Oil and Gas Investor

RUSSIAN STALKERS

'Ghost Tankers' Spook Global Oil Markets

MIXED SIGNALS

Big Name, High Dollar Deals Obscure Slow A&D Action

WELL-DEFINED AND DEEPLY UNDERSTOOD

The Eagle Ford Shale's Lure of the Familiar

SCALE DOES MATTER

THE OGI INTERVIEW

Earthstone Energy CEO Robert Anderson on Scaling Up While Others Hunker Down

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FEATURES

COLUMNS

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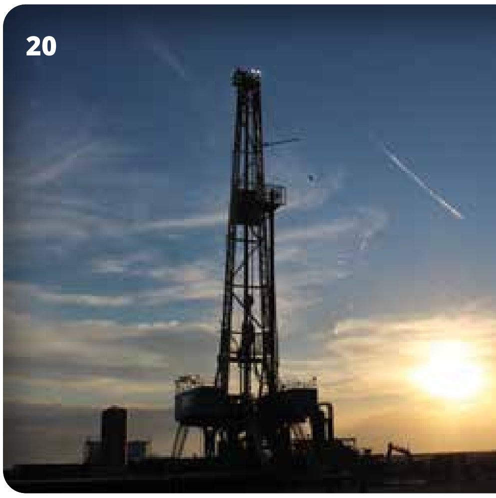
ACTIVITY HIGHLIGHTS

A&D WATCH



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ABOUT THE COVER: Houston photographer Arnaldo Larios photographed Earthstone Energy CEO Robert Anderson at the company's headquarters in The Woodlands, Texas, in February.


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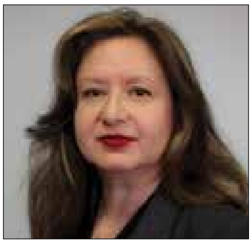
BP'S RECONCILIATION: KEEP IT REAL



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London-based supermajor BP Plc was one of many producers to report windfall profits for 2022 during earnings season in February. It was a jaw-dropping $28 billion for the year that doubled from the previous year and a record annual figure in the company's 114-year history.

BP CEO Bernard Looney said during the company's fourth-quarter 2022 and year-end webcast that the results were indicative of the company's execution of strategic plans laid out three years ago to pivot from its 110-year history of being an international oil company to becoming an integrated energy company.

"I am personally in awe of what the BP team has delivered since then," Looney said. "And all during the most volatile and uncertain times that many of us have ever experienced."

Our international managing editor, Pietro Pitts, listened to the call and reported for HartEnergy.com that management is forecasting production will be largely flat in 2023 relative to 2022. By 2025 and 2030, production is expected to reach 2.3 MMboe/d and 2 MMboe/d, respectively. The latter figure would represent a 25% decline compared to 2019, while a previous forecast called for reducing production by 40%.

The reductions didn't stop there. BP is also dialing back its pledge to reduce carbon emissions by 40% in 2030.

"We are now targeting 10% to 15% reduction by 2025 and aiming for 20% to 30% reduction by 2030," Looney said. "We continue to believe that our ambition and aims taken together are consistent with the goals of the Paris Agreement."

Despite Looney's assertion that BP still aims to reduce its total emissions to net zero by 2050, the blowback from climate activists was swift.

Bruce Duguid, head of stewardship at Federated Hermes, told Reuters that investors are concerned by the apparent "pivot."

"It also raises a significant governance question, given the high proportion of investors that supported the original (emission reduction) target only nine months ago," he said.

Still, Looney insists that BP's direction was set three years ago and remains unchanged.

"Our change was done, and we were now 100% focused on delivery, and that is exactly what we have been doing," he said during the call with investors.

"There are two things that need to happen in this world. No. 1, we need to accelerate the energy transition. And No. 2, that transition needs to be orderly."

—**Bernard Looney,** ***BP Plc***

"The first, and important is that BP is performing. Our businesses are running well. Our costs are being controlled. We are reducing emissions. We are growing value," he said. "We feel and believe our strategy is working, and we are more confident than ever that what we laid out in 2020 as a strategy is the right one."

Looney spoke to Alan Murray at Fortune in what could be viewed as an attempt to stem the potential backlash.

"There are two things that need to happen in this world," he told Murray. "No. 1, we need to accelerate the energy transition. And No. 2, that transition needs to be orderly."

True, but perhaps equally important but often left out of the conversation: the transition—as well as corporate pledges to make it happen—needs to be realistic.

It could be that the folks who invest in BP stock already get this. Prior to Looney's revelations, BP's stock price at market close on Feb. 6 was $34.84 per share. That value had increased to $40.88 per share at closing on Feb. 15.

A 17% increase in stock performance within a week isn't too shabby; when you throw in the fact it took place amid controversy, it's probably a message.

Looney told Murray that the proof of BP's commitment to emissions reductions is evident in its investments: building out solar facilities, hydrogen innovation and investing in biogas.

"People will not judge us on our words, they will judge us on our actions," he said. "While I understand that people are skeptical, I would encourage people to look at the facts." OGI

GEOPOLITICAL REALITIES REQUIRE REALISTIC ENERGY POLICIES

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Geopolitics continues to be the dominant force in the outlook for global energy markets. The escalation of tensions between the U.S. and China and between the West and Russia is impacting the flow of oil, gas and refined products and ultimately markets and prices.

There are signs that demand for oil and natural gas is rising. Although there are still fears of a looming recession, other economic indicators suggest that a recession is far from certain, especially as China emerges from its COVID-19 lockdown. Yet, global tensions threaten to stifle economic expansion.

The Chinese spy balloon incident in February highlighted tensions that have been growing over China's threats to invade Taiwan and its territorial ambitions in the South China Sea and Southeast Asia. Underscoring the energy policy nexus associated with these growing tensions, in one of the first actions taken by the Republican-controlled House of Representatives, legislation was passed to limit the Department of Energy's ability to sell future barrels from the Strategic Petroleum Reserve (SPR) without assurances that SPR crude would not end up being sold to China, Iran, North Korea or Russia. The measure, which the Biden administration has threatened to veto, would also require that federal lands and waters be leased in exchange for future SPR releases.

Across the Atlantic, the EU continues its efforts to use energy policy as a means to punish Russia for its actions in Ukraine. The 27 EU states recently agreed to place a price cap on shipments of Russian refined products, setting the limit at $100 per barrel for diesel and $45 per barrel for low-end products like fuel oil. Notably, recent reports suggest sanctions are beginning to hurt the Russian economy. With Russian natural gas supplies now mostly cut off, Europe is seeking to develop a future that is devoid of Russian gas. Despite the fact that Europe was able to make it through this winter, the future is much less certain.

U.S. and Qatar LNG producers need the commitment of long-term contracts in order to guarantee firm, long-term LNG supplies to Europe, but EU reluctance based on the pursuit of fossil-free energy objectives will make that more difficult. As a result, Europe could face a more difficult situation next winter as well as long-term uncertainty, as Asia (particularly China, South Korea and India) shows its willingness to enter into long-term contracts.

In the meantime, U.S. oil and gas producers are seeing long-term opportunities in LNG and investing in related infrastructure. Examples include Devon Energy's agreement with Delfin Midstream on a floating LNG facility, ConocoPhillips' partnership with Sempra's Port Arthur LNG and Chesapeake Energy's commitment to supply Golden Pass LNG with certified clean natural gas. However, U.S. producers have their own challenges as they continue to deal with inflation, labor shortages and shareholder pressure for capital discipline, not to mention the impacts of ongoing regulatory uncertainty.

The question is clear: Can the U.S. oil and gas industry meet growing demand amid the ongoing challenges created by geopolitical realities? Domestic energy policies should ensure that it can. Last month, U.S. House Energy and Commerce committee chair Cathy McMorris Rodgers (R-WA) released the Oversight and Authorization Plan for the 118th Congress. It vows to "examine the impact of government policies and programs on the efficient exploration, production, storage, supply, marketing, pricing and regulation of domestic energy resources, including issues relating to the nation's energy infrastructure," while investigating the impact of the administration's energy policies on supply chains, U.S. dependence on China and domestic energy production.

During his State of the Union address in February, President Biden accused the U.S. oil and gas industry of keeping retail fuel prices artificially high while profiting from Russia's invasion of Ukraine. "It's outrageous," Biden said. "They invested too little of that profit to increase domestic production and keep gas prices down. Instead, they used those record profits to buy back their own stock, rewarding their CEOs and shareholders." At the same time, the president acknowledged that "we're going to need oil and gas for a while," adding that oil will be needed for "at least another decade … and beyond that."

To be sure, the U.S. and the world will be using oil and gas for many decades to come, alongside renewables, nuclear and other energy sources. The more that our nation's leaders recognize that reality in developing and carrying out policy, the better-equipped the U.S. will be to meet domestic and global energy needs as geopolitical challenges inevitably continue to unfold. OGI

▸ **JOE TO** THE WORLD

TO BOOMS, BUSTS AND A GOOD APPETITE FOR BOTH

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It was January 1981 and oilpatch earnings were, like, bodacious.

Mighty Atlantic Richfield had just reported fourth-quarter 1980 net income of $398.2 million, or $1.60/share. For the month, crude oil would average about $39/bbl, or $134/bbl in 2023 currency.

A happy and hungry energy executive based in Midland, Texas, could hop into his Silver Spirit, blast the Rolling Stones' "Start Me Up" until the windshields rattled in the 5,000-pound luxury beast, have the driver floor it all the way to the airport, slide into a reclining leather seat aboard the company's Gulfstream III and shoot into the sky in a gentle arc toward Houston. There, a sizzling 40-ounce porterhouse steak would be waiting for just under $30. And a bottle of red from Sonoma with flavors of black cherry, red plum and cranberry on the palate and a light touch of bright pomegranate in the finish. And maybe a dinner salad because, you know, vegetables.

"When you look at the old wildcatters, they were boom and bust," Bruce Peterson, senior client partner in Korn Ferry's Houston office, told me. "I remember in the early '80s when there was a Rolls-Royce dealership in Midland because there was so much money—and everybody flying around in helicopters. Well, you don't see that anymore, that's for sure."

The extravagance ended because it had to. The era's sky-high prices made drilling to the max irresistible and the resulting oversupply would slowly chip away at the price of crude. By January 1986, it had ducked under $25/bbl ($68/bbl in 2023 dollars). A barrel of oil was now cheaper than that giant sizzling steak.

Then things got really tough. The average monthly price of a barrel dropped 27.4% from January to February, 21.5% from February to March and … you get the picture, or perhaps are of the age that you're experiencing PTSD just reading this. In July, the monthly average price finally bottomed out at $10.91/bbl ($29.88/bbl in 2023).

The crash devastated the economies, not to mention the collective psyches, of oil towns like Houston, Midland, Dallas, Fort Worth and Oklahoma City.

Then, there were the psyches of the oil folks themselves.

"What type of mindset? I've been through six or seven [downturns] over the last 40 some odd years," Peterson said. "What it really takes is a long view."

Peterson has worked as an energy industry executive and now specializes in executive search for companies across the value stream. Adjusting your mindset to the long view, he said, means accepting the carnage that comes with downturns, including the WTI close of -$36.98/bbl on April 20, 2020. ("That was a shock to the system.")

But past gyrations are not necessarily indicative of future chaos. Lessons have been learned.

"Everyone has now listened to their investors and are looking at it now as a business that has to make money," Peterson said. "If you look at the companies that made it through without restructuring, it's made the companies stronger from a balance sheet perspective.

"It's really shown that companies have the ability to understand and be more prudent with their capital as far as the ability to return capital to shareholders and be more conservative on a go-forward basis rather than growth for growth's sake," he said.

Not everyone can stick it out. Some are unnerved by the cyclical nature of the business.

"When you look at the last downturn and the number of individuals that were displaced out of the business, those individuals have gone on to careers in other industries. They have done extremely well," Peterson said.

And in many cases, those fossil fuel alumni will employ the skills they learned in the oil and gas sector to drive innovation in the future.

"You've got a lot of smart people that have had possibly traditional upstream, midstream or services backgrounds that have gone into the transition side of the industry," he said. "They'll figure things out because they've been well trained."

So, let's raise a glass of that red wine from Sonoma to resilience. Remember that just 31 trading days after WTI closed at -$36.98/bbl in 2020, the market put a mirror to the calamity with WTI closing on the plus side at $37.33/bbl.

And while Rolls-Royce Motor Cars no longer builds the Silver Spirit, the ultra-smooth ride of its 2023 Phantom Series II inspired Car and Driver to gush that "there's probably not a more comfortable luxury car on the planet." For those nostalgic for the past, when the Phantom glides down the road, its V-12 engine guzzles gasoline at the rate of 12 miles to the gallon. And for only $460,000 (plus TTL).

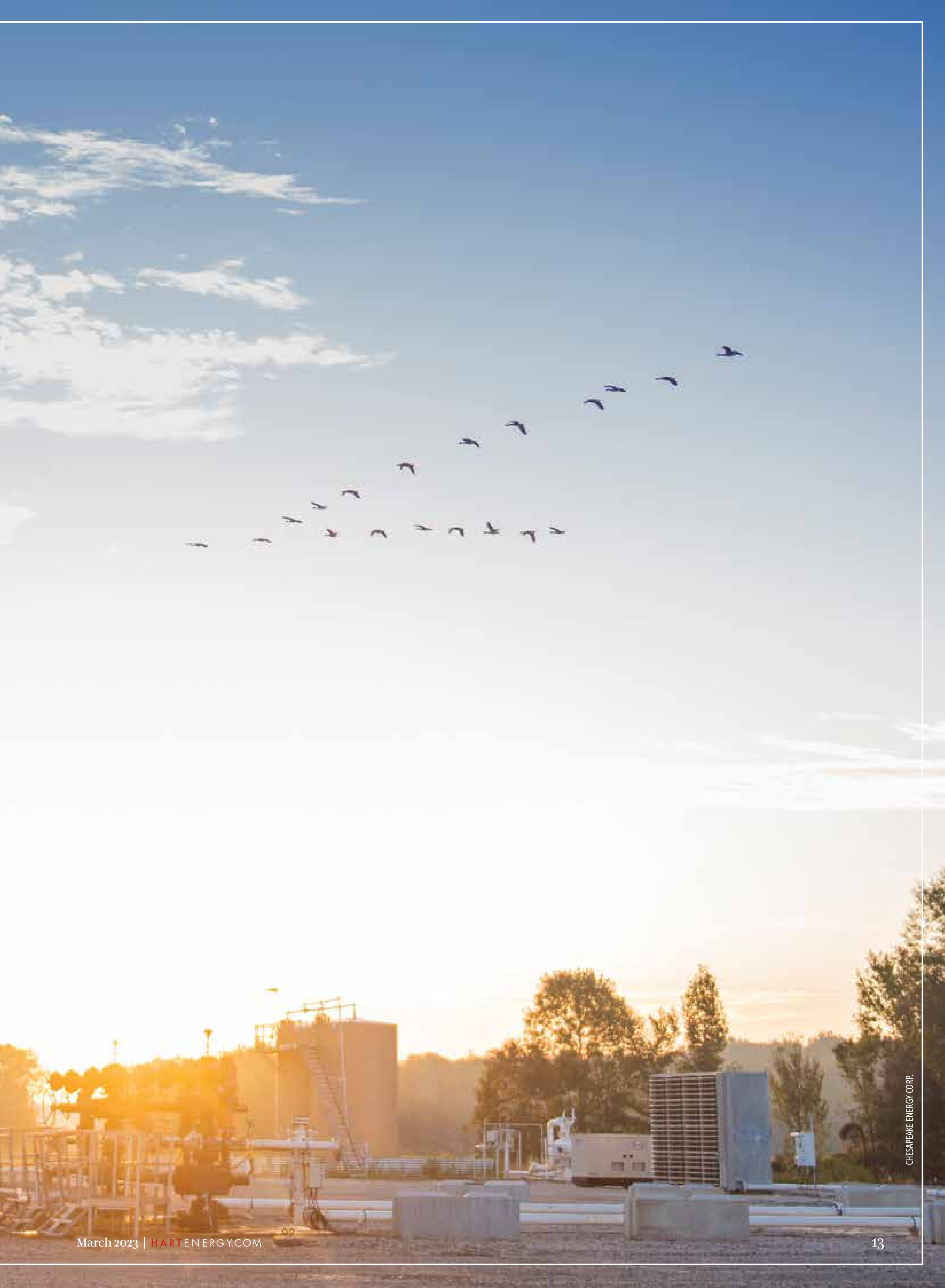
Bodacious. OGI

ACTIVITY HIGHLIGHTS

THE SKY'S THE LIMIT FOR THE HAYNESVILLE SHALE, WHICH SAW ITS NATURAL GAS PRODUCTION SOAR

57%

IN A 10-YEAR PERIOD TO MID-2022.



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▸ **ACTIVITY** HIGHLIGHTS

PERMITS

On a monthly basis, approved well permits in 2022 trailed 2021 throughout the year, except for February and March, according to Rextag.

Permits issued fell off sharply in fourth-quarter 2022, especially in comparison to the same period in 2021, when the totals staged a late-year rally. The December 2022 figure was 47% below that of December 2021. In all of 2022, 22,237 permits were issued, a 13% drop from 25,592 in 2021.

Texas, the dominant state, issued 681 permits in the past month and a total of 9,431 in 2022, just 16 permits shy of the pre-pandemic total in 2019, the Texas Railroad Commission reported. The 2022 figure was 34% higher than in 2021 and 85% above the train wreck of a year in 2020.

Martin County in the heart of the Permian Basin led all counties nationwide with 87 permits in the past month. The county logged 781 approved permits in 2022.

Atop the leaderboard of operators receiving permits was Pioneer Natural Resources Co. It was followed by PDC Energy Inc., which operates in Wattenberg Field in Colorado and in the Delaware Basin.

Permitted Wells By State

State	Well Count
Texas	681
Colorado	284
North Dakota	75
Oklahoma	62
Louisiana	40
Wyoming	40

Permitted Wells By Operator

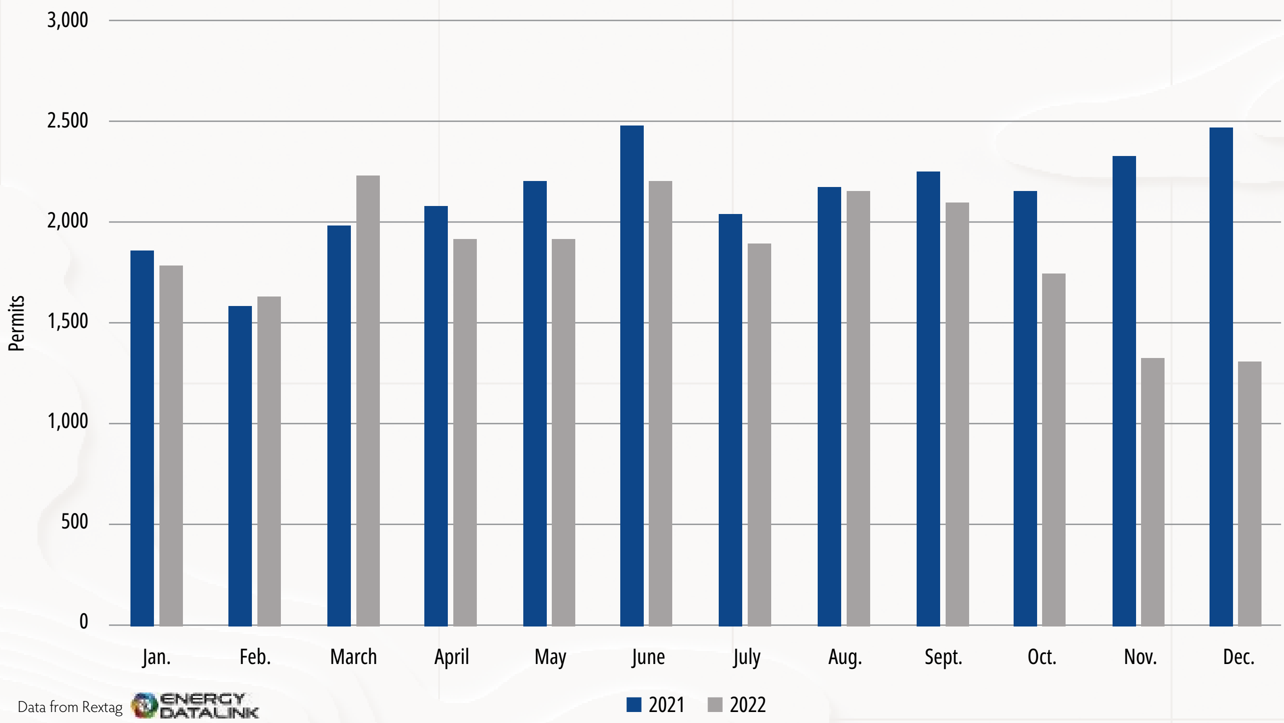
Operator	Well Count
Pioneer Natural Resources	75
PDC Energy	60
Occidental Petroleum	42
Crestone Peak Resources	39
DE IV Operating	33
EOG Resources	26
Exxon Mobil	23
Highpeak Energy Holdings	23
Terra Energy Partners	21

Permitted Wells By County

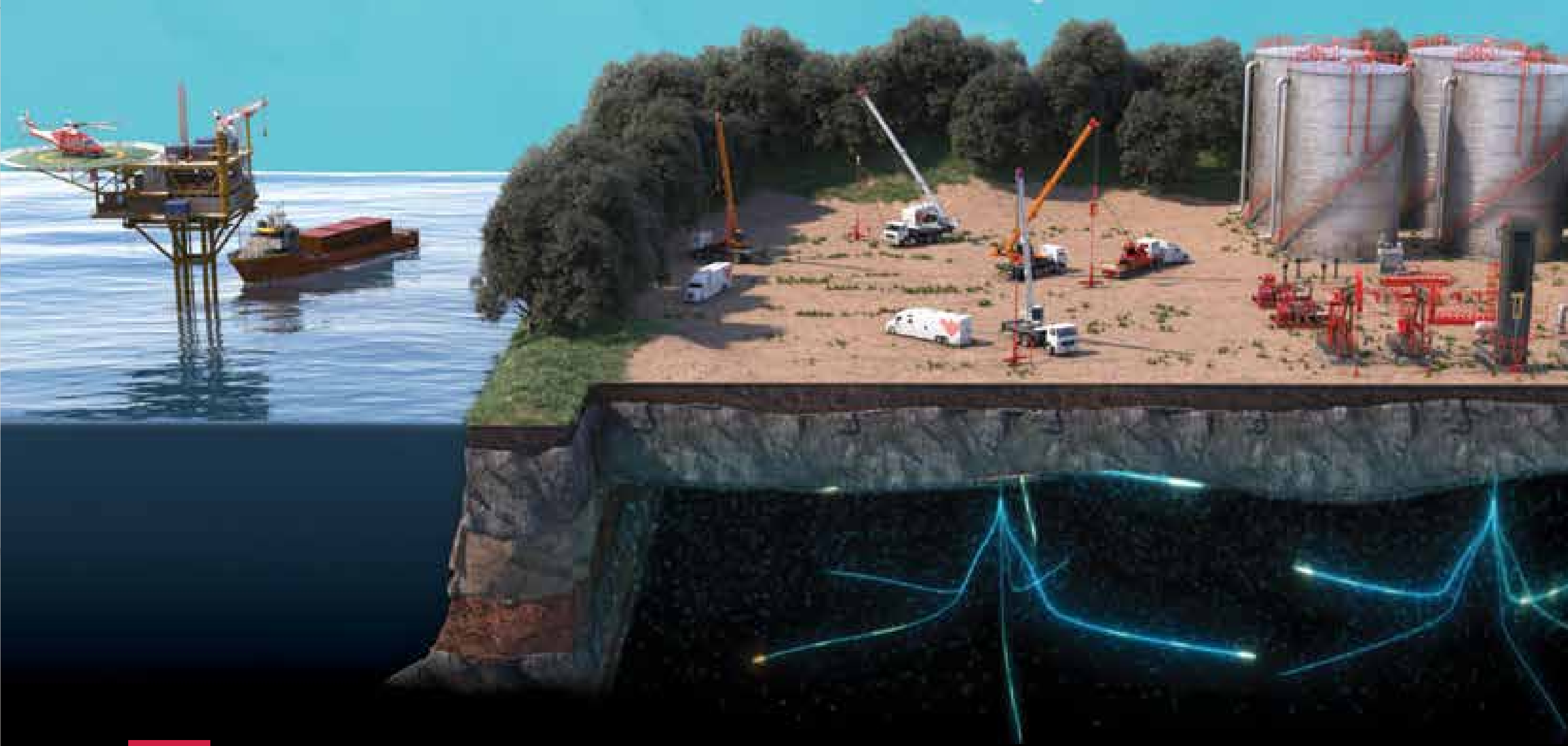
County	Well Count
Martin, Texas	87
Weld, Colo.	77
Reeves, Texas	50
Howard, Texas	49
Reagan, Texas	44
Williams, N.D.	33
Crane, Texas	32
La Salle, Texas	32
Midland, Texas	31
Loving, Texas	26
Glasscock, Texas	21
Mountrail, N.D.	17
Canadian, Okla.	15
Arapahoe, Colo.	11
Campbell, Wyo.	9

US Approved Well Permits

Monthly, 2021 Vs. 2022



Data from Rextag ENERGY DATALINK



FOCUS ON: HAYNESVILLE

Among shale plays, only the Permian and Eagle Ford exceeded the Haynesville in total rigs as of mid-January. And no natural gas play, not even the prolific Marcellus Shale, came close to the Haynesville.

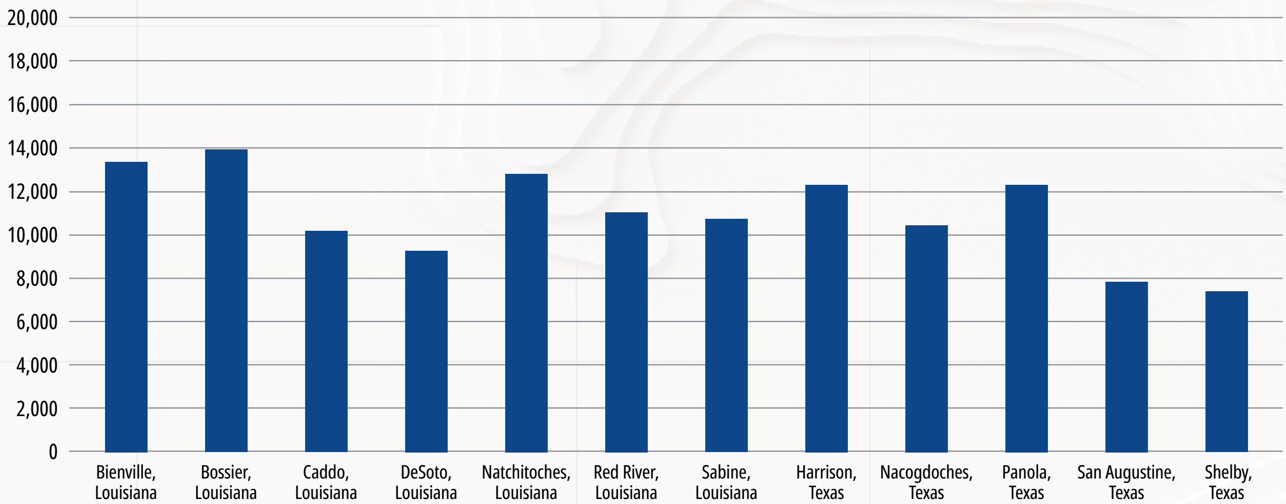
Since dropping to 31 in June 2020, the Haynesville's rig count has more than doubled, opening up a 44% advantage over its Appalachian rival. And in the era in which the power generation battle has tilted decidedly toward natural gas over coal, positioning for growth means everything.

The formation was named for Haynesville, Claiborne Parish, La., a town founded in 1818 that adopted its name from farmer Samuel Haynes in 1843. The Haynesville Formation dates to the Jurassic Period and is 10,500 to 13,000 feet below the surface. The shale is buttressed between sandstone above and limestone below.

The shale covers 23 counties in Louisiana and Texas. DeSoto Parish, La., is the energy leader, accounting for 23.4% of the play's natural gas production.

EUR Of Dry Natural Gas

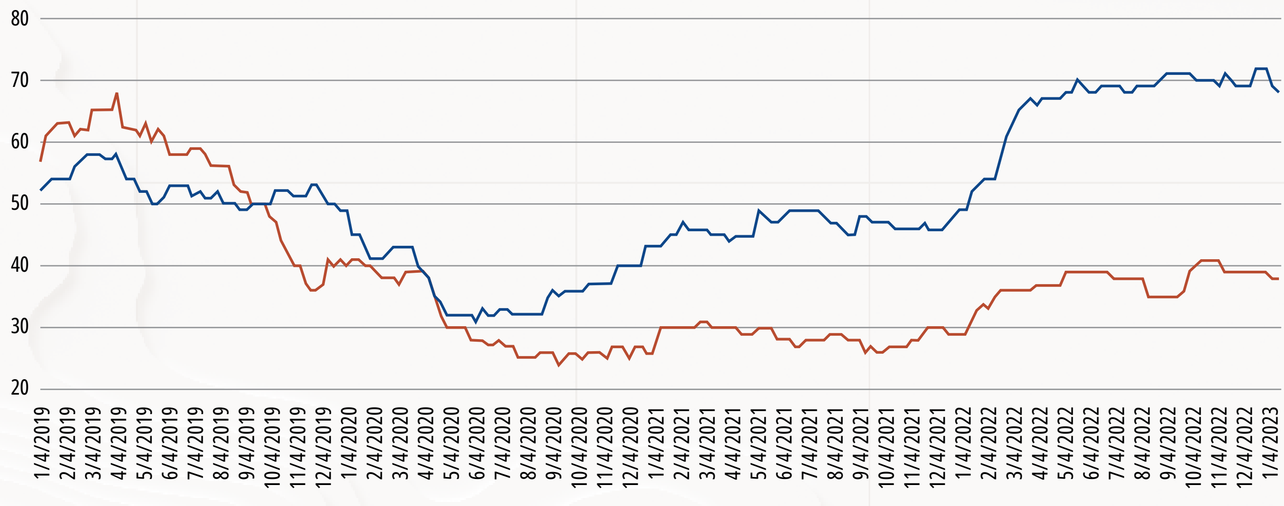
Haynesville Counties, MMcf/Well



Source: EIA

Rig Count: Haynesville Vs. Marcellus

Weekly Total, January 2019-January 2023



Source: Baker Hughes

HARTENERGY LIVE

Oil and Gas Investor

25 INFLUENTIAL WOMEN IN ENERGY

SALUTING THOSE WHO HAVE ACHIEVED OUTSTANDING SUCCESS!

Hart Energy **LIVE** and *Oil and Gas Investor* were honored last month to announce the 2023 Pinnacle Award Recipient and to spotlight 25 talented women who have risen to the top ranks of the oil and gas industry.

2023 WOMEN IN ENERGY PINNACLE AWARD RECIPIENT

Dr. Tabitha Davis

Principal, Young Women's College Preparatory Academy

Dr. Davis holds two degrees in Business (B.B.A. from Houston Baptist University and M.B.A. from the University of St. Thomas) and two degrees in Education (M.Ed. from Lamar University and Ed.D. from the University of Houston).

2023 WOMEN IN ENERGY HONOREES

Barbara Baumann, Chair, **Devon Energy Corporation**

Serena Buck, Vice President of Land, **Ascent Resources**

Le'Ann Pembroke Callihan, Vice President, **American Association of Professional Landmen (AAPL)/NAPE**

Carrie Carson, Director, Commercial Development, **Oxy Low Carbon Ventures**

Naana Danquah Jefferson, General Counsel Americas Land, **SLB**

Keila Aires Diamond, Managing Director and Head of ESG, **Quantum Energy Partners**

Marianella Foschi, CFO, **Civitas Resources**

Deborah Gholson, Gas Development Services Advisor, **Berkshire Hathaway Energy GT&S**

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Alina Parast, Senior Vice President and Chief Information Officer, **ChampionX**

Heetal Patel, Senior Project Manager, **ExxonMobil Corp.**

Megan Pearl, Ph.D., MBA, Vice President of Technology, **Locus Bio-Energy Solutions**

Kathryn Roark, Vice President of Diversity & ESG, **Patterson-UTI Energy**

Allison Sandlin, U.S. Onshore Non-Operated Asset Manager, **Equinor**

Rachel Schelble, Ph.D., Head of Corporate Carbon Management and Infrastructure, **Wood Mackenzie**

Sweta Sethna, Chief Counsel, **Energy Transfer LP**

Teresa Thomas, Partner, US Energy and Chemicals Advisory Leader, **Deloitte**

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Matador Resources to Bolt-On Delaware Basin's Advance Energy in $1.6 Billion Deal

Matador Resources Co. agreed to acquire **Advance Energy Partners Holdings LLC**, an **EnCap Investment** portfolio company in the northern Delaware Basin, for at least $1.6 billion in cash, announced on Jan. 24.

