted by Florida International University.

"There's no short-term solution for Europe's crisis coming from Latin America," the Institute of the Americas vice president of energy and sustainability Jeremy Martin said Oct. 19 during the "Energy Outlook in the Americas" webinar.

Latin America and the Caribbean are home to reserves of close to 341 Bbbl of oil, including around 11 Bboe in Guyana, and then 285 Tcf of natural gas, according to bp Plc's "Statistical Review of World Energy 2021" report. Oil and gas production from the region was around 8 MMbbl/d and 183 Bcm, or 18 Bcf/d respectively.

Despite this potential, near-term reserve additions and production rises are only expected to come from Brazil and Guyana based on discoveries in those countries, mainly by state-owned Petrobras and an Exxon Mobil Corp.-led consortium that includes Hess Corp. and CNOOC.

"A legacy, the reason why production has not performed so well in the region, except perhaps for the case of Brazil, is because of what we typically call above ground risks in the sector," Francisco J. Monaldi, Rice University's Baker Institute for Public Policy fellow in Latin American energy, said during the webinar.

"Meaning the mix of regulatory, expropriation risks and mismanagement of the national oil companies and the likes has made this region, [which] concentrates the second-largest resource base outside of the Middle East, a significant underperformer in contrast."

In the not-so-distant past, Venezuela was the region's dominant oil and gas producer and a key U.S. ally. Today, despite the frequent headlines, the country has little to offer in terms of near-term production after years of oil rent mismanagement and the recent weight of U.S. sanctions imposed in early 2019, which aimed to provoke a regime change.

Venezuela, the lone OPEC member country in the Americas, produced just short of 700,000 bbl/d in September and is still far from its peak potential, IPD Latin America managing director and founding partner David Voght said during the webinar.

Voght argued U.S. sanctions wouldn't be lifted but instead recalibrated, while the private sector participation was needed and the best to likely "preserve" Venezuela's oil infrastructure.

Vaca Muerta shale bet

Argentina's Vaca Muerta Formation, on par with the U.S. Permian Basin and Haynesville Shale in terms of total resources, holds the most potential for the South American country to boost gas production and potentially future LNG exports if key infrastructure is ultimately built.

Persistent political and economic uncertainties remain Argentina's main headwinds despite potential for short-term production gains.

"Argentina has been a tremendous underperformer after they privatized the oil industry in the 1990s," Monaldi said. The country has been able to level off its production in recent years,

and there's potential to boost it more, the executive said.

"Part of the reason why Argentina will be able to develop at least some of Vaca Muerta despite all their problems in terms of institutions and macroeconomics is that the type of investment in shale is … that short-cycle investment where the risks are much smaller than in other, longer-term, bigger projects," Monaldi said.

But there is still some pessimism regarding Argentina's export potential.

"If Argentina had gotten serious about exporting LNG five years ago, they would have been the solution to Europe's current crisis. But they didn't," Martin said. "And they still aren't going to be able to develop the kind of infrastructure needed to export gas."

"If Argentina had gotten serious about exporting LNG five years ago, they would have been the solution to Europe's current crisis. But they didn't."

—Jeremy Martin, *Institute of the Americas*

Exploration boom

South America's Brazil and Guyana have led the region's exploration boom in recent years. Prior finds in Brazil will boost production over the near term as new FPSO vessels arrive. More recent finds in Guyana coupled with FPSOs coming online almost yearly will continue to have a positive impact for the country, its citizens and the oil companies involved.

Brazil has emerged in recent years as the largest oil and gas producer in Latin America as Venezuela has backtracked amid political uncertainties and U.S. sanctions.

Despite the uncertainties around elections in Brazil, the country's production "is geared toward reaching levels of close to 6 MMbbl/d in the next decade," Monaldi said, citing data from Rystad Energy, which would imply doubling current production.

Guyana, the other exploration hotspot, is arguably a more exciting story given the country's small population and the fact that it only recently started producing oil in late 2019.

Exxon Mobil's partner Hess foresees at least six FPSOs with a production capacity of more than 1 MMbbl/d gross coming online on Guyana's Stabroek Block in 2027 and the potential for up to 10 FPSOs to develop gross discovered recoverable resources, the company announced earlier this summer. Average production in Guyana is expected to exceed 300,000 bbl/d this year.

"Guyana could become … the largest oil producer per capita on earth surpassing Kuwait and the Emirates, but in any scenario, it looks like that it is going to be also one of the top three or four producers in the region," Monaldi said.

U.S. sanction recalibration needed

Venezuela, with its massive oil found in its Orinoco Heavy Oil Belt, or Faja and its massive gas potential offshore can't be overlooked by companies or the U.S. government as it scrambles to find barrels and molecules to replace lost supply from Russia after its invasion in Ukraine and subsequent sanctions.

Venezuela's near- and long-term potential is arguably being held prey by U.S. sanctions, which are holding back investors, and the only western oil producer still in the country, U.S.-based Chevron Corp.

"But basically, what we can see is that there is little upside in the short term for Venezuela, and it will require very significant investment by Chevron if there is a license," Monaldi said, adding they could probably only add a bit over 100,000 bbl/d.

"Some people are saying the United States is considering lifting sanctions. No, that's not true. There's going to be no lifting of sanctions. What there is hopefully going to be is a recalibration of sanctions," Voght said.

Voght said the private sector, including companies such as Chevron involved in joint ventures that account for around 50% of Venezuela oil production, was in a better position to preserve Venezuela's oil infrastructure, which has deteriorated in recent decades due to the lack of maintenance and cannibalization of parts.

Besides the recalibration of sanctions, Voght said it was necessary for Venezuela to pivot geopolitically away from China and Iran. Around 95% of Venezuela's oil exports go to China at heavily discounted rates, while Iran continues to provide Venezuela with necessary resources, such as condensate to assist in the production of its heavy and extra-heavy oils.

"I think there's value in creating optionality for Venezuela to divert crude from China to the Atlantic Basin here, promoting improved regional security, regional energy security, particularly for the European market," Voght said.

Venezuelan gas for Trinidad's Atlantic LNG

In terms of Venezuela's gas production and potential to export molecules to Trinidad for later re-export as LNG, Venezuela has two options.

There's potential that could initially come from offshore as well as around 2.5 Bcf/d that is currently being flared onshore in Monagas, Venezuela, Voght said.

The vast majority of Venezuela's gas is "associated with oil production and therefore cannot be exportable necessarily, but our assessment is that within three years, Venezuela could be producing enough to supply Trinidad's Atlantic LNG Train 1 at about 3.3 million tonnes per annum through both the Dragon offshore fields and through gas collection in the northeastern part of the country," Voght said. OGI

Voices

Energy companies reported third-quarter earnings results under the specter of continued uncertainty regarding inflation, the global response to Russia's ongoing invasion of Ukraine and the coming winter.

"Look, there is inflation out there. We've never been hiding from inflation. It's real. As we renew contracts, we see that continue to tick up ... We will continue to monitor that. I think it's too early to say how that manifests over the course of 2023."

—**Clay Gaspar**, *COO, Devon Energy Corp.*

"We're very well prepared for a weaker gas market as we move into 2023 and don't know if that will actually happen. But if it does, we'll be ready for that."

—**Nick Dell'Osso**, *president and CEO, Chesapeake Energy Corp.*

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"This quarter's results reflect us continuing to perform while transforming. We remain focused on helping to solve the energy trilemma—secure, affordable and lower carbon energy,"

—**Bernard Looney Chief**, *CFO, bp Plc*

"A lot of people would say the best remedy against high prices is high prices, but the reality is that with the prices that we are seeing today, many people in society, particularly, the most vulnerable, are suffering very badly as a result. I think it is only sensible, it's a societal reality that governments intervene and alleviate the pressure on those who need the alleviation most."

—**Ben van Beurden**, *CEO, Shell Plc*

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The deadline for nominations is **October 20, 2023**

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RISING TO THE CHALLENGE(S)

Civitas Resources Inc. in the Denver-Julesburg Basin is aligning executive compensation with stakeholders, meeting emissions reduction targets and is on target to generate $1 billion in annual free cash flow this year. And inside its C-suite, a millennial woman from Colombia is showing everyone how it's done.

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Where super-sized independents such as Occidental Petroleum Corp. and European super majors like TotalEnergies are orchestrating some carbon neutral production in its nascent stages, Civitas Resources Inc. is a carbon-neutral producer by its first design. The firm employs Scope 1 emissions offsets and Scope 2 green e-certified renewable energy credits to make the firm Colorado's first carbon neutral energy producer.

A triple merger among Denver-Julesburg Basin producers Bonanza Creek Energy, Extraction Oil & Gas and Crestone Peak yielded Civitas two years ago. But the public company that emerged on the New York Stock Exchange on Nov. 2, 202—and now the largest oil and natural gas pure play in Colorado—is not the story of just any ordinary roll-up.

And its CFO is no ordinary corporate suit.

Marianella Foschi, 35, is young and savvy, a woman of color with dual degrees in finance and economics and a coming-of-age story that started in Colombia. In many ways, she is the future of the U.S. industry. By the time she graduated from high school at 18, Foschi knew she wanted to pursue an education in the U.S., where she found "fascinating" opportunities for someone willing to work hard.

Within the first 10 years of graduating from The University of Texas at Austin, Foschi held key finance roles at two public companies, managed debt and equity investing at The Blackstone Group—the world's largest alternative investment firm with more than $880 billion in assets under management (AUM)—and worked on oil and gas deals at Credit Suisse, where current AUM value is upward of $1.5 trillion.

As Civitas neared its one-year anniversary as a public company, Foschi discussed with Oil and Gas Investor editor-in-chief Deon Daugherty the chances and the challenges ahead for the company, the industry and the next generation of oil and gas executives.

Photography by Michael Ciaglo

Deon Daugherty: ***Civitas is a young company, and it's the sum of several parts. How did it all begin?***
Marianella Foschi: The legacy company I came from—Extraction Oil and Gas—went through restructuring in 2020, not unlike others in the industry. We had come off the prior business model of growth, outspending cash flows when the pandemic and oil [prices] going to zero all hit us at the wrong time.

It was honestly—I mean, I hate saying this—but it was an incredible learning experience for me. It was not something that you would want to do and it's not something that is a shining star on your resume. But for me, it was perfect because I wasn't C-suite at the time. I was two levels down as director of finance.

We emerged from bankruptcy with new leadership that was much more aligned with what E&P companies need to be and what they need to do. Specifically, this was Kimmeridge; they owned 40% of Extraction at the time.

We were very vocal just in advance of emerging from bankruptcy that we were going to be as aggressive as we could. It's something that we believed the industry needed to do. And it took a lot of time and work.

The reason the industry got to be where it was at the time was a lack of compensation alignment with shareholders, and so [Kimmeridge] wanted to make sure there was alignment between management teams and equity holders.

Within ESG is a lot of the compensation [issue]. People always think about ESG being about emissions, but the "G" is just as important for us—making sure we have a diverse workforce and that our board is aligned with us and with the Street. There's a bunch of pieces within that, and they can be forgotten.

DD: ***Where does consolidation fit into the ongoing strategy?***
MF: If you think about the 2016, 2018 period, every company and their mother was getting an equity check from their private equity firm.

[Civitas' management] view was that it is just too inefficient. We need a handful of players in every basin. We are serious about consolidation and balance sheet strength.

I wanted to make sure we never got into another situation like we did in 2020 and ensure we were making a balance sheet that can survive through the cycle. We're in a very cyclical industry and statistically, it's just a matter of time: How many years do you think you have the next cycle?

Just in the [D-J] basin, there was us and three others. To be honest, we didn't need those companies. They overlapped, they were very similar and they could have been one [consolidated firm]. We put those companies together.

Even before we emerged from bankruptcy, we were already having those discussions. We had a very clear vision that we would—obviously, price dependent and market conditions dependent—we would grow the footprint of the business in the basin. The whole goal was to see what we could do within the basin that's accretive to our equity.

And we have big plans. We are continuing to look at acquisitions in Colorado—that's part of our linear daily bread. We're always looking at one to three opportunities, and I think that at the scale we have now, we're already looking at [targets] outside Colorado as well, with the understanding that it's going to be a steeper climb.

But I think we do exhibit a lot of the things that the industry needs to do. And I think to some extent, you've seen other companies adopt some of these pieces. I don't think there's a company that's adopted all of them, like we have. It was easier for us to do it to some extent; we had a fresh start with a bankruptcy.

DD: ***How did you find your way into the U.S. oil and gas industry after growing up in Colombia?***
MF: You probably notice English is not my first language, it's Spanish. I lived in Colombia until I was 18, and after I graduated high school, I wanted a better education than Colombia could afford me.

My plan at the time was just to get my degree here and then move back. And, of course, I didn't do that. The infrastructure of this country and the opportunities available just completely fascinated me. It's just so different. I don't even know what word to use.

This industry is full of challenges. I had only a year to work here under a student visa. I thought, "let me just get the most intense job I can ever get because I could only be here a year." That was investment banking.

DD: ***What has been the biggest challenge for you at Civitas?***
MF: The biggest challenge is the constant change. And I'll give you one specifically about our company, but we're figuring out strategically where we want to be and how we want to position ourselves amidst this sea of change and volatility in the industry. That is pretty challenging.

You have to be nimble, and you need a board that's nimble and supportive. We want to preserve the ability to move quickly.

The other challenge I would say is operating in Colorado. This has never been easy, and it's something that we feel like we do very well. A big part of our strategy that has paid off is the ability to work closely with the communities we operate [in]. We're headquartered in Denver, and all of the fields where we're developing [are] all over the Denver area. All of our field folks go home every day. We're more competitive on the hiring front because of that reason.

But nonetheless, operating in Colorado continues to be something that takes more time. More staffing is needed to permit our wells, more staffing for planning things like air emissions monitoring and other incremental environmental initiatives that we have.

The continued integration of the companies is challenging. It's been difficult, to say the least. But we're coming up on a year of closing, and we've done it very successfully.

The first quarters have been very successful across the board on most metrics. And so I think that concern has very much gone away. But in this industry, there has been a lack of interest from investors. I kind of see that changing, but to be fair, there was a big rally in energy stocks in Q2 [second quarter]. And then it came down again. You just never know what you're going to get every day.

The way we're trying to combat that challenge is by making it very clear that it's not a mutually exclusive thing. We're spending meaningful dollars—tens of millions of dollars—on reducing our emissions operationally. We're actually building a pipeline right now toward the south of the basin because we don't want to use trucks. By not trucking, we're also not paying for the trucking fee, but we're also building the pipeline.

I think we're just trying to make sure investors understand that, "Hey, you don't need to sell us if you have an institutional mandate just because we're oil and gas. At least give us a shot by understanding what we're doing. We think you're going to be really impressed."

DD: ***It seems that it is going to take more time for the investor community to come back to oil and gas, if that's possible.***
MF: I think there's going to be a very clear differentiator of the dos and don'ts [for companies making changes]. And I think that's kind of once the SEC [U.S. Securities and Exchange Commission] finalizes their emissions reporting standard. That's when it's all going to come to light, who's actually doing something and who's not.

