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Stephens maintains a long history of advising oil & gas companies. In recent years, we have been particularly active advising mineral & royalty businesses across a wide variety of transaction types.

Recent Minerals & Royalties Transactions

UNDISCLOSED	UNDISCLOSED	UNDISCLOSED	UNDISCLOSED	UNDISCLOSED
Haynesville Minerals Platform	Diversified Minerals Aggregator	Midland Basin Operator	Eagle Ford Minerals Platform	NOBLE ROYALTIES, INC.
EQUITY PRIVATE PLACEMENT	STRATEGIC PARTNERSHIP	ASSET ACQUISITION	EQUITY PRIVATE PLACEMENT	EQUITY PRIVATE PLACEMENT
Sole Placement Agent	Sole Placement Agent	Financial Advisor	Sole Placement Agent	Sole Placement Agent
UNDISCLOSED	UNDISCLOSED	UNDISCLOSED	UNDISCLOSED	$350 MILLION
VIKING MINERALS	VIKING MINERALS	Shadow Creek Minerals	NOBLE ROYALTIES, INC.	VIPER Energy Partners
ASSET DIVESTITURE	ASSET DIVESTITURE	ASSET DIVESTITURE	ASSET DIVESTITURE	FOLLOW ON OFFERING
Financial Advisor	Financial Advisor	Financial Advisor	Financial Advisor	Underwriter
$66 MILLION	$104 MILLION	$53 MILLION	UNDISCLOSED	UNDISCLOSED
			Multi-Basin Minerals Company	Multi-Basin Minerals Company
FOLLOW ON OFFERING	INITIAL PUBLIC OFFERING	FOLLOW-ON OFFERING	ASSET DIVESTITURE	VALUATION ANALYSIS
Underwriter	Underwriter	Underwriter	Financial Advisor	Financial Advisor

MINERALS & ROYALTIES STATISTICS

~$2.4 Billion
Aggregate Transaction Volume Since 2017

15 Closed Transactions Since 2017

PRIVATE FINANCING STATISTICS

~$11.4 Billion
Aggregate Capital Raised Since 2009

35 Closed Transactions since 2009

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COLUMNS

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Oil and Gas Investor

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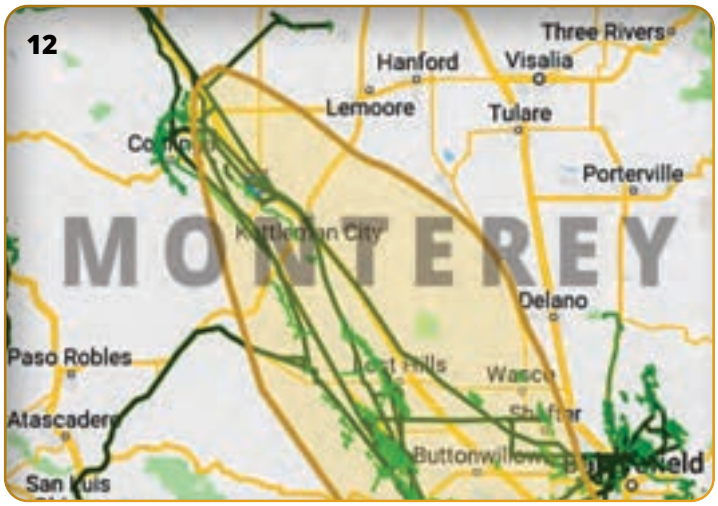
ACTIVITY HIGHLIGHTS

A&D WATCH

FINANCE & INVESTMENT



PERSPECTIVES

Oil and Gas Investor

by HARTENERGY

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AROUND THE INDUSTRY

MIDSTREAM

TECHNOLOGY

ABOUT THE COVER: In an exclusive Q&A, bpx energy CEO Dave Lawler discusses delivering $1 billion a year in free cash flow to parent bp Plc and what's in store for 2022. Photo by Ricardo Merendoni. *www.merendoniphoto.com*

HONOR THE PAST, RESPECT THE LEGACY, CREATE THE FUTURE

DEON DAUGHERTY
EDITOR-IN-CHIEF
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ddaugherty@hartenergy.com

The privilege of writing this column is one I share with only two people. Both are gone too soon and both of whom pushed *Oil and Gas Investor* magazine across boundaries, beyond challenges and into the future with their own brands of brilliance, experience and swagger.