Matador said it will add oil- and gas-producing assets in Lea County, N.M., and Ward County, Texas, as well as some midstream infrastructure, according to a press release. Most of the acreage is strategically located in Matador's Ranger asset area in Lea County, the company said.

The bolt-on adds approximately 18,500 net acres, 99% HBP, in the core of the northern Delaware. The deal would also "significantly" increase Matador's inventory by 406 gross (203 net) drillable horizontal locations with prospective targets throughout the Wolfcamp, Bone Spring and Avalon formations.

Advance Energy is currently utilizing one drilling rig to drill 21 gross (19 net) wells in the northern portion of Matador's Antelope Ridge asset area in Lea County, but the wells are not expected to be turned to sales until early 2024, the company said.

Along with the initial cash payment, Matador agreed to pay an additional $7.5 million for each month in which the average oil price exceeds $85/bbl.

Matador expects the Advance Energy assets to generate one-year adjusted EBITDA of approximately $475 million to $525 million at strip prices as of mid-January 2023, which represents a purchase price multiple of 3.2x.

Matador estimated the PV-10 value of the assets at $1.92 billion, based on proved oil and natural gas reserves at mid-January strip price.

The company also said the PV-10 value of proved developed oil and natural gas reserves at Dec. 31, 2022, is $1.14 billion, or approximately $45,600 per flowing boe, utilizing strip pricing as of mid-January 2023.

Matador said it will maintain a strong balance sheet with leverage expected to remain below 1.0x.

Tudor, Pickering, Holt & Co. (TPH) analyst Jeoffrey Lambujon said the transaction announcement makes sense at "first blush, in our view, given valuation metrics, management's consistent transparency regarding opportunistic M&A for both upstream and midstream assets, and the balance sheet strength (TPHe 0x leverage by YE23) and free cash flow (TPHe 9% FCF/EV) that support these activities."

Matador's disclosed production value of $45,600 per boe/d "implies about $25,000 to $30,000 per acre (depending on monthly cash payments), and MTDR's [Matador] disclosed forward EBITDA of $475 million to $525 million implies a 3.2x multiple," he wrote in a Jan. 24 commentary.

Matador's capex guidance is about $325 million at the midpoint, including "DUC-spend (based on a single rig program, with 20 net to be turned to sales H223)," Lambujon said.

Matador said the Advance Energy deal includes about 35 miles of in-field gas and water gathering pipelines. The company is also acquiring an active Devonian salt water disposal well "with strong proven injection capacity."

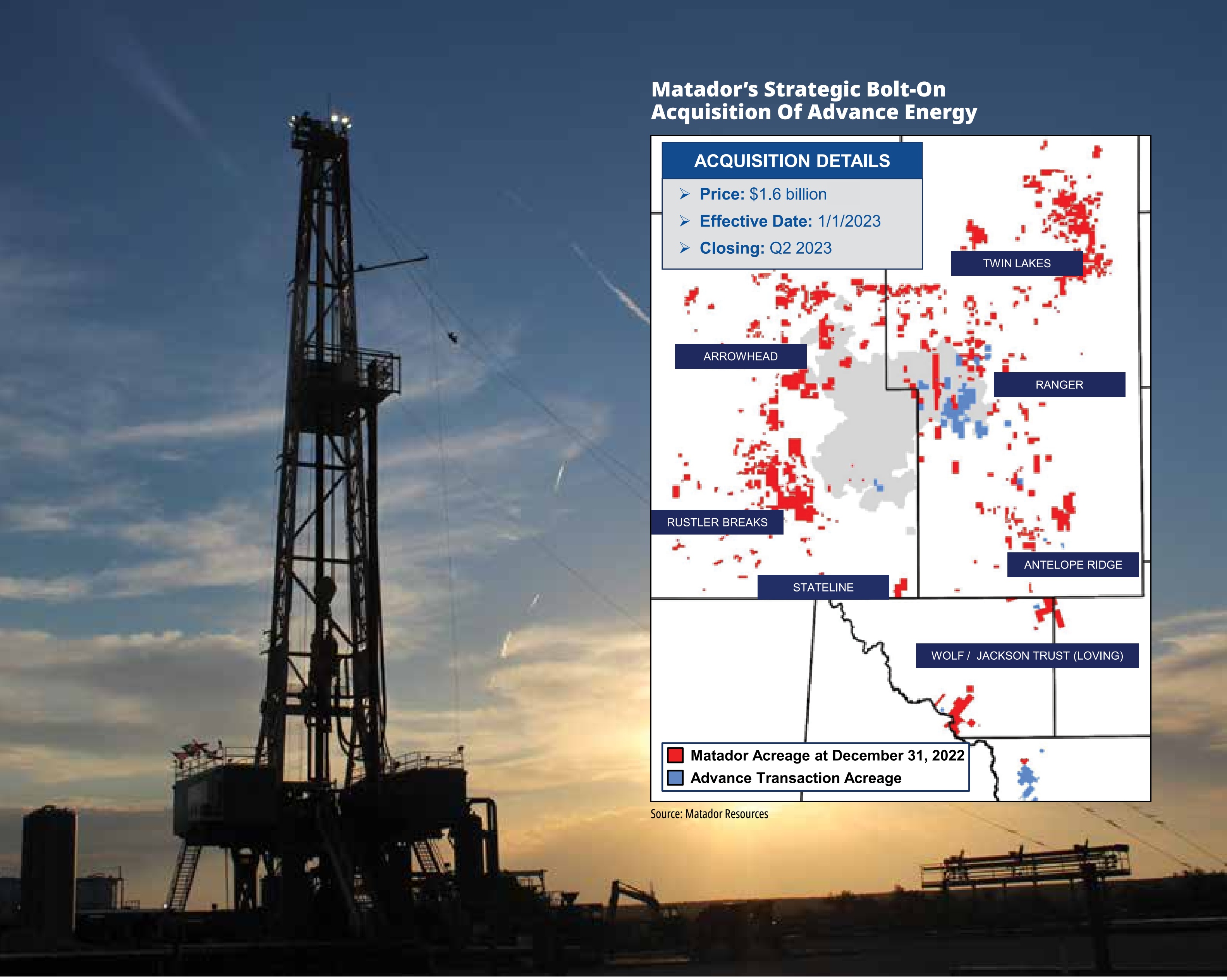
Matador sees the potential connection of undedicated acreage to Matador's midstream subsidiary, **Pronto Midstream LLC**, said "to further enhance flow assurance and provide upside midstream value."

Joseph Wm. Foran, Matador's founder, chairman and CEO, said the company views the transaction as a "unique value-creating opportunity for Matador and its shareholders.

"We evaluated this transaction based on rock quality, the strong existing production and cash flow profile, the potential reserves additions, the high-quality inventory, the available midstream opportunities and the strategic fit within our existing portfolio of properties," Foran said. "We intend to fund the Advance transaction with a combination of cash on hand, free cash flow prior to closing and borrowings under our credit agreement, under which we expect to increase our elected commitment in connection with this transaction."

In late November 2022, as part of the fall 2022 redetermination process, Matador's lenders completed its review of the company's proved oil and natural gas reserves at June 30, 2022. As a result, the borrowing base under Matador's credit agreement was increased by 13% from $2 billion to $2.25 billion.

"Importantly, this acquisition should not significantly impact Matador's leverage profile, as we expect



Matador's Strategic Bolt-On Acquisition Of Advance Energy

Source: Matador Resources

Shutterstock/Austin Fellmy

to maintain a pro forma leverage ratio below 1.0x throughout 2023," he said.

Baker Botts is representing Matador in the Advance transaction.

Matador bolt-on in perspective

Andrew Dittmar, director at **Enverus Intelligence Research**, said the deal continues to thaw a cold couple of weeks that started 2023.

"The deal looks to be a sensible bolt-on in the core Delaware for Matador at multiples slightly accretive to its trading numbers," Dittmar said. "At the same time, the company was able to add a significant runway of high-quality locations that are immediately competitive in its portfolio for drilling capital. While not super cheap at about $25,000 per acre, the deal prices are in line with other recent M&A for core assets like **Diamondback Energy**'s buys in the Midland Basin in late-2022."

Matador benefited from being a small- and mid-cap (SMID) with a higher share price than most of its peers and that it has retained cash to make an acquisition.

"Like some of the other recent buyers, it has also won the trust of investors with a successful track record on deals," he said in a Jan. 24 commentary.

Advance was another of the major portfolio companies of EnCap that the company was looking to monetize as it came to the end of its investment timeline.

"Given the value paid for the undeveloped assets, this transaction definitely looks like a win for EnCap as well," Dittmar said. "Private equity companies are likely to continue to make up the bulk of sellers as they take advantage of public companies' need for inventory and strong commodity prices as an opportunity to exit. That has winnowed the participation of private equity as asset owners, with the pace of sales by these companies not nearly being matched by new acquisitions."

Dittmar said companies are likely to be "highly selective" on what assets they add with the core Permian Basin, Eagle Ford Shale and other areas of similar quality likely to make up the bulk of deal activity.

"While we believe ultimately SMID-cap operators that need inventory will have to look at tier two or three opportunities, the market does not appear to be there yet, and public companies are interested in just the highest-quality inventory," he said.

—Darren Barbee

Permian Resources Adds, Subtracts in Nearly $300 Million in Deals

Permian Resources Corp. announced A&D transactions that totaled $293 million, including a Permian Basin bolt-on as well as sales of assets in the Delaware Basin and southern Delaware midstream water assets, the company said on Jan. 17.

Oliver Huang, an analyst with **Tudor, Pickering, Holt & Co.**, said in a Jan. 18 report he expects the transactions to be viewed positively by the market.

"This lays out a potential blueprint for how the company could continue to create value through smaller-scale transactions via the M&A market in the future," he said. "In summary, deals net the company $97 million of cash, add ~45 top-quartile, 2-mile lateral locations that immediately compete for capital, while adding ~3.1k net royalty acres with net PDP on divestitures only ~700 boe/d."

In its bolt-on deal, Permian Resources entered into a definitive agreement to acquire 4,000 net leasehold acres, 3,300 net royalty acres and average net production of 1,100 boe/d (73% oil). The assets are located predominantly in Lea County, N.M., from an undisclosed third party for a total purchase price of $98 million, according to a press release.

The purchase price reflects an acquisition value of approximately $8,000 per net leasehold acre and approximately $7,000 per net royalty acre.

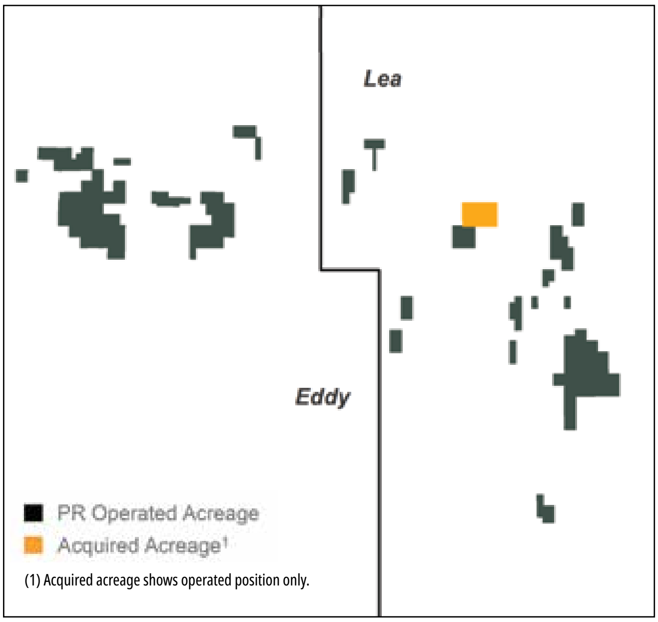
The properties' operated position consists of largely undeveloped acreage and is contiguous to one of the company's existing core blocks in Lea County.

Permian Resources said it identified approximately 45 gross operated 2-mile locations from the acquired properties that immediately compete for capital within the existing portfolio. The properties also include nonoperated acreage largely adjacent to and surrounding its position. The company plans to engage in future acreage trades and other portfolio management transactions.

Nonoperated Delaware Basin divestitures

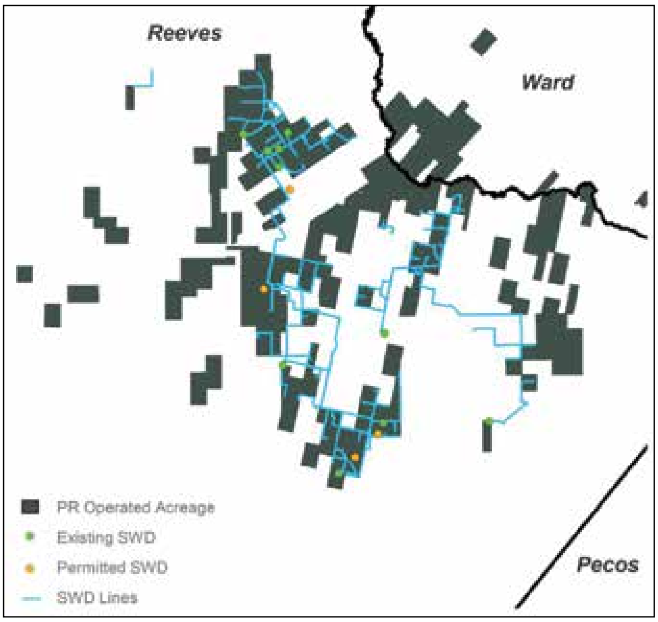
Permian Resources also said it had divested producing, nonoperated properties in Reeves County consisting of an average 1,800 boe/d (44% oil) and 3,500 net leasehold acres to an undisclosed third party for $60 million. The price reflects a valuation multiple of greater than 5x [GW1] 2023 estimated

New Mexico Acreage



Source: Permian Resources

Divested Midstream Infrastructure



Source: Permian Resources

Transaction Summary

	Net Cash (MM)	Net Acres	Net Royalty Acres	Net Bll/d	Net Boe/d	Status
Bolt-On Acquisition	$(98)	~4,000	~3,300	~800	~1,100	Closing Q1
Non-op Divestitures	$70	~ (3,800)	~(200)	~(800)	~(1,800)	Closed Q4
Midstream Transactions	$125	–	–	–	–	Closing Q1
Total Summary	**$97**	**~200**	**~3,100**	**–**	**~(700)**	

Source: Permian Resources

EBITDA, according to Permian Resources.

The divested acreage represents most of the company's nonoperated positions in Texas, which the company said included minimal remaining inventory. Additionally, the company sold a nonoperated position consisting of 300 net leasehold acres in Eddy County, N.M., for $35,000 per net acre, resulting in approximately $10 million of net proceeds.

Midstream infrastructure transactions

Permian Resources also signed definitive agreements with an undisclosed third party to divest a portion of its saltwater disposal wells and associated produced water infrastructure in Reeves County. The total consideration is $125 million.

The full consideration will be received at closing with $60 million subject to repayment if certain thresholds tied to Permian Resources' future drilling activity in the service area over the next several years are not met. The company expects to retain the full consideration based on its current development plan.

The counterparty has a strong record of operating midstream assets, and the divested infrastructure has ample additional capacity to service the company's future produced water disposal needs. The transaction is expected to close during the first quarter of 2023, subject to regulatory approval.

"At Permian Resources, we believe our focus on portfolio management will continue to drive value for our shareholders," said James Walter, co-CEO of Permian Resources. "The combined transactions high-grade our portfolio, adding 45 top-quartile locations, 4,000 net acres with significant development potential and 3,100 net royalty acres while generating approximately $100 million in net cash proceeds."

—Darren Barbee

Chord Energy Divest Multi-Region Package, Heavy on the Permian

The unwritten rule of M&A is that after most mergers, divestitures ensue. **Chord Energy Corp.**, no exception, has a hefty package of noncore acreage to sell, with the largest chunk in the Permian Basin.

Chord Energy was created after a July 1 combination between **Whiting Petroleum Corp.** and **Oasis Petroleum Inc.** valued at $6 billion. The resulting company is the largest net acreage holder and second-largest producer in the Williston Basin—with an estimated 10% of the basin's production.

Roughly two weeks after the merger closed, the company completed the divestiture of its interests in various assets, including producing wells and an equity interest in a pipeline in Rio Blanco County, Colo., for an aggregate sales price of $8 million, according to November federal regulatory filings.

But the company remains ready to jettison a sizeable chunk of noncore asset across the U.S., including the Permian Basin, Central and Northern Rockies and Gulf Coast.

EnergyNet Indigo has now marketed some of those assets—totaling 46,077 net acres and interests in 1,664 wells—for Chord. A large portion of the production and proved reserves are located in the Permian.

Chord said its preference is a sole buyer for the assets but will consider offers on a regional basis as well.

The combined assets average about 2,200 boe/d, 80% of which is oil that have produced $3.2 million in average operating income over a six-month period from March 2022 to August 2022, according to EnergyNet Indigo. Production is primarily from conventional reservoirs and established waterfloods with predictable production profiles.

The properties "have not been core assets of Chord (and formerly Whiting) for several years," according to EnergyNet Indigo marketing materials. "Whiting USA Trust II held a 90% net profits interest in the properties, which terminated and reverted to Whiting Oil and Gas Corp." on Dec. 31, 2021.

Chord's Permian position spans the Midland and Delaware basins and the Central Basin Platform. EnergyNet Indigo described the assets as "stable operations from conventional and waterflood assets with horizontal development potential."

The Permian package's highlights include:

- Net production of 1,300 boe/d, including 73% oil;
- Average months operating income of $1.7 million;
- Estimated average base declines of 14% from January 2023 to January 2024;
- 23,936 net acres, 96% HBP;
- A total of 656 wells, 485 active and 171 inactive; and
- Of those wells, 305 are operated and 322 are nonoperated.

—Darren Barbee

Chord Energy Assets

Legend
- Permian Package
- Gulf Coast Package
- Rockies Central Package
- Rockies North Package

Source: EnergyNet Indigo

GOM

• Independent E&P **Arena Energy LLC** closed on its acquisition of **Cox Operating LLC**'s interests in the Eugene Island 330 and South Marsh 128 oil blocks, a press release announced on Jan. 24.

Headquartered in Dallas, Cox Operating's interests add to Arena's existing ownership interest in the Gulf of Mexico fields, which it acquired recently from **GOM Shelf LLC**.

"This transaction—coupled with the recent acquisitions from GOM Shelf LLC, as well as the leases awarded pursuant to Lease Sale 257, provides many years of additional inventory to allow Arena to continue producing some of the cleanest barrels for the U.S. and the world," Arena co-founder and CEO Mike Minarovic said in the release.

Combined, the interests will add approximately 1,000 net boe/d to Arena's total production.

The Woodlands, Texas-based Arena is one of the largest private offshore oil and natural gas producers with over 300 decommissioned wells and 45 platforms and other structures in the U.S. Gulf of Mexico.

• **Talos Energy Inc.** is edging closer to wrapping up its $1.1 billion acquisition of private operator **EnVen Energy**.

Talos set a Feb. 8 special meeting for its stockholders to vote on the deal and other matters, according to a prospectus filed Jan. 11 with the Securities and Exchange Commission.

Shareholders were asked to approve the EnVen merger, which the company said in September would increase its Gulf of Mexico production by 40%.

Talos said in a Jan. 11 press release that the company expects to close the transaction soon after the meeting.

Adding EnVen would double Talos' operated deepwater facility footprint, expanding key infrastructure in existing Talos operating areas, the company has said. More than 80% of the combined assets will be deepwater, with Talos operating more than 75% of the acreage it holds interests in.

HAYNESVILLE

WhiteHawk Energy LLC has entered into a definitive agreement to acquire Haynesville Shale mineral and royalty assets for up to $105 million, the company said in a Jan. 17 press release.

The Haynesville royalties are in the core of the basin, WhiteHawk said, adding that its position will cover 375,000 gross unit acres in northwestern Louisiana.

The company said the Haynesville assets acquired will include production from more than 1,230 horizontal wells, 44 permitted wells and another 157 "line of site wells" in the shale play.

The Haynesville interests are being actively developed by "best-in-class natural gas operators," including **Southwestern Energy Co.**, **Chesapeake Energy Corp.**, **Aethon Energy Management** and **Comstock Resources Inc.**

Under the agreement, WhiteHawk will acquire up to $105 million of the royalties with an initial effective date of Feb. 1, 2023.

WhiteHawk management expects the Haynesville royalties to be a strong complement to the company's existing mineral and royalty assets, the company said.

In 2022, WhiteHawk acquired natural gas mineral and royalty assets covering 475,000 gross unit acres in the core of the Marcellus Shale focused in Greene and Washington counties in Pennsylvania.

Pro forma for the Haynesville royalties acquisition, the company will have interests in over 2,300 producing horizontal wells across the two preeminent natural gas basins in North America. WhiteHawk said it will own minerals and royalties in the core of the Marcellus and Haynesville shales spanning 850,000 gross unit acres.

CANADA

TotalEnergies EP Canada Ltd. is acquiring an additional 6.65% interest in the **Fort Hills Energy Ltd.** partnership from **Teck Resources Ltd.** for C$312 million, TotalEnergies announced in a Jan. 27 press release.

The preemptive transaction brings TotalEnergies EP Canada's working interest in the Fort Hills project from 24.58% to 31.23% in an effort to invest in long-term growth projects.

"By seizing this opportunity to grow its business under attractive conditions, TotalEnergies EP Canada will deliver value to the future shareholders of the spinoff entity," said Jean-Pierre Sbraire, CFO of TotalEnergies.

The Fort Hills project is located in the province of Alberta 90 km north of Fort McMurray. Within the same region, the spinoff company holds 50% working interest in the Surmont project.

TotalEnergies EP Canada is a spinoff company of France's TotalEnergies, who announced in September it plans to exit its Canadian operations in 2023 with TotalEnergies EP Canada. The decision will be put to vote in May at TotalEnergies' annual shareholders' meeting.

ATLANTIC

Wind energy powerhouse **Ørsted** plans to take full ownership of the 1,100-megawatt (MW) Ocean Wind 1 project being developed offshore New Jersey, agreeing to buy partner **Public Service Enterprise Group** (PSEG)'s 25% stake in the project.

Pending required closing conditions, the deal is expected to close in first-half 2023, the Danish company said Jan. 18. The price paid was not disclosed.

"With a well-established presence in the U.S., we're confident in our ability to drive the project forward with commercial operations beginning as planned," said David Hardy, executive vice president and CEO of the Americas region of Ørsted.

First power from Ocean Wind 1, which will be New Jersey's first offshore wind farm, is expected by year-end 2024 with full commissioning set for 2025. The project is designed to deliver enough capacity to power about 500,000 New Jersey homes.

PSEG said the decision to sell its stake was difficult.

"As Ocean Wind 1 has evaluated the optimal way to move forward, it's become clear that it's best for the project for PSEG to step aside and allow for a better-positioned investor to join the project so that it can proceed with an optimized tax structure," said Lathrop Craig, senior vice president and chief commercial officer at PSEG.

The transaction came about two years after Ørsted announced it had entered an agreement to sell a 25% ownership interest in Ocean Wind to PSEG.

Located about 15 miles southeast of Atlantic City, Ocean Wind 1 will feature 98 wind turbine generators, up to three offshore alternating current substations and two onshore substations along with cables and grid connections needed for the project.

The project is expected to help move New Jersey closer toward its goal of generating 3,500 MW of electricity from offshore wind by 2030. The state is targeting 7,500 MW of offshore wind by 2035 and 11,000 MW by 2040.

UNLOCKING GEOTHERMAL ENERGY

Quaise Energy, with backers that include Nabors Industries, is using new millimeter wave drilling technology to scale geothermal energy.

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Quaise Energy Inc. is on a mission to unlock geothermal energy by vaporizing hard rock as it drills miles into the earth's crust to tap into superhot thermal systems.

The Massachusetts-based MIT spinoff is developing millimeter wave drilling technology to harvest geothermal energy at scale. Using equipment developed for fusion research, the company aims to tap heat too hot for conventional drilling equipment with the help of companies such as driller Nabors Industries, which invested $12 million in Quaise last year.

The two are working to advance the technology toward its first field demonstration in the U.S.

"Nabors is helping us integrate our millimeter wave technologies within one of their existing rig architectures for the first prototype geothermal scale, millimeter wave drilling rig," Matt Houde, the company's co-founder and project manager, said on a webinar hosted by the Geological Survey of Northern Ireland. "This system is expected to come online in the next two years. In the meantime, we have a much smaller system that is truck mounted that is intended to perform the first field demonstrations within the next year."

While focus is currently on proving out the technology in the lab, developers aim to drill its first superhot geothermal well by 2026 as it matures the drilling technology to deeper depths.

Going hotter, deeper

When it comes to drilling, going deeper usually means more time and money.

Once oil and gas drillers pass basement rock, anywhere from the surface to 5 km to 10 km underground, the rock is more crystalline, Houde explained.

"It's quite hard and abrasive, and it's quite hot, of course. So, a mechanical drill bit begins to typically slow down as it enters these harder rock formations and cannot drill as fast as in softer sedimentary rock," he said.

Time spent on tasks, such as replacing the drill bit or trying to solve issues with stuck pipe moving off center or lost circulation, also adds time and cost to drilling operations.

Millimeter wave technology, conceived at the MIT Plasma Science Fusion Center, comes into play when subsurface conditions necessitate a switch from conventional rotary drilling to technology capable of withstanding high temperatures and pressure.

"Nabors is helping us integrate our millimeter wave technologies within one of their existing rig architectures for the first prototype geothermal scale, millimeter wave drilling rig."

—Matt Houde, *Quaise Energy*

How it works

Instead of using conventional downhole techniques with drilling mud to break rock, remove materials, stabilize the borehole and manage temperature and pressure, energy matter interaction takes place as high-powered radiofrequency energy is used. For millimeter wave technology, microwaves—the same energy that heats food in microwave ovens—are sent downhole via a gyrotron.

Gone are the days of drilling mud.

Instead, the gyrotron—a device that emits intense electromagnetic waves and is commonly used in nuclear fusion as a source of millimeter wavelength radiation—allows the driller to remove rock. The rock is heated with the gyrotron to around 3,000 C, either melting the rock through pressurization or vaporizing it, Houde said.

"Once that rock particulate condenses, we're then able to convey the particulate up the borehole annulus with a circulating purge gas that is also injected down our waveguide or drillpipe, if you like to call it that," he said.

"That purge flow is high enough to actually circulate and lift these particles up because they are so fine—being produced from the vaporization process."

While the hole is being drilled, rock is not only being vaporized but also "melting an outer ring around this vaporized hole that actually stays behind," creating a glass-lined borehole as the melted rock cools, Houde said.

He called the process an underbalanced drilling approach, given drilling mud is replaced with a drilling gas. "This liner allows us to prevent any inflows of fluids from coming into the hole while also retaining a structurally competent borehole during the drilling process."

Shutterstock/Kenan Mutlu

The process operates independent of depth and lowers nonproductive time, he added.

Finding 'Goldilocks'

Houde described operating at millimeter wave, which is a frequency between 30 gigahertz and 300 gigahertz, as a "Goldilocks" region for drilling geothermal-sized boreholes.

"Not only do we have a wavelength that has efficient absorption into the rock—most of the microwave power goes into the rock for heating and vaporizing," he said, "but we also have a wavelength that can be transmitted over very long distances, very efficiently."

This means that most of the microwave power gets to where it needs to go.

"Gyrotrons … also provide the power output that we require for drilling a full-sized geothermal borehole at rates of penetration that we want to be economical," Houde said.

Geological risks still exist. These include hitting non-silicate rocks, overpressurized aquifers and even oil and gas.

"These are going to be technical risks we primarily encounter in the sedimentary overburden before we get down to the basement rock. So, we propose not to replace conventional drilling at what it does best and actually start at the surface with conventional rotary or drag-based mechanical drilling tools," he said. "It's only when we penetrate the basement and get to a depth where we see diminishing returns on that conventional drilling operation that we actually switch over to the millimeter wave drilling assembly and continue until our ultimate depth target."

The economics

At first glance, the drilling system would resemble a conventional onshore drilling rig with millimeter wave technology components integrated into the rig's architecture, he said.

Quaise's projections show geothermal holes can be drilled at a rate of $1,000/m using the technology, House said, drilling 3.5 m per hour. It is projected to deliver wells at costs similar to, or a little more expensive than, today's geothermal wells. The levelized cost of electricity could beat $40 per megawatt hour, he added.

Quaise said the millimeter wave drilling technology enables drilling down to 20 km and 500 C, unlocking an abundant clean energy source.

"These deep superhot systems can be economically competitive with wind and solar resources today without even taking into account their advantages in terms of being a baseload resource that is always on and has a high-capacity factor and the ability to fluctuate that power output depending on what the market requires," Houde said.

BAKER HUGHES, SLB CEOS TALK 'NEW ENERGY'

Energy technology companies, including Baker Hughes and SLB, are spreading technological know-how while forming or strengthening partnerships to reduce greenhouse-gas emissions and improve energy efficiency.

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As investment picks up in carbon capture, hydrogen and clean power projects, in part due to government incentives in the U.S. and abroad, energy services companies known for oilfield technologies are moving deeper into new energy.

Such talk surfaced on Baker Hughes Co. and SLB's recent earnings calls as the energy technology giants shared updates on their progress. Service companies are spreading their technological know-how to reduce greenhouse-gas emissions and improve energy efficiency while working toward sustainability goals.

Speaking to analysts on Jan. 23 following the release of its fourth-quarter 2022 earnings, Baker Hughes CEO Lorenzo Simonelli said the company believes it can achieve about $400 million in new energy orders in 2023, having seen significant progress in 2022 compared to the year earlier. The company's energy technologies and services include hydrogen, carbon capture, utilization and storage, geothermal and emissions management, as well as asset management and digital innovations.

"Over the next three to four years, the new energy content should be around 10% of our gas tech orders. And as we stated previously, we believe by the end of the decade, new energy orders should be in the range of $6 billion to $7 billion," Simonelli said, adding that new energy is expected to accelerate through the second half of the decade. "Direction of travel is clear. We've got the investments in place into the new tech and feel good about the way in which the market segment is really creating on the back of some of the legislation."

The Inflation Reduction Act (IRA) in the U.S. is helping to firm the outlook, Simonelli said, with new legislation potentially coming from Europe.

Signed into law in August 2022, the IRA includes about $369 billion in incentives for clean energy and climate-related spending. Its passage came as the U.S. took steps to lower greenhouse-gas emissions 40% below 2005 levels by 2030, a move to slow climate change. Energy experts believe the law, which includes tax credits for renewable energy development, will draw more investment to the sector.

Orders rising

The latest earnings report marked the first under Baker Hughes' revised organizational structure. The company shrank its four business units into two, creating the oilfield services and equipment business and the industrial and energy technology unit. The latter, which includes new energy alongside LNG both onshore and offshore, recorded $4.3 billion in orders during fourth-quarter 2022. New energy orders alone increased 50% to more than $400 million, compared to 2021.

One of the quarter's orders was from Malaysia Marine and Heavy Engineering to supply CO_2 compression equipment to Petronas' Kasawari offshore carbon capture and sequestration (CCS) project in Sarawak, Malaysia. With a capacity to reduce CO_2 emissions by 3.3 million tonnes per annum, the product is expected to be among the world's largest CCS facilities offshore.

"We continue to develop our portfolio of new energy technologies. We have been particularly active over the last few years acquiring and investing in multiple new technologies around hydrogen, carbon capture, clean power and geothermal," Simonelli said. "We are now transitioning more toward the incubation of the existing portfolio. This will enable our new energy portfolio to achieve its full commercial potential, with a particular focus on high impact technologies like NET Power and Mosaic."

NET Power's technology provides low-emissions natural gas power, while Mosaic Materials—acquired by Baker Hughes last year—offers technology that captures CO_2.

Making progress

SLB, which reported fourth-quarter 2022 earnings on Jan. 20, is also progressing technology in its new energy unit to strengthen its portfolio with new investments and partnerships. It focuses on carbon solutions, hydrogen, geothermal, critical minerals and energy storage.

In addition to offering services such as SLB End-to-End Emission Solutions to help oil and gas companies reduce emissions, SLB CEO Olivier Le Peuch said the company is also accelerating its R&D efforts to develop

> *"Direction of travel is clear. We've got the investments in place into the new tech and feel good about the way in which the market segment is really creating on the back of some of the legislation."*
>
> —Lorenzo Simonelli, *Baker Hughes*

Baker Hughes

technologies that address emissions in hard-to-abate sectors.

SLB and Linde, a global gases and engineering company, built on their relationship in 2022 by agreeing to collaborate on projects that will capture and sequester CO_2 emissions from the ammonia, hydrogen and natural gas sectors.

The company said it has also teamed up with nonprofit research institute RTI International to scale up its "non-aqueous solvent technology, which enhances the efficiency of absorption-based carbon capture."