DD: ***When you tally up the pluses and minuses of operating in Colorado, what does Civitas consider when adding some diversity to the portfolio with assets in other basins?***
MF: At this point, we're in more of a screening stage. We're trying to figure out what makes us a better company. Does this option make us better in ESG? Does this improve our balance sheet? Does this create value?

At this point we're keeping an open mind. We don't have any specific biases. We're at more of an inflection point where we've just closed these mergers and acquisitions that we have successfully integrated.

DD: ***At the end of the second quarter, Civitas reported $436 million in free cash flow. How much do you expect to generate by the end of this year, and how will Civitas use it?***
MF: *We don't* look at the strip too much. We'll look at kind of lower pricing cases, but I would say roughly around $75 a barrel would probably create a billion-plus [dollars] in free cash flow.

We're committed to returning about 60% of that free cash flow back to investors. Then that leaves the other 40%, and we would want to preserve some flexibility.

We're still evaluating whether the 40% would be used for consolidation because we've had a great experience with it. And we're big believers in it.

That said, if we're not seeing an accretive acquisition opportunity, we'll look at other metrics, but it may be that we just won't do it. And at that point, we would look at either a buyback, if we think the stock is at a price that makes sense, or a dividend. But those three, on the relative merits, is what we're going to do with the balance of the cash.

DD: ***What is the professional dynamic—the level of challenge—today for a woman of color to earn a spot in an oil and gas C-suite?***
MF: I probably have two tiers of challenges, to be honest. Being a woman in a primarily male-dominated industry is one but then also being from Colombia. They're not, by definition, insurmountable challenges given where I am, but there is more that can be done [to equalize opportunities].

It's great that we're nursing awareness, but there's a fine line beyond which we don't want to go. For example, I've seen companies that will only interview females for certain roles. That's just not fair to anybody. OGI

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PRIME PERMIAN

As the Permian Basin closes in on its pre-pandemic oil production peak, industry adjusts to accommodate variables in play.

RYAN RAY
CONTRIBUTING EDITOR
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If Permian Basin oil production were a stock, Wall Street brokers would insist their clients buy it.

By almost any measure, the basin delivers.

The 55 counties in Texas and New Mexico that make up the Permian account for almost half—roughly 45%—the U.S.' oil production, according to the U.S. Energy Information Administration (EIA). The basin's market share is up almost 20% since 2013.

There's no other way to put it: The Permian sustains American oil production.

But, since the earliest days of the shale revolution, naysayers have warned that its time in the sun will be short lived. The caution has come from many directions; industry insiders ring out some of the loudest supply warnings.

Back in 2017, shale pioneer Mark Papa, then-CEO of Centennial Resource Development, cautioned on the play's great expectations.

"Even in a constructive oil price environment, I expect the 2018 total U.S. oil growth will be considerably less than the 1.2 million to 1.4 million barrels per day that many people are predicting," he said.

The Permian proved Papa wrong.

The basin's 2017 production of 9.3 MMbbl/d was easily bested the next year. By the end of 2018, Permian oil supply added 17%—1.66 MMbbl/d—for a total 10.96 MMbbl/d that exceeded most predictions.

At the end of 2019, the Permian's daily output easily surpassed 12 MMbbl, putting the play's two-year growth average at a staggering 1.3 MMbbl/d.

Indeed, it took a worldwide virus and its decimation of demand to slow the Permian's trajectory.

But more than two years since COVID-19 upended commodity and global economies, demand is back.

Is the Permian back, too?

Producers that rolled back their growth—in part driven by positive demand signals but also by shareholder demand—remain gun-shy about calling high-number production goals. Demand is heading upward, but the shareholder insistence for returns before growth is firmly in place. And, as the mighty Permian nears its pre-pandemic production high, questions about its sustainability augment the conversation.

What's shaking up Permian production?
Oil wells aren't drilled in a vacuum. Lateral length and geographic location contribute to drillers' results, best practices matter and the ability to secure the best vendor contracts is important. Successful management of drilled but uncompleted wells (DUCs) is a factor.

But there is more that separates one producer's performance from that of another one, and some of those elements may be harder to quantify, such as internal talent pool and recruitment success.

Technology has long greased the wheels of oil production. Improved well design, manufacturing-mode drilling and other advancements are present across the Permian's 86,000 square miles.

Productivity degradation is present in the Delaware Basin because activity is ramping up in the gassier parts of the play.

—Stephen Sagriff, *Enverus*

Lateral length

Phillips Johnston, senior E&P analyst at Capital One Securities, said in a recent note to investors that, "Oil productivity per well per lateral foot has in fact deteriorated in the core northern counties that now comprise ~60% of all new wells in Delaware and ~70% of all new wells in Midland."

Permian investors have raised concerns about the productivity of new wells, he said.

"If you look at the basin as a whole, it is hard to determine if there is degradation," Johnston said. "However, you can find some degradation once you start to isolate the wells by region."

Stephen Sagriff, vice president of intelligence at Enverus, told Hart Energy that some productivity degradation is present in the Delaware Basin because activity is ramping up in the gassier parts of the play. Conversely, oil production is flat in the Midland Basin while gas production is down.

"The biggest difference when it comes to phase window selection or commodity mix between the two sub-basins is the gassier Midland regions (southeast) are far inferior to the [oilier] areas, while in the Delaware, the gassier west is a lot more competitive with the oily central/east, at least on a single well economic basis, particularly with improved NGL and gas pricing over the last year or so," Sagriff said.

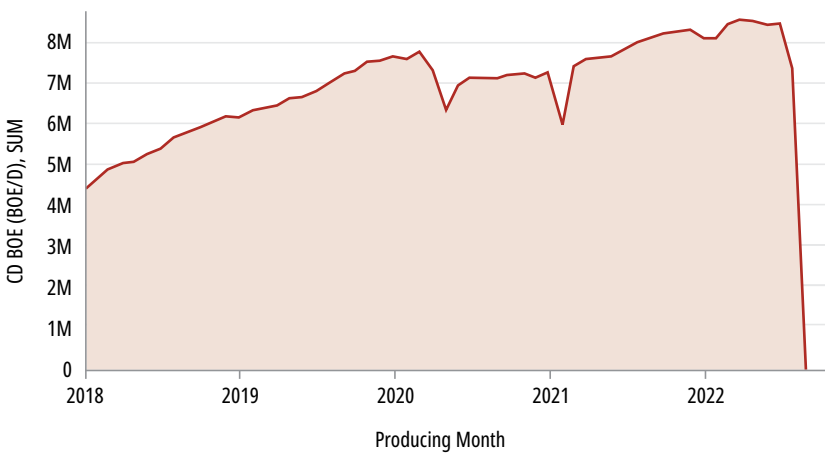
The Permian is one of the nation's most mature basins, and many companies have pushed the lateral length of their wells to greater depths. Some attribute these longer laterals as part of the problem.

Average Weekly Permian Basin Oil Rig Count

Year	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	*2022
Rig Count	482	462	544	279	185	362	475	451	224	244	338

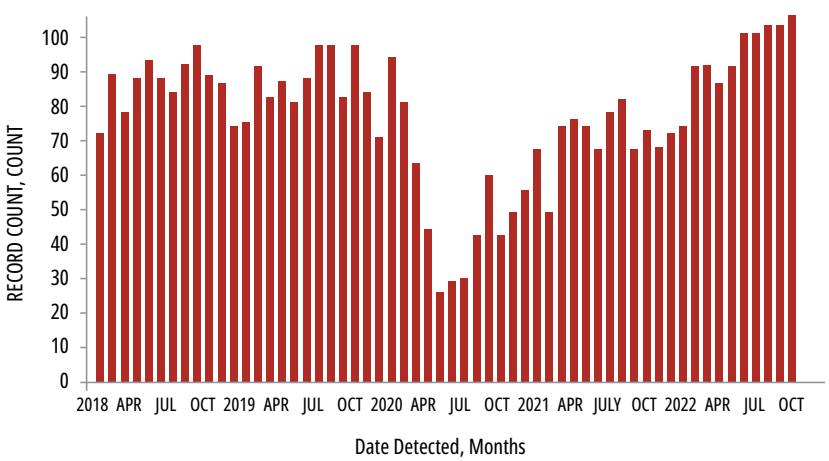
Source: Baker Hughes
*Through Nov. 4

Permian Gross Wellhead Production



Source: Enverus

Permian Frac Crews Through Time



Source: Enverus

You get a slight trade off with longer laterals. "The rate of recovery decreases the farther you push your laterals," said Ted Cross, Novi Labs' director of product management.

"Looking at production on a per-foot basis can be misleading. At current prices, operators are able to drill with a little more freedom. They can make their cost back in nine months, so they might find themselves drilling a well that, on the margin, isn't producing up to historical standards. But that doesn't necessitate that all of their inventory will fall into that same model," Cross said. "We've seen over the years operators try different drilling techniques to get the most out of their wells. From that perspective, nothing is different."

"The rate of recovery decreases the farther you push your laterals."

—Ted Cross, *Novi Labs*

Location

Permian giant Pioneer Natural Resources noted during third-quarter reporting that some 2022 wells did not perform as expected.

"The delayed targets have underperformed where we would have anticipated," Richard Dealy, president and operations chief, said during a call with analysts. "They still have great returns. It is just we have better locations in our portfolio"

As such, Pioneer will "reshuffle the deck" and defer its delayed targets.

Dealy said the firm will focus in 2023 on improving well productivity and returning more money to shareholders.

"We've got a higher bar, and it's going to increase our program productivity," he said. "It's going to increase our annual capital efficiency and result in higher free cash flow generation."

Recent Novi Labs research found the newly combined Permian player, Coterra Energy Inc., has drilled the Permian's strongest wells since 2018, with wells in the western and northern Delaware sub-basin coming in at an average 210,000 bbl of oil flowing first-year production. On the other end of the spectrum, Ring Energy's wells in the Central Basin Platform only produced 42,000 bbl of oil during its first year of production during that same period.

DUCs

During the tough years of the pandemic, many companies turned to the cheapest wells they had on their rosters: those that were previously DUCs.

The Permian's current DUC count of 1,117 is down 70% from the late 2019 total of more than 3,800, according to the EIA.

Each DUC brings with it critical questions about its ability to impact overall production. Specifically, a production variable contrary to reliable production could halt the process. So, why drill a well and then leave it uncompleted?

Some DUCs are wrongly classified. A producer drills the well and intends to complete it quickly, but other constraints such as the availability of a hydraulic fracturing crew may slow down the process. Or it could be as simple as counting multiple holes on a super pad as multiple DUCs.

And, sometimes, companies do start wells only to determine that the well is not as profitable as originally planned, and it becomes a DUC. In those instances, companies may bring them online during a tight capital market or when oil prices hit a certain threshold that makes them profitable enough.

Consequently, with a lack of new drilling, combined with bringing online a historic amount of uncompleted wells, it is possible that the DUCs brought online are dragging production productivity trends downward.

No cause for alarm

The production from some Permian wells this year hasn't measured up to hopes and expectations, but it doesn't appear to be a concern poised to roil the basin's future.

Companies such as King Operating Corp. intend to expand their footprint in the Permian.

"We aren't worried about the Permian. Our results have been great," said Jay Young, CEO of King Operating. "Furthermore, every 10 years, the Permian seems to reinvent itself. So, whatever problems the industry is facing today will be solved. In fact, we're actively looking for more Permian deals right now."

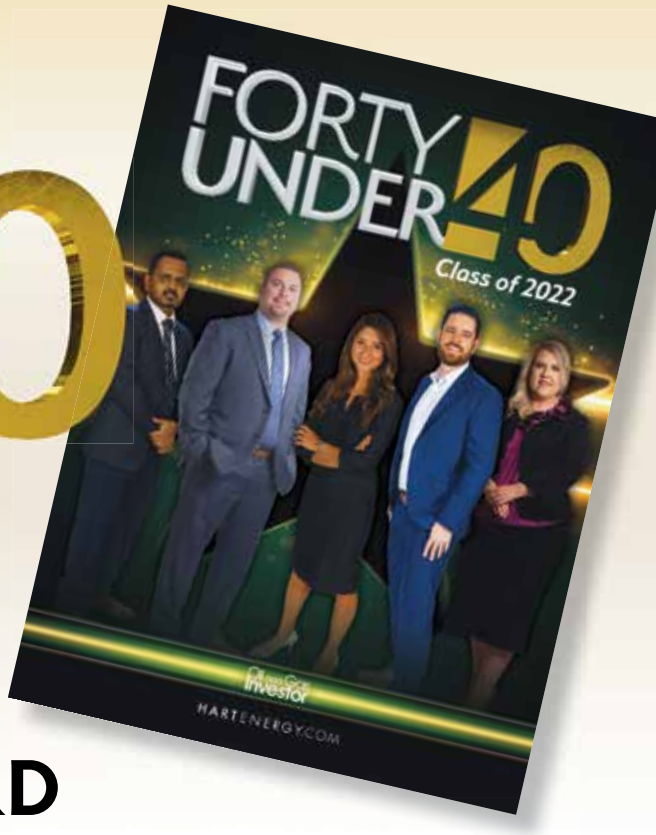
Enverus estimates there are more than 100,000 undrilled locations left in the Permian that break even at WTI prices of less than $40/bbl.

Energy analyst David Blackmon too is confident about the future of the Permian.

"We have seen predictions of doom about per-well productivity in the Permian region periodically for a decade now, and the result has always been the same: A steady rise in per-well productivity," Blackmon told Hart Energy

"With all due respect to the analysts, what consistently tends to go unconsidered in such predictions is the fact that the oil and gas industry is a technology-driven business in which technology and adoption of it advances every day." OGI

FORTY UNDER 40



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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.

NOMINEES SHOULD DISPLAY:

- A desire to find new challenges
- Community involvement
- Leadership initiative
- Creative problem solving
- Professional excellence
- Entrepreneurial spirit

HartEnergy.com/form/fortyunder40

Deadline for submissions is June 9, 2023

Oil and Gas Investor

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NO HALF STEPPIN'

Private equity moves aggressively to transform the midstream sector.

MARK DRUSKOFF
CONTRIBUTING EDITOR

Like conjoined twins, the fates of upstream and midstream oil and gas companies have historically been intertwined. But they are siblings with much different personalities.

Upstreamers are wont to describe themselves as wildcatters that take big risks and generate big rewards. Meanwhile, midstream operators extol the steady, toll booth-like virtues of their assets that provide yield over an extended time frame.

But changes are coming, and they have the potential to transform the midstream sector in ways that reshape traditional relationships between upstream and midstream players. Midstream private equity sponsors have begun maneuvering their portfolio companies to take advantage of these shifts. But potential roadblocks abound.

Consider the state of the midstream space.

The Alerian U.S. Midstream Energy Index, consisting of 31 constituent public midstream entities, has seen many highs and lows since its launch in 2013. The index climbed as high as 863 in September 2014 but dived as low as 155 in March 2020. Unsurprisingly the highs and lows correlate closely to crude oil's zeniths and nadirs. Today the index stands close to 491.