Leslie Haines, the formidable founding editor of *Oil and Gas Investor*, shepherded the publication for more than 30 years and illuminated the impacts of war, global economics and technology on the industry. She was there for the advent of hydraulic fracturing. Her successor, the red-headed firecracker Steve Toon, took the helm of the magazine in 2016 and steered the magazine through the shale revolution's early rumblings of shareholder unrest, industry accountability demands and, of course, an upending pandemic.

Still, among the 50 years of Hart Energy's energy news coverage, the past 12 months will stand out. And this is where I come in.

The industry is at a crossroads. Not for the first time, but the paths from this point are so many and so divergent that once the industry emerges, it may be unrecognizable to anyone who's not paying attention.

We're watching very closely. At *Oil and Gas Investor* and indeed, across all of Hart Energy's platforms, we intend to give our readers a ringside seat.

You see, Leslie and Steve left behind far more than a publication steeped in legacy, a reputation to uphold and shoes so large that I cannot fill them on my own. They bequeathed onto the role as editor-in-chief a special gift: a group of the best energy journalists in the business.

And we've got a lot of work to do.

No one will reasonably argue that an evolution is taking place; perhaps it's one that is a long time in coming. The industrialization and geopolitical mechanizations that framed much of Leslie's tenure remain in place, and the high-stakes accountability gains that Steve presided over grow in their complexity.

The industry we cover is evolving, and our team must do so, too. It is a process of progression, and there is no end in sight to the improvements ahead. Without progress, there is only stagnation and regression. Neither is an option.

We are developing our online presence at HartEnergy.com to work in concert with *Oil and Gas Investor*'s print editions to broaden, speed and deepen our offerings of news, insight and analysis to you.

We are introducing a new column in the July edition of the magazine called Market Watchers. During years of covering all facets of the energy that fuels our world, our journalists have established important relationships with key thinkers and experts in the field. It is an honor to have won their agreement so that each month we can offer you their candid and unvarnished insights in this column.

Working in tandem with our digital team, we will bring Market Watchers to you online. Many of our most trusted sources will speak to you directly on HartEnergy.com about the most important news of the day.

Oil and Gas Investor is connecting the dots between domestic and international energy interests to reflect the prowess that has long existed online. To that end, we are adding a section of the magazine to the impacts of energy that will mirror the treatment we have long devoted to finance and technology.

Perhaps most importantly, we are putting people at the front and center of our reporting, from the cover of the magazine to its closing commentary. We are featuring real experts who will give their unique perspectives and inside analysis online with our digital presence.

Moreover, we embrace the diversity needed to succeed in the energy field and within the world itself. The industry is relevant because people rely on it to survive. Likewise, our relevance depends on our ability to bring the industry to the people of the world. I hope our grasp of this truth is obvious throughout *Oil and Gas Investor*'s pages and across HartEnergy.com

It's not for nothing that we have reported on the industry's struggle to contain talent and recruit the next generation. We understand clearly that we must also work harder and better to retain our loyal audience and attract new generations of readers.

We are not afraid of a crew change; we are excited to welcome everyone aboard. OGI

INCONSISTENT POLICIES SEND MIXED SIGNALS

ENERGY POLICY

JACK BELCHER
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The world today is facing amazingly complex issues: high inflation, war on the European continent, a prolonged pandemic, supply chain meltdowns, food shortages, political turmoil, the threat of climate change and sky-rocketing energy prices. While the degree to which these crises can be managed by public officials varies significantly, energy pricing is one area where government action can indeed make a difference, for better or worse.

Let's take a closer look at what the government is and is not doing to help us meet today's energy challenge. In March, the Biden administration began the largest release ever of the Strategic Petroleum Reserve (SPR) by committing to withdraw 1 MMbbl/d for six months. Although the notion of flooding the market with additional oil might make for a good headline, the reality is that the SPR exists to supply the U.S. with oil in the case of a national emergency. SPR releases are merely increasing our vulnerability to an actual supply emergency at home without offering any relief at the pump. To that end, by May, the SPR dropped to the lowest level since 1987.