In the geoenergy space, SLB has been working with Celsius Energy on sustainable heating and cooling in commercial buildings using energy from the earth. Meanwhile, Genvia, an SLB clean hydrogen joint venture, continues to develop electrolyzer technology that utilizes the thermal energy of waste industrial heat.

"We have a great long-term outlook on this, and more will come on this chapter," Le Peuch said of its new energy unit. "But in general, we are making progress on each of these domains, be it in pilots, be it in early commercial contracts, be it in technology milestones." OGI

HYDROGEN INNOVATION

Hydrogen technology patents are on the rise as the world seeks to go "green."

LIZ FLANNERY AND THOMAS CARTER
BAKER BOTTS

Baker Botts partner Liz Flannery and senior associate Thomas Carter work in the firm's intellectual property department.

Hydrogen has become one of the centerpieces of the world's plans to transition to cleaner energy. But producing, storing and distributing hydrogen at a lower cost entails several challenges. New technologies are being developed to solve those challenges and, as the rate of innovation ramps up, so does the number of patents being filed for them.

Patent protection is essential for innovators to transform hydrogen research into market-ready inventions. Patents are also key to helping businesses raise capital, establish partnerships and ultimately scale up.

Green hydrogen production

Some types of hydrogen are cleaner than others. "Gray" hydrogen, for instance, is created using hydrocarbons such as oil or coal. "Blue" hydrogen uses natural gas in combination with advanced cleanup technologies. "Green" hydrogen uses electrolysis often from renewable power such as wind, solar or hydro sources.

As the world transitions to greener fuels, there has been a spike in patents corresponding to green hydrogen when compared to patents for hydrocarbon-based hydrogen.

Based on data from Techson IP Research, Figure 1 shows a substantial increase in U.S. patent filings related to green and blue hydrogen in the past 20 years as compared to hydrocarbon-based generation.

According to the International Energy Agency (IEA), electrolysis corresponds to about 2% of global hydrogen production nowadays. But there has been a strong uptick in technology being developed to make electrolyzers more efficient, cheaper and scalable. This is translating into an increase in related patents globally.

According to a report from the European Patent Office (EPO) and the International Renewable Energy Agency (IRENA), from 2005 to 2020, 10,894 international patent families (IPFs) related to water electrolysis were published worldwide, with an average annual increase of 18%.

Hydrogen's challenges

Hydrogen is difficult to store and distribute over long distances. Thus, innovators are coming up with technologies to address this challenge.

Data from the EPO and IEA show that the number of published IPFs related to the storage of hydrogen in 2020 grew at a compound average rate of 13%. More recently, there has been a compound average growth of 13% in patents for liquid storage and vehicle refueling technologies, in the period 2011 to 2020, respectively. Innovation in pipeline networks and other related equipment, such as cryogenic heat pumps and valves, needed to distribute hydrogen has also generated a flurry of patent filings during the same period.

End-use applications

Fuel cell cars are a promising end use of hydrogen innovations. Since 2001, there have been significantly more IPFs for automotive applications of hydrogen than for aviation, rail and shipping, as can be seen in Figure 2, based on data from the EPO and IEA.

IPFs for aviation applications have grown at an average annual rate of 15% over the past decade, while IPFs for shipping applications have grown at 8%. However, only 33 IPFs were published for rail applications between 2010 and 2020, according to data from EPO and IEA.

Protecting hydrogen IP

The growth in patents filed for technologies in hydrogen production, storage and distribution and end-use applications demonstrates that there is widespread awareness among innovators on the need to protect their intellectual property (IP). Here are some considerations innovators should keep in mind when filing their patents.

Where to file?

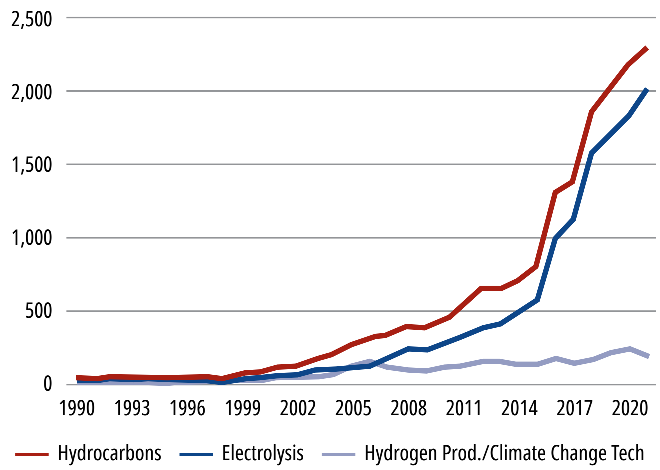
The markets with key policy action supporting hydrogen markets are Europe, the U.S. and Asia-Pacific nations, so innovators in this space should consider filing in those countries (and in many cases, the key players already have).

Innovators should also consider filing in markets where competitors developing similar technologies are filing for patent protection.

Navigating IP rights

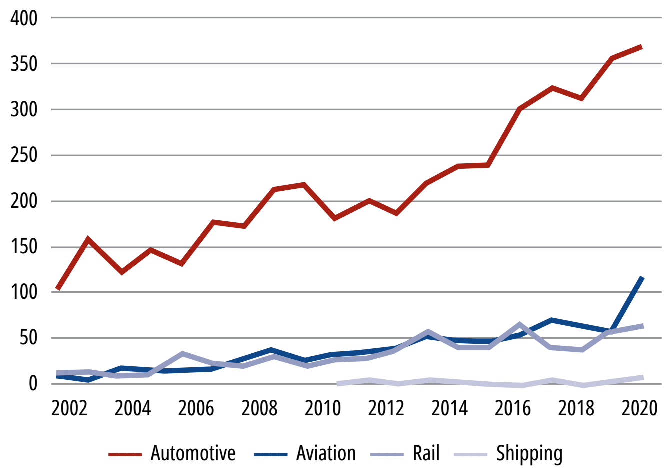
It is important to stay abreast of innovations being produced by market competitors. Even a company that has obtained patents on its own technology could be using practices or products that infringe upon other patents owned by

U.S. Patent Filings Related To Green And Blue Hydrogen Vs. Hydrocarbon-Based Generation
(Figure 1)



Source: Techson IP Research

International Patent Families By Application
(Figure 2)



Source: EPO; IEA

others. This is especially true where, as with hydrogen, the market is rapidly expanding and cutting across multiple industrial sectors.

Companies and other players entering the hydrogen market for the first time or introducing a new product or service should consider whether they should perform a freedom-to-operate study. A freedom-to-operate study provides a more comprehensive look at the patent landscape surrounding products and services that may not be captured in a prior art or patentability search. Specifically, this study looks for any patent rights that may be infringed by the intended use of products or services.

Freedom-to-operate may depend on broad, foundational patents that may not invalidate a patent, but that would necessarily be infringed in a company's process of practicing its own patent. For example, a company may have a patent on a new electrolysis catalyst, but that catalyst must be used in a reactor with particular material separating the cathode and anode. If another company owned a patent on that separator, then use of the novel catalyst may require a license to the patent on the separator.

In the hydrogen space, freedom-to-operate also may depend on use of patents covering technology that is tangential to a company's patents or products. For example, a novel fuel cell for use in automobiles will almost certainly require the use of transportation and storage infrastructure before it could be commercially viable. Automobiles would need a steady supply of hydrogen accessible along all roads across the country, a means of storing enough hydrogen to power the fuel cell onboard the automobile itself and a means of loading the hydrogen into the automobile. These interrelated areas are likely to have patents that may be infringed in the use of even a truly novel fuel cell technology.

After studying the other patents implicated by their own patents and products, companies must decide how to approach licensing those other patents and how they might handle licensing their own patents to others. Freely taking and granting reasonable licenses may promote the overall growth of the industry. On the other hand, being more selective in granting and taking licenses may lead to greater profits for the company.

Even companies that are not providing the relevant technology but instead are sourcing it from others must keep these issues in mind, since the threat of patent infringement could still be an obstacle to the success of their operations and investments. In partnering with others or investing in hydrogen-related technologies, companies should thoroughly investigate whether their partners have the intellectual property rights needed to provide the technology they are offering without freedom-to-operate concerns.

Licensing programs

There does not currently appear to be any hydrogen market standards for licensing. However, using hydrogen as a reliable automobile fuel source may require substantial standardization of the industry. Cars would need reliable, standard connections and methods of obtaining hydrogen anywhere across the country. Thus, it may be advantageous for the industry to adopt licensing systems similar to what is seen in other industries to promote the stability of the industry as a whole.

One option widely used for standardized technologies in the telecom industry has been the guarantee of a fair, reasonable and non-discriminatory (FRAND) license to any patent deemed a "standards essential" patent. Thus, an automobile maker would be able to obtain FRAND licenses to use particular storage systems and hydrogen delivery systems that were deemed the "standard" for the industry. Another common option is the possibility of a patent pool. In a patent pool, many leading companies may reach an agreement to cross-license their patent portfolios to one another. In this manner, the companies that reach an agreement are able to use each other's patents freely, while still maintaining their right to exclude those who are not willing to share their own technology.

Neither of these options, nor any other standard licensing program, has been implemented to date in the hydrogen industry. But given the possibility of these, or something similar, being adopted in the future, it is important to keep them in mind when making business decisions around licensing and patent protection. Companies should be diligent both in protecting their own innovations and monitoring the broader patent landscape in the hydrogen space to best position themselves to benefit from (and potentially influence the creation of) these types of programs as they emerge in the hydrogen industry.

The increase in patent filings signals that there will be more innovation, making it essential for those developing new hydrogen technologies to keep a close eye on an ever-changing market and ensure their innovations are fully protected. OGI

EMISSIONS MANAGEMENT: THE NEW 'E' FOR E&P

Market Watchers

IAN NIEBOER
ENVERUS

Ian Nieboer is managing director and head of energy transition research at Enverus.

Emissions management is emerging as a new 'Big E' for E&P. Profitability, historically dominated by the ability to find and exploit new resources, is beginning to be influenced by emissions management strategies and the capacity to capture low-carbon investment opportunities. And the shift is accelerating.

Profitability is impacted on three fronts: directly through changes to core operations; indirectly through the administrative burden of navigating a more emissions-aware world; and through the social license to operate as an E&P business.

Most obvious are the direct costs that impact profitability. Carbon taxes, acquiring carbon credits to meet net-zero commitments and the planned methane tax introduced in President Joe Biden's Inflation Reduction Act (IRA) all add direct costs associated with voluntary and mandatory moves to reduce emissions.

Less obvious are the operational changes imposed by greater public scrutiny. Satellites have made flaring, once an acceptable externality of oil extraction, an easily observable black eye. Operators have responded with strategies ranging from reinjection, to gathering and marketing associated gas, to reduced flaring during flowback and workover operations. As a result, flared volumes fell by more than 50% from 2019 to 2021. Based on satellite-derived data, emissions last year are estimated to have fallen an additional 30% to 14.8 mt CO_2e.

The allure of direct profits from new business models like carbon capture and storage are also changing the nature of the modern E&P. Why not build a business around reducing emissions? Four hundred and twenty-five metric tons (mt) of North American sequestration projects have already been proposed, a 170-fold increase in current operating capacity in North America. When combined with the incentives from the IRA, IRRs for the best projects exceed 100%, according to our calculations.

Renewable natural gas (RNG) projects also made headlines with majors such as BP Plc and Shell Plc respectively acquiring Archaea Energy and Nature Energy for a combined $6.1 billion. Typically designed to capture methane emissions from agriculture and landfills, project IRRs can exceed 100% if you can construct the right combination of source and market to capture the credits that can drive over 95% of project revenues.

An emissions-aware world also imposes an administrative burden on organizations. New departments dedicated to collecting, managing and reporting emissions performance are now the norm. Critical to initiatives driving direct profitability, these teams are also necessary to meeting rising regulatory requirements and addressing public scrutiny.

Looming on the horizon are proposed rules from the Securities and Exchange Commission for emissions reporting. This raises the stakes for reporting entities—not only would emissions performance (Scope 1, 2 and potentially 3) be required alongside financial results, but climate-related risks and plans for progress could also be required. These proposals imply reporting both the primary production product of the business, hydrocarbons for an E&P and the production of the associated emissions with similar emphasis.

The direct imposition of costs, the policy incentives to support new business models and the regulatory requirements that ratchet up disclosure and scrutiny are a consequence of stakeholder discontent and changing terms of the industry's social license to operate.

Industry has responded. Seventy-three percent of the 56 operators we run through our detailed ESG algorithm now have greenhouse-gas reduction targets, a 20% increase from a year prior. The impact on emissions has been significant. Industry's emissions reduction of 28% between 2019 and 2021 fell by 28%, or 34 mt CO_2e, which is equivalent to swapping 7.7 million gasoline-powered vehicles to electric vehicles. This is nearly three times the amount of electric vehicles currently on the road in the country.

What has been created is an ecosystem of scrutiny, accountability and opportunity around emissions management. Scrutiny driven by interest from external (financial and non-financial) stakeholders and supported by required reporting and data availability. Accountability enabled by imposed costs (like methane taxes) and independent verification tools like satellite observation. Opportunities created by large financial incentives and new business models designed to profit from an emissions-aware world.

In this ecosystem, hydrocarbon production will remain a cornerstone of most operators, but emissions management is set to take a bigger role in determining the profitability and success of the business. The energy company of the future must be as much a manager of emissions as a producer of energy. OGI

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TUDOR, PICKERING, HOLT'S 2023 M&A PLAYBOOK

From the bruising to the guileful to artful misdirection, Tudor, Pickering Holt & Co. talks about how M&A could unfold for the rest of the quarter and the year ahead—via football-heavy analogies.

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The confluence of Super Bowl LVII, M&A and the NAPE Energy Summit in Houston proved too enticing an (extended) metaphor for Chad Michael, president of Tudor, Pickering, Holt & Co. (TPH) to pass up.

If most of 2022's dealmaking seemed like a year-long series of fumbles—or, only slightly less awful, the equivalent of the New York Jets third-down conversions attempts—Michael brought his own statistical highlight reel. His point: Not everything about 2022 was quite as brutal as it first appeared.

Yes, "it was a difficult backdrop," Michael said. "More broadly, geopolitical pressures, inflation, a Fed that appears to be very steadfast at driving the economy to a slower position" made the year, for all sectors, one long and annoying spin move.

But Michael said that after observing a year of M&A, a certain playbook emerged for 2022—and a rather straightforward one at that. And, yes, 2023 seems to have its own set of offensive and defensive rules, with some more likely than others to get called. Look for long bombs, fake punts and lines of scrimmage most may not have considered.

First the backdrop Michael mentioned: In the U.S., all sector M&A volumes were down, capital markets dried up and in the U.S. market, M&A wobbled its way in 2022 to $1.2 trillion, down 40% from the $2 trillion counted in 2021.

"By any account, Wall Street dealmaking was just a bit slower," Michael said.

Yet while 2022 upstream M&A on its own wasn't great, it certainly wasn't Dave Shula-bad.

Energy, though, was a top performer in deals despite an iffy 2022. Energy M&A volumes relative to U.S. volumes accounted for about 10% of the market, despite the energy sector's weighting to the S&P 500—just 5% of the market.

"From an M&A standpoint, energy's punching above its weight with respect to just M&A activity," Michael said.

Dig a level deeper and upstream constitutes about half of that volume.

"If you think about how the volumes of upstream M&A compared today to yesterday, we had a $55 billion M&A market in the U.S. and upstream this year. Last year we had $65 billion," he said. That's down about 13% from upstream's typical haul of $70 billion, he said.

"So it was a slower M&A year, but it wasn't the kind of year that the broader markets of … Wall Street experienced," Michael continued. "So there was still plenty to do in upstream M&A, is the point. So let's talk about what the upstream M&A playbook was in 2022."

Watching the tape: the 2022 M&A playbook

Get ready for some football analogies. The bread-and-butter M&A play for 2022, Michael said, was what he called the "power run up the middle," otherwise known as the bolt-on.

Michael said for many companies the play was easy to execute, a low risk to call and needed four "key blocks" to find success.

"The first key block would've been an invasive transaction, a bolt-on, so to speak," he said.

Next, the buyer—usually a public company—buying an asset at a far lower multiple than the public. The deal had to be accretive to financial metrics, particularly cash flow and free cash flow.

The average acquirers' multiple at the time of a deal announcement was 4.4x, according to TPH. The average transaction multiple? 2.6x. And the average relative performance for the buyers versus the market one day after a transaction? 2.5x. In other words, arbitrage was everywhere.

Such deals included Devon Energy Corp.'s purchase of Validus Energy or Marathon Oil Corp.'s purchase of Ensign Natural Resources.

Finally, the "play" needed to add inventory and, more than likely, the buyer was going to slow down the "pace of drilling activity to ensure that there could be accretion to free cash flow."

Michael said that if those four elements came together, "you would end up with a share price that outperformed on a regular basis."

"And, in fact a lot of touchdowns, so to speak … were scored as a result of this play," he said.

M&A saw other 2022 "plays," Michael said. He termed one the "fair catch"—typically a combination of two companies.

"Fair catches maybe don't seem very exciting," he said. However, they're often the smart move. Fair catches, in Michael's vernacular, included mergers that were generally the same size, the same location and created new companies.

Such deals include the formation of Chord Energy Corp. from the combo of Williston Basin players Oasis Petroleum Inc. and Whiting Petroleum Corp., and the creation of Permian Resources Corp. from the merger of Centennial Resource Development and Colgate Energy.

Next, 2022 saw a number of what Michael called "counter plays," here referring to passive or non-op, which he said have grown dramatically in terms of value and sophistication, he said.

"It's been really exciting to see many members of this room start to institutionalize that. For the first time since we can remember, that part of the market … is well over 10% of the market now and, in fact, [it] depends how you define it," he said, adding that such companies' share could have been as much as 15% of the 2022 market.

Offense in 2023 will be a mix of the familiar and unfamiliar.

M&A playbook 2023: enter the SMIDs

Some plays just work, and 2023 looks likely to stick with the "power run up the middle" for E&Ps. In 2023, they may require more work as companies will now face more consolidated basins.

"But every chance that play has to be run, we think it will be run and be run successfully," he said. "The middle play is getting right at the heart of 'let's get bigger, let's add more inventory [and] let's improve the company. So you're going to see more of that."

But Michael sees a new tactic potentially emerging in 2023: the "run-pass option."

"It took NFL football until about four or five years ago to see that options were really valuable," he said. "So what do we mean by the run pass option play? We think the SMID [small and mid]-cap universe … has more options than it had in the past."

The SMID-cap universe, as Michael defined it, comprises companies with market values ranging between $1 billion and $10 billion.

TPH sees such companies now mimicking the capital discipline and balance strength that's been the hallmark of their large-cap peers. And it's a sector of the upstream market that's been growing. In the depths of the pandemic, SMIDs were worth an aggregate of about $10 billion. In 2022, SMIDs grew to as much as $100 billion in value before, more recently, settling in at about $75 billion, TPH said.

"Now, for context, that is a mirror image from a market cap standpoint to EOG [Resources]," Michael said. "You've got an EOG out there ... embedded in around 20 companies."

Consolidation among SMIDs isn't as simple as a linebacker blitz. But the potential is there.

"A lot of alignment has to come together for that to occur," he said. "These transactions are quite difficult to pull off."

The apparent value, beyond potential upside, longer laterals and typical M&A synergies, is in overhead costs. Returning to the example of EOG, Michael noted that the G&A of that large-cap is about $500 million. For the 19 or 20 companies populating the SMID-verse, G&A totals about $1.6 billion.

"This group of companies we think are very efficiently run," he said. There's just a lot of them.

But it is possible "there's maybe some kind of G&A prize there to be had."

SMID-caps have also dramatically improved alongside their larger-peer rivals. SMIDs have gone from outspending like most of the rest of the sector to handling their money as tightfisted as large-caps. SMIDs spend roughly 40% to 50% of their cash flow.

In some cases, the return on their equities has gone even higher than larger publics, Michael said. And many SMIDS have seen their balance sheets' solvency improve, while their leverage has dropped to well below 1.0x.

TPH noted that 2023 year-to-date, reinvestment rate capex for the median large-cap is 43% compared to 54% for SMID-caps. Likewise, year to date return on equity in 2023 is 28% for large-caps and 31% for SMID-caps.

"We actually think that these SMIDs do have a lot of options," he said. We expected them to be more active in the M&A marketplace. They're more than capable of buying, potentially with cash or stock."

"From an M&A standpoint, energy's punching above its weight with respect to just M&A activity."

—**Chad Michael,** ***Tudor, Pickering, Holt & Co.***

Surprise and trick plays

Every game has its surprises, Michael said. After 2022's false starts and occasional offsides, Michael predicts there's bound to be some unexpected trickery.

For one: the onside kick. The theory TPH has been toying with is that the days of low-premium public-to-public company transactions may be going away.

"Public company M&A, there's always a premium," he said. While the pandemic had lacerating effects on public company valuations that may have bled away premiums, in the upstream space the traditional markup has ranged between 20% and 40%.

"We just think that the return of the public to public premium is around the corner," he said. "And so we won't be surprised if we see a return back to some public company premiums."

He noted that among the broader S&P 500 M&A market, premium come downs have compressed but not as much as those seen by upstream E&Ps.

"We also think that fundamentals can justify it because we think there's some trading dislocation out there right now where premium can be justified," he said.

Michael also said it's possible that there may be an E&P that is willing to take on leverage—"the long bomb"—to increase its inventory. But in an era of capital discipline, it remains to be seen if a company would be willing to face the market. "I wouldn't say it's likely to happen," he said.

Finally, Michael also believes a "fake punt" is at work, and private equity is ready to catch everyone off guard.

"We think the idea that private equity going away was the fake punt," he said. "Private equity has slowed down. Private equity has stopped raising as much money as it had raised."

But there are indications that while private equity won't return to the glory days of 2015 or 2017, TPH does expect a much more liquid private equity space this year with, as TPH measures it, roughly $15 billion being raised now.

"We think that's really important for the industry," he said. "We think the industry is going to [need] more private equity capital. We think there's room to take a bit more risk. Private equity can help with that risk management." OGI

PRIVATE EQUITY EXECS EXPECT ACTIVE YEAR FOR A&D

Executives in the private equity space expect this year to be an active one for A&D and M&A activities.

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> ***"The U.S. E&P sector is expected to maintain the disciplined approach it demonstrated in 2022, with limited capital reinvestment, modest supply growth and elevated returns."***
>
> **—Henry Makansi, *Kimmeridge***

In 2023, the M&A story looks to remain the same: Public companies need inventory, which could augur a busy year for dealmaking, private equity firms said Jan. 19 in Houston at an Independent Petroleum Association of America (IPAA) event.

Executives at Opportune, Kimmeridge and other private equity firms said 2023 could be active, although it remains unclear how fluctuations in commodity prices will drive deal dynamics and how public companies will afford acquisitions.

"We anticipate 2023 to be an active year for A&D, though publics' ability to pay up for inventory is still limited," Kimmeridge managing partner Henry Makansi told the attendees at IPAA's Private Capital Conference in Houston. He said a "reload cycle for new inventory will eventually come, with publics having to pay up for drillable locations."

The A&D market remained strong in 2022, Daniel Kohl, Opportune co-head and managing director, said during the conference, noting that "private equity played a critical role and will continue to play a critical role."

In recent years, oil and gas companies from independents to integrated majors have demonstrated capital discipline and increased share buybacks and dividend distributions amid the COVID-19 pandemic and the Russia-Ukraine war that started in February. 2022.

Kimmeridge doesn't expect companies' plans to deviate much from their 2022 plans.

"The U.S. E&P sector is expected to maintain the disciplined approach it demonstrated in 2022, with limited capital reinvestment, modest supply growth and elevated returns," Makansi said. "Despite a likely economic deceleration and weakened demand, oil prices are likely to stay above $70/bbl."

In the Permian Basin, the discipline amongst public E&Ps has impacted production. Growth among private operators, which represent 25% of U.S. supply, now appears to be decelerating, while the majors, who represent just 13% of supply, appear to be ramping up growth, Makansi said.

From a valuation perspective, Nuveen portfolio manager Don Dimitrievich expects to see some correlation this year between increased costs and higher commodity prices and expects a declining shale inventory will likely support increased A&D activity.

Multiples to drive M&A activities

While the upstream sector saw a lull in deals in December due to a decline in commodity prices, public E&Ps will pursue efforts to replenish inventory, analysts said.

The energy sector remains attractive on a price-to-earnings multiple basis as well as in comparison to pre-COVID valuations relative to virtually every other sector, according to Dimitrievich. "Energy is still trading at a 49% discount to pre-COVID valuations while the broader S&P is trading at just a 6% discount," he added.

Despite being the best performing sector the past two years, energy stocks are still cheap versus the broader market, Makansi said, while valuations for small-cap E&P stocks remain further dislocated relative to the rest of the sector.

"The significant disparity in multiples between large caps and SMID [small and mid] caps in upstream will continue to drive M&A activity with large caps buying SMID caps due to a limited inventory and wide multiple spread," Makansi said, "Multiples are expected to remain compressed but expand from 2022." OGI

OFS EARNINGS DRIVEN BY EVERYTHING, EVERYWHERE, ALL AT ONCE

International growth, along with offshore and strength in North America, propelled fourth quarter and 2022 earnings for oilfield service companies SLB, Baker Hughes and Halliburton.

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Tight global oil and gas supply will continue to bolster strong across-the-board performance of major oilfield service and equipment providers in 2023, the companies' top executives said during January earnings calls.

International operations are expected to thrive as countries reinvest in fossil fuel production to replace imports from Russia. Offshore, in particular, which accounts for a large share of international activity, will drive much of that growth.

"There is a greater sense of urgency around energy security," Olivier Le Peuch, SLB's CEO, told analysts on Jan. 20. "This is resulting in new investment in capacity expansion and diversity of supply. You will see this reflected in the number of new projects sanctioned, gas supply agreements signed and the return of offshore exploration, all at a pace unforeseen just 18 months ago."

The heads of Baker Hughes, Halliburton and SLB all discussed plans to return high levels of their free cash flow (FCF) to shareholders during the calls.

Bright international scenarios

The companies' bet on international growth is supported by the U.S. Energy Information Administration (EIA). OECD production is forecast to grow about 8% from 32.3 MMbbl/d in 2022 to 34.9 MMbbl/d in 2024. Non-OECD production is expected to be flat, and total world production is expected to rise about 2.9%.

SLB's international revenues accounted for $6.19 billion, or 79%, of its fourth-quarter total of $7.88 billion. That constituted a 5% sequential and 26% year-over-year (yoy) increase. Full-year international revenues totaled $21.9 billion, or 20% higher than 2021. Adjusted EBITDA came to $5.43 billion, or a 24.8% margin, compared to 24.3% in 2021.

To analysts, the numbers were encouraging.

"While some might take the small increase as a negative, we actually believe it's a positive," Piper Sandler senior research analyst Luke Lemoine wrote. "It shows international margins still have a considerable amount of room to expand as the more profitable areas of the Middle East and offshore are just inflecting and should drive a meaningful increase in margins over the next few years."

For Matt Murphy of TPH Energy Research, international potential overcame other reservations about SLB.

"Despite trimmed near-term FCF and shareholder returns projections, we continue to like the story as a play on the constructive international growth backdrop," he wrote.

Analysts liked the approach taken by the other major oilfield service companies as well.

"Halliburton's vision of the future of the oil

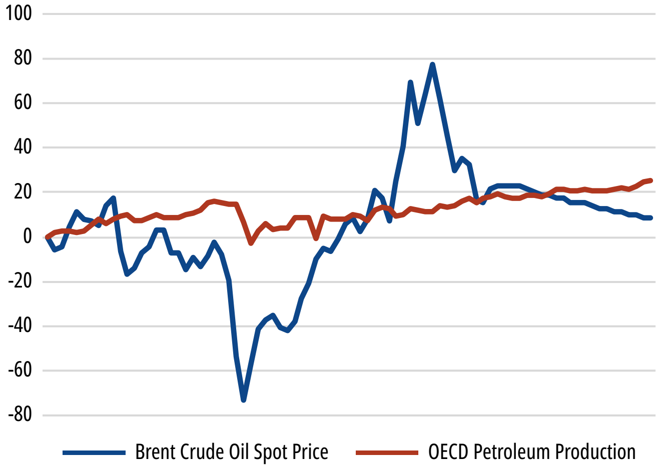
Shutterstock/ Oil and Gas Photographer

"Halliburton's vision of the future of the oil field aligns with our own—an industry that is lower cost/ higher margin, less capital intense, more internationally focused and digital—with an enhanced return profile."

—**James West, *Evercore ISI***

International Oil Price Vs. Production

Percentage changes Brent price and OECD production since January 2018



Source: EIA

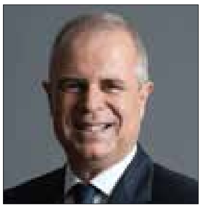
field aligns with our own—an industry that is lower cost/ higher margin, less capital intense, more internationally focused and digital—with an enhanced return profile," wrote James West, senior managing director at Evercore ISI. "The industry is in the beginning of a global upcycle for E&P spending, especially internationally and offshore, which coupled with limited oil service capacity, will drive significant top line and earnings growth as it unfolds."

The strengthened international positioning, West wrote, "will continue to drive significant earnings upside in this multiyear upcycle and as NOCs [national oil companies] rebuild production capacity globally."

International business accounted for 52.7% of Halliburton's full-year revenues of $20.3 billion. International revenue for the year increased 20% to $10.7 billion.

Noting that Halliburton expected its North American spending to rise 15% in 2023, Lemoine said "international is expected to be up 15%+ as well, and it wouldn't shock us to see this be up ~20% year-over-year, driven by the Middle East and Latin America. Roughly one-third of the broader international market is resetting every year, and the market could be in a position where it grows 15%+ for the next few years."

Baker Hughes reported a 4.7% increase in yoy international revenue for the fourth quarter to $2.55



"For 2023, we are targeting to return a total of $2 billion to our shareholders in the form of dividends and buybacks."

—**Stephane Biguet**, ***SLB***

billion. The company is primed for growth to continue.

"For the full year 2023, we expect another strong year of market growth internationally, spread across virtually all geographic regions, led by the Middle East, Latin America and West Africa," Baker Hughes CFO Nancy Buese told analysts. "Overall, we expect international D&C [drilling and completions] spending to likely increase in the middle double digits on a year-over-year basis."

Free cash flow to shareholders

Halliburton reported FCF of $856 million in the fourth quarter and $1.43 billion for the year, up 4.5% over full-year 2021. The company announced it would seek to return at least 50% of FCF to shareholders.

"There's nothing magic in the 50%, per se," Halliburton CFO Eric Carre told analysts. "We think that it's a number that gives some level of certainty in terms of what we're going to return to shareholders while giving us a lot of optionality to continue to invest in our business, to continue to make bolt-on acquisitions or to make acquisitions that are complementary to our product line business. And also give us optionality over the next few years to continue to work on strengthening our balance sheet."

Baker Hughes reported FCF in the quarter of $657 million, up 57.6% from the previous quarter. The company also aims to return 60% to 80% to shareholders. Baker Hughes returned $1.6 billion to shareholders in 2022.

"Based on the EBITDA guidance midpoint of $3.7 billion and the … FCF conversion, FCF should hover around $1.5 billion to $1.7 billion," Lemoine wrote. "Based on the current dividend rate along with the midpoints of FCF and FCF returns, there could be a few to several hundred million of share repurchases; however, dividend growth will be prioritized, and share repurchases will be used to fill in."

SLB expects to distribute more than 50% of its FCF to shareholders. A 43% increase in the quarterly cash dividend brought it to $0.25 per share.

"For 2023, we are targeting to return a total of $2 billion to our shareholders in the form of dividends and buybacks," said Stephane Biguet, executive vice president and CFO.

Lemoine said he expected 2023 dividend payments to be in the neighborhood of $1.3 billion, leaving about $700 million for buybacks. SLB said it intends to repurchase at least $200 million in the first quarter.

M&A CRITICAL PATH TO E&P VALUE CREATION

Market Watchers

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Investors are increasing their attention toward E&P companies' well performance and the longevity of shale inventory as public companies enter 2023 with tailwinds of dramatic broader market outperformance in the year prior amid weakening commodity pricing.

In 2022, the public E&P sector outperformed the S&P 500 by 69% and yet, it continues to maintain superior free cash profiles of roughly 7% at strip versus 5.1% for the S&P, underscoring the dramatic transformation driven by massive deleveraging, cost cutting and consolidation since the COVID-driven lows of early 2020.

Thematically, focus has shifted from ESG/climate concerns and historically poor returns of/on capital to the sustainability of free cash payouts in a world where service costs continue to creep, supply chain issues constrain timing, many companies maintain low hedging balances and questions around inventory arise. To further positive investor sentiment, E&P companies will undoubtedly begin differentiating themselves via reserve and resource quality and longevity, and shifts seen in year-to-year well performance, particularly as these performance changes make their way to the Permian Basin.