Challenging market dynamics have combined with ESG mandates to create a tough fundraising environment for existing and prospective private equity players.

"Generally speaking, private equity interest in energy in recent years has been way down," said Creighton Smith, partner at Vinson & Elkins. Some of the largest private equity providers to the sector have taken a step back from investing in the space, he said.

"The overall pool of private equity-sourced capital has diminished," agreed

> **"Generally speaking, private equity interest in energy in recent years has been way down."**
> —Creighton Smith, *Vinson & Elkins*

Tim Fenn, partner at Latham & Watkins. "Some of that slack has been taken up by other investor types. For instance, infrastructure funds have stepped in and taken private equity's place."

Fenn flagged Buckeye Partners as a stand-out example. In November 2019, Australian infrastructure player IFM Investments paid $10.3 billion to acquire Buckeye Partners and take it private.

"The market is still strong, but there are headwinds looking farther out," said Chad Smith, partner at Kirkland & Ellis. Global economic pressure is putting pressure on commodity prices, and inflation is a "growing concern."

Private equity sponsors that have remained in the space are feeling downright enthusiastic about their future prospects, however.

"We firmly believe we are entering an energy awakening," said Jason Downie, co-founder and managing partner of Tailwater Capital. Discussion no longer focuses just on supply and demand but also on reliability, accessibility and affordability. In such an environment, oil and gas offers clear benefits, he said.

"We certainly believe we're at the front end of a new investment cycle," said Billy Lemmons, co-founder and managing partner of EnCap Flatrock Midstream. "There have been a lot of favorable fundamentals and have been many world events that increase or renew the role of hydrocarbons."

Acknowledging that some private equity investors have moved out of the space, Lemmons sees that as a positive. "From an investment standpoint, there's less capital that we need to compete with," he said.

"The overall pool of private equity-sourced capital has diminished."

—Tim Fenn, *Latham & Watkins*

The export effect

Although EnCap Flatrock Midstream did not put much capital to work in 2020 and 2021, the midstream private equity shop has not been shy of deploying capital in 2022. The firm has completed nearly $2 billion in acquisitions, and its portfolio companies are positioned to add more than 1 Bcf/d of new capacity, said Lemmons.

EnCap Flatrock lists 20 current midstream portfolio companies on its website. One of those investments is M6 Midstream, which also boasts the backing of Yorktown Energy Partners, Martin Sustainable Resources, Ridgemont Equity Partners, Bengas Midstream Partners and Blackstone Credit.

In September, M6 Midstream announced a pair of acquisitions in the Haynesville Shale: the East Texas business of Midcoast Energy and Align Midstream II. The combined assets give M6 Midstream 1.7 Bcf/d of capacity with the ability to expand to 2.2 Bcf/d to move natural gas from the Haynesville to the Gulf Coast and LNG markets.

"We've certainly spent more time looking at LNG in the last year than in the past 14 years," said Lemmons.

M6 Midstream is not EnCap Flatrock's only investment close to LNG export facilities. It also backs Clearfork Midstream, which acquired Azure Midstream Energy in early 2022, giving the company 500 miles of pipeline and 1.2 Bcf/d of treating capacity across systems in North Louisiana and East Texas.

Infrastructure for LNG export is a "huge opportunity," said Downie. Tailwater invested in Align Midstream II in 2017, which had assets that connected natural gas supply to key downstream pipelines serving the growing Haynesville Shale. Tailwater is again looking at additional investments in the Haynesville, Downie said, but he also sees the Eagle Ford playing a role in LNG supply.

RBN Energy has seen a steady uptick in LNG interest through its consulting business, said CEO David Braziel. "Nearly every deal we've done this year is impacted by trends in the LNG market," he said.

TAKING STOCK

In the upstream space in recent years, a number of private equity-backed portfolio companies have accepted a hefty amount of equity when they exited to public buyers. In the midstream space, meanwhile, cash has been the main form of consideration. That could change, however.

"A lot of private equity companies have a positive outlook on stock," said Chad Smith, partner at Kirkland & Ellis. "Many midstream companies have seen themselves as undervalued, and private equity shares that view."

Smith noted there's a number of midstream companies in the market looking to get deals done in 2023.

Accepting equity as part of the exit consideration will be particularly relevant to midstream companies that have gotten so large that public companies are the most likely buyers. "To get the valuations they want, they will need a stake in the deal," said Smith.

A potential harbinger of a shift is a recent deal involving EagleClaw Midstream, backed by Blackstone and I Squared Capital. In February, the company combined in a $3.11 billion all-stock transaction with Apache-owned Altus Midstream to form Kinetik, giving EagleClaw's sponsors 75% of the new company.

"The market is still strong, but there are headwinds looking farther out."

—Chad Smith, *Kirkland & Ellis*

LNG sits at a critical juncture between energy security and energy transition, Braziel noted. "Not only do we want to help our allies in Europe but also exporting U.S. natural gas is the best thing we can do for decarbonization goals."

Growing gas volume from the Permian Basin is also fighting to make its way to LNG facilities, Braziel said. Thanks to strong international oil demand and constrained global supplies, crude and associated gas production is booming in the basin but pushing up against capacity. Prices at the Waha hub went negative in late October, he noted.

Not surprising then that private equity has seen some of its biggest midstream exits in the Permian.

In January, Warburg Pincus-backed Navitas Midstream was sold to Enterprise Products for $3.25 billion. In February, EagleClaw Midstream, backed by Blackstone and I Squared Capital, combined in a $3.11 billion all-stock transaction with Apache-owned Altus Midstream to form Kinetik. In July, Riverstone and Goldman Sachs completed the sale of Lucid Energy Delaware to Targa Resources for $3.55 billion in cash.

Next big thing

It's not just the ebb and flow of markets and caroming impacts of geopolitical events that have private equity investors chomping at the bit. They see midstream as uniquely positioned to not only participate but possibly even lead the way in a whole new area of investment thanks to the signing of the Inflation Reduction Act (IRA) in August.

"We firmly believe we are entering an energy awakening."

—Jason Downie, *Tailwater Capital*

At first glance, the new legislation might not seem cause for excitement for midstream private equity sponsors. Yet the new legislation promises to turn molecules that used to be considered waste into new sources of economic value.

The IRA includes significant tax credits and benefits for carbon capture utilization and storage (CCUS) through enhancements to Section 45Q of the Internal Revenue Code, according to a publication by BakerHostetler.

"Carbon capture and sequestration—that is literally midstream 101," said Tailwater's Downie. Midstream companies have long generated fees removing CO_2 from natural gas to make it pipeline ready. "An amine treater is literally a CO_2 stripper," Downie said.

Midstream also has expertise in injection wells, which will be critical to sequestering carbon, he said.

The IRA provides a tax credit as high as $85 per metric ton if the captured carbon is stored in a geologic formation, or $60 per ton for CO_2 used in oil and gas fields. Available 45Q tax credits more than double to $130 per metric ton for carbon used in oil and gas fields that have been removed from the atmosphere through direct air capture.

Latham & Watkins' Fenn noted that another important new feature of the IRA is the transferability of the tax credits. With the new legislation, tax credits can be transferred to another party, like a bank or insurance company that would have a greater need for the credits. Transfers come with "lots of requirements" but makes CCUS far more attractive to midstreamers. Previously they had little use for credits because of the tax benefits of depreciation, which can significantly lower their tax bills, as well as the overall limitations on the use of credits by passthrough entities.

Tailwater is all in.

The private equity firm created Tailwater Innovation Partners to provide guidance to portfolio companies on ESG, energy innovation and operational improvement. And Tailwater already has one portfolio company, Frontier Carbon Solutions, focused on bringing CCUS to Wyoming. The company announced a partnership with direct air capture technology company CarbonCapture to create a system that could permanently remove up to 5 million tons of CO_2 from the atmosphere by 2030.

EnCap Flatrock also sees great promise in adding CCUS to the traditional suite of services its midstream companies provide. When M6 Midstream announced its dual acquisitions in the Haynesville earlier this year, it disclosed plans to build what it calls a "new generation gas gathering" system that can capture and sequester up to 2 million tons of CO_2 per year.

Stakeholder Midstream, another EnCap Flatrock portfolio company, seeks to provide CCUS of CO_2 extracted from its Campo Viejo gas plant in the Permian. In September, Stakeholder announced that it received Environmental Protection Agency approval of its monitoring, reporting and verification plan for the permanent sequestration of CO_2 at its Pozo Acido injection well near the Texas-New Mexico border.

Looking ahead

Midstream management teams "have to figure out how to adapt and get really creative," said Braziel. One wrinkle is that the 45Q credits have just a 12-year life, he said. That could impact valuations in an industry accustomed to projects delivering 20 to 30 years of cash flow.

Although midstreamers have always faced risks, they were well-understood hazards, he said. Entering the CCUS market will challenge them with unfamiliar regulatory and political risks. "Some will make the jump, and some will not," he warned.

"We certainly believe we're at the front end of a new investment cycle."

—Billy Lemmons, *EnCap Flatrock Midstream*

For this new strategy to work, it's clear midstream players will need to find ways to share with upstream partners.

Tailwater's Downie sees joint ventures between midstream and upstream companies as one way to split this newfound economic value.

EnCap Flatrock's Lemmons expects the details to be ironed out through negotiations and thinks a percentage of liquids or percentage of proceeds model could address the situation.

But the rewards are worth the risks.

Lemmons said that the addition of CCUS offers a compelling investment thesis that could attract generalist private equity funds or infrastructure funds that might otherwise avoid the oil and gas back to the sector. They could become the future acquirers of midstream systems being funded today, he pointed out.

Carbon capture is "definitely" attracting private equity that has traditionally stayed away from energy, said Kirkland & Ellis' Smith. Even those private equity sponsors that have gotten out of the E&P space for ESG reasons could look at midstream to retain exposure to upstream without being directly invested in it.

For Lemmons, who has had a front row seat to observe the industry over multiple decades, carbon capture is just the latest character in a story constantly being written.

"We really do believe there is perpetual opportunity in midstream, and in every new chapter there's an opportunity to invest." OGI

ASSUME NOTHING

Between 2016 and 2019, private equity-backed midstream companies were getting high valuations on acreage dedications alone, said Chad Smith, partner at Kirkland & Ellis. There was less focus on the upstream producers underpinning those dedications, but going forward, buyers will more closely scrutinize "how realistic the producers' forecasts are," he said.

Creighton Smith, partner at Vinson & Elkins, saw such buyer activity first hand when he advised Outrigger Energy II on the sale of midstream assets in the Denver-Julesburg (D-J) Basin. Backed by NGP Energy Capital, Outrigger Energy's main focus is North Dakota and saw its D-J Basin as noncore, Smith said.

In October, Summit Midstream announced paying $305 million for D-J Basin assets that include Outrigger's position. The buyer spent a lot of time analyzing future producer activity because they wanted to "make darn sure the midstream systems' customers are committed to capital plans," Smith explained.

And with good reason, Smith noted, since producers are more focused on returning more capital to investors, which creates "a bit of tension" for midstream partners.

RBN Energy CEO David Braziel also noted that E&P companies are acquiring acreage to fill in contiguous acreage positions but then drop their rig counts to extend the life of their inventory because of "pressure from Wall Street to be prudent in their long-term production planning."

That slower pace of development could make it hard on midstream partners looking to maximize their exit valuations.

GLOBAL EMISSIONS REDUCTION EFFORTS TO FALL SHORT

Even with global efforts to address climate change and reduce emissions that include trillions of dollars of investment, the planet is on course to warm by 2.2 C by the year 2100, the latest "Energy Transition Outlook" report from DNV reveals.

JUDY MURRAY
CONTRIBUTING EDITOR

Despite an increase in investment forecast to increase to over $1.3 trillion a year, the world is unlikely to meet its goals for decarbonization.

The dour prediction is a part of findings in DNV's recently published "Energy Transition Outlook" report, an independent global supply and demand forecast. Still, a bright spot in the outlook is Denmark, which DNV Group president and CEO Remi Eriksen commended for leading by example with its "bold action" during a presentation summarizing the group's findings on Oct. 13.

Denmark, Eriksen said, is a frontrunner in developing renewable solutions and its ambitious goal of boosting offshore wind capacity to 380 gigawatts by 2030 using new technologies such as dedicated "energy islands." However, although countries such as Denmark are making significant progress on the path to net zero, he said, other countries are encountering difficulties finding a way to deliver energy that is affordable, sustainable and secure.

> **"For some [oil and gas] companies, the focus will be on CCS, for others, the focus will be on getting more out of what they're producing."**
>
> —Richard Barnes, *DNV*

This "trilemma" poses a formidable challenge, and, "if ever there was a year when the energy trilemma is most pressing, it must be this year," he said.

Resolving complex supply issues requires an increased focus on technologies that cut emissions over the long term and deliver affordable energy without compromising energy security, Eriksen said. This is an enormous challenge, and the biggest enabler in overcoming it is expanded electrification.

Making increased renewable energy a reality

Global renewable energy expenditures are forecast to double during the next 10 years to more than $1.3 trillion per year.

"The standout feature of the energy future is without doubt electrification," Eriksen noted.

DNV expects electrification to rise from 19% to 36% in the global energy mix during the next three decades. As electricity becomes more important, it also will become greener due to ramp-ups in solar and wind energy production, he said.

Despite near-term raw material cost challenges, solar and wind capacity are expected to grow by twentyfold and tenfold respectively by 2050. By mid-century, analysts project wind power will account for 31% of global electricity generation, climbing to 19,000 TWh/year in 2050—up from 6% in 2021. At the same time, grid-connected solar power is expected to reach 38% of global electricity generation, up from 4% in 2021.

Together, wind and solar will supply nearly 70% of electricity in 2050, Eriksen said, and when hydropower and nuclear are added to the mix, the non-carbon share of energy in 2050 will be 88%. This represents, "a large shift from the 80:20 split we have today," he said.

Unfortunately, even if the anticipated transformation of the power sector is achieved, global emissions will fall short of Paris Agreement goals.

The role of CCS

Analysts anticipate annual energy-related CO_2 emissions will fall to 19 Gt in 2050, achieving a 45% reduction from the present level. Although companies continue to introduce and improve carbon capture and sequestration (CCS) technologies, uptake will be very limited in the near to medium term and will effectively be too late and minimal in the longer term to meet Paris Agreement targets, Eriksen reported. In fact, total carbon capture will only abate 8% of all annual energy-related emissions.

To achieve net-zero emissions by 2050, carbon removal expenditure must reach $1 trillion annually by the 2040s. Because less wealthy regions of the world will miss their net-zero targets, high-income countries will have to achieve below-net-zero performance to reach global net-zero goals.

"The standout feature of the energy future is without doubt electrification."

—Remi Eriksen, *DNV*

Hydrogen shortfall

Even with continuing investment, hydrogen is expected to meet only 5% of global energy demand in 2050, which is about one-third of what is needed to reach net zero. This is due in great part to the fact that the high costs for blue and green hydrogen prevent production from scaling until the 2030s.