Meanwhile, in response to the loss of Russian gas supply to Europe, the U.S. committed 15 billion cubic tons (Bct) of LNG to Europe through the end of this year and an additional 50 Bct through 2030. If we follow through and put the right policies in place to make it happen, and the investment capital follows, Europe and the U.S. will greatly benefit. Yet, despite pushing the U.S. oil and gas industry to increase production and communicating support for American energy exports to allies in Europe, the administration continues to send mixed messages.

For example, while the president and his senior advisors urge industry action, his Envoy for Climate, John Kerry, recently took the opportunity to push back against "this new revisionism suggesting that we have to be pumping oil like crazy, and we have to be moving into long-term [fossil fuel] infrastructure building, which would be absolutely disastrous," accusing "vested interests" of exploiting the war in Ukraine.

While recent actions like authorizations for increased LNG exports are a welcome change, the administration is still not taking the steps necessary to significantly boost domestic production to meet domestic and global demand. In fact, on the whole, federal policies enacted thus far are doing precisely the opposite.

After pledging to end oil and gas leasing on federal lands and waters during the campaign, in addition to indefinitely withdrawing specific marine areas off Alaska from future leasing, imposing a moratorium on drilling in the Arctic National Wildlife Refuge and making millions of acres off limits to oil and gas development in the National Petroleum Reserve-Alaska, in his first week in office the president instituted a "pause" on all new federal oil and gas leasing.

Not surprisingly, 18 months into the Biden administration, we have yet to see a plan for the next five-year offshore oil and gas leasing program, with Interior Secretary Deb Haaland recently saying she would release a draft plan on June 30, 2022, the day that the existing five-year plan expires. As a result, it is now likely that 2022 will be the first year since 1958 that no new federal offshore leases will be offered. It also placed a pause on onshore Bureau of Land Management oil and gas leasing for over a year. Consider that production on federal lands accounts for 24% of total U.S. oil produced and 11% of natural gas.

Make no mistake, an all-of-the-above approach to energy that includes renewables is needed. President Biden's June 6 invocation of the Defense Production Act to boost domestic manufacturing of solar panel components, building insulation, heat pumps and equipment like electrolyzers, fuel cells and platinum group metals and power grid infrastructure will contribute to our overall energy security. However, they will do nothing to address rising fuel prices or anticipated shortages in electricity this year or in the near future. To meet our current challenges and ensure more affordable gas for our cars and electricity for our homes and businesses in the months and years ahead, we need immediate solutions and clear policy signals that will boost our domestic supply of oil and gas.

The policies currently in place are not anywhere near conducive for boosting domestic energy production, combating high prices and supporting long-term energy exports to America's allies. Instead, they are a continuation of policies and rhetoric that have thwarted investment by financial institutions into our oil and gas sector.

It does not have to be this way, and it is not too late to make a course correction. The path to lower U.S. energy prices and greater energy security begins and ends right here at home. OGI

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

Scan me

THE SUN RISES OVER AERA ENERGY'S OPERATIONS IN SAN ARDO, CALIF., IN MONTEREY COUNTY. AERA IS THE MONTEREY SHALE'S MOST PROLIFIC OIL PRODUCER.