Most shale names remain in a band of 0% to 5% production growth, with healthy balance sheets and 7% free cash flow (FCF) yields at strip. Within our research coverage, FCF declines 35% in 2023 at strip pricing, implying that payout yields would be approximately 4% in 2023 versus 9% in 2022, placing more importance than ever on macro-outlooks.

Natural gas has had to contend with a seasonally warm winter, LNG outages and historically high production levels while the oil markets assess the global demand impact of recessionary pressures along with OPEC production cuts.

The public investable universe is still quite healthy at sub-0.5x leverage and still projected to underspend cash flows by 40% in 2023. But in terms of commodity price weakness, there is a limited relief mechanism that now exists on the supply side as former activity declines would have pivoted from growth to maintenance levels, and operators are less likely to pivot from current maintenance levels to sub-maintenance levels. As a result, demand clarity becomes chiefly important and field level execution becomes a differentiator in our view.

For reference, public operators exhibited a 6% degradation in first six months oil recoveries in the Midland Basin and a 5% decline in the Delaware Basin. This follows relatively flattish recovery since 2018. However, lateral lengths continue to increase, offsetting some of the recovery performance. With Midland average lateral lengths at 11,200 feet versus 10,000 feet in 2020 and 9,500 feet in the Delaware versus 8,500 feet in 2020, one wonders if this progression can be sustained. Major tone-setters such as Pioneer Natural Resources Co. and Chevron Corp. have both discussed development methodology changes, higher return thresholds, larger projects and increased codevelopment.

This situation may yet be another trigger for M&A activity, which dropped precipitously in 2022 by roughly 24% based on deals announced and 13% based on dollars spent. However, of the 54 deals consummated in 2022 above $100 million, roughly 80% came with significant production versus inventory, highlighting the importance of free cash accretion.

In a lower commodity environment, creativity in dealmaking will be key as operators look to attractively add Tier 1 inventory to public models along with operational tweaks and a focus on managing base declines that perhaps were not highly valued previously. For now, the market appears to be largely in a holding pattern until dealmaking or commodity views heat up. At the same time, our small/mid-cap coverage trades at a 2.0x-plus turn discount to our large-cap names on estimated 2023 EBITDAX valuation multiples and has lagged in stock performance by 26% since the beginning of 2022.

Fourth-quarter 2022 results and capex guides for 2023 will be closely watched as operators navigate inventory life management and challenged performance while fighting costs and lower pricing.

Ultimately, the setup appears to be a perfect storm to catalyze deal activity. We expect that M&A will be a critical path to creating further value, as new shale play exploration is limited and investors clamor for greater visibility around cash flow as public management teams focus on relative return capital versus the S&P 500 versus merely outperforming their peers in years' past. OGI

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EQUITY

Company	Exchange/ Symbol	Headquarters	Amount ($MM)	Comments
Gradient	N/A	San Francisco, Calif.	$18	Closed Series A funding round to finance: design and development of window heat pump unit product; accelerate decarbonization with a focus on solutions for multifamily homes; add hardware monitoring, maintenance, leasing and demand response services; and adding headcount to key roles. Funding led by **Sustainable Future Ventures** and **Ajax Strategies,** with **Safar Partners, Climate Tech Circle, Shared Future Fund, At One, Impact Science** and other contributors also participating.
TXO Energy Partners LP	NYSE: TXO	Fort Worth, Texas	$15	Granted underwriters of its IPO the option to purchase up to 750,000 additional common units representing company limited partner interests at IPO price, less underwriting discounts and commissions. IPO underwriters exercised overallotment option and purchased the additional common units at $20 per common unit, consummated Feb. 6. Proceeds were before deducting underwriting discounts and commissions. Joint book-running managers for the offering were **Raymond James, Stifel, Janney Montgomery Scott** and **Capital One Securities**. IPO was announced Jan. 30 and stock traded at approximately $22 per unit as of 11 a.m. CST that morning.
TotalEnergies SE	NYSE: TTE	Paris	N/A	Proposed 6.4% increase in fiscal year 2022 ordinary dividend from 2.64 euro per share to 2.81 euro per share. Additionally increased three ordinary interim dividends 7.25% from 0.69 euro per share to 0.74 euro per share, as well as a confirmed 1 euro per share special dividend, allowing shareholders to receive a combined 3.81 euro per share dividend for fiscal year 2022 subject to approval at shareholders' meeting.
EQT Corp.	NYSE: EQT	Pittsburgh	N/A	Declared first-quarter 2023 cash dividend of $0.15 per share to shareholders on record by close of business Feb. 21, 2023, payable March 1.
Northern Oil and Gas Inc.	NYSE: NOG	Minneapolis	N/A	Declared cash dividend on company's common stock of $0.34 per share, a 13% increase from the prior quarter. Dividend is payable to stockholders on record as of business close on March 30, on April 28. Management recommends a further 9% increase to $0.37 per share for the second quarter of 2023.
Williams Cos.	NYSE: WMB	Tulsa, Okla.	N/A	Approved regular dividend of $0.4475 per share ($1.79 annualized) on company's common stock. Dividend increased 5.3% from fourth-quarter 2022 dividend of $0.425 per share and is payable on March 27 to shareholders on record as of business close March 13.

Scan to see the New Financings database.

DEBT

Company	Exchange/ Symbol	Headquarters	Amount ($MM)	Comments
Eni SpA	NYSE: E	Rome	€2,000	Launched its first sustainability-linked bond dedicated to the Italian market. The five-year bond has an initial coupon of 4.3%, which could rise if certain sustainability targets are not met. The bond will be issued on Feb. 10 at a price equal to 100% of the nominal value. More than 300,000 investors submitted orders for over €10 billion compared to the €1 billion initially offered. The annual coupon will remain unchanged until maturity on Feb. 10, 2028, and "subject to achievement of the sustainability targets relating to the renewable energy installed capacity and the net carbon footprint upstream [Scope 1 and 2]," Eni said.
Waste Management Inc.	NYSE: WM	Houston	$1,250	Priced aggregate principal amount of senior notes: $750 million for 4.625% senior notes due Feb. 15, 2030, and $500 million for 4.625% senior notes due Feb. 15, 2033. Net proceeds will go toward repaying borrowings under commercial paper program used for working capital supported by the company's $3.5 billion revolving credit facility, repaying $500 million aggregate principal amount of outstanding 2.4% senior notes in May 2023 when they're due and for general corporate purposes. Joint book-running managers for the offering are **J.P. Morgan Securities LLC, Mizuho Securities USA LLC, SMBC Nikko Securities America Inc., Wells Fargo Securities LLC, Barclays Capital Inc., BofA Securities Inc., Deutsche Bank Securities Inc., RBC Capital Markets LLC** and **Scotia Capital USA Inc**.
Brazos Delaware II LLC	N/A	Fort Worth, Texas	$800	Completed issuance of new senior secured Term Loan B due February 2030. Net proceeds plus excess balance sheet cash will be used to pay existing $830 million Term Loan B due May 2025. Also increased currently undrawn super-priority revolving credit facility from $90 million to $150 million, extending maturity date to 2028. **Jefferies Finance LLC, Bank of Oklahoma Securities** and **Cadence Bank** jointly underwrote and arranged book-running, with **Barclays** leading the group. Subsidiary of Brazos Midstream.
Civitas Resources Inc.	NYSE: CIVI	Denver	$300	Agreed to repurchase approximately 4.9 million common stock shares from **Canada Pension Plan Investment Board (CPP)**, the company's largest shareholder, par value $0.01 per share priced at $61 per share. Had approximately 85.1 million common stock shares outstanding prior to the repurchase as of Dec. 31, 2022, and will have 80.2 million shares outstanding following the repurchase. CPP will remain the largest shareholder with 21% of the common stock following the repurchase.
Martin Midstream Partners LP	NASDAQ: MMLP	Kilgore, Texas	N/A	Announced expiration and results of cash tender offers to purchase any and all of approximately $53.7 million outstanding principal aggregate principal amount of its 10% senior secured 1.5 lien notes due 2024, as well as any and all of approximately $291.4 million outstanding aggregate principal amount of the issuer's 11.5% senior secured second lien notes due 2025 and a portion of net proceeds from issuer's concurrent private placement of $400 million in aggregate principal amount of 11.5% senior secured second lien notes due 2028.
Phoenix Capital Group	LSE: PHNX	Denver	N/A	Expanded Regulation D bond offerings. Available to everyday investors through Regulation D and Regulation A+ bond offerings. Offerings can provide up to 12% APY in returns depending on investment level, chosen term or payment structure. Regulation A+ bond requires minimum $5,000 investment with a three-year investment term and a 9% APY, plus monthly payments of 0.75%. Regulation D bond requires minimum $100,000 investment with an investment term between nine months and seven years and an 8% to 12% APY, plus monthly payments ranging from 6% to 84%.

AROUND THE GLOBE:
LATIN AMERICA'S A&D CAPITAL: BRAZIL

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When it comes to A&D, Brazil is No. 1 in Latin America due to state-owned Petrobras' deal flow generation triggered by governmental mandates to spur competition.

In the first 11 months of 2022, the oil giant boasted $3.9 billion in cash inflows through such activities. In 2021, Petrobras closed 16 deals for a total $5.1 billion, according to financial details in its 2021 Form 20-F. Massive, to say the least.

As 2023 gets underway, Petrobras has six assets in the teaser and nonbinding phase, 15 in the binding phase and 10 signed and waiting to close, according to recent investor presentations. The bulk of assets across the three stages include refining, distribution, energy and natural gas assets, followed by E&P assets.

Deals closing this year will only add to the revenues generated in recent years and offer opportunities to companies looking to take part in Brazil's hydrocarbon sector.

The deal flow has come about as part of the Rio de Janeiro-based company's competition mantra, which has sharpened its portfolio management strategy to improve capital allocation while maximizing value.

For Petrobras, and specifically in Brazil, that value proposition is best found in its deep and ultradeep water pre-salt assets in the prolific Santos and Campos basins. There the company has held a competitive edge in terms of high productivity and lowering greenhouse-gas emissions.

This pre-salt focus has seen Petrobras shed nonstrategic upstream assets, as well as refineries, power and nitrogen fertilizer plants, and fiber optics networks. The company has even divested mining rights for potassium salts.

Brazil's new president, Luiz Inácio Lula da Silva, started his tenure on Jan. 1, 2023. The reelection of Lula, now serving his third term as president of the South American country, has cast some uncertainties about what his four-year term will bring.

Petrobras will lose some production due to its active A&D agenda, as the company brings on 18 FPSO units between 2023 and 2027 as part of a plan to boost production to almost 3.1 MMboe/d from around 2.6 MMboe/d in 2023. In 2022, Petrobras and other companies in Brazil produced close to 4 MMboe/d, according to Brazil's national petroleum agency, ANP.

Brazil's oil and gas market is not just hot, it's large as well, with major financial players spanning from U.S. and European companies such as Chevron Corp., Perenco, Repsol, Shell Plc and TotalEnergies, to national oil companies like Equinor and QatarEnergy, to numerous Brazilian entities.

The Brazilian opportunity set is unparalleled in Latin America in comparison with countries with mature oil and gas sectors, including Argentina, Mexico and Venezuela—all of which have their own set of peculiarities such as political, financial and economic headwinds, political mandates around energy sovereignty or even sanctions.

Of the three countries, Argentina holds the most potential for A&D activity amid efforts led by President Alberto Fernandez to urgently boost pipeline capacity in order to support plans to hike production from the Vaca Muerta Shale. Argentina's state-owned YPF continues to play a key part in those efforts but contends with financial limitations.

Foreign exchange restrictions, regulated prices and tariff freezes have created significant uncertainties for potential investors, which are deeply affecting oil and gas M&A activity in Argentina, according to Argentine law firm Bomchil.

"In this scenario, the trend is mainly one of international companies selling their assets in Argentina to local (or regional) companies or to international funds focused on business opportunities," the Buenos Aires-based legal entity said in a January statement.

Mexico President Andrés Manuel López Obrador favors political policies around energy sovereignty and strengthening state oil company Pemex. Investors in the country continue to be in a wait-and-see situation, hoping for better opportunities with the next president.

Finally in Venezuela, where President Nicolas Maduro's so-called socialist regime has watched Washington impose sanctions on the financial and petroleum sector, the A&D environment is all but dead. Cash-strapped state-owned PDVSA, which dominates the OPEC country's oil sector, doesn't have willing buyers to take assets even if it could divest them. Likewise, the remaining bulge-bracket players like Chevron and China National Petroleum Corp., with potential assets or stakes to divest, wouldn't find buyers willing to take such a financial gamble amid the lingering political uncertainties.

For these three reasons all roads to continued active A&D activity in Latin America point to Brazil and Petrobras, despite Lula's return and the uncertainties around his plans to turn the country around. OGI

CANADIAN GAS PRODUCERS TO BOOST UNCONVENTIONAL PRODUCTION

Canada's largest natural gas producers are expected to continue to grow their unconventional production in 2023 despite inflation pressures, energy consulting firm Wood Mackenzie says.

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Canadian oil and gas producers will boost capex in 2023, but average production growth isn't likely to exceed the single-digit percentage range, according to Wood Mackenzie.

"The largest Canadian gas producers will continue to grow unconventional production next year but will also experience the highest cost inflation pressure," the firm wrote in its December 2022 Canada upstream report.

The top three Canadian E&Ps, each with a presence in the Montney Shale, plan to boost capex and production to varying degrees. Tourmaline Oil is expected to boost capex by about 9% while production grows 40,000 boe/d, or 8%. Canadian Natural Resources Ltd. (CNRL) expects to increase capex by 18%, with resulting production growth of 6%. ARC Resources Ltd. will spend 40% more with just 2% more production, Wood Mackenzie said.

Canada's oil and natural gas industry is active in 12 of 13 provinces and territories, the Canadian Association of Petroleum Producers (CAPP) said on its website. Canada is the world's fourth-largest oil producer and sixth-largest gas producer. Canada's gas production is destined for domestic and U.S. markets and in the future will feed LNG export projects on both sides of the border between the two North American countries.

Top three gas producers

Tourmaline: Canada's largest gas producer and the country's fourth-largest gas processing midstream operator is eyeing capex of CA$1.9 billion in 2023 and production between 520,000 boe/d and 540,000 boe/d, the company said in a January corporate presentation.

"Tourmaline's scale in Canada's premium gas plays, production base and low-cost infrastructure provide investors a suite of advantages with efficiency, profitability, growth and return on (and of) capital unparalleled by peers," Tourmaline said. The company's inventory ownership provides multiple decades of development with no need to seek expensive resource additions, it said.

CNRL: Canada's second-largest gas producer and the country's largest oil producer is eying capex of CA$5.2 billion in 2023, the company said in a November press release. CNRL's long-life, low-decline assets offer sustainable production and free cash flow in a low-price environment and the ability to ramp up production with improving prices, according to the company.

CNRL is eyeing year-over-year production growth of 56,000 boe/d based on the midpoint of its guidance range of 1.33 MMboe/d to 1.374 MMboe/d for 2023, the company said.

ARC: Canada's No. 3 gas producer and the country's largest condensate producer is eyeing capex of CA$1.8 billion in 2023 with approximately 70% allocated to Alberta and 30% to British Columbia, the company announced in December in a corporate presentation. "The capital program balances profitable growth with the flexibility to increase capital returns to shareholders as net debt is reduced," ARC said.

ARC is expected to produce average production of between 345,000 boe/d and 350,000 boe/d (60% gas and 40% oil and liquids) in 2023 and includes infrastructure investment to lower operating costs at Kakwa, its largest producing asset, according to the company.

Oil-sands capex

In 2023, capex destined for sustaining oil-sands activities is also expected to rise but at a lower rate, according to Wood Mackenzie.

Whitecap Resources is forecasting production growth after its acquisition of Exxon Mobil Corp.'s Montney and Duvernay acreage. Cenovus Energy Inc. is forecasting a 130% rise in capex while also upping oil sands production 60%, according to Wood Mackenzie.

"But adjusting for recent acquisitions, no company is looking to grow production beyond single digits. The only exception are companies leading in the fast expanding Clearwater play," the firm said.

In the Clearwater heavy oil play, production exceeded 100,000 bbl/d in 2022. There, Tamarack Valley Energy looks to retain its spot as the play's top operator, while jockeying with Spur Petroleum for top status. Headwater Exploration, which bought Cenovus' position in the play, forecasts growth of 38%, with production guidance of 18,000 bbl/d in 2023, according to Wood Mackenzie. OGI

GLOBAL HIGHLIGHTS

UNITED STATES

Equinor, BP Bid to Expand Wind Project Offshore New York

Equinor and BP Plc submitted a joint bid to build a second stage of their Beacon Wind project to supply more offshore wind power to the state of New York, the companies said in a statement.

The planned 1,360-MW capacity project, some 60 miles off the eastern tip of Long Island, would be able to power about 1 million New York homes.

Equinor and BP are already developing three wind projects off New York—Empire Wind 1 and 2 and Beacon Wind 1—with a total capacity of 3,300 MW.

The projects should help the state of New York in achieving its goal of generating at least 70% of its electricity needs from renewable energy sources by 2030.

Engie Acquisition Strengthens US Solar Portfolio

Engie has added to its utility-scale solar energy and storage portfolio in the U.S., with the acquisition of all shares in two renewables companies.

Engie purchased all of the shares of Revolve Renewable AZ LLC and Revolve Parker Solar LLC on a cash and debt free basis, according to a news release.

The deal includes the 1,000 MW Bouse solar and battery storage project and the 250 MW Parker project—both in Arizona. The transaction included an upfront payment of $2 million, which was paid on the completion of the transaction, Revolve said. The upfront payment was inclusive of the reimbursement of development costs.

The deal also includes an option that allows Engie to sell the projects back to Revolve after getting results of upcoming interconnection studies for each project. If Engie decides to pursue the option, Revolve will repurchase the projects and refund Engie development expenses.

Milestone Opens Slurry Injection Field

Milestone Environmental Services opened its first slurry injection oilfield waste facility outside of Texas. The New Mexico facility, dubbed Battle Axe, is the first of its kind to be permitted in the state, the company said in a statement.

The Battle Axe facility is permitted by the New Mexico Oil Conservation Division to inject liquid oilfield waste and manage associated solid waste.

Battle Axe is the company's ninth operational facility overall and its seventh in the Permian Basin. Open 24 hours, seven days a week, the facility accepts used drilling fluids, flowback, produced saltwater, tank bottoms and other RCRA-exempt liquid E&P waste streams.

UNITED KINGDOM

Aker Solutions for *Petrojarl Knarr* FPSO Upgrade

Aker Solutions will upgrade the *Petrojarl Knarr* FPSO to be redeployed at Equinor's Rosebank field development offshore U.K.

Altera Infrastructure

Aker Solutions and Drydocks World-Dubai will upgrade the Altera Infrastructure-owned Petrojarl Knarr *FPSO for deployment on the Equinor-operated Rosebank field offshore the U.K.*

Under the engineering, procurement and construction (EPC) contract from Altera Infrastructure, which owns the FPSO, Aker Solutions will carry out the work in a joint venture with Drydocks World-Dubai, with the upgrade taking place at the yard in Dubai.

The upgrade includes a combination of work with newbuild, demolition and life extension that are required for the FPSO to be kept on the field for 25 years without drydocking.

Aker Solutions will carry out detailed design in Norway in collaboration with Citec Norway AS, ABB Norway AS and OneSubsea Processing AS. EPC work is planned to start up during the first half of 2023 and is scheduled to be completed at the end of 2025. The *Petrojarl Knarr* FPSO was transported to Aker Solutions yard at Stord in August 2022 and will be stored there until the planned tow to Dubai during the second half of 2023.

Aker Solutions expects to book an order intake of around NKr 2.5 billion related to this contract in the first quarter of 2023, pending final investment decision and regulatory approvals.

Equinor's development concept for Rosebank Field includes redeployment and reuse of the existing *Petrojarl Knarr* FPSO.

Hydrocarbons Found at North Sea's Isabella

Ithaca Energy announced the TotalEnergies-operated Isabella appraisal well in the central North Sea found 146 ft of hydrocarbons in Upper Jurassic and Triassic sandstone reservoirs.

The company acquired logging while drilling and wireline logs to establish reservoir quality for the well on the U.K. Continental Shelf. The operator was planning to plug and abandon the well and evaluate the drilling results to establish commerciality of the reservoir.

Isabella lies about 25 miles south of TotalEnergies' operated Elgin Franklin Field. TotalEnergies holds 30% interest in Isabella in Block 30/12d-12 and operates it on behalf of partners Neptune E&P UK Ltd., with 50% interest, Ithaca Energy UK Ltd., with 10%, and Energean Exploration Ltd., with 10%.

NSTA, GUH Highlight Offshore Opportunities

The North Sea Transition Authority (NSTA) said a study conducted with Global Underwater Hub (GUH) indicated a wave of opportunities are coming for the U.K. offshore energy supply chain.

Information supplied to the NSTA and GUH by operators showed that seven near-term projects will require 30 new wells and 194 km of pipeline. The core study also showed that over 5,000 vessel days and nearly 2,500 rig days will be needed for the projects. Much of the work will begin in 2023 or 2024, the NSTA said.

The NSTA and GUH also analyzed environmental statements for five additional near-term projects as part of the wider study. Those projects would require a further 17 wells, 128 km of pipeline, around 3,400 vessel days and 1,400 rig days.

Eight of the 12 projects included in the wider study are Avalon, Cambo, Captain EOR Phase II, Jackdaw, Murlach, Rosebank, Talbot and Teal West.

Perenco

Perenco's FSO PARGO is expected to be moored in April and operational in August.

BRAZIL

FSO *PARGO* Heading to Brazil

The FSO *Pargo* has left Dubai and is on its way to the Pargo Cluster in the Campos Basin offshore Brazil, Perenco announced.

The double-hull vessel was built in 2004 and has 750,000 bbl of storage capacity. DryDocks World initiated conversion work on the FSO in September 2021 to extend its service life by two decades and adapt it to meet Brazilian standards. Modifications included installation of an external turret mooring system, a helideck, a metering skid, an extra crane, a new offloading system and export line.

FSO *Pargo* is expected to be operational in August 2023 following final licensing approval. The company called it a key milestone in the $400 million Pargo development plan.

The Pargo concession, which comprises the Pargo, Carapeba and Vermelho fields, is now producing 12,000 bbl/d, an increase of almost 300% from when Perenco Brazil took over the Pargo Cluster in October 2019.
The 2023 Pargo Cluster development plan calls for the installation of two new pipelines from the Carapeba and Vermelho fields to the Pargo units; intensive well works with up to three simultaneous workover units in operation; the upgrade of the Pargo water treatment system, resuming operation of the Vermelho 1 and 2 platforms; and reservoir assessments for potential new plays. Perenco said these projects will enable the next production milestone of 15,000 bbl/d by the end of 2023.

Perenco Brazil holds a 100% stake in the Pargo concession.

TechnipFMC Wins Petrobras Subsea Services Work

TechnipFMC announced that Petrobras awarded the company a substantial master services agreement (MSA) for subsea services. The three-year contract can be extended by two years.

TechnipFMC will provide life-of-field services to support its installed base offshore Brazil.

The contract covers installation, intervention and maintenance of both equipment and tooling, as well as technical support for subsea umbilicals, risers and flowlines.

The agreement succeeds a previous MSA and supports Petrobras's increased volume of operations. Services will be supplied from TechnipFMC's base in Macaé, Brazil.

CANADA

White Rose Recoverable Reserves Updated

The Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) has updated its estimation of recoverable reserves at White Rose.

Cenovus Energy's decision to construct a wellhead platform and proceed with the White Rose Extension Project has extended the life of the White Rose Field from 2032 to 2038.

The C-NLOPB estimates proven and probable (2P) at the field is 436 MMbbl of oil, up from the 404 MMbbl estimate from 2015. The board attributes that increase to the extended life of the field.

On the other hand, 2P contingent gas and NGL estimates have both decreased from 2015 estimates.

C-NLOPB dropped the 2P contingent gas estimate for White Rose Field to 1.5 Tcf from the previous estimate of 2.7 Tcf based on a change in methodology for assessing gas resources.

C-NLOPB said a decrease in gas volume is responsible for dropping the field's 2P NGL estimate to 45 MMbbl from the 2015 estimate of 82 MMbbl. The decrease results directly from the decrease in gas volume.

RUSSIA

Wintershall: Russian Operations 'Not Tenable'

Wintershall Dea intends to fully exit Russia "in an orderly manner," complying with all applicable legal obligations.

"Wintershall Dea will end its Russian activities," Wintershall Dea CEO Mario Mehren said in a press release. "Continuing to operate in Russia is not tenable. Russia's war of aggression in Ukraine is incompatible with our values and has destroyed cooperation between Russia and Europe."

Mehren also said limitations imposed by the Russian government have "made it impossible for Wintershall Dea to operate in Russia as before and resulted in an economic expropriation of the joint ventures in Russia."

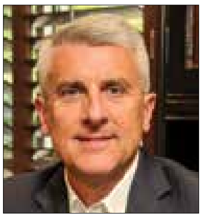
Wintershall Dea deconsolidated its Russian business from its financial reporting in fourth-quarter 2022 and expects to record a one-off non-cash loss of €5.3 billion (USD$5.8 billion) related to Wintershall Dea's Russian joint ventures, as well as impairments from Nord Stream AG and the WIGA midstream business. OGI

Voices

Fourth-quarter earnings highlight the adaptability of energy companies in response to the changing landscapes of the industry going into 2023.

"As others experience downtime, that sometimes opens up opportunities for us to, on a one-off basis, supply some [competitors'] customers in the market. It generates an opportunity for us to even increase our product sales beyond our normal levels."

—**Brad Corson**, ***chairman, president and CEO, Imperial Oil***

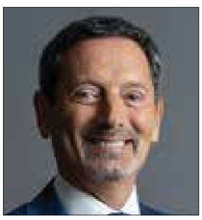


"We recognize that energy company stakeholder expectations continue to evolve and now include energy security and affordability in harmony with expectations around ESG, and Diversified remains committed to and has a track record of responsibly and sustainably producing our assets."

—**Rusty Huston Jr.**, ***CEO, Diversified Energy***

"We now believe that we will place into service approximately 32,740 to 41,000 megawatts of new renewables and storage projects from 2023 through the end of 2026. To put these numbers into context, just executing at the low end of our new development expectations through 2026 would more than double the size of our core renewables and storage operating portfolio, which took us more than 20 years to complete."

—**John Ketchum**, ***CEO, NextEra Energy***



"We laid the foundation for further growth and market expansion through pricing improvements and a solid pipeline of incremental contract awards. In the Middle East ... we expect record levels of upstream investment by NOCs [national oil companies] to continue in the next few years."

—**Olivier Le Peuch**, ***CEO, SLB***

THE OGINTERVIEW

Scale Does Matter

Earthstone Energy CEO Robert Anderson on scaling up when others hunker down

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THE OGI INTERVIEW

Watch the video interview here:

Earthstone Energy's production in the Permian Basin closed out 2022 topping its pre-COVID volume by more than 600% from a footprint some 250% larger than its 2019 holdings.

The growth stands out against a backdrop of lackluster upstream M&A dictated largely by COVID's downward yank on most business metrics. But all told, the pandemic's impact on M&A offers just one snapshot of trouble within an ecosystem of headwinds: the new norm of shareholder angst in the public markets, a general growth slowdown, Russian aggression and wildly vacillating commodity prices each contributed to a skittishness in dealmaking.

Most North American E&Ps looked over the landscape, saw the shadows and opted to keep their powder dry.

CEO Robert Anderson and his team of industry veterans—a well-oiled machine after working deals together for decades—also observed the coming storm. But they saw opportunity within their sites—several rounds' worth of opportunity—and they pulled the trigger.

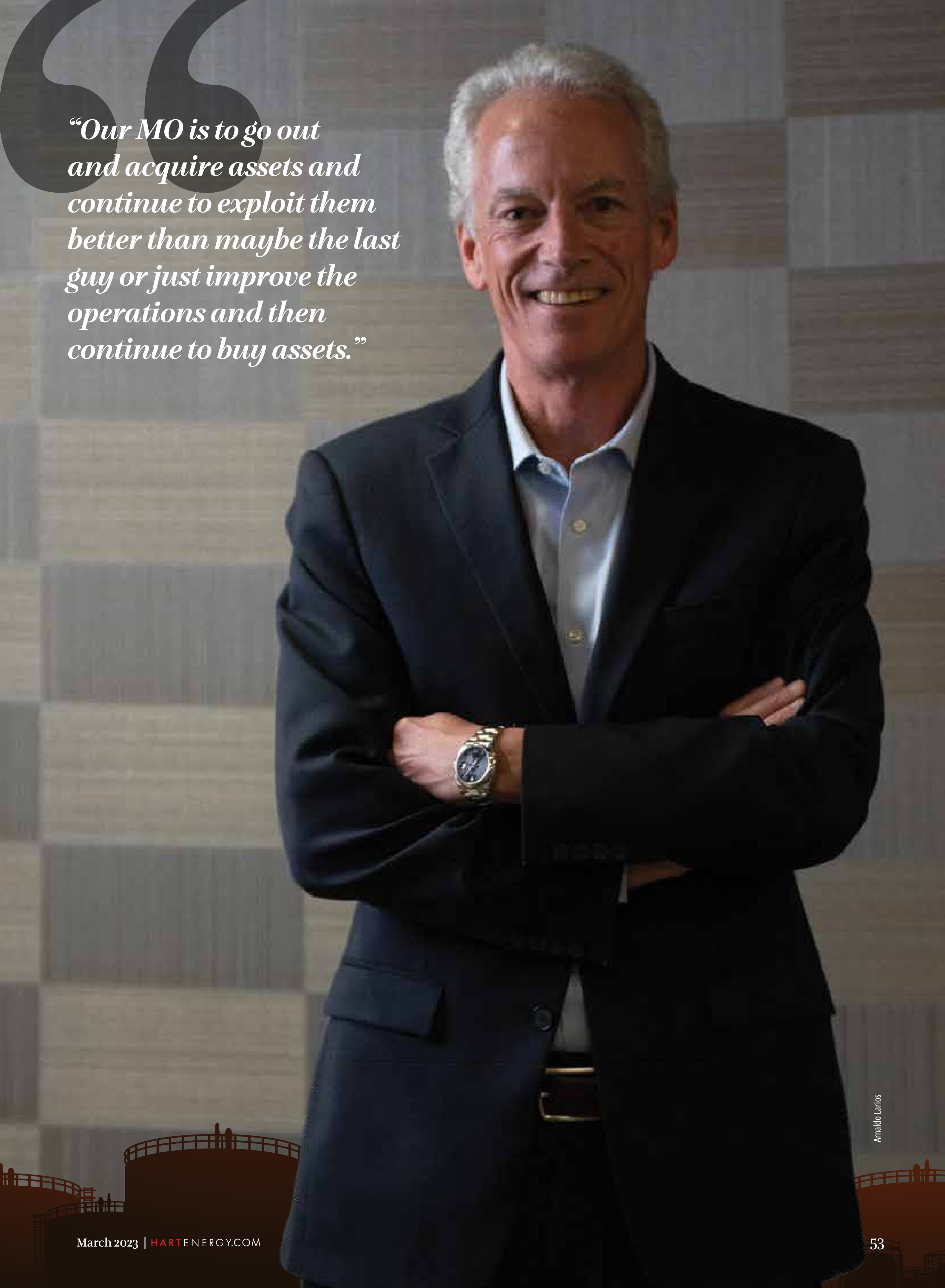
"Our MO is to go out and acquire assets and continue to exploit them better than maybe the last guy or just improve the operations and then continue to buy assets," Anderson told editor-in-chief Deon Daugherty for *The OGInterview*.

"We are not that kind of company that goes to put together a 20,000 acre land position and then drill two wells to flip it. That's not our DNA," he said. "Our expertise is to see that somebody put the land position together and now we can go exploit it better than the rest of them."

That comes down to technical excellence, driving down costs and putting in a top-notch performance quarter-after-quarter.

"You don't have to be the biggest guy in a basin to operate efficiently. Part of what makes that so interesting is everybody was saying, 'Oh, you need scale, you got to get to manufacturing mode before you can start driving down your cost.' Little Earthstone was already doing that," he said. "We're nipping on the heels of the two big large independents in the Permian Basin in terms of operating cash, costs and margins."

"Our MO is to go out and acquire assets and continue to exploit them better than maybe the last guy or just improve the operations and then continue to buy assets."



Arnaldo Larios

> *We've been around here a long time. We just get up every day, work hard and do the right thing."*

Handshake dealmaking

Earthstone management hasn't forgotten the lessons they've each learned in the field, and they recognize that in many cases, the folks working in the field know it the best.

"We're giving people in the field the ability to make decisions without a bureaucracy. We know the pumper in the field is the expert who knows what makes it tick every single day," he said. "So let's make it maximize production and minimize downtime. And if it breaks, we're going to fix it right the first time. We're not going to use a Band-Aid on it so that when we fix it, it will last a long time."

It works in part because many employees have a long history and built trust throughout the company's growth.