According to the forecast, hydrogen from renewables and grid-connected electrolyzers is expected to dominate, though hydrogen produced from natural gas will play an important role in hard-to-abate sectors. Ammonia, e-methanol and other fuels derived from hydrogen are expected to be used for aviation and maritime transportation.

Gas remains part of the energy mix

While there is no disputing the argument that fossil fuels must be phased out to meet carbon reduction goals, the fact is that natural gas will continue to play a major role.

According to the forecast, natural gas will overtake oil in the 2040s to become the largest energy source by 2050. North American LNG, in particular, will account for 38% of global liquefaction capacity at that time. Unfortunately, only 12% of gas will be carbon-free in 2050, DNV said.

DNV and decarbonization

There is no silver bullet for achieving global decarbonization goals, but capitalizing on insights from the "Energy Transition Outlook" report gives DNV an edge, said Richard Barnes, DNV region president, energy systems North America.

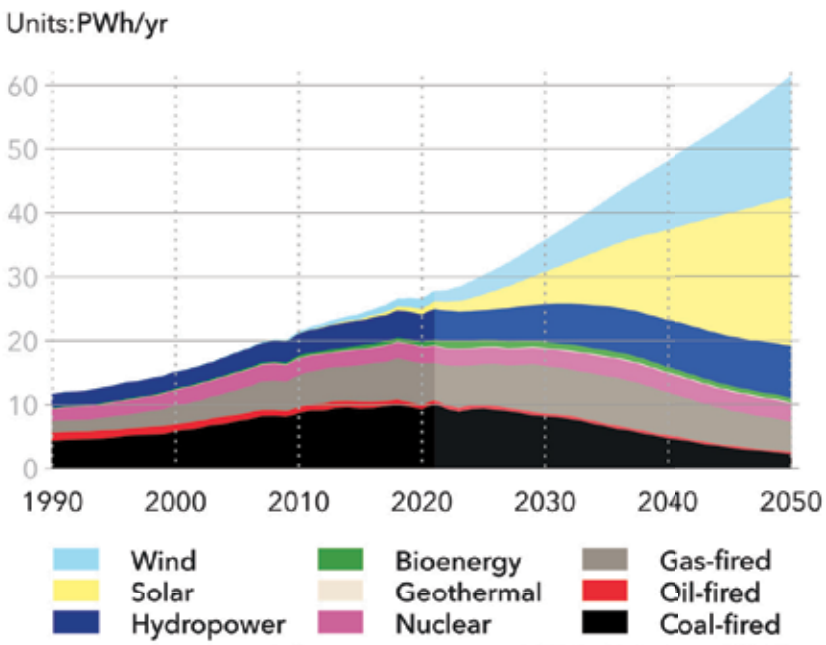
In an interview with Hart Energy, Barnes explained that this annual outlook has been foundational to identifying critical focus areas for the company for the past six years.

In considering the results of this year's outlook, it is not surprising to see that the future will be characterized by "a more electrified world that is powered by non-fossil fuel sources," he said, noting that the move to greener electrification presents challenges for companies that historically have provided fossil fuels for electricity generation.

"DNV focuses heavily on supporting customers to prepare and transition, helping them navigate around risks and identify opportunities to lower energy costs and increase margins," Barnes said.

For oil and gas companies, that means looking at a more diversified business model. "For some companies, the focus will

World Grid-Connected Electricity Generation By Power Station Type

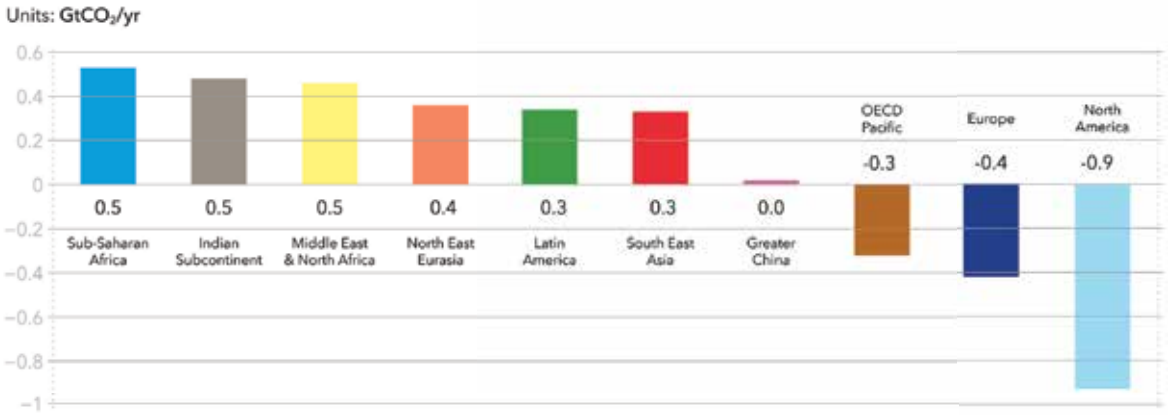


Source: IEA; GlobalData; DNV

Electrification is expected to more than double to 2050, and at the same time, electricity generation will shift from reliance on fossil fuels to renewables.

2050 Energy-Related CO_2 Emissions After CCS And DAC

Leading regions have to transition faster and reach net zero sooner, says DNV.



Source: DNV

be on CCS, for others, the focus will be on getting more out of what they're producing," he said.

Understanding that change is inevitable is one thing. Knowing which changes require targeted support is another. As an example, Barnes said, "Three or four years ago, it became clear we had to invest ahead of battery storage." DNV increased its staff and focused on helping the industry identify challenges and develop solutions.

"We are in the same situation with green hydrogen today," he said, noting that the organization is focused on recruiting and developing expertise that will help companies in this space develop their green hydrogen business models, from strategic planning to securing offtakers.

"There are a whole lot of risks," Barnes said, but they are manageable with the right partner. The key to facilitating the energy transition is understanding the diverse nature of the changes that are underway and working with customers to help them navigate unfamiliar waters. OGJ

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TEXAS SEEKS AUTHORITY OVER CO_2 CAPTURE PERMITS

The state of Texas is pursuing primacy over underground carbon storage in a move that's proven lucrative for other states.

M. SILINA
CONTRIBUTING EDITOR

When North Dakota became the first state to gain authority over underground carbon storage, a financial boon swiftly followed. Summit Carbon Solutions announced a $4.5 billion plan to pipe carbon from ethanol plants in surrounding states to North Dakota for deep geological storage. Meantime, the state unveiled its own ambitious plans to build the world's largest carbon capture facility. Wyoming made similar gains when it received primacy over Class VI injection wells in 2021.

"The largest hindrance to energy companies seeking to join the carbon capture market has been this exacerbated timeline involved with such projects, but if Texas were granted primacy, this hindrance would be greatly diminished."

—Alexander Kuiper, *Kuiper Law Firm*

Now, Texas is seeking the same opportunities. As it stands, the Environmental Protection Agency (EPA) has sole authority to issue permits for Class VI injection wells, which are used for deep geological carbon storage. Only two well permits, both in Illinois, have been issued for injection as of the publication of this article. This slow moving and arduous application process has been a source of frustration for governments and industries eager to meet climate reduction goals and cash in on a burgeoning, lucrative market.

The Railroad Commission of Texas (RRC) submitted a pre-application to the EPA earlier this year, requesting state oversight over the CO_2 equivalent injection well approval process. If the application is approved, it could help Texas become a global leader in carbon capture and sequestration.

"The Texas Legislature recognized that the RRC is in a strong position to administer and enforce the Class VI underground injection control program in Texas, given our long history of effectively regulating various classes of injection wells to protect public safety and the environment, and has authorized the RRC to seek primacy for the Class VI underground injection control program," RRC spokesman Andrew Keese told *Oil and Gas Investor*.

"Given the variety of geologic settings in which storage will be applied, the RRC is in the best position to evaluate the specifics related to well depth, geology and hydrogeology posed by a Class VI well and assist in reducing carbon-dioxide emissions," he said.

The EPA has issued only three permits for CO_2 wells as of October 2022. Under state authority, it's expected that permits would be processed significantly faster and that the state could see a surge in energy investments. Texas would become the third state to obtain primacy, following North Dakota and Wyoming's successful Class VI well applications years earlier. Louisiana is also seeking state primacy over CO_2 wells.

Financial gains

Alexander Kuiper, managing partner at Kuiper Law Firm, said Texas having state primacy over CO_2 injection wells could yield a multitude of benefits for both the state and the oil and gas industry.

"The largest hindrance to energy companies seeking to join the carbon capture market has been this exacerbated timeline involved with such projects, but if Texas were granted primacy, this hindrance would be greatly

diminished," Kuiper told *Oil and Gas Investor*. "Energy companies operating in Texas would have a much quicker turnaround on their carbon capture-related investments and a quicker and easier means to reap the benefits of the newly approved Inflation Reduction Act."

It doesn't require much imagination to predict how the state might stand to financially gain, he said. One must simply look to North Dakota and Wyoming, where millions in tax dollars are being generated by carbon sequestration projects.

"States that have already obtained primacy, and states that have applied and are close to primacy (Louisiana) have seen more proposed injection projects than their neighboring states, based on the reality that these states can or will soon permit Class VI wells much faster than those relying on EPA approval," Kuiper said. "Essentially, energy companies would face a more efficient and effective regulatory environment resulting in a higher ROI [return on investment]. In turn, one would expect this market to grow considerably within the state."

Environmental concerns

Some environmental groups have expressed concern that drilling wells for underground carbon storage could threaten water resources and public safety. Virginia Palacios, executive director of RRC watchdog Commission Shift, said Texas is ill-equipped to take on the CO_2 injection permitting process.

"The railroad commissioners are on the record either deriding federal climate standards or saying they don't believe in human-induced climate change, disqualifying them from overseeing such a complex and significant technology," Palacios said in a press release.

In its application, the RRC addressed foreseeable environmental concerns and acknowledged that state regulations must be federally compliant. Even with state primacy, the RRC would still be subject to evaluations by the EPA for various reasons.

The commission's Keese said the state would work to ensure that all measures to mitigate any potential environmental impacts are taken.

"In order to be granted primacy, the state's regulations must meet the minimum federal requirements to ensure the safe geologic storage of carbon dioxide and the protection of public safety and environment," Keese said. "The Railroad Commission is in the best position to understand the unique geological challenges that Texas poses."

What's the holdup?

It can take years for Class VI permits to be processed by the EPA, given its limited employee and financial bandwidth. Rory Jacobson, deputy director of policy at Carbon 180, said the complexity of the application process adds further complex yet important steps to the process. Carbon180 is a nonprofit focused on carbon removal solutions that draw down and store legacy emissions that have already been released into the atmosphere and need to be stored underground.

"Class VI well applications require immense expertise to oversee the permitting process and protect safe drinking water—so it's a capacity issue that we're sympathetic to."

—Rory Jacobson, *Carbon 180*

"Class VI well applications require immense expertise to oversee the permitting process and protect safe drinking water—so it's a capacity issue that we're sympathetic to," he said. "With more and more demand for Class VI wells, thanks to major legislation being passed, including the Inflation Reduction Act and the Bipartisan Infrastructure Law, this EPA program needs more dedicated funding through the congressional appropriations process and improved staffing capacity."

Financial help is on the way. Under the Bipartisan Infrastructure Law, $50 million was allocated to cover costs for states applying for primacy for Class VI wells. An additional $25 million was dedicated to help staff the federal EPA program through 2026.

"Ultimately, EPA will decide how to allocate grant funding; resources could be used to staff up and implement rules to enhance the quality of drinking water, for example," Jacobson said. "There's a strong need for geology expertise within this program. States ultimately seek primacy because the federal EPA Class VI program has been historically underfunded and under-resourced, yielding lengthy waiting periods for approval, which could be avoided by leveraging resources and capacity at the state level."

It's not clear how long it will take for Texas's application to process. It took five years for North Dakota's application to be processed but just 250 days for Wyoming's application to be processed.

"Given the size and prominence of Texas and its oil and gas industry, it is reasonable to expect some pushback from the EPA and the current administration," Kuiper said. "I would anticipate a timeline closer to North Dakota's end of the spectrum than to Wyoming's." OGI

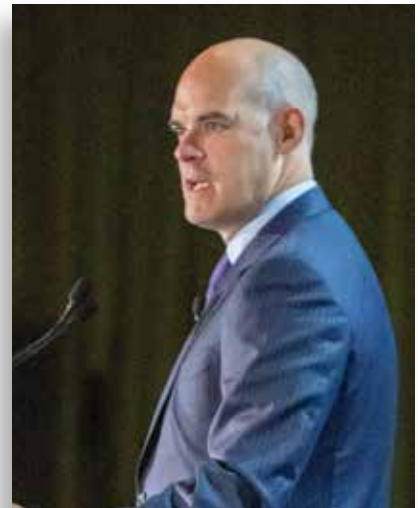
CAPITAL AND CONSOLIDATION: ENERGY INVESTORS AND DEALMAKERS CONVERGE ON BIG D

Photos by Arnaldo Larios/Hart Energy

Hundreds of upstream and midstream executives rubbed elbows at The Fairmount in Dallas for Hart Energy's conference double whammy with the Energy Capital Conference (ECC) and A&D Strategies & Opportunities Conference back-to-back this fall. Attendees networked, explored new resources for accessing and deploying capital and weighed M&A potential and trends.

Well into its second decade, *Oil and Gas Investor*'s annual ECC continues to bring key capital providers and seasoned industry executives together for frank discussions about the money that drives the oil and gas business. The A&D conference is an industry touchpoint, providing access to veteran dealmakers who finalize the deals—even amid the uncertainties and consolidation seen in 2022.

Clockwise from top left: Garrett Fowler, COO of ResFrac; Jesse Arenivas, CEO of EnLink Midstream; Holt Foster, partner, Sidley Austin LLP; Mohit Singh, executive vice president and CFO, Chesapeake Energy Corp.; Ashley Nguyen, associate, Latham & Watkins LLP; Patti Melcher, managing partner and co-founder, EIV Capital; Jeannie Powers, managing director, EIG; Doug Getten, partner, Baker Botts; Evan Smith, senior vice president, Stephens Inc.; Tim Murray, managing partner, Bayou City Capital Advisors; Rusty Stehr, senior vice president, WoFD; Michael Grenier, managing partner, BluOx Ventures; Jeannie Powers, managing director, EIG; Cole Robertson, managing partner, Saxum Capital Partners; Mohit Singh, executive vice president and CFO, Chesapeake Energy Corp.; John Goodgame, partner, Akin Gump Strauss Hauer & Feld; Charlie Ofner, partner, White & Case; James Colemen, professor, Dedman School of Law; Parker Reese, president and CEO, Ameredev II LLC; David Harris, executive vice president and chief corporate development officer, Devon Energy Corp.; Nick O'Grady, CEO, Northern Oil and Gas.