AERA ENERGY LLC

PERMITS

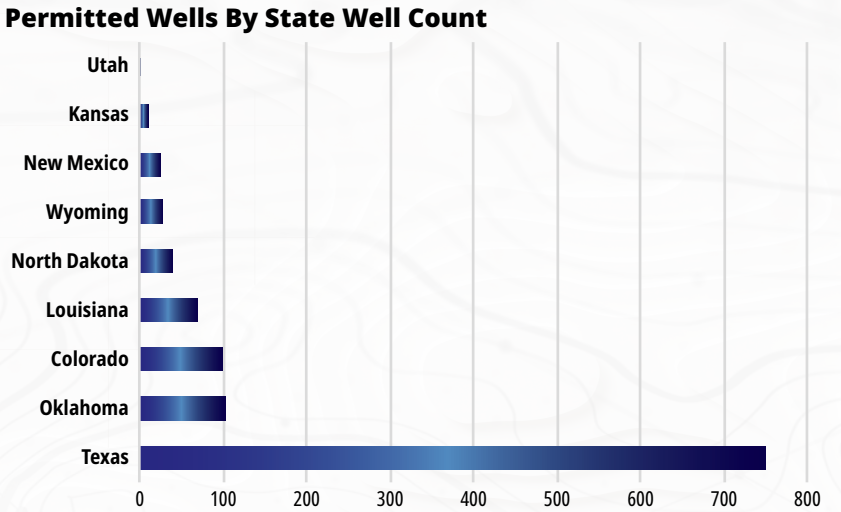
The number of drilling permits issued in Texas jumped 20% in April compared to April 2021, making it the second-highest monthly total since the onset of the COVID-19 pandemic in first-quarter 2020. The No. 1 month was the previous one: March.

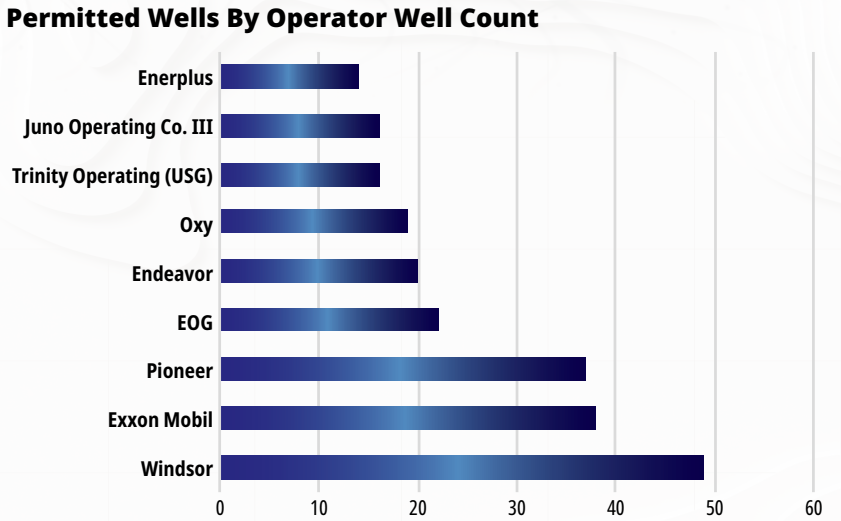
The national total, however, was off by 20% in the April-to-April comparison. Reaching back to compare April 2022 to pre-pandemic April 2019, the national count suffered a 42% reduction. The Texas permit count in that time period comparison was down 6%.

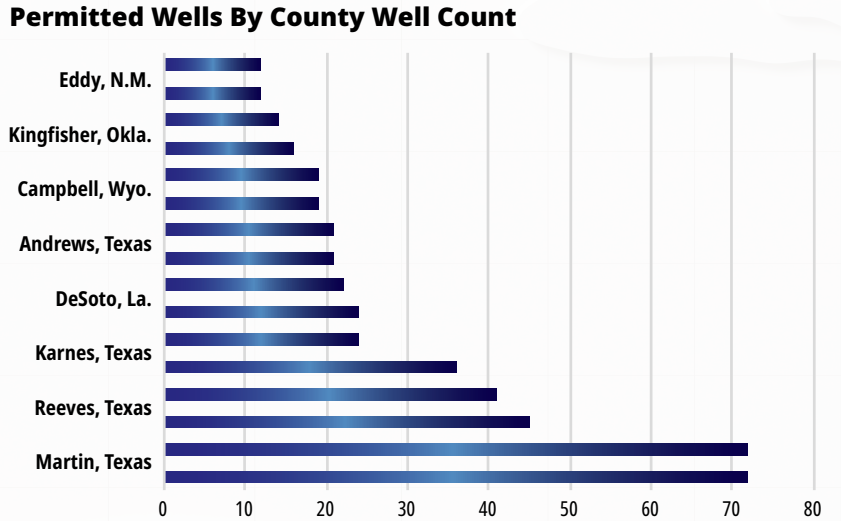
Permits do not translate as concrete decisions to drill, but they do signal confidence that, under the right conditions, companies think they can make money by doing so. And since the pandemic struck, the right conditions have been, to a large extent, known as the Permian Basin.