"It does come from our operating teams and their history of being able to make decisions between an engineer and a field guy without having to go to the boss," he said. "And then they can go out and do things pretty quickly."

Like attracts like, and many of the vendors that Earthstone works with are smaller service providers who can make decisions standing at the job site instead of in a Houston boardroom.

"We like to have companies who will grow with us just the same way we're growing," he said. "We've worked with one frac company in the Midland Basin since 2017. We don't have a contract; it's a handshake deal. They haven't gotten any bigger, but they've provided a great service for us over the last five years now, and it's worked out well for both of us."

Permian consolidation

A typical oilfield dynamic during the Permian Basin's shale gale has been the build-and-sell model by which consolidation has taken place for the sake of scale and manufacturing mode.

Once the notion that there were "too many" E&Ps in the Permian took hold—around the same time that shareholders woke up to the "capital destruction" they still hold against the industry—a wave of consolidation took out dozens of small- to mid-cap firms.

When the winds pick up again, Anderson plans to be there to make some deals.

"We want to continue consolidation," he said. "We have built a track record of being able to integrate assets quickly, efficiently and grow our business. So we've more than tripled our production and we'll use that as a kind of a guidepost. Do we want to triple again? I don't know that there's a number in there."

To be clear, Earthstone plans to be on the buying end of the deals.

"Everybody says they're for sale all the time. We're not ready to sell. I think there's some things we can do to still create value. Every public company hates where they're trading right now, but I can't control that," he said. "I can educate investors of our business and our strategy and our successes and our inventory and all those things, but

Fiscal History

Fiscal Y/E	Q3 2022	2021	2020	2019	2018	2017	2016	2015	2014
Average boe/d	94,329	24,809	15,276	13,429	9,937	2,872	1,465	1,437	882
Total Gross Acreage	~250,000	140,187	65,194	72,363	70,634	108,625	307,000	195,900	252,400

Source: U.S. Securities and Exchange Commission

Valuation History [$ Billions]

Fiscal Y/E	Feb. 10, 2023	Sept. 30, 2022	June 20, 2022	March 31, 2022	Dec. 31, 2021
Market Cap	$1.45	$1.34	$1.08	$0.928	$0.585
Enterprise Value	$2.63	$2.27	$1.71	$1.25	$0.865

Source: Yahoo Finance

it really takes them to drive that. And it's an undervalued industry at the moment."

It's true that almost any CEO in the space will lament dismal share prices, despite the spanking that E&P stocks are issuing to the broader market. And still, the generalist investors are reluctant to engage in upstream.

Why?

"We destroyed a lot of capital, as an industry, and investors are still mad about that. I think there are some who will never come back," he said. "Until the generalists see that the returns are real in this business and that the discipline is going to stay [the market will struggle]. Maybe it just takes time to heal."

The COVID effect

As the long-term pandemic's long-term implications were coming into view, Earthstone leadership didn't necessarily begin sharpening their pencils to redraw the Permian Basin. But the team had been around long enough to spot burgeoning opportunities.

"We sure didn't think that we'd go from $0 to $2.5 billion with acquisitions over two years," he said. "Did we think that we had the bandwidth and the ability to go knock them down? And that after you get the first one, people take notice and it might open up doors for the next one? Yes. And yes."

And while cash did exchange hands, many of the deals included a stock component that made investment easier and selling perhaps more palatable.

"We've had lots of sellers take Earthstone stock in almost all these deals," Anderson said. "We've used equity and the investors for the most part, have come out really well."

Is the approach something another company could replicate?

"Yes and no," Anderson said. "It's in our DNA to go out and do acquisitions and then develop the asset, like having organic growth alongside of M&A. We like to use our balance sheet or our conservative platform to be able to grow by producing assets that you can borrow against for [reserve-based lending]."

Moreover, several E&Ps were still under the pressure of heavy debt as the weight of the pandemic bore down. Their credit facilities were limited. Private equity needed to put a win on the board. Companies that were effectively stuck needed an exit.

But perhaps the biggest differentiator between then-tiny Earthstone and its peers?

"We had the gumption and the track record to go do it," he said.

Tight club

Earthstone's epic increase in scale can be measured by more than barrels and acres. The incumbent headcount addition that accompanies M&A has boosted the firm's workforce more than 267%—from 60 employees to more than 200.

"We're a very conservative, consistent company. One of our defining characteristics is longevity."

Income Statement [Trailing 12 Months]

Revenue	$1.34B
Revenue/share	$17.93
Quarterly Revenue Growth [year/year]	381.5%
Gross Profit	$343.91M
EBITDA	$886.24M
Quarterly Earnings Growth [year/year]	1929.7%
Operating Cash Flow	$786.73M
Levered Free Cash Flow	-$1.3B
Return on Assets	15.6%
Return on Equity	34.22%

Balance Sheet [Q322]

Total Debt	$1.18B
Total Debt/Equity	54.21
Current Ratio	0.64

Source: Earthstone Energy, US Securities and Exchange Commission, Seeking Alpha

Stock Price Performance

Adjusted Close/Feb. 10, 2023	$13.78/share
52-Week Change	6.77%
S&P 500 52-Week Change	-8.51%
52-Week High	$22.25
52-Week Low	$10.65
Average Volume [three months]	1.37M
Shares Outstanding	105.42M

Source: Seeking Alpha, Yahoo Finance

"We have created a culture that people want to come to work here. And when you do that, you can get a lot out of people. We've got a very talented employee base that has grown up over the last two years with the amount of activity we've done in a number of acquisitions," Anderson said.

"If we had a different culture, we wouldn't have been able to get people to drive as hard as they did because we asked a lot of our employees when we were much smaller."

Still, among those workers are employees who've been with the firm since its private days before the reverse merger in 2014. One reservoir engineering tech, who has been with this team for over 20 years, drives from Katy, Texas, to Earthstone's headquarters in The Woodlands—just shy of 100 miles roundtrip—every workday. The same longevity of employees exists in the field as well.

"That's a heck of a commute, but that goes back to the culture that we've created."

Anderson's tight team includes his longtime mentor, Frank Lodzinski, Earthstone's executive chairman and a build-and-sell specialist since the Reagan years, and COO Steve Collins. The trio, along with others at the officers and staff level, has worked together through various endeavors dating back to the early 2000s.

"I've got a blue collar," said Anderson, whose first break into the oil business was working as a rig floor "worm" in North Dakota where wintertime conditions in the Bakken are often enough 30 degrees below freezing.

Anderson was hooked on the business—not as much the work as a rig hand as the science of the work. He earned a degree in petroleum engineering from the University of Wyoming in 1986, which timed out to a 67% plunge in oil prices that made jobs scarce. He went on to obtain an MBA from the University of Denver, which put him on the path that he now walks in the C-suite.

"We've been around here a long time. We just get up every day, work hard and do the right thing. Not that any of those other companies that I've been with don't do that. But the culture was not the same," he said. "And this culture is so much for me. I've had the ability to influence what we were doing."

Longevity is a consistent theme during a conversation about Earthstone's culture. The leadership team also has a long tenure with EnCap Investments LP, a relationship that began in 2013 with assets that are no longer in the firm's portfolio. Earthstone is the third Lodzinski-Anderson entity in which EnCap has invested.

"We're a very conservative, consistent company," he said. "One of our defining characteristics is longevity."

Indeed, cash from the jars of Vlasic pickles that have lined grocery store shelves since 1942 has been invested in the team's oil businesses for more than 30 years across multiple companies, he said.

WHAT'S THE STORY ON INVENTORY?

Inventory exhaustion, depletion and replenishment are a growing concern for oil and gas producers, but it's the subject of heightened alarm when compounded with the short-term challenges of broken supply chains, labor shortages and infrastructure complaints.

That is, until you talk to Robert Anderson, CEO of the highly acquisitive Earthstone Energy.

"I'm not worried where the next inventory is going to come from," he said. "I didn't know where the last inventory was going to come from, and we bought it."

Earthstone has cobbled together its footprint—now a vast spread of some 250,000 acres, mostly across the Permian Basin—via dealmaking. It's an approach that's paid off, Anderson said. And it's a strategy the firm will continue to employ.

"We've never had the 'core of the core, the absolute best rock to drill,'" he said. "A lot of times we've bought assets that are kind of on the edges. And our job is to figure out how to make that economical."

Earthstone encountered the same spacing upsets and parent-child well interference hiccups that slowed progress for a time but worked around them.

"Like everybody else, we found out that, 'Oops, we're drilling wells too close together, and we need to be spacing out a little further.' And guess what? Now our economics look better."

The firm continues to advance the number of drilling zones and explore within its own footprint. That process still allows for a rate of return of up to 60% when crude trades between \$70/bbl to \$80/bbl, he said.

"If we can go into areas that are less core and still make decent returns, what's wrong with that?" he said. "That's still above our cost to operate the business."

Earthstone takes something of a wait-and-watch approach. For example, the firm will drill some wells in the Wolfcamp D zone this year now that there is clear intelligence on the rock.

"We've been slow to jump on that bandwagon because we'll let everybody else test it and sort of bring the risk down and prove it up closer to our acreage," he said. "We see that it will work [on nearby acreage] and so, it ought to work here. Geologically, everything looks the same. So let's go drill it."

Some of the deeper zones in the Permian will create more inventory, he said. While it's not core Wolfcamp, or Bone Spring or lower Sprayberry sites, returns can still be attractive and add to the inventory life.

"Now, when gas is \$9, there are areas in the Permian that work very well. It doesn't work as good today, so we won't drill it today," he said. "But it's still inventory for us that at some point down the road where we can turn that allocation of capital. It all makes sense."

▸ INVESTMENTS

KEN HERSH AND BUILDING NGP

Retired NGP co-founder Ken Hersh shares lessons learned in the energy private equity firm's first 28 years, green lights and red lights, growing a new investment class and repotting plants.

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Although growing up in Dallas, Ken Hersh knew little about the energy business. He enrolled in political science at Princeton University. But he took a job at Morgan Stanley post-graduation before enrolling in Stanford University—where he chose to get an MBA.

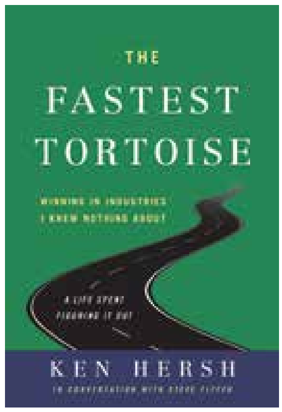
While at Stanford, he won a summer internship with McKinsey & Co. in its Dallas office, using the comp airfare from San Francisco to also visit with the late Fort Worth-based Richard Rainwater, the investor for the Bass family who by 1986 had formed his own firm. Rainwater didn't have a summer job for Hersh but hired him for freelance work. The job was to analyze potential natural gas investment opportunities in response to a new McKinsey report. The report had concluded that prices were about to skyrocket.

Hersh joined Rainwater's office in early 1989 while still a student as part of the newly formed oil and gas private equity firm Natural Gas Partners (NGP) with David Albin, John Foster and Gamble Baldwin. Early on, NGP created an investment methodology that has become the standard way capital is allocated to the sector.

"I was 25 years old," Hersh said. Today, NGP is older than Hersh was when the firm was established. "We built something from scratch into a firm that has invested tens of billions of dollars."

In a planned succession, Hersh handed leadership to another generation of NGP team members in 2016 and began a new chapter: CEO of the George W. Bush Presidential Center.

His memoir, "The Fastest Tortoise: Winning in Industries I Knew Nothing About," will be published March 28. The Oil and Gas Investor *team had a page-turning preview in January, poring over thrilling tales of investments that turned out well and a couple that didn't as NGP grew into one of the largest and most successful energy private equity firms.*



Among deals that went well was the restructuring of the late T. Boone Pickens' Mesa Inc., resulting a year later in Mesa's merger with longtime Permian Basin wildcatter Parker & Parsley Petroleum Co.

The new leadership: Scott Sheffield. The new company: today's $52 billion market cap Pioneer Natural Resources Co.

NGP was also there for the early days of Energy Transfer LP. Founders Ray Davis and Kelcy Warren were looking to buy a South Texas midstream gas asset. NGP invested $37 million in 2002. In 2008, upon distributing the last of the equity to NGP's investors, the return totaled $1.3 billion.

It was extra helpful to compensate for an investment that went bust in the midst of the late 1990s financial crisis. While doing the deal, a green light had turned yellow, but NGP moved forward, stepping outside its typical investment parameters.

The lesson: Yellow lights don't turn green.

Q&A

Nissa Darbonne: Your first experience in the oil and gas business was at Morgan Stanley. You were put on the team that was trying to help Texaco Inc. figure out how to pay $12 billion to Pennzoil Co. for getting in the middle of the Pennzoil-Getty Oil deal. Did that result in a distaste for stepping into other companies' deals?

Ken Hersh: I never wanted to operate in the gray areas. Richard Rainwater used to always say, "Don't go near the foul line." For example, we didn't ever want to drill near Yellowstone. We wanted our companies to operate in places where they were welcomed.

There was enough to do in the fairways with people who were quality people we trusted. You just didn't need to go that far afield. We had plenty to do down the middle.

ND: There was a time at NGP when action could have been brought against a bank but you chose not to. Is it best to avoid

being litigious?

KH: I'm not going to say we were just going to be a pushover. You're referring to our Sunoma Energy Corp. transaction in 1998. In that case, we had to make a decision as to whether we should attempt to work out a restructuring or go to war with the bank that chose not to fund under the agreement we each had signed.

At the time, the banker was very honest and said, "You can go that [court] route, but it will drag on for years, and I will [need to] disengage." We discussed our options. In that case, the whole economy was in a really bad place.

And our industry was worse. Oil had gone from $20 to $9. Long-term Capital Management had threatened a global financial crisis. Russia was defaulting on its debt. There was real fear of contagion. Banks had to hoard their liquidity. So they made a decision not to fund.

Had we been consumed by that deal, we may not have done the half-dozen other great deals at that same time.

So the key thing was not losing our confidence in our business plan. We clearly learned some valuable lessons. But the same [external forces] that were causing that company to get hurt were creating great opportunities [for us] elsewhere.

We had a whole fund and teams were buying assets and planning for the upturn. By not being consumed [by that one deal], we were able to play offense elsewhere.

ND: In another deal, the numbers were simply untruthful. What did you take away from that?

KH: I don't want to use "untruthful." I'm not saying that they were fraudulent. Auditors audit the information that they're handed. Behind that, in the files, there are many assumptions. As we know, assumptions can be wildly optimistic.

So our lesson from that was to be leery of what you read in public financials. Always do your due diligence.

ND: That McKinsey report which formed the basis for NGP's founding … How much confidence did you have after that in prognostications by those who don't have skin in the game?

KH: The report definitively predicted a sharp rise in natural gas prices. That was our thesis: We were going to buy [gas] low and sell high.

That turned out to be essentially wrong. Prices went down for about seven straight years.

The lesson there was that reality sometimes gets in the way of great theory.

ND: What have you found to be the best use of investment banking firms?

KH: Bankers were bringing us information that they gleaned from annual reports and quarterly reports that were 90 days or six months or a year old. I said, "Wait a minute. I'm going to these meetings and depositing more information than I'm getting."

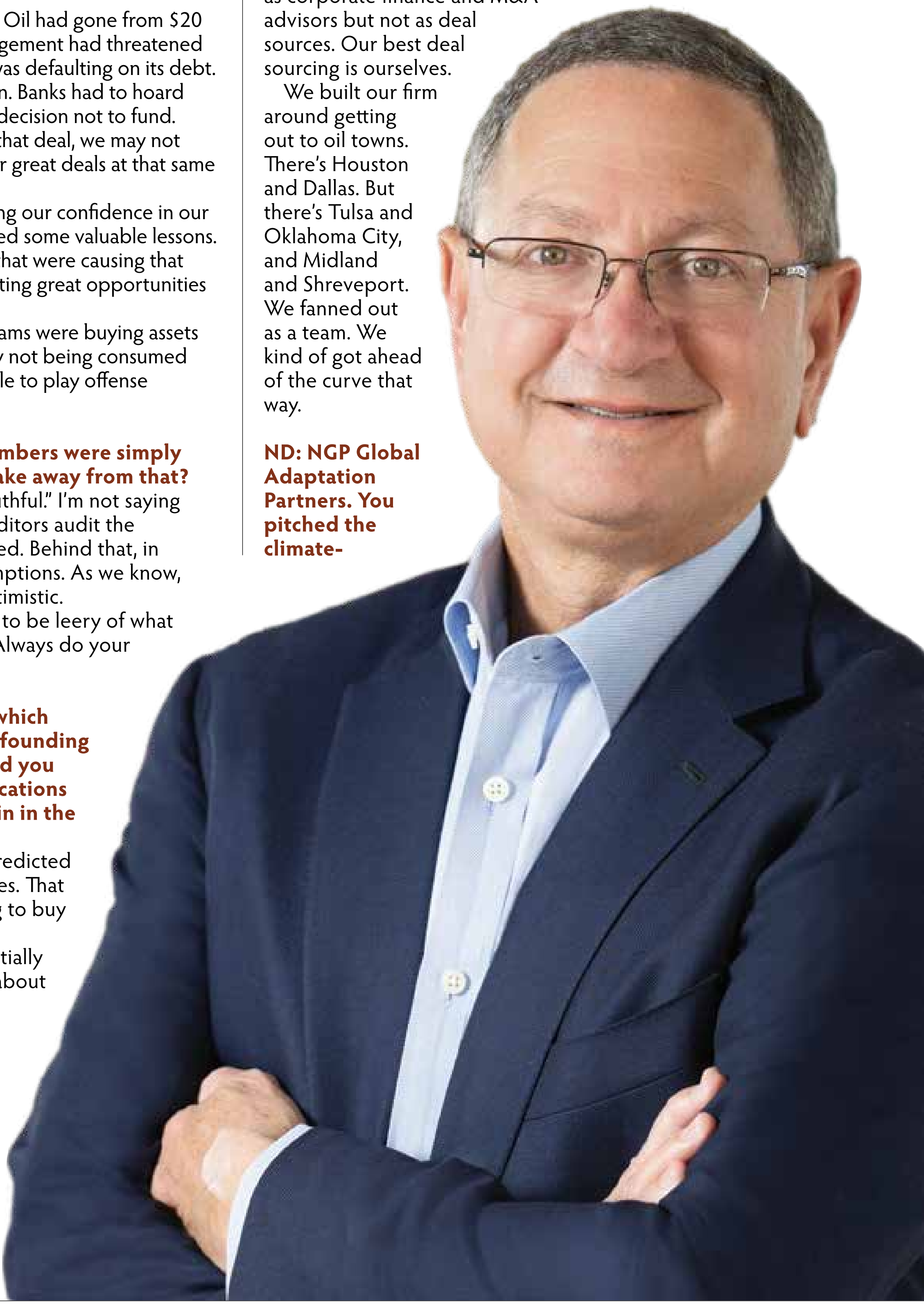
I concluded that we should not be relying on the Street for primary information when we have so many portfolio companies spread across the industry.

What the Street is good at is how capital markets distill the information. How are M&A markets functioning?

So, we said we should use the banking community as corporate finance and M&A advisors but not as deal sources. Our best deal sourcing is ourselves.

We built our firm around getting out to oil towns. There's Houston and Dallas. But there's Tulsa and Oklahoma City, and Midland and Shreveport. We fanned out as a team. We kind of got ahead of the curve that way.

ND: NGP Global Adaptation Partners. You pitched the climate-



response fund in 2010 and it failed to launch. Too soon?
KH: Today it would be in vogue. Being in the energy business, I knew all the numbers. The world's population was going from 7 billion to 9 billion. Two billion more people were going to want to enjoy middle-class consumption.

It didn't matter whether you believed the climate models. The planet was changing.

But mankind has adapted to changing climates long before there were fossil fuels. We need to look forward and say, "If the planet's changing, why are we spending all of our time and money focused on preventing change that's going to be inevitable? We're not going to get to the year 2100 if we don't focus on getting to 2030."

So the way to get to 2030 is to protect our populations.

When you have countries that no longer can support agriculture, populations move and the machetes come out. That is not a good condition.

Looking at the numbers [in the aughts], I said, "This is inevitable."

ND: Your position is that we needed to adapt.
KH: If you're in the oil business, you're looking at geology that says this area and that area were underwater for millions and millions of years. And now they're not.

These mountains are this many years old. They weren't there before.

My point is, we had an ice age before we were burning fossil fuels, and the ice age went away. The planet warmed without any CO_2 from man.

The narrative needed—and still needs—to change to adaptation. I liken it to saying, "If we're all on a boat that is taking on water, would the people on the boat vote to repair the boat or start a 50-year research project on new boating materials that don't leak?"

The world is doing the latter when we need to do both. The world has spent more than $2 trillion in the last 15 years on renewable energies. And fossil fuels have gone from 82% of global energy demand to 84%.

Emissions have gone up and the Paris Accord allowed emissions to increase.

ND: Tell us more about that.
KH: We've spent the last 20 years trying to get 196 countries to agree on a plan that we heralded in 2015 in Paris as "We did it."

No, we didn't.

We came up with an outline and everybody was to submit their goals and not a single country has met its goal. In fact, the Paris Accord allowed China to increase its emissions from 10 billion tons of CO_2 to 15 billion.

Well, that incremental 5 billion tons is the equivalent of 100% of [the] United States. We've taken our emissions from about 9 billion down to 5 [billion] because of the shale-gas revolution.

Well, if the Paris Accord was rewritten and it said, "We're going to allow the introduction of an entire United States to the world's CO_2," people would've gone bananas.

But that's effectively what they did.

So the Paris Accord was a nice thing to have, but getting 196 countries together is meaningless. The top five emitters emit 70% of the world's CO_2; we don't need 196 countries.

We could have just had a G2 [Group of Two] or G3. Instead, the world went ahead and spent $2 trillion and has almost nothing to show.

As a planet, we're not doing a great job. We need to be spending more money and time focusing on adaptation.

ND: So the fund never came to fruition.
KH: The adaptation crowd back in the day was lumped with the climate deniers; they were pushed aside. I tried to be ahead. I was getting feedback from the market. But when it was time for people to commit, they basically said, "We're not ready."

And, you know, one of my expressions is "feed the ducks while they're quacking." So I moved on.

I can only lay out the investment thesis and ask people to be forward thinking. But when push comes to shove, if it doesn't look like it's going to generate a return the next two or three years, they don't want to talk about it.

So I just chalked that up to "lessons learned."

ND: Do you agree with Greta Thunberg?
KH: I wouldn't comment on her specifically. I would just say that I am not a denier. The planet is changing. The planet has always changed. If you believe in the models, the one thing we don't have is time.

ND: What's next?
KH: We need to be working on leapfrog technologies. I love the fact that we're working on fusion.

Natural gas should be a massive bridge, and let's get rid of coal and replace it with gas. That'll buy us two decades or more.

Nuclear power …France is sitting pretty with a strong nuclear grid and low emissions. There can be a safe nuclear power industry in this world. But we've decided nuclear is dirty.

I think nuclear power is a big winner of this realization that the energy transition is not going to be easy or quick. You see Japan is going back to nuclear power.

Unfortunately, the world needs to see the building burning. I was talking fire prevention in 2010.

ND: NGP did still create the nonprofit Global Adaptation Institute.
KH: We did. We ran it independently for a handful of years. We've merged it into the Environmental Change Initiative at the University of Notre Dame. They're doing good work on promoting adaptation.

So it's found a home. And hopefully there's some intellectual contribution the institute plays.

ND: Hydrogen wasn't on your short list.
KH: I will leave that one alone.

ND: It isn't among your personal investments?
KH: No.

ND: Would there be any place outside the U.S. that you do feel comfortable with investing in oil and gas? Would you do British shale?
KH: No, I wouldn't. You're just at the whim of whatever political power lets you live. The cycle times in the business have gotten shorter with shales, but the project times aren't any shorter. The well will last a decade. So that's a 12-year time interval, at least.

If you're in an area that's not developed, especially if it's gas, you have to have oilfield services, gathering systems and processing ready. You have to have the downstream

Ken Hersh, CEO of the George W. Bush Presidential Center; President Bush; and Bono at Bush's Crawford, Texas, ranch in 2017.

Photo courtesy of Ken Hersh

ready as well. And all of this before you drill your first well.

You've done a decade of front-end work.

Then that drilling rig stands up and the neighbors say, "What the hell's this?"

ND: Sounds like Colorado.

KH: That's true everywhere. In Colorado, in parts of Wyoming, in parts of the Northeast. I mean, New York state doesn't have a fracking industry; Pennsylvania does. New York chooses to import natural gas. It doesn't mean they don't have any natural gas there. They have plenty of gas in the ground.

It's very frustrating, but it's just a reality of our industry.

So to go someplace where you could be switched off on a dime [by the government] is really problematic. The business is hard enough.

Colorado has been a place that might switch on and off over a decade. Parts of Colorado have become inhospitable that used to be hospitable. That's hard enough.

As we built NGP, we just said, "Let's go where we're wanted."

ND: What else?

KH: I'm not a geologist. I'm not a geophysicist. I'm not a petroleum engineer. What I really loved about the energy industry is that I was able to make an impact in a business I knew nothing about by just diving in, meeting people and listening.

You don't have to be a geologist or geophysicist to have a good conversation about energy. For a generalist, I did okay. OGI

REPOTTING THE PLANT

Nissa Darbonne: You write about "repotting the plant" in business and in one's personal life. You and your family moved to London in 2008, while NGP was building its network of potential investors overseas. You didn't get a car; you walked and used public transit and cabs. Tell us about repotting the plant.

Ken Hersh: One of my adages is "be uncomfortable." I thought it would be a great experience to take my family out of our Dallas comfort zone and repot ourselves in another country. Professionally, it was like starting over with meeting new people and learning new ideas.

My family really was brought together by experiencing city living.

ND: Retiring to lead the Bush Presidential Center is another example.

KH: Moving from the NGP world to the Bush Center, I was now running a nonprofit. I didn't have big bonuses or equity points to give out. It's a completely different incentive structure. Figuring out how to motivate people in that environment has been very exciting.

ND: How's it going?

KH: I feel 20 years younger when I go to the office at the Bush Center. There's a cadre of young, motivated, mission-driven people who want to change the world. I could start a company with this group and be wildly successful.

But they wouldn't come. "Why would I make a widget? I want to change the world."

And I get to help them!

VOLUME OVER VALUE: A&D MARKET PRIMED FOR ACTIVE BUT THRIFTY REBOUND

Despite large-cap publics such as Devon Energy Corp., Diamondback Energy Corp. and Marathon Oil Corp. dominating M&A in 2022, the overall deal count fell to the lowest level since 2005, according to Enverus.

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Upstream dealmaking value plunged 13% between 2021 and 2022, while deal activity fell to the lowest level since 2005 and was down by 24% for the year, according to Enverus Intelligence Research.

Still, dealmakers found an occasional trigger to pull on transactions—particularly, large, independent E&Ps that shook loose acquisitions for smaller private companies in the Eagle Ford and Permian Basin in the second half of the year.

"Large-cap public companies like Devon Energy, Diamondback Energy and Marathon Oil dominated deal activity in the back half of 2022," said Andrew Dittmar, director at Enverus Intelligence Research. "These buyers have the balance sheet strength and favorable stock valuations to take advantage of large, high-quality offerings from private sellers."

But the year also illustrated the widening mismatch between large-cap companies with attractive valuation and their smaller rivals, which are unable to compete for deals on an equity basis. Economic headwinds and commodity prices may also be at play in stifling M&A.

But in 2023, the persistent need to replenish inventory will likely keep E&Ps chasing deals.

Dittmar said that in 2022, large-cap companies were able to strike deals that were both accretive to current cash flow and extended their runway of drilling locations.

"For smaller companies, which are still having their equity value discounted, it is challenging to thread the needle of buying assets at accretive multiples and being able to pay for inventory," he said.

Last year, deals appeared to split along two trend lines. Earlier in the year, transaction value was "heavily tilted toward production value as deals were focused on buying discounted production or modestly priced inventory," Dittmar said.

By the fourth quarter, large-cap buyers were more willing to pay for inventory with valuations exceeding $2 million per location, including the deals by Diamondback Energy Corp. and Marathon Oil Corp.

"Given the need for inventory, we anticipate deals will continue to see more value allocated to the upside, both from paying more per location and targeting less developed assets with more development runway," Dittmar wrote in the report.

Forty percent of the operators in North America expect their capital spending to increase slightly this year, according to the findings of the winter Dallas Fed survey. And almost 25% expect a significant increase in spending in 2023.

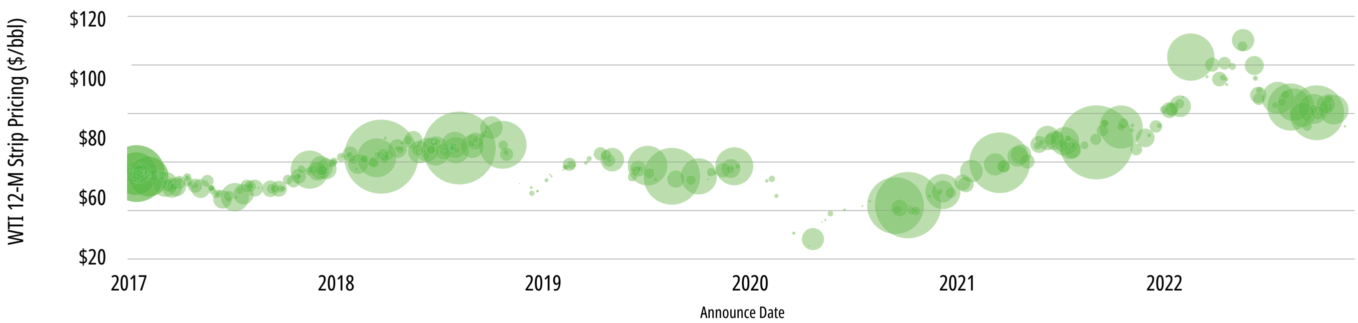
What's the point of this increase? Inventory.

A "maturing asset base" was among the top responses to the survey question, "Which of the following is the biggest drag on crude oil and natural gas production growth for your firm?"

Inventory is life

The need for public operators to secure inventory should provide a tailwind for M&A and private

Oil Deals Vs. Nymex 12-Month Strip Pricing



Note: Bubble size denotes size of transaction. Includes deals where production exceeds 50% oil.
Source: Enverus M&A Analytics

equity-backed sellers with high-quality asset packages.

Large-cap companies that have a premium valuation will "target the highest quality inventory in the core of plays—like the Permian and Eagle Ford for oil and Appalachia and Haynesville for gas," Dittmar said. "Inventory in these plays is likely to continue to increase in value as fewer quality positions with scale remain."

That disconnect hasn't been lost on small- and mid-cap (SMID cap) E&Ps, such as Midland Basin operator HighPeak Energy Inc. On Jan. 23, the company, which has a market cap of about $3 billion, said it would explore a possible sale. Jack Hightower, HighPeak's chairman and CEO, said the company is undervalued by the market—a point he effectively turned into a sales pitch.

"We believe our share price should move up the trading multiples currently realized by certain potential purchasers and large-cap, pure-play owners of Midland Basin assets," he said.

Dittmar said SMID operators that need inventory but lack a supportive equity price may target less-proven areas, such as the Permian Rim and eastern Eagle Ford for oil and the Rockies regional plays for natural gas.

"A SMID-cap operator could test the market with a deal that is inventory accretive but dilutive to EBITDA multiples and free cash flow," Dittmar said.

However, even if such a deal is strategically necessary, it may prove unpopular with investors over the short term.

"Another option is a return to public-public M&A, either from SMID mergers seeking to garner a higher multiple from increased scale or to sell to a large-cap peer that is more attractive to investors," he said.

"The barrier to entry to the Permian is pricing out a lot of companies who might want to get in but do not have the technical expertise or experience in the basin."

—Preston Bernhisel,
Baker Botts

January M&A begins to thaw

After a slow start in January, two E&P megadeals were announced by mid-month.

Chesapeake Energy Corp. agreed to an initial sale of its Eagle Ford acreage for $1.425 billion—part of a larger divestiture of its assets in South Texas. In the Permian Basin, Matador Resources announced a bolt-on acquisition valued at $1.6 billion, excluding contingency payments.

Matador's recent deal was, in part, a result of its status as SMID-cap with a higher share price than most of its peers. The company has also retained significant retained cash to make an acquisition.

Dittmar said Matador's bolt-on acquisition of Advance Energy Partners Holdings LLC, an EnCap Investments portfolio company, appears to be a sensible bolt-on in the Delaware Basin core.

Matador was able to pay at multiples that were slightly accretive, Dittmar said, and add a significant runway of high-quality locations that are immediately competitive in its portfolio for drilling capital.

"While not super cheap at about $25,000 per acre, the deal prices are in line with other recent M&A for core assets like Diamondback Energy's buys in the Midland Basin in late 2022," Dittmar said.