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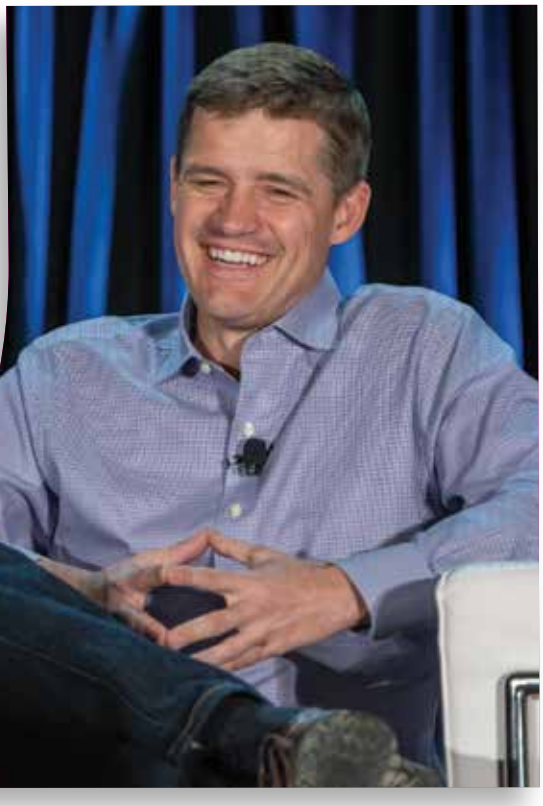


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James Coleman
Parker Reese

RING ENERGY'S CONVENTIONAL WISDOM ON ITS PERMIAN DEAL

Ring Energy's acquisition of Stronghold Energy II Royalties LP's assets in the Permian's Central Basin Platform doubled the company's production reserves and projected adjusted EBITDA.

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This summer, after months spent working its way out from under crippling debt, Ring Energy Inc. emerged as the buyer of Stronghold Energy II Royalties LP's assets in the Permian's Central Basin Platform.

The $465 million deal, layered with cash, stock and contingency payments, nearly doubled Ring's production, reserves and projected adjusted EBITDA. But the deal was also notable for its focus on mature conventional assets that the company believes are storehouses of vast amounts of oil waiting for the application of new technology.

Ring Energy's CEO and board chairman, Paul D. McKinney, spoke with Hart Energy at the A&D Strategies and Opportunities Conference in Dallas about the deal—and the almost limitless opportunities he sees for future acquisitions.

Darren Barbee: ***The first thing I wanted to ask Paul is, conventional assets: You're kind of the odd man out at this conference. A lot of people obviously are talking [at the conference] about unconventional assets. I'm curious what you saw as the value proposition for your acquisition this year of Stronghold.***

Paul D. McKinney: We believe the conventional angle is what differentiates us from the rest of the marketplace. We believe that we are a unique investment opportunity for people that want to invest in the oil and gas space. We are experts at horizontal drilling and multifrac technology that was traditionally developed to recover

resources from the unconventional shales and really tight rocks. But what we've found is that as the industry rushed to develop these unconventionals, they have forgotten the fact that many of the more mature fields and oilfield developments in North America are limited really by the economic limit of producing vertical wells. And with the advent of horizontal drilling multifac technology, when you apply that to conventional resource that has considerably better higher pros and permeabilities, you can get incredible rates of return.


Paul D. McKinney

So that's what we specialize in. Many of these zones are shallow, so the well costs are going to be considerably less. And by applying these modern technologies, you are covering a much larger percentage of the oil in place than you could have done back in the old days or the earlier days using the traditional and older conventional technologies. That is what sets us apart. If you look at our San Andres horizontal oil play that we have in Yoakum County, Texas, 5,000-ft wells 1 to 1.5- mile horizontals, and we're getting incredible rates of return. And we're finding that in the public market space, because the majority of the public market space is seeking unconventionals, we believe that we can pick up acquisitions of conventional rock where these technologies work at higher discount rates.

So I leave that margin for my shareholders. That is a strategy that sets us apart. We also believe that because we're a relatively small company compared to many of the other companies out there, the opportunity set out there, I'm not going to say it's infinite growth, but it does represent substantial growth for a company our size. We got years and years; more acquisition opportunities are going to hit the marketplace than we'll ever be able to take in on our own. So we're looking forward to what the marketplace throws our way as we go into 2023.

DB: ***How do you deal with leverage issues when you're trying to expand and do further acquisitions? Is there a period where you have to sort of clear the decks of some of the debt you have now, or do you think that you're in a financial position where you can go ahead and make some additional acquisitions right away?***

PDM: Well we're still in the transition services agreement on the last one. So we're still integrating these assets in; we almost doubled the size of the company. We actually did double the number of the wells we operate [and] double daily production to increase our reserves by 90%. So it was a very transformational acquisition. So first we're going to digest that, but we are very keenly focused on several different opportunities that we are looking at, even before we actually took that transaction down. We do believe that there are opportunities out there. When we bring all that back to hedging, I think it would be very easy to say that our banks and my board of directors really kind of share a similar philosophy that you really need to keep about 50% of your production hedged for the next least 24 months.

But the key to being and having a successful hedging strategy is not being put in a position where you have to put in hedges as a defensive mechanism. But if you can get on the other side of that, and you can be more opportunistic if you've met that basic hedging requirements as some of the more punitive lower price hedges roll off, you pick that strategic time in the right time and put in the right type of derivative that preserves the upside for your shareholders. And so that can only happen with a careful study of the marketplace, understanding where you are in the cycles and being aggressive. There may be times where we'll hedge more than 50%, so that we can unwind some of the less favorable hedges.

So, you'll see us working the book over the time period going forward, but by and large, we believe that it is the right thing to do to manage risk and ensure that you have the cash flows to sustain your capital development programs, your debt repayment programs and all of that kind of stuff. So we'll always have in that vicinity of 50% or more of our production hedged.

DB: ***Can you tell me about the competitive landscape as far as conventional assets are concerned?***

PDM: There's competition. What we've seen here for the last half of 2022 the volatility has kind of put everybody into a "wait and hold and see" mode, right? And so there were some failed sales. The majority of those failed sales processes were associated with conventional assets. And so we'll see how that plays out. But I do believe though that the pullback that we've seen here in the last part of this year in terms of commodity prices, which is actually the cause of volatility in the public market space ... I believe that pullback really is the pullback before the next surge. I think that the world set itself up for a really high inflationary environment, which the world is experiencing now.

I'm sure there is at least a high probability, if not certainty, that we will enter a recessionary period sometime in the future. Predicting that is really hard to do. You have other factors associated with the lockdowns in China and those parts of their economy opening back up, and then the demand for energy as a result of them opening up all of these dynamics.

There are so many of these various different issues that are affecting commodity prices. It's really hard to predict, but I think that the fundamentals still remain. The world has not invested enough capital over the last five to eight years to keep up with a growing demand, especially for many of these emerging economies around the world. So I think that the fundamentals are in place.

We're [in for] a really exciting 2023. We believe that A&D activity will pick up because if it is true that you see a steadily increasing oil price environment, you'll see more sellers willing to sell and you'll have more buyers that have stronger balance sheets and more wherewithal to buy. OGI

Editor's note: Questions and answers have been edited for clarity and brevity.

A LOOK AT EARTHSTONE'S BUYING SPREE

Robert Anderson, Earthstone Energy's president and CEO, spoke to Hart Energy about the company's extraordinary growth journey and what's next.

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Earthstone Energy Inc. has been on a buying spree as of late.

Since the end of 2022, The Woodlands, Texas-based independent oil and gas producer closed on several acquisitions including Independence Resources, Tracker Resource Development, Chisholm Energy, Bighorn Permian Resources and Titus Oil & Gas.

Earthstone's president and CEO, Robert Anderson, spoke with Hart Energy at the A&D Strategies and Opportunities Conference on Oct. 26 in Dallas about the company's extraordinary growth journey so far and what's next.

Jordan Blum: ***Can you take me through all this beefing up in the Midland Basin and then in the northern Delaware?***

Robert Anderson: A year ago we came out here and we spoke where we were and we had spent about $300 million. And this year, we spent $2.5 billion in total now acquiring assets and we're not necessarily trying to balance one versus the other. It's a little bit opportunistic, but we really like assets in both places, the Midland and the Delaware Basin. The Delaware rock has great inventory and we paid up for some of it, depending on how you want to allocate value, but we really like both places.

JB: ***How do you handle some of the regulatory issues that you deal with in New Mexico?***

RA: It's a process, and you have to be prepared to undertake a really long lead time and you can't change things quickly. So you make sure you have a lot of pre-planning before you go out and make changes.

When we acquired Chisholm, most of the pads were set up for two wells at a time and now we're trying to get to where we can be more efficient and drill four or five wells on a pad. So, it's going to take some lead time and that's a nine to 12 month process in some cases, but we're just getting started now drilling larger pads, which will really drive efficiencies on our drilling program.

JB: ***Earthstone this summer extended its credit facility and doesn't have any debt maturities until 2027. Then we talked about having private equity (PE) ownership with Warburg Pincus and others. Can you explain how you aggressively pursue these acquisitions without being overwhelmed with that?***

RA: It's a key factor of the way we look at acquisitions and over the last two years, in terms of every transaction, we've modeled out where our leverage ratio would be about 12 months. And depending on where oil prices are, you might be OK at one and a half times if oil is at $40. But when oil is at $90 or $100, you want to make sure leverage is as low as possible because that turns to a much higher number when oil drops as we've seen historically.

So, we've continued to work hard on using equity and other sources of capital in order to minimize the amount of debt that we have to take on. We've got our leverage in a great spot now, and we'll continue to pay down with the free cash flow that we're generating right now.

JB: ***It seems like you haven't had much time for sleep or vacation, but I mean, can you talk about just what's next? Asset sales? More acquisitions? Where does Earthstone go from here?***

RA: I think it's a combination. We definitely have some house cleaning to do. When you buy as many assets as we have over the last two years, you end up with some that sort of aren't necessarily core to you and don't fit your strategy going forward or there's no upside. It needs to be in somebody else's hands to focus on, and so we've got some of that going on.

Secondarily, we've worked our people pretty hard to get to this point. We have increased our staff considerably as well though, so now we have a little bit of internal bandwidth to be able to continue to look at deals. We'll probably be a little bit more selective and don't necessarily need to just buy 100% PDP deals. We love the inventory that we have, but you're always looking for more if you can buy it in an acquisition and buy it right.

JB: *With more PE ownership as well. At any point, is there more pressure to be part of someone else's consolidation, or is it to just appraise those opportunities as they come?*
RA: I think we just look at opportunities as they come. However, our job as a management team is to create value and if the best way to create value is to roll into somebody else and we get a premium for our assets, then we would surely look at that. I'm not here sitting in my seat just to sit in it every day. I'm trying to create value for all our stakeholders, which includes both private equity who have been with us for a while now, but also the public equity investors.

"We've continued to work hard on using equity and other sources of capital in order to minimize the amount of debt that we have to take on."

—Robert Anderson, *Earthstone*

JB: *You make it almost sound easy with all the deals Earthstone has pulled off in the last few years, but can you take me into a little more of just the sausage making and just everything that goes into getting the numbers, making everyone happy, so to speak?*
RA: Each deal is very unique. Some have been negotiated and sometimes those take a lot longer because they are negotiated, and there's a lot of trying to make it win-win for both sides. And then the fact that we've used equity in a lot of transactions has helped because we all see that the value in 2021, early in 2021, all these stocks were undervalued and including Earthstone. And so, if we were using equity, there was some upside there.

Our job was to try and create win-win situations between us and the seller because they have choices. They could go to somebody else, they could hold the asset.

In some cases, we moved effective dates a little bit to help the seller with a hedge book that was maybe underwater. In other cases, we asked the seller to defer cash consideration for six months to make sure we had enough liquidity to do the entire transaction and they were taking equity so it made sense to them. So, you have to be flexible to create a win-win for you and the seller. OGI

NORTHERN OIL AND GAS DETAILS RECENT PERMIAN A&D TEAR

Since August, Northern Oil and Gas has announced acquisitions totaling roughly $727.5 million of nonoperating interest in the Permian Basin.

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Northern Oil and Gas Inc. (NOG) has significantly boosted its position in the Permian Basin in 2022.

Just since August, NOG announced acquisitions totaling roughly $727.5 million of nonoperating interest in the Permian Basin. Most recently, the company continued its A&D tear in the Permian with an agreement to acquire working interest in the Mascot Project in the Midland Basin for $330 million in cash.

NOG CEO Nick O'Grady and president Adam Dirlam spoke with Hart Energy at the A&D Strategies and Opportunities Conference in Dallas about the company's recent acquisition streak in the Permian Basin and whether it was time to slow down yet.

Darren Barbee: ***I saw an analyst report that was talking about the recent acquisition NOG made with the Mascot Project and one of the things it mentioned was maybe this will be a time where Northern Oil and Gas will slow down and kind of digest what they've purchased. Do you agree with that sentiment or do you have more on the drawing board?***

Nick O'Grady: I do. I mean, I think we're opportunistic. So, I mentioned this in our speech, but it's our fiduciary responsibility to take everything as it comes in the door. But I do think just from an organizational perspective, we definitely want to see these things closed through late this year and next year.

Adam Dirlam: When you think about everything that's out there, the opportunity set, these three were all coming kind of at the same time. I think we would've been happy with one, two. And the ability to actually get all three done was not something that was necessarily expected just given the conversion rate. So, we'll take the time to integrate the assets and continue to see what comes to market.

DB: ***I did notice that also there's a small midstream component to that deal. Is that something you guys have done in the past, and why was it important to do it in this deal?***

NO: Typically it's an excluded asset. In this case, it's really a fully integrated project. They've spent, I think, about $80 million in total on the gathering and treating facilities. And it's fully built out from a tank battery perspective. Since we're buying all the leasehold in the project, it's a sort of one-and-done. I wouldn't say that's typical.

AD: I think partnering with the operator, [we] wanted to make sure that we maintained alignment, and so it was an undivided interest in effectively the entire project.

DB: ***Do you still think next year, because you told me you're really looking at building as you go along and building that scale, your acquisitions budget is going to get bigger. You said in June, maybe $950 million next year. Do you see maybe a little bit more than that?***

NO: I would say that there's a difference between capacity and opportunity. I think the capacity will certainly be there and as we are larger and as our leverage stays in check and we continue to generate more cash, that capacity will keep increasing. That's one of the great benefits of scale.

When I started at NOG, we had done a $52 million acquisition, which was five times larger than the company had ever done. And now I think that represents the smallest one we've really done up scale in the last four and a half years. And so, as you get bigger, it obviously begets bigger deals.

That being said, it's impossible to tell because in the first six months of this, as usual, there were a ton of transactions in the market, and frankly, very few of them were interesting to us. They come in and the quality can vary.

I think a lot of it has to do with oil prices. I think, low oil prices, it's very unlikely you're going to see a lot of high-quality assets come to market because good assets only come when prices are good from the seller's perspective.