"Like some of the other recent buyers, it has also won the trust of investors with a successful track record on deals," he said in Jan. 24 commentary.

Chesapeake Energy's sale of its Brazos Valley assets to WildFire Energy I LLC advances its goal of being a pure gas producer focused on Appalachia and the Haynesville Shale, he continued.

Chesapeake's hope is that the more specific focus raises its stock price, Dittmar said.

"The company is also unloading an asset that was no longer viewed as competitive in its portfolio, and the deal checks off one of Chesapeake's widely telegraphed goals from last year," he said.

Dittmar said the sales price at first glance looks "a bit underwhelming though, especially considering the company paid nearly $4 billion in the purchase of WildHorse Resource Development that brought these assets into its portfolio."

The $1.425 billion purchase price also appears to be "a bit beneath the value of the production with no value attributed to the undrilled locations."

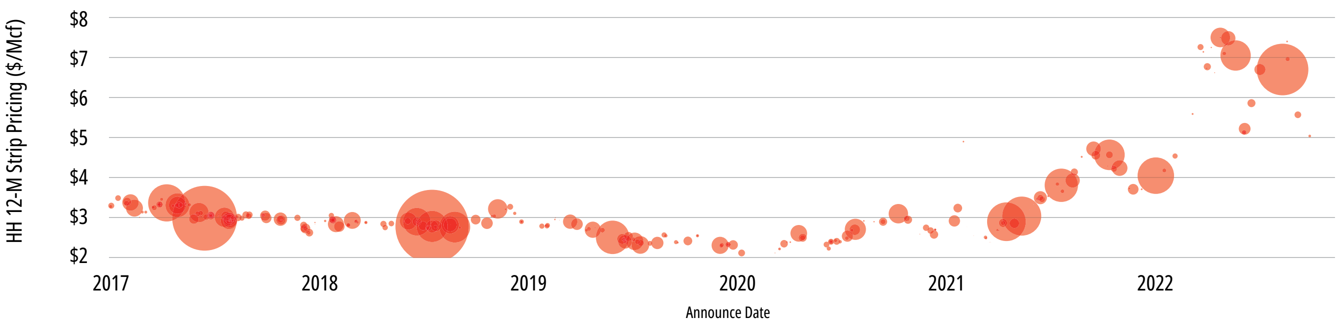
The sales price likely reflects the limited buyer pool for this region of the Eagle Ford, and an overall challenging M&A market outside of the highest quality assets, Dittmar said.

"Chesapeake will likely continue to consider sales options for its remaining Eagle Ford assets, dependent on economic conditions and commodity prices," he said.

Though the deal makes sense given Chesapeake's goals, it is unlikely to kick start any trend of public-to-private asset sales, Dittmar said.

"Most public companies will likely view the offers from private E&Ps as being insufficient to be worth giving up the cash flow from even noncore positions, and private companies are likely to stay conservative in their offers," he said.

Gas Deals Vs. Nymex 12-Month Strip Pricing



Note: Bubble size denotes size of transaction. Includes deals where production exceeds 50% gas.
Source: Enverus M&A Analytics

Supply and demand

OPEC predicts that the global population will increase from 7.9 billion to 9.5 billion by 2045. The organization estimates that the global GDP will rise from $133 trillion in 2021 to almost $270 trillion by 2045. This growth comes with an increase of 65 MMboe/d during the same period, a rise of 23%.

While oil production numbers hit near all-time highs, it was not enough to stabilize prices in 2022. According to the EIA, in 2022, the price of WTI ranged from $70/bbl to over $120/bbl. Natural gas saw plenty of swings ranging from $4 to almost $9 during the year.

The price volatility stifled a fast start to the mergers and acquisitions space.

The $6 billion in January deals made a five-year high, according to Enverus. Despite the hot start to 2022, Enverus reports that the year's $58 billion worth of transactions reflected a deal volume total that had dropped to a nearly two-decade low.

"You have to be nimble. Larger units are going for a premium. We've found that we can acquire smaller units at a valuation that works for our investors."

—Crosby Shaver,
Blue Darter Energy

"The volume of deals is relatively sluggish, but we are seeing some bigger deals get done, so values are relatively high," Dittmar said.

"The main theme is private equity-backed positions taking their positions to market looking to sell to major operators. That's where we are seeing most of the large deals take place."

While 2022 saw a wild swing in prices, a more stable market may be ahead for this year, said Tim Kotzman, founder and CEO of Jubilee Royalty.

"We're expecting prices to level out over the next few years," he told Hart Energy. "The large swings and predictions for future swings have made it hard to get minerals at reasonable prices. If the market becomes more stable, that will allow for more deals."

Stable oil prices, above break even, would be good for the industry, but it's unlikely to cure all problems.

"The challenge associated with larger-scale acquisitions in more mature basins such as the Eagle Ford and Bakken will continue to be the limited amount of tier-one inventory."

—Neal Dingmann,
Truist Securities

The primary driver of U.S. oil production has been the Permian Basin. The hyper-focus on the basin has driven up acquisition prices and might give companies pause before entering the basin.

"On the oil side, the Permian is still where it's at. Many companies will look for opportunities in the Delaware and Midland basins," Dittmar said.

"Much of the core in those two basins has been acquired by larger companies that will not be looking to exit. This will push companies outside the core to look for deals priced well."

Companies are giving prime consideration to the areas they best understand, Preston Bernhisel, chair of the Dallas corporate practice of Baker Botts, told Hart Energy.

"If you are a Permian operator, that is where you want to focus your efforts," he said.

While it makes sense for companies to hone in on areas they believe they can exploit the best, it is keeping out companies that need more expertise and extra cash to pay the premium required to enter the Permian.

"The barrier to entry to the Permian is pricing out a lot of companies who might want to get in but do not have the technical expertise or experience in the basin," Bernhisel said.

Higher Permian prices have slowed down deal flow in the basin and pushed smaller operators to other basins such as Haynesville, Anadarko Basin, Arkoma Basin and Eagle Ford.

"We look at the deals in the Permian and can't make that math work," Crosby Shaver, managing member of Blue Darter Energy, told Hart Energy.

"Now, we are focusing on Oklahoma. The competition is less fierce, and the prices are more reasonable," he said.

"Smaller companies can't afford to hold assets on their balance sheets for years. The write-offs larger companies perform allow them to buy and hold assets for several years. Their cash positions differ completely from ours. When we buy something, at a minimum, it needs to be permitted to drill."

Shaver's firm is looking at acquiring smaller units than before.

"You have to be nimble. Larger units are going for a premium. We've found that we can acquire smaller units at a valuation that works for our investors," Shaver said.

Smaller operators are also reconsidering the commodity they will buy as well.

"The most significant shift we have noticed is that companies are more interested in buying natural gas assets than in previous years," Kyle Souza, "data wizard" at P&P Oil & Gas Solutions, told Hart Energy.

Ignoring the Permian and focusing on a play like Haynesville is not a cure-all. Even in the smaller plays, operators are not looking to exit right now.

"There are a lot of buyers in the market, but sellers are tough to come by," Souza said.

It's not a tiny uptick in buyers.

"This is the most excited we've seen people wanting to buy since 2015. There's been a change in the industry's perspective. There are younger people in the companies that we work with. With the new leadership in place, it's more about long-term returns than just expanding your drilling program or buying an asset hoping to flip it in two or three years," Souza said.

For P&P Oil and Gas Solutions, the renewed interest in buying has pushed their company to hire new employees and leverage technology.

"We've had to hire people to keep up with the demand, but we leverage a lot of artificial intelligence [AI] to scale faster without hiring as much as we have historically. We can sometimes reduce the time to complete a project by as much as 50% with a quarter of the staff. The deals are complex," he said. "With many people retiring, we've had to figure out how to keep up with client demand while knowing there is a tight labor market. We've leveraged AI to do that, and the results have been better than expected."

There is another risk looming out there for the smaller players. Not only can larger oil and gas companies buy and hold assets in prime plays like the Permian, they will also drill wells that are less profitable to keep rigs running and frac crews busy.

2022 Deal Values By Region

$ Billions

	1Q22	2Q22	3Q22	4Q22	Full Year
Multi-Region	$0.3	$3.5	$2.2	$5.2	$11.2
Permian	$4.4	$6.1	$1.1	$4.2	$15.8
Gulf Coast	$0.0	$0.6	$2.0	$3.1	$5.7
West Coast	$0.1	$0.3	$3.9	$0.6	$4.9
Rockies	$7.3	$1.4	$0.1	$0.1	$8.9
Midcontinent	$0.1	$0.9	$0.2	$0.0	$1.2
Ark-La-Tex	$0.0	$0.2	$0.1	$0.0	$0.3
Eastern	$2.7	$0.0	$6.0	$0.0	$8.7
Gulf of Mexico	$0.1	$0.1	$1.2	$0.0	$1.4
Total	**$14.9**	**$13.1**	**$16.7**	**$13.3**	**$58.0**

Source: Enverus

Potential Buyers During The Next Wave Of A&D

Company	Ticker	*Closing $/share	*Market Cap ($/billion)
APA Corp.	APA	$41.05	$14.01
Civitas Resources	CIVI	$63.21	$5.69
Callon Petroleum	CPE	$39.57	$2.58
Devon Energy	DVN	$60.30	$41.54
Earthstone Energy	ESTE	$12.79	$1.45
Diamondback Energy	FANG	$141.47	$27.16
Ovintiv	OVV	$45.86	$12.13
PDC Energy	PDCE	$63.28	$6.21
Permian Resources	PR	$9.93	$3.04
Pioneer Natural Resources	PXD	$221.32	$54.98

*Feb. 10, 2023
Source: Truist Securities

"Our concern right now is low gas prices. The upside to buying in places like Anadarko and Arkoma is less competition. The risk is still there. We have to buy at the right price. Here, companies are less likely to keep a rig running at low prices. Each deal we look at needs to be permitted, and we want to buy the acreage with as low of a breakeven as possible. If you are not careful, you can find yourself with acreage that will not get drilled in the next year," Crosby said.

Concerns about not making immediate returns keep excited buyers from splurging on risky deals.

"While our buyers are looking to buy, there is no push to buy today. Our clients want to make strategic purchases," Souza said.

"Our clients can raise money. None need to exit a current position to buy a new one. They are raising money from private sources to add to their assets, but our clients focus on buying producing assets. At times, they will operate the wells. Others want the cash flow. The priority is to buy an asset that is cash flowing, not one that might have cash flow."

While smaller operators are looking to move into areas they have not been as active in, larger operators are focused on doubling down on their strengths. If prices stabilize, Dittmar believes that could lead to an increase in activity around mid-year—"it's most likely to pick up in late Q2 or early Q3."

Many of these acquisitions will be targeted at expanding drillable assets companies have on the books.

"Over the past few years, operators have proven they can return value to their shareholders. As companies evaluate their assets, they see that if they have less than 10 years of inventory on the books, shareholders devalue their stock. So, companies with less than 10 years of inventory will look to acquire acreage to get above that 10 year threshold," Dittmar said.

In 2022, private equity-backed companies were not as active as they had been in previous years allowing the larger E&Ps to close on many of the deals that were available.

"We saw fewer private equity deals in 2022 than we did before the pandemic. Depressed multiples for dispositions or acquisitions drove this. While we expect larger companies to continue to scoop up assets from smaller companies, we've seen hints of a more robust private equity market in 2023. This will be a mix of companies looking to exit and reinvest and new teams looking to raise and enter the market," Bernhisel said.

Multibasin consolidation

The Permian Basin remains the most likely spot for A&D, said analyst Neal Dingmann at Truist Securities in a note to investors.

But there are potential sellers across the Lower 48, including those with assets in Colorado's Denver-Julesburg (D-J) Basin, the Bakken in North Dakota and the South Texas Eagle Ford Shale.

"The challenge associated with larger-scale acquisitions in more mature basins such as the Eagle Ford and Bakken will continue to be the limited amount of tier-one inventory," Dingmann said. "With continued investor angst surrounding continuity in the Anadarko Basin and to some extent, the D-J, we believe deals in these regions would have to be somewhat discounted."

However, Enverus' Dittmar said that there are firms in the Eagle Ford looking for an exit and there are buyers with interest in those assets. Outside of the Permian, the next major play that might see activity is the Eagle Ford shale.

"There is a tremendous amount of private equity positions in the Eagle Ford that the groups holding them would like to unwind—especially noncore assets," he said. "We saw that recently with the WildFire acquisition from Chesapeake Energy."

Infrastructure access

Access to takeaway capacity is a consideration in most A&D, insiders said.

"It is always an important consideration in any deal," Dittmar said. "Your model has a certain number of volumes baked in and you have to make sure you have the pipe to get those volumes to market."

Takeaway is an issue regardless of resource, he said.

"Even when you look at gas, there are two considerations. If gas is the target, then of course you will need to get it to market," he said. "However, if you are acquiring acreage in the core of the Permian, operators will want to have access to pipelines to help reduce flaring and maximize profit off the well by selling that gas to market as well."

Indeed, infrastructure can heighten the allure of a deal.

"Infrastructure is a concern," Bernhisel said. "Producers with a midstream group in house, or contracts in place, are more attractive."

Even if the activity picks up, the market should expect more volume, not larger deals than have happened already, he said. OGI

▸ SHALE TALK

EAGLE FORD SHALE TAKES FLIGHT

The South Texas Eagle Ford Shale's emergence as an M&A hot spot in late 2022 highlights the play's market potential this year.

BY JAMES THOMPSON III
CONTRIBUTING EDITOR

EOG Resources. Devon Energy. Marathon Oil.

Some of the largest U.S. independent E&Ps are thriving in the South Texas Eagle Ford Shale, adding acreage and assets and counting on the play—long in the shadows of the neighboring Permian Basin—to be a highlight of their portfolios.

The Eagle Ford is producing more than 1.2 MMbbl/d; that's up slightly from this time last year, when production was close to its pre-pandemic level of 1.1 MMbbl/d, according to U.S. Energy Information Administration (EIA) data.

While the basin's per-barrel tally remains a stretch away from its 2015 peak of almost 1.8 MMbbl/d, business there is keeping the play in a tight race with the Bakken in North Dakota as both basins compete for second place to the mighty Permian Basin, where producers in West Texas and New Mexico coaxed more than 5.6 MMbbl from the earth each day in January.

Natural gas production in the Eagle Ford Shale has been a far steadier story with EIA drilling productivity data showing routine production near 7 Bcf/d range since 2015, after a climb from around 5 Bcf/d that began in 2013.

The basin's rig count this year is solid, holding in the 70s since July and up 44% year-over-year from 50 rigs, according to Baker Hughes data.

Location, location, location

By proximity alone, the Eagle Ford offers several advantages, analysts at East Daley Analytics said.

"[It is] one of the best understood shale plays [in terms of exploration and extraction]. There's not a lot of surprises anymore."

—**Andrew Dittmar, *Enverus Intelligence Research***

"Producers in South Texas are closer to Gulf Coast industrial demand centers and export terminals, resulting in higher realized prices for crude oil, natural gas and NGL. And unlike the Permian, producers in the Eagle Ford aren't plagued by significant takeaway constraints for natural gas," the analysts said in late November.

Indeed, the Eagle Ford was adding rigs in November, peaking at 97 by Dec. 1, with a gain of five rigs added across four weeks. That figure represents the highest count since March 2019.

By contrast, the Permian in West Texas and eastern New Mexico shed 23 rigs during the same period.

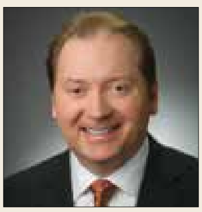
One of the reasons the Eagle Ford Shale is a popular place for oil and gas resource development is that it

THE EAGLE FORD SHALE: DEFINING DEALS

Dealmaking in the Eagle Ford Shale during the second half of 2022 was a rare bright spot in an otherwise dark year for upstream A&D in the U.S. Large-cap public companies like Devon Energy Corp. and Marathon Oil Corp. dominated deal activity with balance sheet strength and steady stock performance that gave them the ability to capitalize on their positions and take on the large, high-quality offerings of private sellers.

Marathon Oil

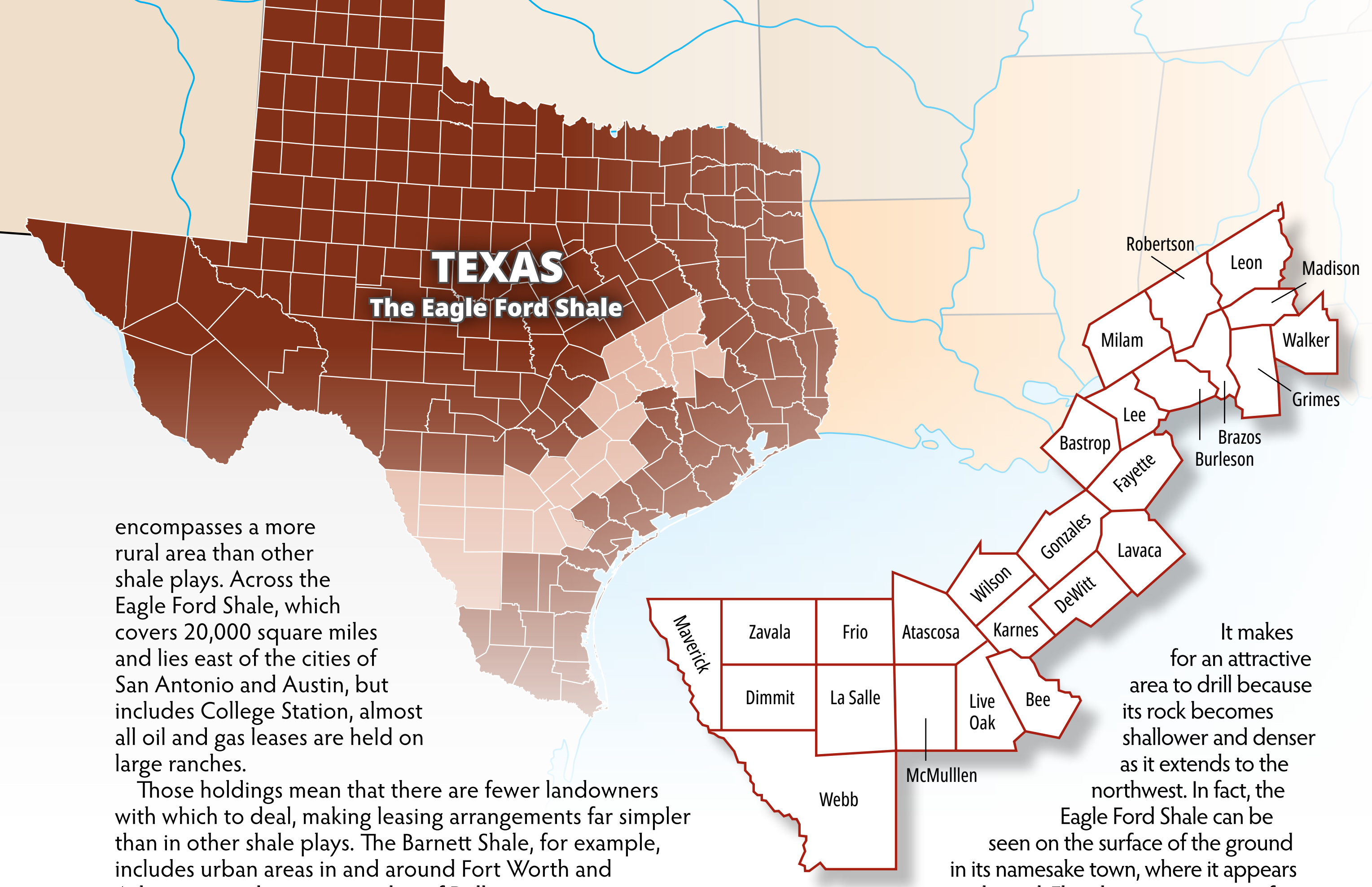
Marathon Oil closed its acquisition of Ensign Natural Resources' Eagle Ford assets for $3 billion cash in December.



Lee Tillman
Marathon Oil CEO

"This acquisition satisfies every element of our disciplined acquisition criteria," said chairman, president and CEO Lee Tillman. "It's immediately accretive to our key financial metrics, it will drive higher shareholder distributions consistent with our operating cash flow driven return of capital framework, it's accretive to our inventory life with attractive locations that immediately compete for capital and it offers truly compelling industrial logic given our existing Eagle Ford footprint and our track record of execution excellence in the play."

The acquisition adds 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, Marathon said.



encompasses a more rural area than other shale plays. Across the Eagle Ford Shale, which covers 20,000 square miles and lies east of the cities of San Antonio and Austin, but includes College Station, almost all oil and gas leases are held on large ranches.

Those holdings mean that there are fewer landowners with which to deal, making leasing arrangements far simpler than in other shale plays. The Barnett Shale, for example, includes urban areas in and around Fort Worth and Arlington, on the western edge of Dallas.

"It certainly helps that, at least in large parts of the Eagle Ford, you're dealing with large landowners," said Andrew Dittmar, director at Enverus Intelligence Research. "It definitely makes it (oil and gas development) much easier."

The ownership landscape makes for a sparsely populated region to develop. As such, across much of the Eagle Ford Shale there are fewer people to raise concerns about oil and gas development.

Well-defined and deeply understood

A mature play, the Eagle Ford's oil and gas reserves are well-defined, Dittmar said. Oil production is centered on the upper end of the basin, and natural gas is produced in the south.

It makes for an attractive area to drill because its rock becomes shallower and denser as it extends to the northwest. In fact, the Eagle Ford Shale can be seen on the surface of the ground in its namesake town, where it appears as clay soil. Elsewhere, an outcrop of the Eagle Ford Shale is visible in part of the Dallas-Fort Worth metropolitan area.

Additionally, the Eagle Ford deposits of oil and natural gas, which were formed about 80 million years ago, lie within rock that is more brittle, and thus, more permeable, than the rock in other basins, meaning that the deposits within it are far easier to extract by fracking.

"[It is] one of the best understood shale plays" in terms of exploration and extraction, Dittmar said. "There's not a lot of surprises anymore."

Indeed, EOG Resources has operated in the Eagle Ford for more than 10 years. It's a mature relationship that works in the firm's favor.

EOG's early wells in the basin were 8,500-foot laterals drilled

Along with that acreage, the acquisition included 700 existing wells across Live Oak, Bee, Karnes and DeWitt counties in Eagle Ford as part of what is now Marathon Oil's presence in Eagle Ford of 290,000 net acres.

According to Marathon Oil, the existing wells "offer upside redevelopment potential." In a November news release, Marathon estimated the deal would bring them "more than 600 undrilled locations, representing an inventory life greater than 15 years."

At the time of the acquisition, Marathon Oil was anticipating fourth-quarter 2022 production at 67,000 net boe/d, nearly double what the company's presence had been in the Eagle Ford Shale.

Tillman said the acquisition would boost the company's inventory life with high rate-of-return locations, driving a 17% increase to 2023 operating cash flow and a 15% increase to free cash flow.

Devon Energy

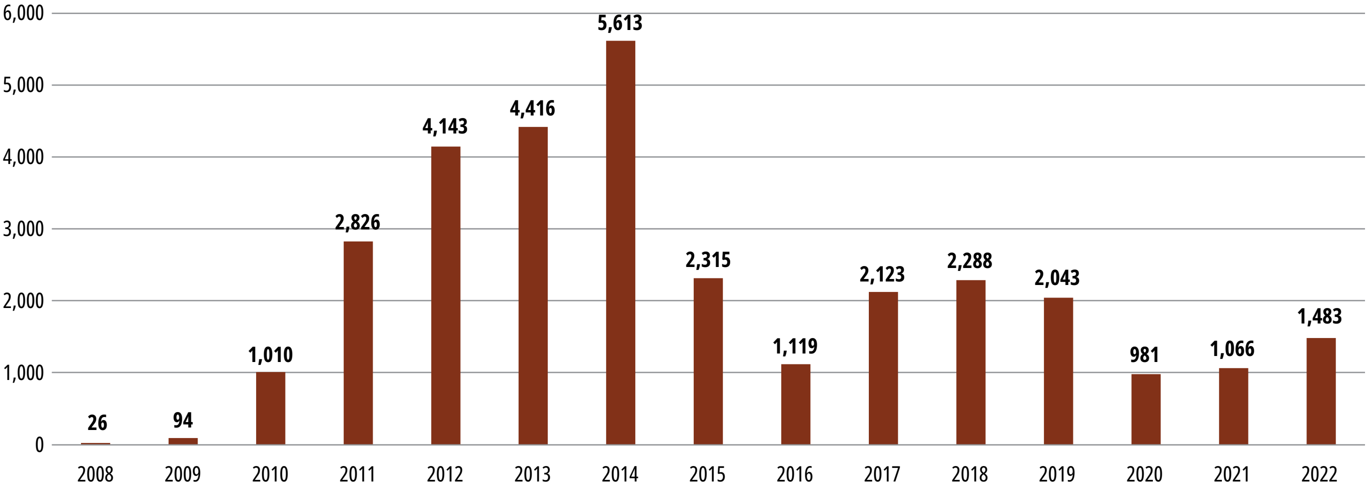
In August, would-be Eagle Ford consolidator Validus Energy accepted a $1.8 billion cash consideration to sell to Devon Energy.

Just two months before, the company's CFO, Cameron Brown, said the Denver-based firm only had $1 billion of capital commitments available for deals with which the firm "would love to continue to consolidate the basin."

Fast-forward to the fall, and instead, Devon president and CEO Rick Muncrief was touting the benefit of adding Validus' assets to his company's portfolio: 42,000 net acres with production of about 35,000 boe/d.

Texas Eagle Ford Shale

Drilling permits issued 2008 through December 2022



Source: Texas Railroad Commission Drilling Permit Query (Includes New Drill & ReEnter Permits)

at a cost of $12 million. The price is now down by more than half, between $4 million to $5 million each, said Ken Boedeker, EOG's executive vice president for exploration and production, in November.

"That's that continual improvement," he said during the 2022 BofA Securities Global Energy Conference webcast.

Boedeker also said the location of EOG's assets in the Eagle Ford presents new opportunities in the wake of global desire for LNG.

"We have a significant amount of flexibility on what we can take with LNG," he said. "The majority of our gas out of the Eagle Ford … obviously goes into [Corpus Christi]. We do have an increased exposure to LNG. We have 140 million a day now exposed to international pricing with LNG. And that goes up to 420 million a day in 2025 with Cheniere Stage 3 coming on. There's an additional 300 that's linked to Houston Ship Channel, just to make sure there aren't any differentials at that point in time."

In short, producers see abundant opportunities in the Eagle Ford. And many want to get in on it. RBN Energy analyst Housley Carr said recently that heightened M&A activity in the area may represent at least the beginnings of a return to the mid-2010s in the Eagle Ford Shale.

Consolidation may be key. Acreage ownership is fragmented in the Eagle Ford, largely among dozens of private companies running one or two rigs that would be prime targets for acquisition by larger companies.

At present, the Eagle Ford Shale is "more a buyer's market than a seller's market," although acquisitions will come at a premium for buyers, Dittmar said.

The future of the Eagle Ford Shale

Looking forward five to 10 years, Dittmar said, the Eagle Ford Shale will still be an active and important play, with small private companies still playing a role in developing its resources as larger companies look to acquire those smaller interests as consolidation of the Eagle Ford Shale's resources continues.

Companies such as EOG continue to test new ideas in the Eagle Ford, such as its EOR program, which has boosted its drilling results exponentially in recent years.

Today in the Eagle Ford Shale, oil and gas exploration companies are revisiting old well sites and trying out new extraction techniques. Thus far, he said, results of that approach have been mixed. But that innovation will be "one of the interesting go-forward stories" in the Eagle Ford Shale, he said. OGI

The buy "captures a top-tier oil resource with a meaningful runway of highly economic inventory that is complementary to our existing footprint in the Eagle Ford," Muncrief said.

The addition of Validus almost doubled Devon's current Eagle Ford footprint. The company's pro forma position of 82,000 net acres was expected to produce an estimated 73,000 boe/d in 2022—well above the 38,000 boe/d that Devon reported for the basin during the second quarter.

"Color us a bit surprised," said Tudor Pickering Holt & Co. analyst Matt Portillo in a note to investors.

The added scale poised Devon to realize $50 million in average annual cash flow savings from capital efficiencies, operating improvements, and marketing synergies, while keeping leverage relatively unchanged at current strip prices, management said.

WildFire Energy LLC

WildFire Energy has gobbled up billions of dollars' worth of acreage in the Eagle Ford since making its entrance there in 2021, when it acquired rival E&P Hawkwood Energy in a $650 million deal.

The firm emerged in January as the buyer of Chesapeake Energy's 377,000 acres in the Brazos Valley region of the Eagle Ford Shale in a $1.4 billion deal.

The terms included more than 1,300 wells and will boost WildFire's presence in the eastern Eagle Ford to nearly 2,000 wells on 600,000 contiguous acres across Burleson, Brazos, Robertson, Madison, Lee, Washington and Grimes counties.

President and COO Steve Habachy said the deal was designed to be "transformative to the business" by providing WildFire with an economy of scale for getting barrels into the Gulf Coast market.

BP: UKRAINE WAR LIKELY TO SPEED DECLINE IN FOSSIL FUEL USE

The fallout from Russia's invasion of Ukraine includes a global movement away from imported fossil fuels toward domestically produced renewables, BP said in its annual "Energy Outlook."

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An intensified global focus on energy security, stemming from the Russia-Ukraine war, will likely hasten the move away from fossil fuels toward greener sources, BP Plc said on Jan. 30 in its "2023 Energy Outlook."

But the report's lead author emphasized the continued importance of oil and gas as the world's economies transition to new energy sources.

"Even in Accelerated/Net Zero [scenarios], in which oil and gas demand fall materially … the natural rate of decline of existing production is even greater, meaning that continued investment in upstream oil and gas is required to meet future demand," Spencer Dale, BP's chief economist, said during the company's webcast discussing the report.

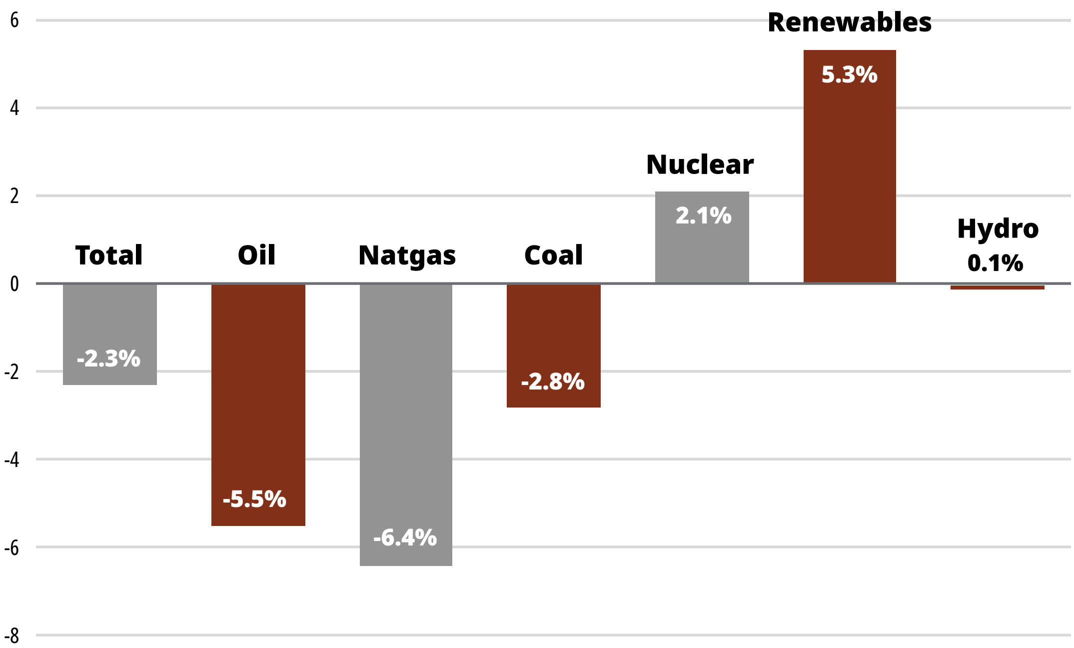
BP employs three scenario designations in its outlook modeling:

- Accelerated, which assumes a significant tightening in climate policies;
- Net Zero—a "what if" scenario like Accelerated that also assumes a shift in societal behavior and preferences that further support gains in energy efficiency and low-carbon energy; and
- New Momentum, which models the current broad trajectory of the world energy system, including the speed and global ambitions for decarbonization.

Echoing Dale's concerns during the webinar, Jason Bordoff, founding director of Columbia University's Center for Global Energy Policy, noted the possible repercussions if fossil fuel investments were to decline too rapidly.

"How do you make sure that you're synchronizing—as much as possible—declines in investment in supply with the declines in demand?" he asked in a subsequent discussion. "Because if you see declines in supply but

Change In Primary Energy In New Momentum Scenario
% Change from 2022 Energy Outlook



Source: BP 2023 Energy Outlook

BP's projection for energy consumption in 2035 has changed since the 2022 version of its outlook. In the scenario in which adaptation of renewable sources is least aggressive, oil and natural gas nevertheless drop sharply.