And so, I think a lot of it's going to be dependent. The capacity is certainly there, the mental horsepower's another question, but I think we'll take some time here and then we'll be rejuvenating and ready to go.

DB: ***Can you talk about how you've built those relationships with sellers***

because they clearly have become an important part of your model?

AD: I mean, you can do a bad deal once. And so we try to approach everything with a level of reason and we try to keep things equitable and maintain alignment. And it goes without saying that as we've done more and more deals, it's a small world out there, and so people talk. And so, we obviously have our proactive reach-out programs, those types of things. But as we continue to set the market and get things done, we've got more and more folks coming to us with opportunities. So, [it] continues to kind of snowball on itself.

DB: ***What's your level of comfort now with your technical team in terms of selecting the right asset, truly understanding the rock, truly understanding the economics?***

NO: I think it's easy when you buy a really good asset out of the gates and you can build upon that. So, I think your technical knowledge, especially in the Lea and Eddy County footprint that we really started with, it's very easy for us to underwrite that and know, and we've figured out the areas where you want to be.

I think when I say the best of the best and the worst of the worst is that the Delaware Basin is large, and there are parts in the south and the west that are poor, a lot of them, even within counties like a Reeves County, [where] there are some great spots and some really tough spots.

We've found that you can't really price or engineer lower-quality assets. Meaning you can underwrite them for the same return but the risks associated with those assets from a shock in pricing or operator behavior, ultimately the best assets tend to get developed in a linear and consistent fashion.

The second-tier assets can be more herky-jerky, and you have a lot more underwriting risk and commodity price risk in those things. So, where I'd tell you is that if you asked our engineering team, they're sort of the never-satisfied type. I think we still feel like we have tons of work to do to delineate and build out those things.

But we really started this in the fall of 2018 and it was a long time of watching to the point where some of the operators shopping those things to us were getting very frustrated with us because we kept looking and not buying.

But some of that too was that the market has done that for us, the delineation that's gone on in the past few years, the shock of the pandemic to force people into actually making money as opposed to just capturing a resource, has made a market that we find ourselves very competitive in.

AD: I think it's just continuous lookbacks and understanding what the dynamic in the market is, right? So we're in an inflationary market right now. Who are the operators that have more of a propensity to overrun, right? Because you can get your EURs right, but your rate of return might be way off. So, it's continuing to assess what the macro is but then also being able to boil it down on an operator-by-operator basis. OGI

DEVON ENERGY SHARES SECRETS OF A&D

David Harris, executive vice president and chief corporate development officer at Devon Energy, spoke with Hart Energy about what it takes to keep shareholders happy while embracing a strategic growth model.

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Devon Energy may be one of the few U.S. independents that could pull off a merger during the depths of the pandemic and emerge not only bigger but also better.

Two years after announcing its merger plans with WPX Energy, Devon's coupling of disciplined growth with a profound–and ongoing–return of cash to shareholders has positioned the Oklahoma E&P to lead the industry and the S&P 500 this year.

Devon's chief corporate development officer, David Harris, spoke with Hart Energy at the A&D Strategies and Opportunities Conference 2022 in October.

Jordan Blum: ***The WPX deal was transformational for Devon. How is that combination working? How is the integration going?***

David Harris: The merger with WPX has gone great. You combined two companies of similar sizes with similar values and culture, both Oklahoma-based companies. We announced that during the depths of the pandemic, which was certainly a challenging time for all of us in September of 2020, closed in early 2021 with most of the integration work really being completed by the middle of the year. Since then, the businesses performed at a really high level. We were the highest performing stock in the S&P 500, and we've been a leader in the industry with our new discipline growth business model and our return of capital strategy that we've employed that our shareholders have been very supportive of.

JB: ***And the markets seem to be responding very well. How does that $50 billion market cap feel?***

DH: I think as we highlighted in our last quarter earnings presentation, we've returned more capital to shareholders or to the benefit of shareholders this year than the combined market caps of the company when the merger was announced. And so certainly we've had some benefit from commodity prices moving higher as we've come out of the pandemic. And economies have reopened. So the timing has been good, but it's created a lot of excitement, enthusiasm and momentum within the building to continue to continue to perform at a really high level.

JB: ***Devon could have taken it easy and really just focused on integration, but the company has been really busy. Since then, Devon has had the RimRock deals and most recently Validus Energy. Can you take me through that decision making process, how the sausage gets made?***

DH: It starts with the strategy that we've laid out that I just alluded to. It's really a discipline growth model where we're looking at production growth more like 0% to 5% really with more of a focus in growing our per share metrics, maintaining a really solid balance sheet, reducing our reinvestment rates, and then returning much of that excess free cash flow to shareholders in various ways. So just like we've been a leader in the establishment of that business model and trying to reestablish credibility with our shareholders, we've now been a leader in incorporating potential acquisitions into that model.

And so we really found unique opportunities that fit our business well that check all of the boxes in terms of the value creation for our shareholders but also it within our business and that are going to allow us to continue to further advance that model that we've laid out.

JB: ***Most recent dealmaking has been Permian centric and some investors like that one basin focus, but Devon Energy is diversifying with the growth and the Williston Basin and Eagle Ford Shale. How is that approach going?***

DH: Both Devon and WPX had always been multibasin companies, and that sort of portfolio diversity, both geographic and product mix, is something that we think is really important. Scale matters as we've moved into this new era of unconventional development, and we believe having really high-quality, low-breakeven assets in the pemiere basins around the country is an important part of that. So the Williston and the Eagle Ford are both important basins to Devon. They both have been key to

our success over a long period of time, and we see great futures for both of those areas within our portfolio. We're not just a one basin company. And frankly, we think being able to evaluate opportunities and places outside the Permian has given us the opportunity to find some unique value creation opportunities for our shareholders.


David Harris

JB: *Can you touch just briefly on the strengths of the Williston and Eagle Ford acreages as well?*
DH: Both of them are oil-weighted assets, and that's where across our portfolio we see our best ability to drive our margins on a per unit basis. And so that's something that we find very attractive. Both asset footprints are directly adjacent to where we currently operate.

So we have a high degree of confidence that we'll be able to execute at a high level and bring the sort of synergies to those assets that you would expect from having greater scale and a bigger footprint.

JB: *There's been a lot of valuation disagreements that have gotten in the way of deal-making. Can you tell me how Devon Energy has been able to get those deals done?*
DH: For the last several years, we've all been dealing with an unprecedented level of uncertainty and volatility, and unfortunately it feels like that may continue on for some period of time.

One of the things that we've really tried to focus on as we've looked to incorporate acquisitions within the discipline business model that we've laid out is where are there opportunities to find win-wins with our counterparties? That hasn't always been the case in deal-making and in previous eras of the unconventional revolution. But to be able to do all cash transactions that both parties are very happy about against the kind of uncertainty that we're experiencing has been really unique and something we're really proud of.

JB: *How is the ramp up and activity going?*
DH: Well that's the key to the business model is there's really not a big ramp up an activity. And in previous times, you would've acquired an asset and looked to materially accelerate the development of that asset to try to pull net asset value forward. We're largely going to bring these assets in and continue on at a relatively steady state sort of development pace. And so, we've seen oil prices everywhere from $45 when we closed the merger in early 2021 to around $120 this year. And all throughout those swings, we've really stuck to the plan and maintained a really steady and consistent level of activity. OGJ

ENERGY EXECUTIVES BRACE FOR POTENTIAL ECONOMIC WOES

Energy companies are making adjustments and embracing government incentives amid recession fears, rising interest rates and inflation, executives say.

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KPMG chief economist Diane Swonk delivered sobering remarks recently.

Dressed in black, she joked about her request that alcohol be served before her luncheon keynote at the firm's Global Energy Transformation Conference in November, saying "You're going to need it afterward."

Moments later the Federal Reserve increased its benchmark interest rate again—this time by three quarters of a percentage point, sending it to a range of 3.75% to 4%.

"The Fed feels they have to do it and every other central bank in the world has to do it. They're doing it at the same time, and it's amplifying itself around the world," Swonk said.

"What you worry about is that rate hikes here ricochet around the world and return to shoot ourselves in the foot. You don't want a worse recession than you need to derail inflation."

Speaking of risks of a global recession and the unique role the Federal Reserve plays in determining the course of the U.S. economy and abroad, Swonk shared worries of moving from an era of abundance to an era of scarcity. This is as the world continues to rebound from the pandemic, struggling with supply chain issues as geopolitics impact energy flow and the pace of the energy transformation.

The economy, she said, is more prone to boom and bust cycles as well as bouts of inflation and interest rate spikes. However, she believes a more measured approach in rate hikes is forthcoming as labor market conditions appear to loosen.

CEOs, including some heads of energy companies, are bracing for a recession, according to results from KPMG's "2022 CEO Outlook."

Results from the firm's outlook revealed 86% of those surveyed believe there will be a recession in the next 12 months, and 76% say they have plans in place to address it. Most CEOs are already adjusting or planning to adjust risk management procedures, eyeing global economic growth during the next three years.

VELDA ADDISON/HART ENERGY

The economy is more prone to boom and bust cycles as well as bouts of inflation and interest rate spikes, KPMG chief economist Diane Swonk told attendees at the firm's Global Energy Transformation Conference in Houston in November.

Making adjustment

Recession risks and higher interest rates are prompting some energy companies to better manage costs as they look to add longer-term value. This includes NextEra Energy Resources, the clean energy unit of NextEra Energy.

"This is a great time to focus on how we take advantage of the opportunity to decrease costs at the same time when you need to improve your business," Rebecca Kujawa, CEO and president of NextEra Energy Resources, said during a panel at the conference. "That's a pretty exciting opportunity to be able to realize, and I think that's the key thing."

Kujawa pointed to clean energy as a way for companies to lower costs in

Read the full article here:

VELDA ADDISON/HART ENERGY

KPMG's Regina Mayor moderates a panel featuring LanzaTech CEO Jennifer Holmgren, NextEra Energy Resources' Rebecca Kujawa and Shell USA president Gretchhen Watkins.

manufacturing, logistics and transportation, going beyond what she called the strategic imperative of needing to save the planet.

"You can actually improve your business value proposition," she said, adding clean energy's ability to lower costs is an important part of the conversation.

Kujawa called the clean energy space "a terrific place to be, even with the higher cost of capital in the marketplace."

NextEra Energy plans to invest between $85 billion and $95 billion between 2022 and 2025, growing many parts of its business.

Speaking on the current interest rate environment, Kujawa said financing in a rising interest rate environment is different than in a declining or exceptional low-interest rate environment.

So, NextEra is taking different steps than it had in the past to lock in interest rates. The company said earlier this month it had "$15 billion worth of interest rate hedges in order to lock in what we think are attractive rates today to enable us to continue to invest capital going forward," she said.

"We need to make sure that we're thinking holistically with the investment community, helping them understand how important it is to put their money where their mouth is, supporting the investment goals long term," Kujawa said. "For us, we'll also continue to price our renewable projects appropriately given the cost of capital." OGI

OFFSHORE RIG MARKET ON THE RISE

Globally the offshore rig market is going back to pre-pandemic numbers, with the drillship market increasing by 23% and the jackup market increasing by 6%, according to Westwood energy experts.

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Despite a pandemic, the Russian invasion of Ukraine and an energy crisis in Europe causing the oil and gas market to become all wonky, the rig market is thriving in ways that haven't been seen in years.

Globally, drillships and jackups are seeing utilization at levels "not seen since the oil price crash in 2014," said Teresa Wilkie, research director at Westwood, during the group's offshore breakfast briefing on Oct. 20.

As the industry in 2020 faced financial problems during the pandemic, many companies were forced to cut bait with drillships. In total, Westwood counts 42 drillships retired between 2015 and 2022. During that same seven-year span, over 150 older jackup rigs were also retired. However, this paved the way for 110 new jackups to be delivered within that same period.

So far in 2022, there has been no drillship retirements, signaling a return to form for the rig market. Day rates for a drillship now exceed $400,000, and they're only set to increase, according to Westwood.

Also, with a higher demand for jackups coming from national oil companies like Saudi Aramco as NOCs look to ramp up E&P efforts, an increased number of jackup rigs are entering the market. Currently, Westwood expects 14 more jackup rigs will move into the Middle East from China and Singapore during the next year. Day rates for jackups have now grown to $100,000 to $150,000 per day, up from the $60,000 to $80,000 prices a year ago.

While drillships and jackups are seeing a record growth during this time in the rig market, the same can't be said for semisubmersible rigs. Between 2015 and 2022, the semi market experienced a "severe lack of demand," according to Westwood's Wilkie.

Since 2018, 122 rigs have been retired, with the average age of those decreasing from 34 years in 2018 to just 16 years in 2022. Only 15 semisubmersibles have been delivered since 2015, with no recent increases in supply, activations or newbuilds.

NOBLE CORP.

The Noble Stanley Lafosse drillship is currently operating in the Gulf of Mexico. The U.S. Gulf of Mexico remains setting the pace for drillships.

The Americas

The American rig market tells a slightly different story.

While drillships are also thriving in both North and South America, semisubmersibles are booming in the region as well. Most of the recent contract awards have been in the Americas and they have also had the highest day rates, said Terry Childs, head of RigLogix at Westwood.

"Day rates continue upward movement for all rig types in all regions," Childs said. "The U.S. Gulf remains setting the pace for drillships … Other regions are improving but still lagging behind what's happening in the U.S. Gulf."

The Gulf of Mexico has a 100% market utilization for drillships, of which there are 48 total, and a 91% utilization rate for semisubmersibles, of which there are 16 total.

The jackup market in the Gulf of Mexico has been in decline for some time, as there are only six jackups currently under contract. The jackup rig market in the region looks vastly different than it did in the early 2000s, when there were 143 contracted jackups in the Gulf.

The rig market wasn't the only thing discussed at the briefing. Mark Adeosun, Western Hemisphere offshore manager at Westwood, revealed that they would have their highest expenditure for EPC since 2014.

"We anticipate a total of 79 FPS units to be sanctioned over the 2022 to 2026 period, and that would include 37 newbuild units, 27 conversions, 15 units are expected to upgrade all the deployments," he said. OGI

Events Calendar

The following events present investment and networking opportunities for industry executives and financiers.