"History has taught us that threats to energy security can have large and persistent impacts on the structure of global energy."

—Spencer Dale, *BP Plc*

"When you layer on top of the urgency of dealing and coping with energy security risks, I think that is a powerful combination."

—Jason Bordoff, *Columbia University's Center for Global Energy Policy*

demand doesn't fall, the consequence is going to be higher prices and more volatility and maybe more, not less, geopolitical influence for traditional petrostates that step in to fill the gap."

War's lasting impact

Dale described three major energy implications of the war in Ukraine: heightened concerns for energy security, the changing composition of global energy supplies and weaker economic growth.

The renewed focus on energy security is assumed to cause countries to want to reduce their dependence on imported energy and instead consume more domestically produced energy, he said. It also spurs improvements in energy efficiency.

"History has taught us that threats to energy security can have large and persistent impacts on the structure of global energy," Dale said.

For example, the 1970s Arab oil embargo led to the creation of the Strategic Petroleum Reserve in the U.S. and a massive buildout of nuclear power plants in France.

The common thread to this era is the demand to relieve dependence on imported fossil fuels with higher demand for renewables and other non-fossil fuels, which are predominantly produced domestically, he said. This will help to accelerate the energy transition.

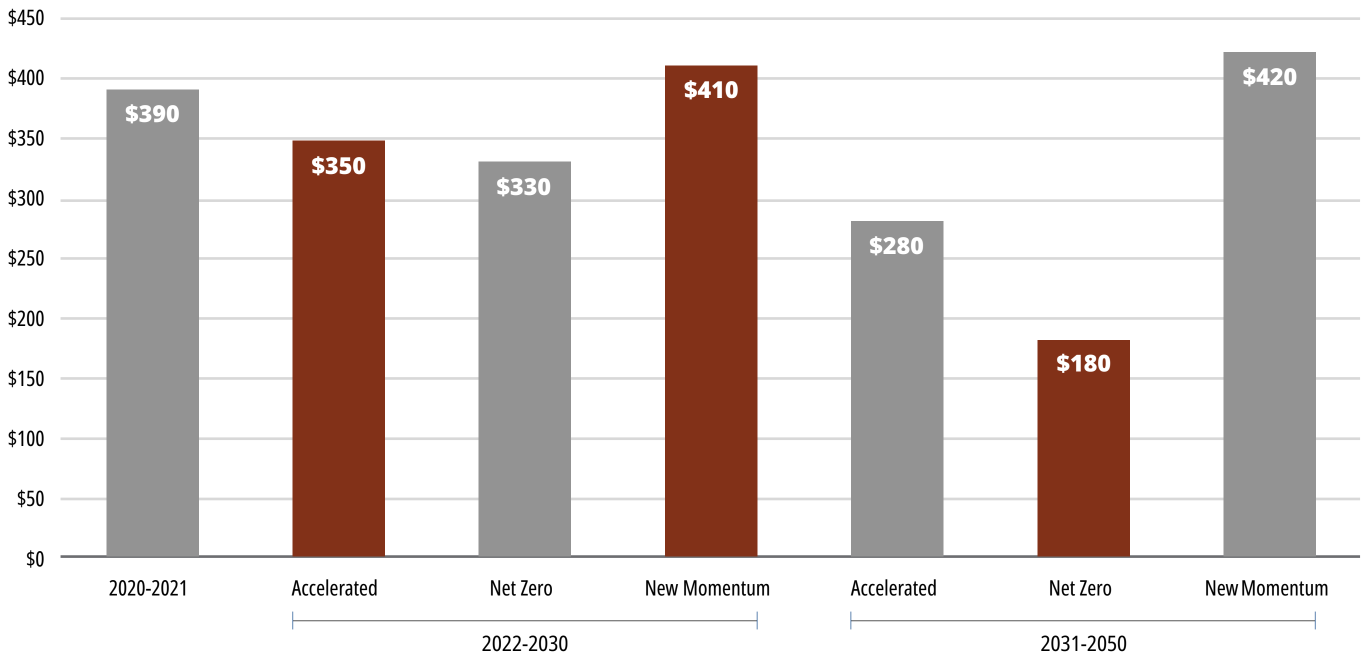
"People jump through hoops when energy security is at risk, and we have a growing—not yet sufficient, but growing—sense of urgency that we need to jump through hoops a lot faster to deal with the climate crisis," Bordoff said. "When you layer on top of the urgency of dealing and coping with energy security risks, I think that is a powerful combination."

To examine the New Momentum scenario, BP compared its energy outlook with the 2022 report. The change in energy consumption varies, depending on the fuel, but oil and natural gas will experience a disproportionately large impact, Dale said.

Weaker economic growth is seen over the near term in high food and energy prices, which BP expects to persist for the next few years. Over the long term, fallout from the war will result in a reduction in the pace of global integration and trade as countries and regions reduce their exposure to international shocks, the outlook says. The slower pace of globalization will curb economic growth over the next 30 years.

The effect will be small on a yearly basis—only about 0.1%—but over time will reduce global GDP by around 4% in 2050. Its impact on countries will vary. Emerging Asian economies will be hit much more harshly than developed economies, such as the U.S. OGI

Average Annual Investment In Upstream Oil And Gas
$ Billions



Source: BP 2023 Energy Outlook

The average global investment in oil and gas, which totaled about $390 billion in 2020 to 2021, will decline in BP's accelerated and net-zero scenarios.

▸ ENERGY INSIGHTS

DAN PICKERING TALKS M&A, U.S. PRODUCTION GROWTH

Dan Pickering, chief investment officer of Pickering Energy Partners, discusses U.S. production and M&A after a "funky and weird" 2022 and sees the U.S. shale boom settling into a "shale business."

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Pickering Energy Partners chief investment officer Dan Pickering spoke exclusively with Hart Energy about a slew of energy topics: the future of U.S. production growth, 2023 M&A after a "funky and weird" 2022 and the (fading?) U.S. shale boom.

Additionally, Pickering addressed the market outlook amid the Russia-Ukraine conflict. Whenever the war ends, he said, Russia will remain in the sanctions' "doghouse" for a long time to come.

Pickering also weighed in on how the war has altered the pace of the energy transition. "Russia has reminded us that hydrocarbons are pretty damn important," he said.

Pickering Energy Partners offers expertise that spans decades across the entire energy landscape. The firm has deployed \$15 billion in investments across all energy subsectors since 2004. Hart Energy's international managing editor, Pietro D. Pitts, interviewed Pickering on the sidelines of the Independent Petroleum Association of America's Private Capital Conference on Jan. 19 in Houston.

Pietro D. Pitts: Where is the U.S. market going in terms of any increases in oil and gas production?
Dan Pickering: We've got a positive price environment, and we have energy security as a dynamic. But at the same time, amid all this uncertainty and scars of the past … There's high profitability in the business, so there's plenty of cash to reinvest but a fairly low willingness to get aggressive and try and grow.

Over the next five years, U.S. production will go back to new highs. Spending is going to go up a little this year, but it's not going to accelerate dramatically. So, the answer is not as much activity as you would expect with oil at \$80/bbl, but it's building, and that sort of slow burn that's happening is going to flow over into kind of the global reinvestment cycle.

The U.S. took a bunch of market share during the shale boom. It's probably not taking any more market share as demand recovers, and so the next two or three years the U.S. claws back a little bit. These longer dated projects internationally offshore are going to pick up some steam because we know we need the crude, we need it from trustworthy places and the health of the business is now such that folks can start to think about spending on longer[-term] projects.

PDP: Now that the U.S. has had this shale boom that's now a "shale business," do we have that energy independence that we really have been pushing for?
DP: The U.S. is at near record levels of production, so we are in as good a shape as we've been in decades around energy security and independence. The reality is it's a very complicated market, particularly on the oil side. We don't refine all of our crude … we're shipping out products and crude because of all of the logistics of different crude grades and whatnot. Just because we have a lot of production doesn't necessarily mean that there can't be bottlenecks in the supply chain that can make things funky. So we couldn't and wouldn't want to be an island because we're not built to just run U.S. energy. We're built to run global energy. That's part of why all of this is going to take a very long time to sort out because it's a massively complex system. Again, you don't necessarily see that complexity when you put gasoline in your gas tank, but it's there right behind the scenes.

PDP: In 2022, we saw a lot of share buybacks. Is that trend going to continue this year, or do you see more money going toward M&A to grow production this year?
DP: You have a couple of dynamics going on. The demand from investors for the return of capital I don't think is going away. We're going to see continued dividends, special dividends and share repurchases. At the same time, we're starting to see some maturing of conventional shale production. So if you're

“Our view is that in 2023 M&A picks up. There was some this [past] year, but again, it was such a funky, weird macro world. We expect fewer surprises in 2023.”

—Dan Pickering, *Pickering Energy Partners*

a company in that environment, you’re trying to balance out your shareholders with rebuilding inventory or having quality inventory. Our view is [that] in 2023, M&A picks up. There was some this [past] year, but again, it was such a funky, weird macro world.

We expect fewer surprises in 2023 as we come in with our eyes wide open on the pandemic, the economy, interest rates, all of those things, Ukraine. So the ability to sort of say, OK now let’s get back to business. And things aren’t expensive, valuations are four or five times cash flow, not eight times cash flow. The publics are comfortable using their stock as some currency in transactions, and the private equities are willing to take it. So there should be more activity because 2023 is less surprising than 2022.

PDP: Is the U.S. shale boom behind us or is it still going on? Is there sufficient shale production to anchor new LNG projects on the U.S. Gulf Coast, or in the U.S. in general, and then LNG projects planned in Mexico?

DP: We had our shale boom. We now have the shale business. I don’t think we’re going to see the kind of dramatic rig count and production additions. The geology is there and because productivity’s beginning to plateau, we’re going to have to drill more wells to get more production, [and] we’re going to have to have more rigs, more activity. Given all the dynamics, it’s unlikely that things explode and we boom. Is there enough productivity for LNG projects? The answer on the gas side is yes. I think we have a lot more gas reserves, supply availability [and] speed to market. So right now in the U.S. we have too much gas. In 2025, when these LNG projects start coming on, probably not. But the Haynesville, Eagle Ford, Permian—Permian associated gas—we’ll do some stuff on the East Coast and get the Appalachia involved, so the answer is I’m not worried about the supply side of gas for LNG projects.

PDP: Does the U.S. really have enough gas to send down piped gas to Mexico for their current needs and not considering their LNG?

DP: I don’t know what the actual physical pipe situation looks like to Mexico, but if there’s pipe capacity, we’re going to have productive capacity. We have gas to put in, and if they want more, we’ll send them more, assuming we’ve got the midstream to do that. So Mexico and LNG, they want [the gas and] we got it. It’s not going to be $2.50/Mcf, and that’s the other issue that we’ve put a better floor under.

The Europe situation, LNG visibility centers put a better floor under gas prices. So we’re not going to ship $2 gas there, we’re going to be shipping $3, $4 and $5 gas.

PDP: How will the ongoing Russia-Ukraine conflict dictate the market this year? Are you modeling an end to the conflict anytime soon?

DP: We’re not geopolitical experts, so we’re modeling the status quo, which is neither a dramatic escalation or de-escalation because it doesn’t seem like the people that could stop this are going to step up and really stop it. The U.S. isn’t going to escalate, and it doesn’t feel like either side has really got a tactical advantage. So status quo is what we’re assuming.

If there’s a resolution there, it’s probably great for markets, [and] it’s probably not great for the commodity in the short run because our expectation would be everybody is going to assume Russian supply gets a lot more plentiful or easy. The reality would be Russia’s in the doghouse for as long as the eye can see, and therefore the reality is they’re going to be sanctioned, they’re going to be a declining influence in global oil and gas markets for the next decade. But the knee-jerk reaction if peace happens, oil and gas prices go down.

PDP: How have recent years with the pandemic and the Russia-Ukraine war changed the outlook for the energy transition? Has that transition slowed because of what happened in Ukraine, and if so, how do we get back on track?

DP: What we’ve seen over the last two years is that the faster you go on energy transition, the more volatile things can be because of the intermittency around renewables, and it’s expensive. Russia has reminded us that hydrocarbons are pretty damn important and will be for a while. High natural gas and U.S. gasoline prices sort of increase the resolve of governments and others to move more quickly toward energy transition. The one thing that everybody wants is to decarbonize. Very few people know what that actually costs. And it’s being masked in many cases by government subsidies or whatnot.

The energy transition, if anything, has accelerated because of high hydrocarbon prices. But the flipside is we also learned that we can’t go fast, [and] we can’t get there fast, so it’s really important to make sure we have secure sources of energy, and that’s going to be fossil fuels. The energy transition didn’t take a hit from everything that’s happened. And if anything, the Inflation Reduction Act sort of helped accelerate it. So, the energy transition is alive and well, and it’s going to be a big story for a long time.

▸ CRUDE OIL

RUSSIAN 'GHOST TANKERS' STALK GLOBAL OIL MARKETS

As many as 600 ghost tankers ferry Russian crude oil and oil products to markets at high risk and reduced prices.

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Russia's huge fleet of "ghost crude tankers" succeeds in generating revenue and evading western sanctions but at great cost and considerable risk, a global energy expert told Hart Energy.

"They're adding friction, they're adding cost to the system, some of which is being borne by Russia in the form of discounting crude oil to find new homes for it," said Mark Finley, fellow in energy and global oil at Rice University's Baker Institute for Public Policy. "There are real costs in the system, for sure. We'll have to see what it means for refined products because those are different tankers, they tend to be smaller."

Ghost tankers are vessels that disguise their ownership and movements to move cargoes under sanction. They have been used to transport Venezuelan and Iranian crude for years.

"The oil market's a big place with a lot of dark corners," Finley said. "That's not new. What's new is the scale of what's happening."

Russia's ghost fleet has expanded to about 400 crude carriers and about 200 oil product carriers, a Trafigura executive told Bloomberg Television. That constitutes about 20% of the world's crude vessel fleet and about 7% of all oil product tankers.

Dodging sanctions

The higher cost of shipping Russian crude stems from several factors. Most crude oil in the world is transported on very large crude carriers with capacities of up to 320,000 dead weight tons (DWT), or 2.2 MMbbl. Aframax-class tankers, one of the types employed in the ghost fleet, are only able to haul about 160,000 DWT.

Reuters reported that a recent invoice showed the shipment of 700,000 bbl of Russian crude on an Aframax tanker from a Baltic port to an Indian refinery. The charge was about $10.5 million, compared to a cost in the range of $500,000 to $1 million a year ago.

One trader in Russian crude told Reuters the business was "crazy good."

But the older, smaller tankers pressed into service were likely on the verge of being scrapped, Finley said. They are more at risk for mechanical breakdowns, accidents or spills. The vessels may well be self-insured because sanctions have prevented western

Shutterstock/Aerial-motion

insurance companies from doing business involving Russian seaborne crude.

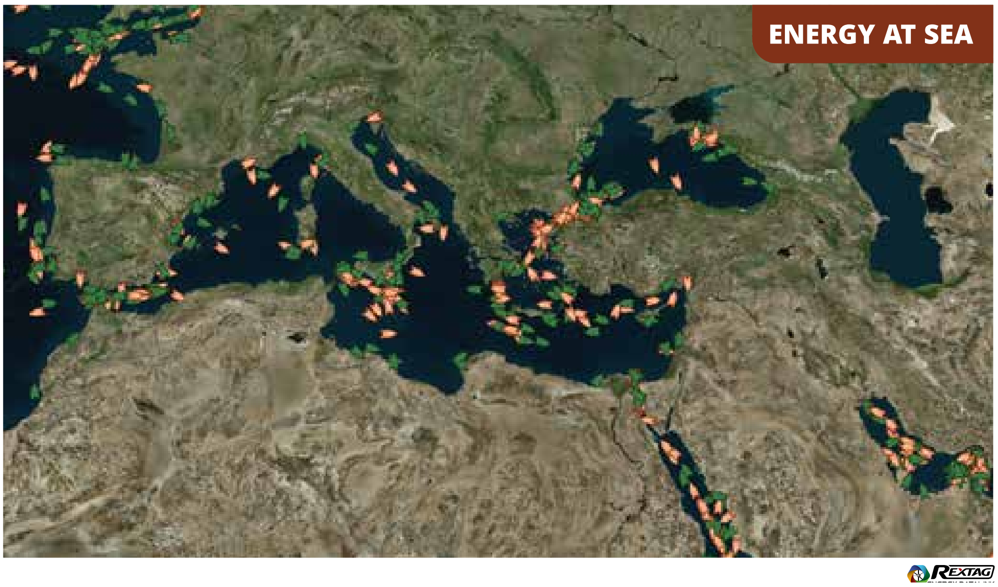
"The market's full of characters who are happy to find creative ways of doing business, shall we say, if there's money to be made," Finley said. "In that sense, it's not surprising to me that these embargoes have come into place without major disruptions to the marketplace."

And it can be argued, he said, that new centers for shipping and insurance, and transactions that don't use U.S. dollars, can develop in the global marketplace.

"The risk is that people find workarounds that, in the future, could undercut the leverage the U.S. and its allies have over our adversaries because we've hastened the development of these alternative systems," Finley said.

He noted that Iranian entities have tutored their Russian counterparts on how to evade sanctions since the invasion of Ukraine in February 2022. That doesn't mean the world of international trade has gone over to the dark side. Not yet.

"The reason why the successful exchanges are in the west, and the successful insurance entities are in the west, and why the successful shipping companies are in the west, is because these are the places with competitive advantages in terms of rule of law and transparency,"



Representations of crude oil (orange) and chemical tankers swarm the seas on a recent day. Ghost tankers disguise their ownership and movements, making them difficult to identify.

he said. "While there is potential for these alternative channels to develop, they are likely to be more expensive, and therefore be a durable source of competitive disadvantage."

Budget troubles

The EU's ban on seaborne imports of Russian crude oil took effect on Dec. 5. A similar ban is now in place for diesel and other fuels. The group of leading industrial nations known as G7 imposed a price cap of $60/bbl on seaborne Russian crude in December.

Prior to the invasion, Russia's Urals blend tracked Brent fairly closely. Since then, the spread has widened significantly. Urals closed at $55.12/bbl on the spot market on Feb. 7, well below international benchmark Brent's mid-$80s.

Urals is a medium sour crude with sulfur content of 1.7% and API gravity of 31.7, which is broadly equivalent to Arab Light produced in Saudi Arabia. By comparison, WTI Midland, a light sweet crude, has a sulfur content of 0.2% and API gravity of 42.

Russia's budget is based on a Urals price of $70.10/bbl. With Urals sold at a significant discount to just a few countries—India, Turkey and China, among them—the Russian federal budget registered a deficit of $25 billion in January. The month's oil and gas revenues were down 46.4% compared to January 2022.

Urals is a sanctioned seaborne crude. However, Russian crude that travels east on the 2,600-mile Eastern Siberia Pacific Ocean oil pipeline traded closer to market price at $68.56/bbl on Feb. 8. That oil is shipped to Japan, China and South Korea.

"The market's full of characters who are happy to find creative ways of doing business, shall we say, if there's money to be made."

—**Mark Finley,** ***Baker Institute for Public Policy***

The intent of the sanctions, Finley emphasized, was not to disrupt exports of Russian oil, but to reduce revenues and thereby hinder its war effort in Ukraine.

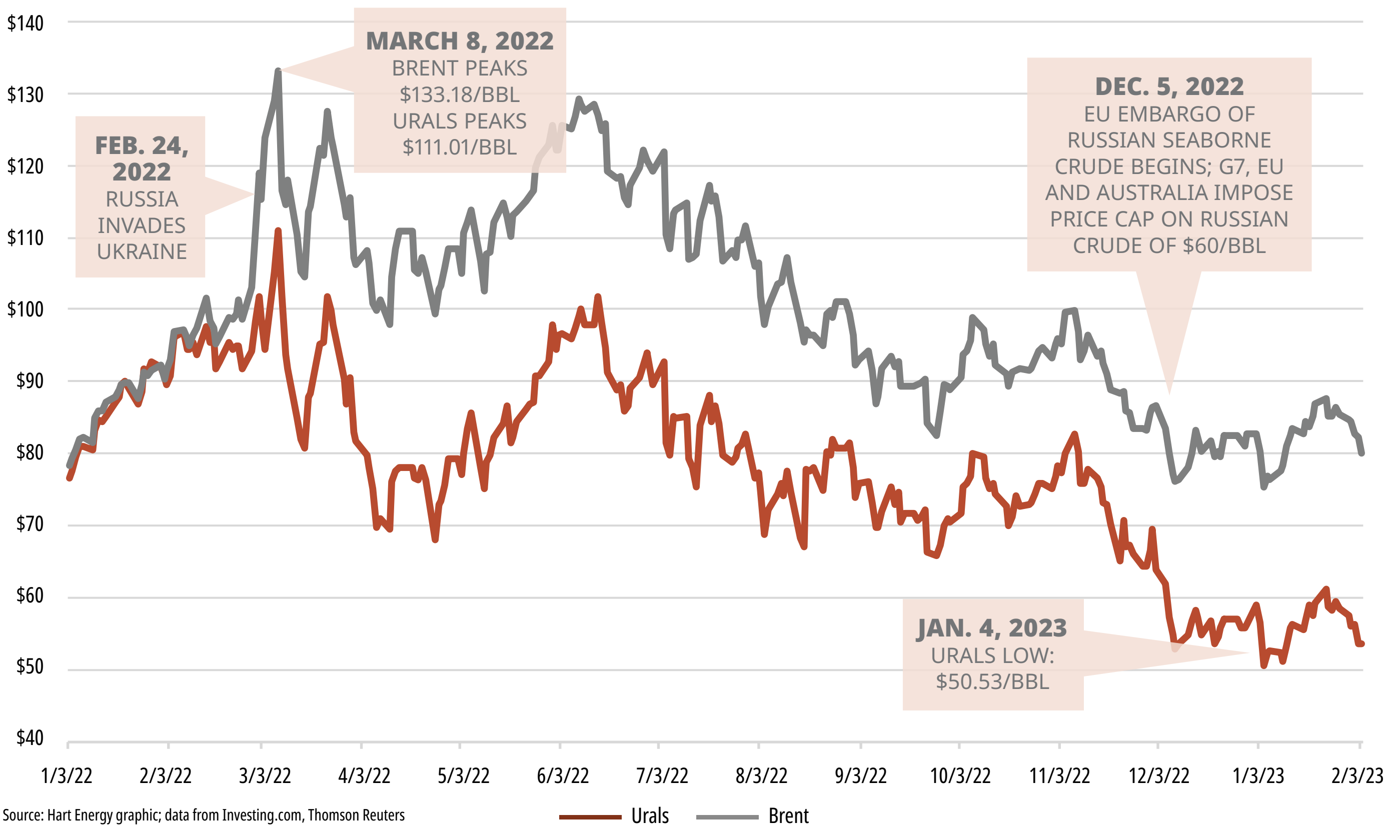
By contrast, the Joint Comprehensive Plan of Action (JCPOA) sanctions against Iran were designed to stop Iranian oil from flowing altogether. The sanctions prevented transactions involving Iranian oil from moving through the western financial system and worked, in large part, because U.S. shale production was ramping up dramatically at the time.

Russia was the world's second-largest exporter of both crude oil and oil products before the Ukraine war, putting the U.S. and allies in a tight spot. Allowing Russian oil to flow helps to keep prices low for U.S. consumers at the pump.

"This is a completely different approach than was used against Iran during the JCPOA," Finley said, "and harder to make it stick because of that." OGI

Urals Vs. Brent Prices

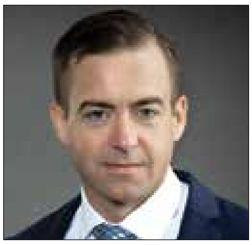
January 2022-February 2023



Source: Hart Energy graphic; data from Investing.com, Thomson Reuters

OPINION:

BUSINESS SCHOOL BUZZWORDS APPLIED TO MIDSTREAM



HINDS HOWARD
CBRE INVESTMENT MANAGEMENT

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

Read the full column here:

Business school theories can seem basic, but there are some frameworks and buzzwords that can be a useful lens to view the current midstream landscape—more useful because so much has changed in the sector in a short period of time.

The first concept is the industry life cycle, which includes five stages: startup, growth, shakeout, maturity and decline. The growth phase for midstream was roughly the decade that ended in 2014, with high capex to build infrastructure in support of high production growth from unconventional development of shale basins. The sector then had an unusually long shakeout period that ended at some point in the past few years, typified by new entrants competing margin away, leading to fewer viable companies.

That brings us to the current stage: maturity. In this stage, growth is limited, so there's less need for capex. The focus shifts to reducing expenses, which leads to further consolidation that tends to be accretive to margins as scale can reduce per unit costs and overhead can be spread over a larger business. Industries in this phase seek to deter entry of new competitors to maintain profitability.

This stage generally has the highest cash flow. The maturity stage can last a long time, but the stage that follows is the decline stage, when companies become increasingly desperate to survive even as the industry starts to fade.

But for now, midstream is mature, and investors are pushing companies within this industry to focus on slowing investment, growing free cash flow and returning capital. Investors want them to be cash cows—another great business school buzzword.

The next business school concept to explore is "Porter's Five Forces," which seeks to identify where an industry's strengths and weaknesses are that can help with competitive advantages.

Competition within the industry is one of the Five Forces. In midstream's growth phase, with abundant capital available, there was intense competition. After years of consolidation, inflation of materials and labor, higher interest rates and low returns for private capital, competition within the industry has been reduced substantially.

"Threat of new entrants" is another of the Five Forces that has shifted in favor of existing midstream operators. In addition (or perhaps as a result), the power of customers (another of the Five Forces) has been reduced. A decade ago, when a fragmented midstream industry served few large companies, the power of major customers like Exxon Mobil Corp. or Pioneer Natural Resources Co. was extremely high and that led to the overbuilding of pipelines and processing capacity in certain regions with high production growth. However, not so today, especially with regulations creating larger hurdles to new energy infrastructure.

The improved competitive positioning of midstream companies within the broader energy value chain could potentially lead to higher rates and higher margins for remaining midstream operators. It may finally come to pass that existing pipe in the ground sees its value realized in the form of pricing power and growing margins, even if volumes stagnate. The biggest threat to this improved competitive position is customers reverting to building their own infrastructure.

New company formation in midstream is at its lowest point in the sector's history. Rattler Midstream's IPO in 2019 was the last real IPO in the space. Since then, Kinetik Holdings was created via a special purpose acquisition company that combined with Blackstone's midstream business, and DT Midstream was spun out of utility company DTE. Even counting those, we are talking about just three new companies in four years. Compare that to 75 IPOs in the 10 years from 2006 to 2015, a more than seven per year average, not counting the general partner holding company IPOs (another 14 tickers) and not counting the coal, nitrogen and E&P MLPs (another 30 or so tickers).

Back in October 2014, just before the roll up of Kinder Morgan's MLPs closed, there were 94 publicly traded companies in the midstream space, including MLPs, U.S. corporations and Canadian corporations. Sixty-two of those companies had market capitalizations greater than $2 billion.

Today, there are 30 remaining companies and 24 with market capitalizations greater than $2 billion. There is a recent high for midstream companies in the S&P 500 at four, though.

Old companies are going away, new companies are not being formed, and competition among the industry is lower than at any point in the past 20 years. The major shakeout period for the industry is behind us, setting up a period of maturity and free cash flow that should endure as the world slowly transitions to a more inclusive energy mix with renewables displacing oil and coal over time. OGI

PROMISING OUTLOOKS FOR ENTERPRISE, MAGELLAN, HESS MIDSTREAM

In a strong earnings season, Enterprise surpassed $9 billion in EBITDA, Magellan beat earnings per share guidance and Hess Midstream weathered a tough winter to please investors.

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Has Enterprise Products Partners reached the final frontier of EBITDA achievement? Given how its motivated workforce performed in 2022, that trek is far from over.

The company's Project 9 was meant to increase operations efficiencies to push company EBITDA beyond $9 billion for the year. Among the successes: increasing methyl tertiary butyl ether production and increasing fractionation throughput at Mont Belvieu, Texas.

The Star Trek-themed program—"Boldly go where Enterprise has never gone before"—promised $3,000 bonuses for each employee if the company recorded $9 billion in EBITDA for the year. If the total crossed $9.3 billion, the employees would receive $5,000. It did and they did.

"We had so much fun with this," said co-CEO of Enterprise Jim Teague during the company's February earnings call with analysts. "We decided we are going to have Project 9.3 for 2023."

But don't take it for guidance, he quickly told analysts on the line.

Strong earnings and bright outlooks were the theme for three midstream companies reporting fourth-quarter and full-year 2022 earnings.

Enterprise Products Partners

Enterprise reported a net income of $1.45 billion on revenues of $13.65 billion for the quarter and a net income of $5.49 billion on revenues of $58.19 billion for the year. Earnings per common unit rose 38.3% to 65 cents for the quarter compared to 47 cents in fourth-quarter 2021. For the full year, earnings per unit were $2.50, a 19% increase over full-year 2021.

Enterprise's stock hovered around $26 for most of 2023, or about 10.3x earnings per unit. That price is well below analysts' consensus price target of $31. Of 21 brokerages that cover the stock, 18 give it a 'Buy' or 'Strong Buy' rating.

Quarterly distributed cash flow increased 22.2% year-over-year to $2.03 billion and 17.3% to $7.8 billion for the full year.

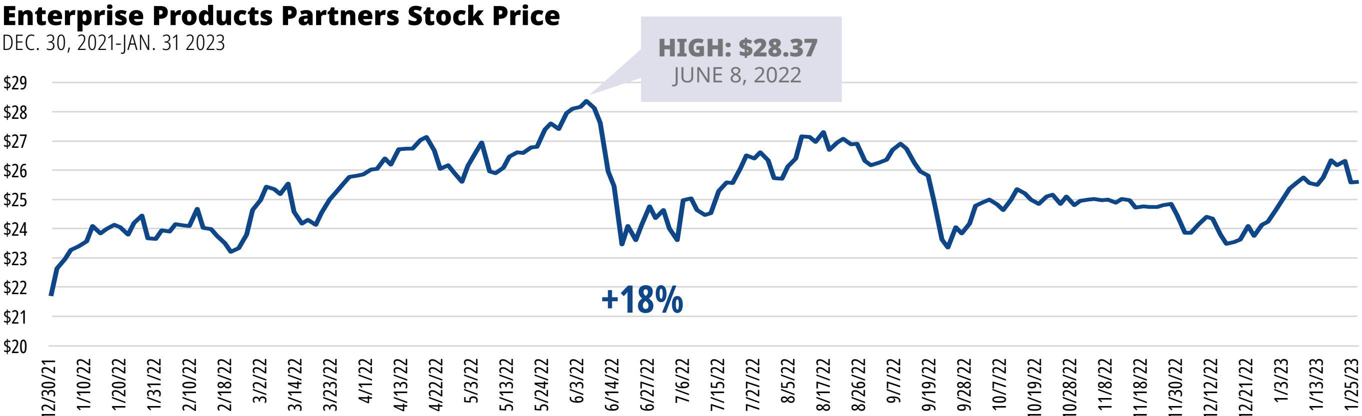
Teague noted record volumes across several of the company's assets, as well as contributions from its purchase of Navitas Midstream in February 2022.

"This acquisition was immediately accretive to Enterprise's cash flow per unit and has exceeded our expectations," he said.

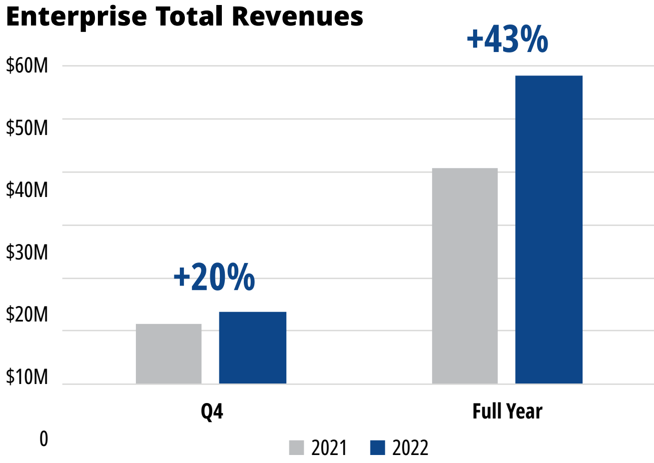
During the fourth quarter, the company purchased about 580 miles of pipeline and related assets on the Texas Gulf Coast to expand its NGL and petrochemical pipeline systems in the region. More acquisitions are possible as well.