EVENT	DATE	CITY	VENUE	CONTACT
2023				
IPAA Private Capital Conference	Jan. 19	Houston	Post Oak Hotel	ipaa.org
NAPE Summit	Feb. 1-3	Houston	George R. Brown Conv. Ctr.	napeexpo.com
Women In Energy Luncheon	**Feb. 7**	**Houston**	**Hilton Americas-Houston**	**hartenergyconferences.com**
SPE A&D Symposium	Feb. 8	Houston	Petroleum Club of Houston	spegcs.org
The Energy Venture Investment Summit	Feb. 16-17	Golden, CO	The Colorado School of Mines	theenergyventuresummit.com
GoM Energy Transformation Conference	**Feb. 21**	**Houston**	**Norris Conference Centers**	**hartenergyconferences.com**
LOGA Annual Meeting	Feb. 27-28	Lake Charles, LA	Golden Nugget Casino	loga.la
CERAWeek by S&P Global	Mar. 6-10	Houston	Hilton Americas-Houston	ceraweek.com
The Energy Summit of Texas	Mar. 21	Tyler, TX	Green Acres Crosswalk Conf. Ctr.	tylertexas.com
DUG Haynesville	**Mar. 28-29**	**Shreveport, LA**	**Shreveport Convention Center**	**dughaynesville.com**
Mineral & Royalty Conference	April 10-11	Houston	Post Oak Hotel	mineralconference.com
Global Energy Forum	April 11-12	Houston	Petroleum Club of Houston	usenergystreamforums.com
Energy Infrastructure Conference	**April 12-13**	**Houston**	**Norris Conference Centers**	**hartenergyconferences.com**
SPE Innovation & Entrepreneurship Summit	April 26	Houston	Norris Conference Centers	spegcs.org
Energy Workforce & Technology Council Annual Mtg.	April 26-27	Austin, TX	Omni Barton Creek Resort & Spa	energyworkforce.org
Offshore Technology Conference	May 1-4	Houston	NRG Park	2023.otcnet.org
Williston Basin Petroleum Conference	May 2-3	Regina, Saskatchewan	Delta Hotels Marriott Regina	wbpc.ca
ASA Energy Valuation Conference	May 11	Houston	The Briar Club	houstonappraisers.org
AGA Financial Forum	May 20-23	Fort Lauderdale, FL	Ft. Lauderdale Marriott Harbor Beach	aga.org
DUG Permian/Eagle Ford/Midcon/Bakken	**May 22-24**	**Fort Worth, TX**	**Fort Worth Convention Center**	**dugpermian.com**
Louisiana Energy Conference	May 31-June 2	New Orleans	Ritz-Carlton New Orleans	louisianaenergyconference.com
Energy Cyber Security Conference	**June 7**	**Houston**	**Norris Conference Centers**	**hartenergyconferences.com**
Texas Energy Forum	Aug. 23-24	Houston	Petroleum Club of Houston	usenergystreamforums.com
SEG/AAPG IMAGE Conference	Aug. 27-Sep. 1	Houston	George R. Brown Conv. Ctr.	imageevent/org/2023
Carbon Management Conference	**Aug. 30**	**Houston**	**Norris Conference Centers**	**hartenergyconferences.com**
America's Natural Gas Conference	**Sept. 6-7**	**Houston**	**Hobby Center**	**hartenergyconferences.com**
GPA Midstream Association National Convention	Sep. 17-22	San Antonio	Marriott Rivercenter Hotel	web.coga.org
Energy ESG Conference	**Sep. 19**	**Houston**	**Hobby Center**	**hartenergyconferences.com**
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Tuesday, odd mos.	Fort Worth, TX	Petroleum Club of Fort Worth	adamenergyfortworth.org
ADAM-Greater East Texas	First Wed., odd mos.	Tyler, TX	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, TX	Petroleum Club of Midland	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, OK	The Tavern On Brady	adamtulsa.com
ADAM-Rockies	Second Thurs./ Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin, TX	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 Brandy Fidler at bfidler@hartenergy.com.
For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com/events.

PIPE IN THE GROUND

EnLink Midstream's established pipeline infrastructure makes them uniquely suited to moving CO_2 in Louisiana.

EMILY EASLEY
NOVUS ENERGY

In October, EnLink Midstream LLC entered an agreement with Exxon Mobil Corp. to utilize portions of its existing pipeline network to deliver CO_2 from CF Industries in the Mississippi River corridor in southeastern Louisiana to Exxon Mobil's secure geologic storage under development in Vermillion Parish.

CF Industries is estimated to capture up to 2 million metric tons of CO_2 from its operations, which will be transported via EnLink's over 4,000 miles of pipeline established in Louisiana to Exxon Mobil's developing 125,000-acre CO_2 storage location.

"Utilizing this extensive network enables us to provide the most timely and cost-effective solution to CO_2 transportation, with a significantly lower environmental impact," said EnLink CEO Jesse Areniva in a company press release.

"Because of this, EnLink is uniquely positioned to be the CO_2 transportation provider of choice in Louisiana's Mississippi River corridor. We look forward to working with Exxon Mobil to help CF Industries and the state of Louisiana reach their decarbonization goals," he said.

Arenivas joined EnLink Midstream in June after spending nearly 20 years at Kinder Morgan.

He recently spoke with Emily Easley, CEO of Novus Energy Advisors, at Hart Energy's Energy Capital Conference in Dallas in October regarding the pipeline project and what's in store for the midstream company.

Editor's note: Questions and answers have been edited for clarity and brevity.

Above, Emily Easley, CEO of NOVUS Energy Advisors, speaking with EnLink Midstream CEO Jess Arenivas at Hart Energy's Energy Capital Conference in Dallas.

Scan for Hart Energy conference coverage

EMILY EASLEY: ***Tell us about the CO_2 project and where you see EnLink going.***

JESSE ARENIVAS: The underinvestment the last decade, energy security and the tailwind that's providing the industry today sets up for a great opportunity for EnLink. EnLink is more of a mid-cap, and one of the big drivers for me coming over with my CO_2 background was the unique opportunity that EnLink has in southeast Louisiana.

The announcement that we had [recently] is a big deal for EnLink. CF Industries is the largest emitter in the Donaldsonville area, up to 8 million metric tons a year. This initial deal with Exxon will capture 2 million tons of that 8 [million], with the reserve capacity of 3.2 and the ultimate reserve capacity of the pipe of about 10 million metric tons a year. Exxon Mobil entered a transportation services agreement with EnLink, and we will transport those initial 2 to 3 million metric tons to their sequestration site within a hundred-mile radius of the emission.

What makes that area of the country very unique is ... the complexity of emissions, the concentration of

emissions, the midstream infrastructure needed to deliver that and then a sequestration site. Louisiana has all three of those. You've got a high concentration of emissions, you've got great geologic structure right underneath you and then you have existing pipeline. Our competitive advantage is having the pipe in the ground. We have a very large diameter pipe that's redundant, so we have the unique opportunity to service the growing LNG and industrial demand.

We move natural gas products in the state today, but we're not cannibalizing that business. We have redundancy. This is an incremental opportunity for us to be a first mover in CCUS [carbon capture, utilization and sequestration].

EE: ***Why has EnLink committed real estate to carbon versus natural gas?***

JA: When you look at the unique opportunity set, the emissions are there, the emitters, again, linking up the value chain. The evolution of this space was getting the emitters committed and willing to do this. So, I think the financial incentives with the IRA [Inflation Reduction Act] are a positive for this space.

I think the IRA will further accelerate and broaden the addressable market here. I think the biggest impact is direct pay, the incremental credit, but the threshold for the emission from 100,000 metric tons to 12,500 just exponentially creates opportunity in this space.

EE: ***Exxon has some social equity for [how] it has gone all in on carbon reduction with its low-carbon strategy, but EnLink has the capabilities to do both of those, right?***

JA: Yes. The evolution of the midstream space will do what they traditionally have done, and that's move the hydrocarbon or, in this case, the carbon from the emission source to the sequester. I think initially, the market was looking for a holistic solution, so the Talos deal that we did early, which was a LOI [letter of intent], contemplated us doing both or all three: capture, transport and sequestration.

I think we still have the capability and the wherewithal to do that. I think what we're looking at today is emitters are incented; the sequestration players, the E&P players, are going to play the role they've traditionally played. This is not a new space, we've been sequestering, as an industry, carbon for four to five decades, and that's through the use of EOR. I think the market's developing into the emitters solving their own problem, the transportation being done by the midstream space and then the ultimate sequestration is from the guys who've been doing it for a very long time.

EE: ***Pivoting back to your [previous] role at Kinder Morgan in the transportation business for CO_2 … Can you speak a little bit more to the background [that] this isn't a new technology? Why now are investors starting to get the momentum behind it?***

JA: A couple things. Historically, CO_2 movement in the U.S. was solely for the purpose of enhanced oil recovery. It's been over 40 years; I think the Cortez Pipeline has been in operation since 1982. It goes into the Permian Basin, about a 500-mile pipe, 30-inch diameter, moves about 1.2 to 1.5 Bcf a day for the whole sole use of EOR. Fast forward to where we are today, and the motivation behind decarbonization has just expanded that market. The difference in EnLink's positioning and Kinder's positioning is the high concentration of emissions. The infrastructure's there. EnLink has been moving hydrocarbons for 20-plus years in Louisiana. We have that last mile connection to the emitter, and we have that core advantage in the market.

Again, nothing new here. It's been done in the industry for many, many years. We're in the envious position to be in a high concentration, infrastructure-rich and geologic close proximity to that.

EE: ***What do you see for EnLink in the next hundred days and the next year, and where things are going under your new leadership?***

JA: I think first off, again, the energy macro environment [and] the tailwinds behind us. We have three very well-located gas gathering and processing regions, the Permian being our largest, which has had double digit growth for the last two or three years. We're seeing a resurgence in activity in both Oklahoma and North Texas. I think we're very well-positioned in the basins that we're in for future growth.

The downstream market in Louisiana is very interesting. We're already seeing a lot of activity around LNG supply, and we're connected to several of the players already. We've got a huge opportunity there. We're looking at potentially another pipeline out of the Haynesville to service the eastern part of the state, which all the LNG demand is pulling everything to the southwest part of Louisiana.

We believe the next LNG growth or FID [financial investment decision] projects will be in the southeastern part of Louisiana, so we're very well-positioned to capture those opportunities. But what our CO_2 business will look like in five years is really the exciting piece here. We think it'll rival the contribution of our Louisiana business today, so that's significant growth. That's about 20%, 25% growth, and we think we can achieve that over the next three to five years.

We believe that Exxon will continue to win the race in that Donaldsonville area. We fully expect to utilize that 10 million metric tons over the next few years. We're still in multiple discussions. We have LOIs with ConocoPhillips and Oxy and Talos, and we've got a lot of dialogues with smaller emitters and other large players in the region. I think they have certainly appreciated our positioning and our ability to move quickly.

The advantages at EnLink in the connectivity, especially that last mile, provides very exciting times for EnLink overall. I think we will continue to be a large GMP [Global Methane Pledge] player, and I think we will continue to see growth over the next few years and beyond. But the real growth driver I think is going to be more on the CCUS and the downstream service side for us. OGI

FRESH LOOK AT NORTH SEA DRY HOLES

Machine learning and related technologies are speeding up the time-consuming task of well analysis, allowing speedy processing of vast volumes of data in the Norwegian North Sea.

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A new machine learning project analyzing 545 dry exploration wells in the Norwegian North Sea identified more than 300 potential missed pay intervals.

In 2021, the Norwegian Petroleum Directorate (NPD) commissioned Earth Science Analytics (ESA) to use machine learning technology to crunch well and seismic data on the wells in a bid to gain a better understanding of the region's petroleum system and unearth potential missed in hydrocarbon-bearing zones. The NPD made the results available in August through both npd.no and Diskos.com.

"When you gather more data, you can get more out of the data," said Arne Jacobsen, who directed this project for the NPD. "We are promoters of data sharing."

The project, which started as a continuation of one carried out by the Oil and Gas Technology Centre (now Net Zero Technology Centre) on a majority of the wells in the North Sea, was intended to provide more insight into the remaining dry wells on the Norwegian Continental Shelf, NPD geoscientist Petter Dischington said.

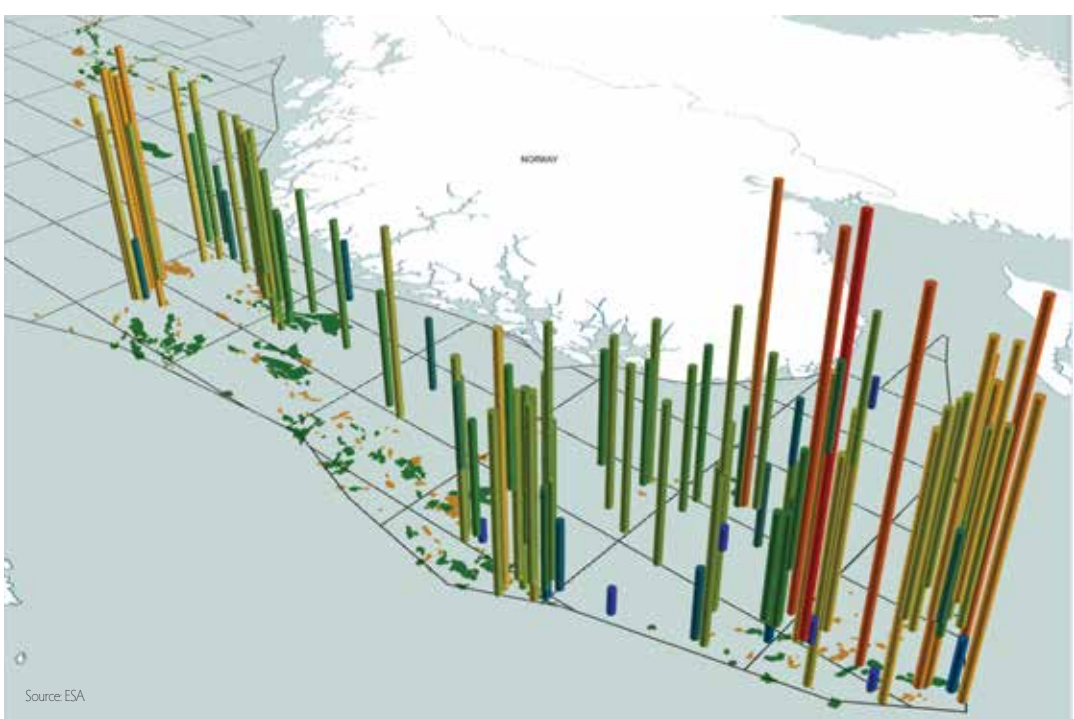
When the NPD announced the project in 2021, about 1,250 wildcat and appraisal wells had been drilled in the North Sea. Of those, 796 were wildcats with around 43% of those being reported as discoveries.

"We know there's a number of dry holes. This technology has come up as a way of extracting more insights from these wells that are otherwise forgotten about," he said. Now, there is "dry hole analysis in the entire Norwegian North Sea."

Jacobsen said the study focused on identifying hydrocarbon intervals that were originally overlooked.

The analysis carried out by ESA uncovered 350 intervals with hydrocarbon-bearing potential, Dischington said.

"They generated log curves showing porosity, water saturation and lithology," he said. "We had a number of wells that had the segments, most of which quite short, some several meters thick, that



Source: ESA

The Norwegian Petroleum Directorate commissioned Earth Science Analytics to use machine-learning technology to analyze 545 dry exploration wells in the Norwegian North Sea and unearth potential missed in hydrocarbon-bearing zones. The data show that many dry wells in the Norwegian North Sea may have potential missed pay intervals in them.

could be hydrocarbon-bearing."

Dischington said the insights garnered from the project suggest there has been overlooked pay, and those zones should be looked at further.