"We are interested in asset acquisition opportunities that make sense, that can come in and bolt on to our system and get good returns on capital," co-CEO Randy Fowler told analysts. "And that's where the lower leverage gives us flexibility to … do these cash transactions. I think over the last … 18 months we've sort of completed that pivot to go from

Enterprise Products Partners Stock Price
DEC. 30, 2021-JAN. 31 2023

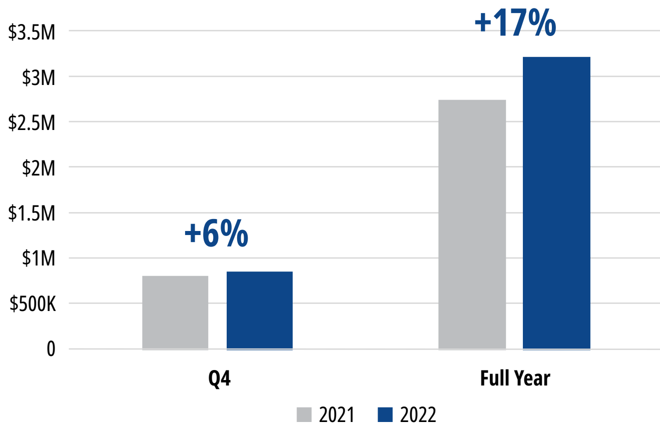


Enterprise Total Revenues



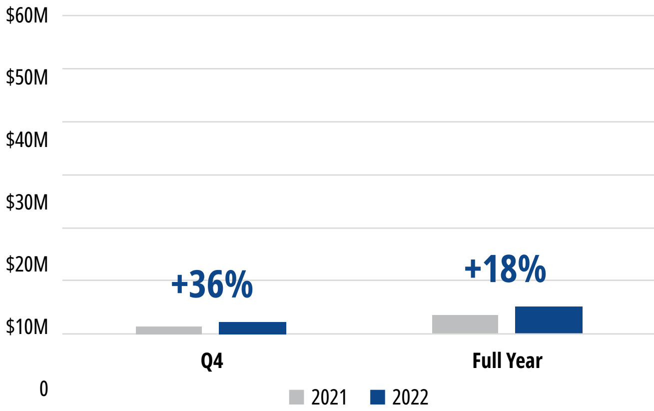
Source: Enterprise Products Partners

Magellan Total Revenues



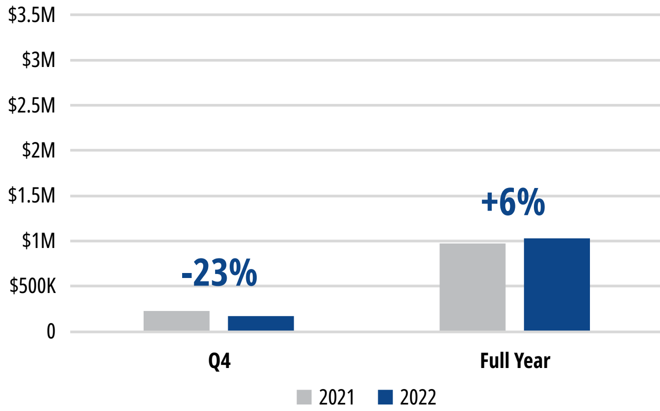
Source: Magellan Midstream Partners

Enterprise Net Income



Source: Enterprise Products Partners

Magellan Net Income



Source: Magellan Midstream Partners

an externally funded model to an internally funded model."

By segment:

- NGL pipelines and services reported a gross operating margin of $1.3 billion in the fourth quarter, up 17% year-over-year;
- Crude oil pipelines and services saw a 4.6% drop year-over-year to $418 million, with West Texas Pipeline System up $31 million and Seaway Pipeline up $18 million;
- Natural gas pipelines and services margin jumped 61% year-over-year to $315 million, setting a record of 17.6 trillion Btu, compared to 14.6 trillion Btu in fourth-quarter 2021; and
- Petrochemical and refined products services margin was flat at $339 million for the quarter, compared to $338 million in the same quarter of 2021.

Enterprise does not expect to return to the capital markets, Fowler said, and expects to mark 25 consecutive years of distribution growth in 2023.

Magellan Midstream Partners

Higher-than-expected revenues from refined products transportation, as well as a higher commodity margin from additional blending volumes, buoyed net income for the company in the fourth quarter. Magellan reported net income of $187 million, affected by a non-cash charge of $58 million related to its investment in the Double Eagle pipeline.

Without that impairment, diluted net income per unit of $1.34 handily beat guidance of $1.22 issued last fall. The Double Eagle impairment involved nonrenewal on terms of customer commitments expiring later in 2023 and reduced demand for condensate transport from the Eagle Ford basin. Diluted net income per unit for the full year was $4.47.

Total revenue was $861 million in the quarter, compared to $809 million in fourth-quarter 2021. Full-year revenue of $3.2 billion beat 2021 by 17%. Full-year net income was $1.04 billion, compared to $982 million in 2021.

Magellan's crude oil shipments in the quarter rose 47.2% year-over-year to 65.2 MMbbl. For the full year, the company shipped 229.8 MMbbl, up 21.2% over the 189.6 MMbbl moved in 2021.

Quarterly crude oil operating margin increased 23.5% to $128.2 million year-over-year. For the full year, the margin was up 8.4% to $466.9 million. Higher average rates on the Longhorn pipeline, higher terminal fees and increased dock activity from customers using a simplified pricing structure in the Houston area pushed up transportation and terminals revenue by $9 million in the quarter.

Crude oil shipments are projected to rise in 2023 on company-owned pipelines. Magellan expects shippers on its joint-venture pipelines to not meet commitment levels and to make deficiency payments.

For 2023, Magellan expects to generate distributed cash flow of $1.18 billion. Free cash flow is projected to be $1.07 billion, or $216 million after distributions. This is based on an average crude price of $80/bbl for the year. The company estimates that each $10 change in the price of crude affects its financial results by about $35 million.

Hess Midstream

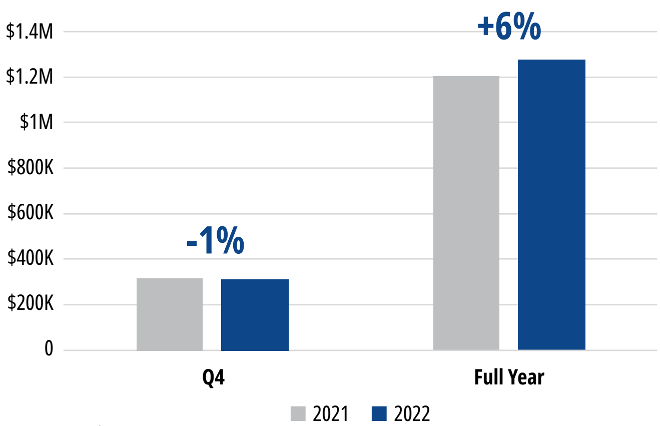
Quarterly net income was $149.8 million, with net income attributable to Hess Midstream of $21.8 million, up 29% from $16.9 million in the same quarter last year. Total revenue in the quarter was $314.6 million, essentially flat year-over-year, with full-year revenues of $1.275 billion exceeding 2021 revenues by 6%.

Gathering operations accounted for $166.1 million, or 52.8%, of revenues in the quarter. Processing and storage revenues totaled $118.8 million, and terminaling and export revenues were $29.7 million.

Throughput volumes for gas gathering dipped 4.9% year-over-year and 11.4% from the third quarter to 328 MMcf/d due to severe weather in the Bakken and Three Forks shale plays. Crude oil gather was off 12.3% in the quarter year-over-year and 8.8% from the third quarter.

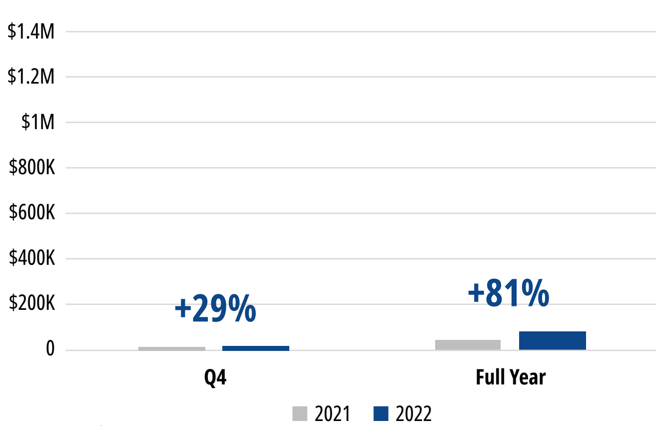
In its 2023 guidance, Hess Midstream projects full-year gas gathering volumes to average 365 MMcf/d to 375 MMcf/d. Gas processing is projected at 350 MMcf/d to 360 MMcf/d. Crude oil gathering is expected to average 95,000 bbl/d to 105,000 bbl/d, and crude oil terminaling is projected to average 105,000 bbl/d to 115,000 bbl/d. OGJ

Hess Total Revenues



Source: Hess Midstream

Hess Net Income



Source: Hess Midstream

▸ REGULATORY

VENEZUELA SANCTIONS: PAST, PRESENT AND FUTURE

JAMES E. SMITH
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James Smith's law practice is principally focused on environmental, safety, and regulatory matters. He is a shareholder based in the Houston office of Crain Caton & Smith.

Venezuela has been subject to U.S. sanctions since 2006. Sanctions have remained through both Republican and Democratic administrations and have increased in severity since first imposed.

In 2022, the Biden administration's Department of the Treasury issued a general license allowing Chevron Corp. to operate and manage its joint ventures (JV) with Venezuelan national oil company PdVSA. These steps have led to speculation about further lessening, or even removal, of Venezuelan sanctions. A look at the history of Venezuelan sanctions, the scope of current sanctions and the Biden administration's announcements related to the sanctions indicate full sanction removal is unlikely.

In 2006, the Bush administration's Secretary of State, Condoleezza Rice, made a determination that Venezuela was not cooperating fully with U.S. anti-terrorism efforts. This resulted in a ban on U.S. commercial arms sales. Also starting with the Bush administration, Venezuela has been designated as a country that has demonstrably failed to keep its obligations under international narcotics agreements.

In 2014, Congress passed legislation requiring the president to impose sanctions on individuals responsible for serious human rights abuses. In 2015, the Obama administration placed sanctions on several Venezuelan officials.

The Trump administration imposed more severe sanctions. Notably, in 2019, PdSVA became subject to sanctions. Generally, U.S. companies and individuals are prohibited from engaging in transactions with PdVSA.

Current Venezuelan Oil Minister Tareck el Aissami is one of several Venezuelans designated as a Specially Designated Narcotics Trafficker. He has been indicted by two U.S. grand juries, and the U.S. has offered a reward of up to $10 million for information leading to his arrest. In classic bureaucratic understatement, the Congressional Research Service reports: "Should Al Aissami remain in that position, it could complicate efforts to lift oil sanctions."

The Venezuelan government continues to be subject to severe U.S. sanctions. Transactions with the Venezuelan government, including government-owned companies, remain generally prohibited.

The Treasury department has issued several general licenses to allow transactions within a limited scope. Most of the general licenses relate to financial transactions, humanitarian assistance and ensuring the sanctions do not overly disrupt transportation and communication infrastructure.

In 2022, after the Maduro regime announced it was returning to negotiations with the opposition, the Treasury issued a general license allowing Chevron to resume business in Venezuela. However, the general license only allowed for "limited natural resource extraction operations in Venezuela."

The general license 1) prevents PdVSA from receiving profits from Chevron's oil sales, 2) only authorizes activity related to Chevron's JVs in Venezuela and 3) does not authorize any other activity with PdVSA. The Office of Foreign Assets Control guidance indicates U.S. companies and individuals can provide certain goods and services to support Chevron's authorized efforts, including: the production and lifting of petroleum or petroleum products produced by Chevron's JVs; related maintenance, repair or servicing of Chevron's JVs; sale of petroleum or petroleum products to the U.S. produced by Chevron's JVs (provided that the petroleum and petroleum products produced by the JVs are first sold to Chevron); the procurement and import into Venezuela of goods or other inputs for authorized activities; and the processing of payments by U.S. financial institutions related to these activities. Transactions with PdVSA not related to Chevron's efforts or another general license remain illegal.

The Biden administration has stated that maintaining Chevron's general license (which is valid for only six months unless extended) and further loosening of sanctions will depend on the progress of the Maduro regime toward the peaceful restoration of democracy.

Venezuelan sanctions have had wide bipartisan support through multiple Republican and Democratic administrations. The Biden administration has been careful to note the limited nature of the Chevron license and continued illegality of doing business with Venezuela, including PdVSA.

Until this administration, or the next, sees noticeable positive changes, especially toward free and fair elections and removing those viewed as criminals from senior government posts, current sanctions will remain. Due to the regime's history of using energy assets and profits for corrupt and illegal activities, transactions involving U.S. energy companies will largely remain limited to the Chevron license, which itself may not last through 2023. OGI

HOW MUCH IS A DIGITAL TWIN WORTH?

HUVRdata and VEERUM partnered to engineer digital twin technology that contextualizes inspection data in virtual facilities and asset models.

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One still photograph can convey multiple ideas, but in the digital age, a picture is no longer worth a mere thousand words; images speak volumes. But are there even better ways for operators to capture images, identify ideas, describe situations and contextualize datasets?

Matt Alberts, director of strategic partnerships at HUVRdata, believes there is.

"When we talk about contextualizing data, I'm always of the opinion that a picture is worth a thousand words. A video is worth 10,000 words. But if I can pinpoint where an issue is on a piece of equipment in the middle of an oil refinery inside of a 3D model, well that's worth a million words to me," Alberts said.

HUVRdata partnered with VEERUM, a digital twin technology software company, to provide a new digital inspection solution. HUVR is combining its inspection data platform with VEERUM's 3D digital twin to create a tool that collects and contextualizes data found during inspections. The result is that operators will be able to see and understand the exact location of inspection findings on an asset, better equipping them to plan for maintenance.

This system will also standardize language around findings, making it easier to communicate information from those findings and share other data, creating an updated, easier process.

"Twenty-five years ago, it was an inspector handwriting out notes, describing where this was on this asset, maybe referencing an equipment drawing. You were depending on how well that inspector or technician could articulate where an anomaly was on an asset so that you could adequately give it to a planner or maintenance team to go make a repair," Alberts said.

Though this approach is flawed and time-consuming, operators still use the process today.

"The big discrepancy, both in my personal experience and what HUVR saw in the industry, was when inspectors and technicians go out looking at equipment, nine times out of 10, they're going to find the anomaly or what's wrong with the piece of equipment if anything is wrong. But how they describe it is going to be the big issue that we're going to have, and we lack standardization for how somebody

"I'm always of the opinion that a picture is worth a thousand words… But if I can pinpoint where an issue is on a piece of equipment in the middle of an oil refinery inside of a 3D model, well that's worth a million words to me."

—Matt Alberts, *HUVRdata*

describes something," Alberts said. "Some guys write you a paragraph, some guys write you a page, some give you a sentence, 'Hey, there's a weld crack.' OK, how big is it? How small is it? Is it leaking? What part of the equipment is it on?"

In short, "Data without contextualization is meaningless," HUVRdata co-founder and COO Ben Williams said.

Adding context

HUVRdata recognized these discrepancies and designed its vendor-agnostic platform to have a single, secure archive to store data from any source in any format, including large video files from ROVs. With it, inspectors could identify, structure and store key findings for future reference and inclusion within custom reports.

But regardless of these advancements, HUVR didn't have the ability to remedy the problem themselves. While it is an "open agnostic platform that specializes in inspection data management," the company didn't have the capacity to build its own additional twin platform, Alberts said. That is why partnering with VEERUM, which has those capabilities, made sense.

The inspection process is made much faster through VEERUM's digital twin technology, which creates a 3D representation of equipment and allows users "to be virtually in a facility or in an environment without having to travel to be there," Alberts said.

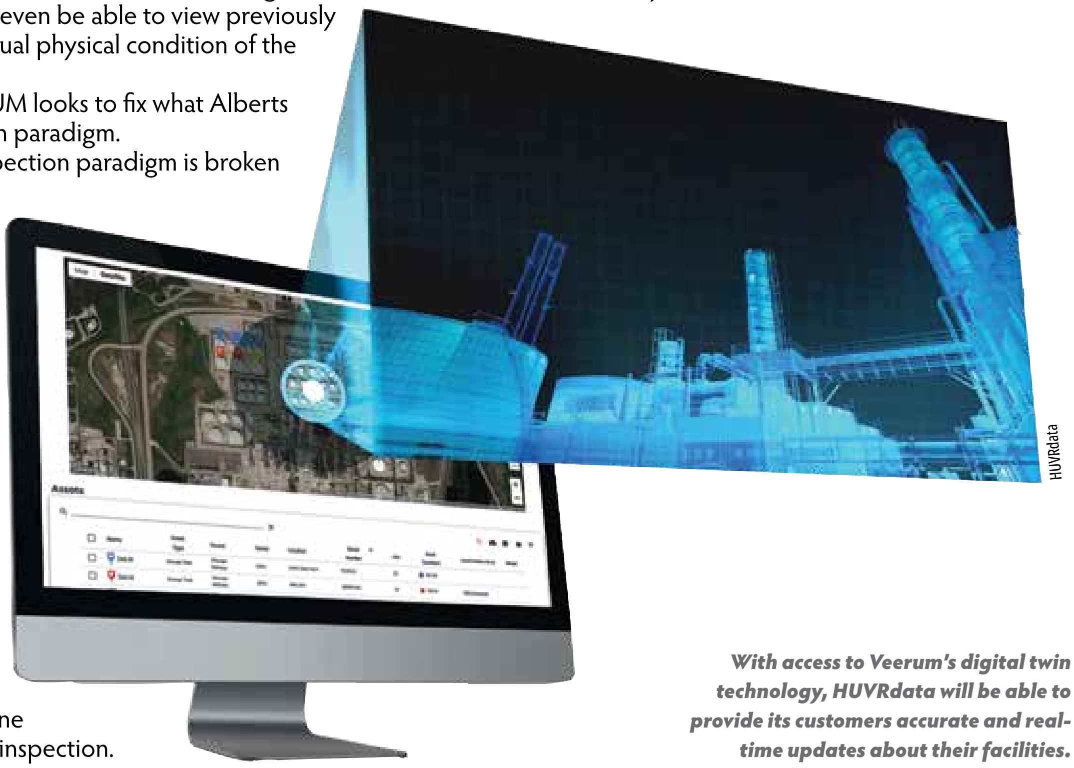
For inspections, users will be able to go inside a 3D model and pinpoint the anomaly on the specific location of the asset. VEERUM makes specifically curated facility models that can be updated using data HUVR collects during inspections. Operators will even be able to view previously scanned data to see the actual physical condition of the equipment in their model.

HUVR's work with VEERUM looks to fix what Alberts called a "broken" inspection paradigm.

"We believe that the inspection paradigm is broken across just about any industry out there," Alberts said. "And what we mean by it being broken is the fact that today the average inspector is tasked with using such a variety of different software tools to complete his inspection … but that's also the hole that HUVR's filling for users, for inspection companies, for asset owners."

HUVRdata and VEERUM will provide a configurable solution that allows users to only need one software platform to do an inspection.

"We have a very flexible solution that allows you to handle all the new inspection technology, the drones, the robotics, the different handheld devices, but also build that into the human workflow, allowing HUVR to help you leverage all those tools successfully," Alberts said.



With access to Veerum's digital twin technology, HUVRdata will be able to provide its customers accurate and real-time updates about their facilities.

ENERGY PUNDITS SAY EUROPE MUST PREPARE FOR NEXT WINTER

In 2022, Europe raced to fill gas storage with LNG imports. Now its focus must turn to next year's winter, top executives at Commonwealth LNG and Chesapeake Energy say.

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Europe and the U.K., having survived their first winter with reduced Russian gas, now must turn their attention to next winter, according to the leaders of Commonwealth LNG and Chesapeake Energy Corp.

The energy crisis in Europe caused by the Russia-Ukraine war has awakened the world and Europe in particular to its risky reliance on Russian gas, Commonwealth LNG founder and chairman Paul Varello said Feb. 1. Varello spoke during a panel discussion alongside Chesapeake Energy chairman and CEO Nick Dell'Osso at the annual NAPE Energy Summit in Houston.

While the outcome of this winter looks promising for Europe, Varello said Europe now realizes "that it needs a continual tactic focused on how we now fill up for next winter and how do we avoid this eventually by getting contracts in LNG long term."

Recently, Asia has also joined in the mix with Europe to assure they don't get short-changed again after having LNG cargoes redirected to Europe last year, Varello said.

Russian President Vladimir Putin's military exercises in Ukraine last year led to a full-scale war that continues to rage on nearly a year later. U.S. sanctions on Russia, as well as key allies' decisions to steer clear of Russian gas, has prompted an energy crisis in Europe and the U.K. due to a scarcity of gas. A combination of efforts last year to fill storage and replace Russian gas with U.S. LNG imports, coupled with a milder than normal winter, have been a lifesaver so far for Europe.

"The Europeans are starting to realize it's just good politics to have more business with America and maybe less with Russia, or even Qatar, which is right now pretty safe, but one day that could flip and then you are left with too much dependence on it," Varello said. "Europe is looking for not another sole supplier but a variety of choices."

But next winter could be worse.

Long-term contracts

Issues in the U.S. around permitting and building LNG export terminals remain a headwind to boosting exports, although government subsidies aren't necessarily needed, Dell'Osso said.

"But we need to be thinking about the long-term fundamentals," Dell'Osso said.

"When you look at the long-term fundamentals, it's very clear markets outside the U.S. will be short natural gas and the U.S. will be long natural gas."

—Nick Dell'Osso, *Chesapeake Energy Corp.*

Uncertainties continue to confound U.S. companies considering LNG export opportunities, including facility construction costs amid an inflationary environment, shipping expenses, supply-demand fundamentals once gas reaches Europe and uncertainties around future Russian gas, which is "offline" for now.

Such uncertainties make it challenging for companies to commit to long-term contracts and make it "a challenge to break that chicken and egg problem," Dell'Osso said.

"When you look at the long-term fundamentals, it's very clear markets outside the U.S. will be short natural gas and the U.S. will be long natural gas," he told the attendees. "So, we are a supplier of choice, and the rest of the world is very interested in solving their future supply problems. But we have not yet really cracked the code to see these contracts start to come with any pace."

After filling gas storage with Russian gas in 2022, the challenge for Europe will be refilling storage for next winter, both Varello and Dell'Osso said. They agreed the U.S. has ample gas supply for export as LNG but warned about an arbitrage market in which gas is supplied under contract then resold at higher prices.

In the future, there will be increased gas supply, whether from the U.S., Qatar or another source, followed by increasing demand. But market disconnects will eventually come together. Arbitrage profits don't last, Dell'Osso said.

"The market for U.S. gas is expanding. The price that gas receives is expanding so we should have exposure to that but you shouldn't assume it's an arbitrage," Dell'Osso said. OGI

INNOVATION AT FOREFRONT OF 2023 SPE HYFRAC CONFERENCE

Engineers from different corporations discuss different approaches to fracking, including the benefits of fiber optics and geothermal fracking.

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The spirit of collaboration and innovation was in the air at the 2023 Society of Petroleum Engineers Hydraulic Fracturing Technology Conference and Exhibition.

During the Feb. 1 opening plenary session, executives and engineers from SM Energy Co., Devon Energy Corp., Hess Corp. and Fervo Energy discussed key findings from projects and how these developments led to follow-up business decisions in other fields.

"We need to say 'yes' more often to learning [and] applying that knowledge, really just using our relationships," said Mary Ellen Lutey, senior vice president of exploration, development and EHS at SM Energy.

During the session, Lutey illustrated how working together can lead to innovation, especially in the use of fiber optics, which can capture measurements and gather information about downhole conditions to provide more context to the data being gathered from the well. In 2020, Erich Kerr, engineering supervisor at SM Energy, extolled the benefits of fiber optics to Lutey and suggested it could be used for diagnostic fracture injection tests. The technology can be used to detect strain, decay, stress and temperature, among other things within the well.

Devon Energy's use of fiber optics and other technologies raised their completion efficiency from 19% to 81%, said Kourtney Brinkley, drillings and completions engineer.

Working primarily in the Eagle Ford region, Devon experienced parent completions that Brinkley described as suboptimal.

"We had to have some significant drawdown in our parent networks, and we weren't actually invading the entire face of the core as we were pulling it out of the ground. Additionally, the samples where we did find proppant were pretty sparse," Brinkley said.

Through the use of fiber optics, downhole gauges and sealed wellbore monitoring, Devon was able to raise its completion efficiency and make strides with contacting new rock.

After initially believing they were re-dilating parent networks, the company's engineers realized they were making completely new fractures in the ground. Devon was able to increase its estimated ultimate recovery from 27% to 46% in comparison to the original completion approach, said Brinkley.

Shutterstock/Jens Lambert

Using fiber optics

While SM Energy and Devon are using fiber optics for traditional hydraulic fracturing in shale, Fervo Energy is using fiber optics for monitoring the results of geothermal fracking.

"We're working on a reservoir management concept that is very similar to what's done in shale," Fervo CTO Jack Norbeck said. "We're doing horizontal drilling, multistage hydraulic fracturing using distributed fiber optics for monitoring characterization. There's a lot of similarities about what we're trying to do and what [shale] does every day."

Geothermal fracking makes cracks in hot rocks where none existed, allowing heat to be harvested from Earth's interior. Larger frac plugs and well casings are required to survive temperatures reaching as high as 425 F.

Hess' augmented drainage development involves producing oil from an unstimulated well that produces from the fracture network created by the offset wells.

"We are starting to look at something called augmented drainage development, where we drill two standard laterals. And then we drill another lateral in between it—these are all at the same time," said Craig Cipolla, senior completions engineer at Hess, adding that the next step involves fracking through the uncemented slotted liner.

Hess first introduced this idea back in 2021 and has "no idea whether it's going to turn into a transformational concept at all," Cipolla said. Nevertheless, the company is getting record production from hydraulic fractures in the far-field, and finding the idea promising, drilled two more wells in that fashion in 2022. OGI

Events Calendar

Scan me

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

EVENT	DATE	CITY	VENUE	CONTACT
2023				
CERAWeek by S&P Global	March 6-10	Houston	Hilton Americas-Houston	ceraweek.com
GoM Energy Transformation Conference	**March 21**	**Houston**	**Norris Conference Centers**	**hartenergyconferences.com**
TACC Energy Summit	March 21	Tyler, TX	Green Acres Crosswalk Conf. Ctr.	tylertexas.com
DUG Haynesville	**March 28-29**	**Shreveport, LA**	**Shreveport Convention Center**	**dughaynesville.com**
TIPRO Annual Convention	April 3-5	Austin, TX	Sheraton Downtown	tipro.org
Mineral & Royalty Conference	April 10-11	Houston	Post Oak Hotel	mineralconference.com
Energy Infrastructure &Technology Conference	**April 12-13**	**Houston**	**Norris Conference Centers**	**hartenergyconferences.com**
EnerCom Dallas	April 18-19	Dallas	Hotel Crescent Court	enercomdallas.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
Super DUG	**May 22-24**	**Fort Worth, TX**	**Fort Worth Convention Center**	**dugpermian.com**
Louisiana Energy Conference	May 30-June 1	New Orleans	Ritz-Carlton New Orleans	louisianaenergyconference.com
Mexico Gas Summit	June 6-7	San Antonio	St. Anthony Hotel	mexicogassummit.com
Cybersecurity Energy Conference	**June 7**	**Houston**	**Norris Conference Centers**	**hartenergyconferences.com**
CIPA Annual Meeting	June 8	Tahoe, CA	TBD	cipa.org
Uncoventional Resources Technology Conference	June 13-15	Denver	Colorado Convention Center	urtec.org/2023/
KIOGA Annual Convention	Aug. 20-22	Wichita, KS	Hyatt Regency	kioga.org
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
Energy ESG Conference	**Aug. 30**	**Houston**	**Hobby Center**	**hartenergyconferences.com**
Carbon Management Conference	**Aug. 31**	**Houston**	**Norris Conference Centers**	**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.

Oil and Gas Investor

COMPANIES IN THIS ISSUE

This index refers to the pages of the story or news item in which the company is first mentioned. Advertisers are in boldface.

▸ AT CLOSING

A TIME TO EXPLORE

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New-play news has resumed after a few years in the "for a better commodity day" folder.

There's EOG Resources Inc.'s work in the northern Midland Basin in Dawson County, Texas, that's west of the prolific, highly oil-weighted Howard County where HighPeak Energy, with its additional leasehold in Borden County, is exploring a sale.

J.P. Morgan securities analyst Arun Jayaram reported EOG picked up two permits in Dawson, offsetting a two-well Trinity Lease pad.

"Enverus data indicate all four of these wells to be in the middle Spraberry Formation, though that has not been confirmed by public data," Jayaram wrote.

EOG is leasing and drilling in the county as CGS Operating LLC. "Initial developments in the Leatherwood and Crockett units showed (uneconomic) results."

Meanwhile, though, the Santorini and Bluebonnet leases are looking better but whether they're economic is "yet to be determined," he added.

There's also Marathon Oil Corp.'s development of the Woodford and Meramec in the Delaware Basin. A first three-well combo pad in Ward County in 2021 is being followed by a four-well pad, reported Enverus analyst Erin Faulkner.

"Long-term production data show the 2021 pad … to be highly productive," she wrote, adding that it's even better than an average Oklahoma SCOOP or STACK Woodford well.

One well (King George SA 3 7803H) made 666,075 boe (about two-thirds oil) its first year from a 7,828-ft lateral.

Back in the Midland Basin, Pioneer Natural Resources Co. is testing the gassy, deep Barnett and Woodford this year.

And Apache Corp. has resumed drilling its gas and gas-liquids Alpine High play in southern Reeves County. It is its first pad since 2019.

The renewed interest in Permian gas is derived in part from the expected construction start later this year of another new LNG terminal—NextDecade's long-awaited plant at Brownsville, Texas.

It's also derived from continued solid gas demand from Mexico, which is importing some 7 Bcf/d from north of the border and experiencing a manufacturing boom from factory reshoring there from China.

Sempra Energy expects to source gas for its Baja California, Mexico, LNG export facility from the Permian and Rockies via the El Paso Pipeline.

Over in the Eagle Ford, EOG's immense Austin Chalk play, "Dorado," in Webb County might be a 20-Tcf field of ultimately recoverable reserves, chairman and CEO Ezra Yacob told Goldman Sachs conference attendees in January. EOG has about 50 wells online now and estimates more than 1,000 locations.

"If you think about that 20-Tcf number … that would be a Bcf a day produced for 50 years," Yacob said.

EOG is building a 36-inch pipe to connect 720 MMcf/d to Cheniere Energy Inc.'s Corpus Christi LNG plant in a contract that has EOG getting the international gas price for 420 MMcf/d.

Meanwhile, Gene Shepherd, who has an oft-proven knack for picking new acreage and turning it into a build-and-flip success, has chosen the Red Bull play in the Coyanosa area of the Reeves-Pecos counties' border in the southern Delaware.

Shepherd and energy trader Vitol's new VTX Energy Partners LLC is buying the property from Delaware Basin Resources (Patriot Resources).

The late oilman T. Boone Pickens said in 2016 about Red Bull, "Of all the wells I drilled, this actually turned out to be the biggest prospect that I've ever been involved in."

Taking the Permian on the road—well, across the Atlantic—oil and gas analyst Subash Chandra at Benchmark Co. LLC reported, "Algerian shales, finally." He cited a Wall Street Journal report that Chevron Corp. is looking to commence shale exploration in the desert.

Of all the places on Earth where shale development might not meet with surface constraints, Algeria is one. There are very few neighbors, the country's political regime is energy friendly, and there's plenty of takeaway infrastructure.

It's also closer to market: Russia's former customer, Europe.

"Chevron's technology transfer from the Permian makes this a prize worth pursuing," Chandra wrote. The source-rock is loaded with Btu and "gamma-ray readings, thickness and thermal maturity rival U.S. shale basins."

More inspection is needed of clay content. "Whether it is substantially a 'hybrid' play—high-deliverability conventional rock charged by adjacent shales—needs study," he added.

Should development begin, one of the challenges will be accessing water. OGI

Join us at the sixth annual DUG Haynesville conference March 28-29 at the Shreveport Convention Center. Speakers include Chesapeake Energy, Southwestern Energy, Aethon Energy, Rockcliff Energy, TG Natural Resources, Sabine Oil & Gas, Diversified Energy, Sempra Infrastructure and Williams Cos. More details at HartEnergy.com/events.

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Join us in congratulating Diane Montgomery on being recognized as Oil and Gas Investor's 25 Influential Women in Energy for 2023.

Oil and Gas Investor's
25 INFLUENTIAL Women IN ENERGY

Diane joined the Continental team in 2012 and is currently responsible for overseeing Finance, Treasury and Corporate Planning activities. With more than 33 years of industry experience, Diane exemplifies the heart of the Women in Energy award, as she has risen to the top of her profession.

Diane is a passionate champion of the culture of the possible. Her integrity and financial acumen have helped make Continental's world-changing achievements possible.

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