Small zones indicating the presence of hydrocarbons are valuable, "not necessarily as reserves of hydrocarbons but for understanding the petroleum systems," he said.

And vast amounts of data underpin that better understanding.

"When you gather more data, you can get more out of the data."

—Arne Jacobsen, *Norwegian Petroleum Directorate*

Machine learning

"We pulled all the wireline data, around 5,700 km of wireline logs, and used this data for the predictions," said Daniel Stoddart, principal data geoscientist at ESA. "Machine learning is data thirsty, and ESA is no stranger to handling large amounts of data."

He said ESA did everything in EarthNET, which is a cloud-native machine learning-driven software ESA developed.

The first step after centralizing the data feed was to understand what data was available and check its quality before working to gain results about porosity, water saturation and lithology.

Stoddart also said the adage "rubbish in, rubbish out is very prevalent with machine learning projects."

ESA built a six-component workflow built on fundamental principles such as using all the available data and predicting missing data, Stoddart said.

"A sonic log or part of a sonic log may be missing from the wellbore. We can predict the sonic log using all the logs in the project to get a good prediction and infill where the sonic log is absent or missing a section," he said.

Alienor Labes, a geodata scientist at ESA who worked on the project, said the ability for machine learning to predict attributes such as missing data and then use that synthetic data is "very interesting" for geoscientists.

"Geoscientists know there is no absolute truth, and that is true with machine learning as well. But the better data quality, the better the predictions will be," she said. "With machine learning, you can also find and identify esoteric relationships between different types of data that you might have missed or not seen."

ESA built a model and validated and benchmarked the model and the predictions both statistically but also geologically, Stoddart said.

He said the end game was "predicting pay intervals in dry wells and outside the main producing intervals using porosity and water saturations. These parameters are interesting to the geologist when doing evaluation for prospectivity in the area."

But, as Stoddart said, the term missed pay could be ambiguous.

"What's missed pay to me is maybe not missed to you," he said.

Of the more than 300 instances the results predicted as potentially missed pay, "we are not saying every one of those pay intervals are hydrocarbon-bearing," he said. They are, he said, candidates for geoscientists to further explore.

He called the work a prospect portfolio accelerator.

"It's not a silver bullet. It's a fast way of getting to pay," he said. The workflow "identifies the pay zone, but it's the geoscientist who must place the data into the geological context and decide whether it makes geological sense."

Faster workflow

According to ESA, the approach saved a lot of time, and if the analysis were conducted again by EarthNET, it would take around three to four months, while conventional methods would take between one and two years.

That accelerated workflow is increasingly important, Stoddart said, as companies downsize personnel but still have the same level of work that needs to be done.

"There is still money to be made, and machine learning can get you to that point faster," he said.

Jacobsen said he sees many further possibilities when it comes to using machine learning to process and analyze well data. A project covering producing wells "could be interesting," he said.

And Dischington wants to see analyses done on dry exploration wells in the Norwegian and Barents Seas.

But in the meantime, he's "really intrigued to see what the industry will do with this dataset." OGJ

"This technology has come up as a way of extracting more insights from these wells that are otherwise forgotten about."

—Petter Dischington, *Norwegian Petroleum Directorate*

THE NEW APPROACH TO SAFETY IN OIL AND GAS

Leaders in the oil and gas industry from Chevron Corp., bp Plc and vPSI Group discussed the power of operational learning at ATCE and offered tactics on how to implement the new approach to safety.

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Safety is paramount within the energy industry. However, a new approach to safety has cropped up in the industry: what if instead of learning from mistakes, oil and gas companies learned from their successes?

Industry leaders speaking during a session on "Learning From Accidents or Learning Before Accidents" at SPE's Annual Technical Conference and Exhibition (ATCE) shared their visions on learning from normal work, or operational learning, discussed how it can benefit the industry and offered tactics on how to implement it.

"It's about our ability to learn from those instances where nothing goes wrong, from our everyday operations. It's about those opportunities to help us get ahead of the times we might have an incident," said David Hammons, organizational learning manager at Chevron Technical Center.

"When we want to learn from normal work," continued Hammons, "it's really critical that we've started that human and organizational performance journey. That we really accept that error is normal. We really understand that blame doesn't fix anything, that our responses matter and that learning is vital."

Operational learning is a relatively simple yet revolutionary way of learning, as it focuses on how work actually happens. It doesn't require waiting for a mistake to happen and it's not as cookie-cutter as a textbook or training module. It's taking an organization's successes and building on them, even when results don't happen in a standard way.

When successful outcomes don't happen in a standard way, many workers are reluctant to share this information. That is why Norman Ritchie, director at vPSI Group, believes organizations must foster a culture of psychological safety.

"The idea that your organization, the people in your organization feel confident that they can come to you and say, 'You know, we have to mess around to get this done.' I often feel that it's OK that they can give you this kind of information without repercussions or a negative impact," Ritchie said.

But operational learning is easier said than done. Resources at different organizations are already stretched thin. What can an organization do if it doesn't have the capacity to investigate incidents that happen as well as investigate normal work?

"Those are concerns that are real and need to be addressed, and part of that is through prioritization and risk-based prioritization," said Sandra Adkins, human performance and safety science manager at bp Plc. "It's really looking at the critical task in our work and where things are most likely to have a really bad outcome if something goes wrong. So, there has to be collaborative conversation."

Operational learning is a relatively simple, yet revolutionary way of learning, as it focuses on how work actually happens, according to speakers at ATCE 2022 in Houston on Oct. 5.

For bp, that collaborative conversation is a learning team, often a group of five to seven people who were close to the work or directly involved in the task, that meet with a leader and discuss exactly how the operation went. The team discusses how success was met, even if they didn't follow normal procedure.

The goal is to not punish anybody in the group, but to provide a safe space to find out best practices for the organization and how to learn from the operation.

"We're not trying to tell the one true story of how work gets done. We're trying to tell everybody's story, everybody's context, to help understand all of the variability in that work," Chevron's Hammons said.

Hammons added that he's also had employees approach him post learning team asking to be a part of the next one.

"You wind up with a very powerful tool to understand the normal variability of work, to strengthen your safeguards, to improve your engagement with your people and to move your organization along on this human and organizational performance journey," he said. OGI

CAPITALIZING ON LOW-CARBON NATURAL GAS

Chesapeake Energy Corp. CFO Mohit Singh shared details on the company's strategy to withstand downturns and keep shareholders happy with dividends and low-carbon natural gas.

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Chesapeake Energy Corp. is enjoying the favorable market winds that have lately blown the oil and gas industry's way, but the company continues to quietly strengthen its storm shelter for the next inevitable tempest.

Chesapeake CFO Mohit Singh, speaking at Hart Energy's Executive Capital Conference on Oct. 25, said the company keeps in mind that it operates in a cyclical environment.

"I'd be lying if I sat here and told you what the catalyst for the next downswing might be or what the catalyst for the next upswing would be," he said. "Fundamentally, we just have to be OK with being a price taker in a cyclical industry."

Since emerging from bankruptcy in February 2021, Chesapeake has rebuilt itself as a model of capital stewardship, Singh said. The company's new emphasis is on sustainable dividends even in rocky times.

In a sense, Chesapeake is a new company, Singh said. Following its restructuring, the company saw its board reconstituted, a new leadership installed and a new capital structure in place.

> **"It's a company with the same name and perhaps a lot of history. But I almost argue and ask everybody to think of it as a different company fundamentally."**
>
> —**Mohit Singh,** *Chesapeake Energy Corp.*

"It's a company with the same name and perhaps a lot of history," he said. "But I almost argue and ask everybody to think of it as a different company fundamentally able to add value to shareholders."

The pandemic, which required Chesapeake and other companies to shave off capital and operating costs, also positioned the company to enjoy the recent upswing in prices.

But a rational fatalism has set in that the company will inevitably see commodity prices go sour.

To combat the next downcycle, the company has developed decades of inventory in its Marcellus and Haynesville shale positions. Chesapeake is also shopping its Eagle Ford Shale assets which, pro forma for a sale, would make the company a de facto natural gas producer.

"If and when [prices] come back down, our inventory is in place where we still would deliver very outsized returns," he said.

ROI

Chesapeake has rebuilt itself around four central principles: shareholder returns, a strong balance sheet, deep inventory and environmentally responsible development.

The company is also conscious of reclaiming investors who have left the space in a "mass exodus" because of years of capital losses.

As a result, Chesapeake has instituted a $2.20 per share dividend and a variable dividend based on free cash flow. Added together, that's a yield of 10% to 11%, Singh said.

"You can compare, contrast that to a typical S&P investment that's yielding about 2%, so already we're delivering an outsized return," he said.

Additionally, Chesapeake has authorized a $2 billion share buyback. As of its last earnings report, the company has repurchased $700 million of stock.

With its dividends and buybacks, the yield rises to as much as 18%, Singh said.

"In a rising inflationary environment, I mean, that's very attractive," he said. "So that's been very well received by our investors."

Naturally, a commodity downcycle would change those dynamics.

Singh said its fixed dividend is considered "sacrosanct." But weathering a pronounced downturn is always on the company's mind. Chesapeake runs internal stress tests to project its liquidity at price environments as low as $2/Mcf.

To survive in a collapsing price environment, the company has anchored its balance sheet to keep leverage at 1.0x.

Chesapeake has also aggressively hedged its production so that it can sell as high as $12.50/Mcf in the best-case scenario and $5 in the worst.

"If you have low leverage and … if I'm able to service my debt and be able to pay it down in a timely manner, then that's the right leverage level," he said. "We have set a boundary condition for ourselves of one turn of debt to EBITDA."

Chesapeake is also looking to position itself for the second wave of LNG that will start to come online in 2025 and 2026.

With 75% of natural gas demand likely to come from LNG cargoes, "we are looking at making some LNG investments," he said.

ESG

On ESG, Singh said that those who bemoan the central role that ESG has taken in the industry should consider that fossil fuel production and ESG is not a binary choice.

"When people talk about ESG versus developing fossil fuels as an either-or choice, our view is it's a false choice. You have both," he said.

Singh said the onus is on oil and gas companies to communicate to average consumers that natural gas is a clean-burning fuel that can serve energy needs globally.

It's a message that is timely. Alluding to the war in Ukraine, Singh noted that, "in this present climate, if we can't get the message out and still win these people over, I point the finger again back at ourselves."

"If you can't get people convinced that the role that we play is important, I don't know how, what else makes what happen for us to be able to do that," he said.

Chesapeake, with its interest in capturing and selling every molecule possible, can point to its own standards, which far exceed those at the U.N.'s last climate summit. COP26 deemed 0.2% methane intensity as "good."

Chesapeake's Haynesville and Marcellus shale portfolio is already at 0.02% methane intensity, Singh said.

Chesapeake has also committed capital to retrofit 19,000 pneumatic devices to reduce emissions and installed 2,000 continuous methane monitoring devices to detect leaks, he added.

"You know, 80% of our production is continuously monitored," he said. "And what that means is if you go to one of our typical pads, there'll be a monitoring device north, south and east and west. And based on which one of those sensors detects the leak, you can even triangulate [the leak].

"So, what we have done is we have paired it out with our monitoring system and you create a work order where, and the lease operator would be on site within 24 hours to … fix it," he said. OGI

Oil and Gas Investor

COMPANIES IN THIS ISSUE

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THE REAL NATGAS OVER/UNDER

@ CLOSING

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It's a biannual big-money game of shorts and longs on whether U.S. natural gas in storage will be under- or oversupplied entering November and, then, how much will be withdrawn by winter's exit.

This year, as storage was reloading, analysts and others have been curiously silent about what wasn't happening. Instead, the emphasis continued on the comfort-inducing percentage difference between current storage and the year-ago level as well as the five-year average.

The U.S. Energy Information Administration's (EIA) Nov. 10 report on storage as of Nov. 4—the first Friday of November and traditional end of refill season—showed only a 1% difference in this year's level (3,580 Bcf) and a year ago (3,617 Bcf). Compared with the five-year average (3,656 Bcf) for October-end, the 2022 level is 2.1% less.

Sending mega tons of LNG to allies in Europe in crisis, U.S. gas producers and exporters answered the call. It's remarkable—I go so far as to call it "divine," really, considering the "good versus evil" nature of the situation.

What's even more incredible is that the gas-markets analysis has gone without acknowledgement of this, though: Freeport LNG has been offline since June 8. This is what wasn't happening.

And there has been no asterisk on that one of the years in the five-year average was the COVID anomaly, 2020, when storage entering November was 3,927 Bcf—nearly the more typical 4 Tcf—as a great deal of global industrial and other demand went dark beginning in February that year.

First in the over/under analysis: Freeport LNG. It was running at capacity, exporting between 1.8 Bcf/d and 2 Bcf/d until a leak resulted in an explosion and a shutdown the morning of June 8. It remained offline as of Nov. 14.

Let's use 1.8 Bcf/d. If operating, it would have exported 268.2 Bcf in the 149 days of June 8 through Nov. 4. Deducted from the 3,580 Bcf of gas in storage on Nov. 4, the U.S. would have 3,312 Bcf in the ground.

Compared with the year-ago exit of 3,617, the difference would be -9.2%. In comparison with the five-year average of 3,656 Bcf, the difference would be -9.4%.

In short, the record volumes of U.S. gas production this year won't be enough next year upon Freeport LNG's return to making daily calls on supply.

Yet the 12-month gas-futures strip on Nov. 14 was $5.20.

Freeport LNG is aiming for a restart before Jan. 1 and describes output as "a sustained level of at least 2 Bcf/d" and that this represents only 85% of export capacity. Last word was that 100% capacity might start in March.

If we go ahead and use 2 Bcf/d in the math (298 Bcf during the 149 days), U.S. gas storage on Nov. 4 would be 9.4% less than the October 2021 exit.

Not being able to exit this October with more gas in storage would point to too little supply.

This is despite the fact that U.S. gas producers haven't held back. August dry gas output was 99.4 Bcf/d, which was the largest monthly amount ever recorded by the EIA, whose tally began in 1973.

The August level was 4 Bcf/d more than the August 2021 output and represented the 17th consecutive month of growth compared with year-before output.

On the demand side, intra-U.S. consumption was 82.8 Bcf/d in August—5.4% more than in August 2021. Residential demand was 2.8% less (3.3 Bcf/d) than the year before; commercial demand was 0.3% more (4.58 Bcf/d); industrial demand, 0.4% more (21.7 Bcf/d and the second-highest this century); and power generation, 9.4% more (44.5 Bcf/d and the most ever in August this century).

The rest of consumption was in lease and plant fuel, pipeline and distribution use, and a minor amount as vehicle fuel.

Moving to demand outside the U.S., 17.9 Bcf/d was exported via pipe and LNG tankers.

This and intra-U.S. demand consumed all of U.S. dry gas production in August.

So why was 237 Bcf/d added to storage that month? That 7.65 Bcf/d in the 31 days happens to be what was imported from Canada.

The U.S. didn't really have a surplus in August. If not for Canadian imports, there wouldn't have been any add to storage.

The natgas over/under is actually under. OGI

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