Six of the top 10 permitting counties are located in the Permian, two others are in the Eagle Ford Shale, with DeSoto and Caddo parishes in Louisiana filling out the list. Campbell County in Wyoming's Niobrara Shale was left with its face pressed up against the window, peering in.

The leading permit collector was Windsor Energy Inc., an Oklahoma City independent focused on Texas. Exxon Mobil Corp. and Pioneer Natural Resources Co. together scooped up a total of 75.







Data from Rextag ENERGY DATALINK

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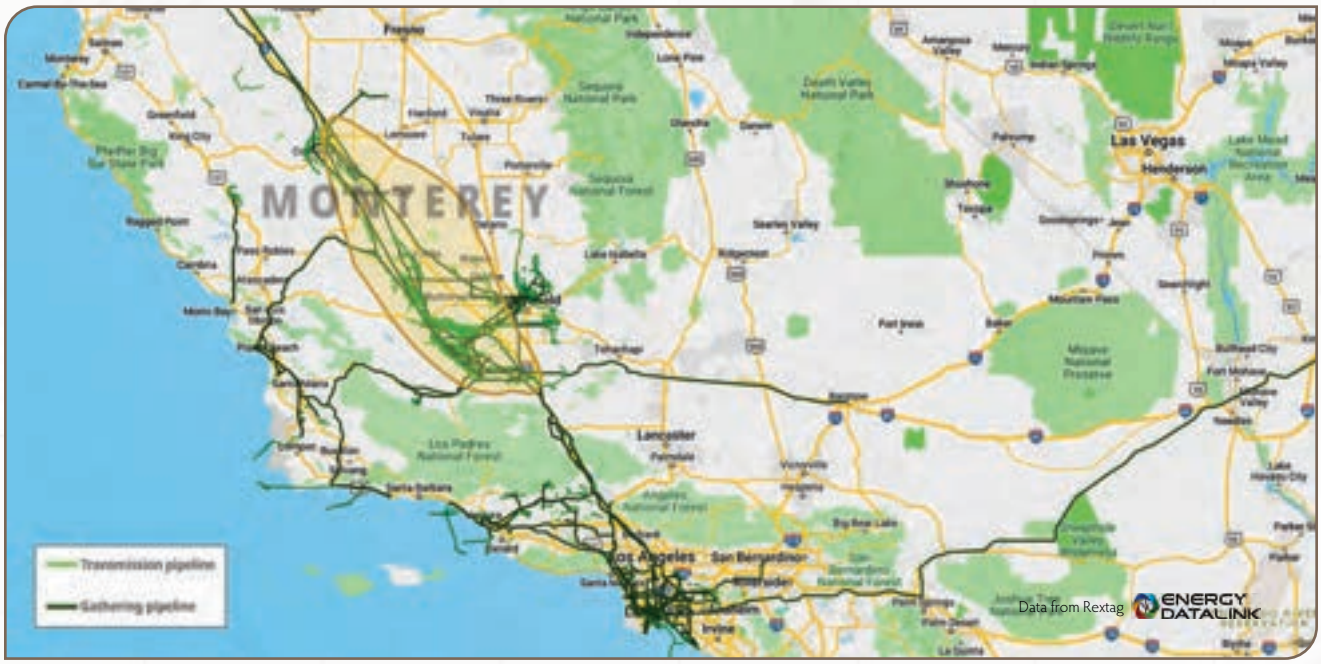
FOCUS ON: MONTEREY SHALE



One of energy history's most profoundly awkward moments arrived on California's doorstep in May 2014, when the U.S. Energy Information Administration reduced its estimate of technically recoverable oil in the Monterey Shale by a whopping 96%, from 15.4 Bbbl to 600 MMbbl.

Had the original estimate held, the Monterey's reserves would have exceeded those of the Permian Basin and Eagle Ford Shale combined. Thus ended the California dreamin' of state budget officials who were looking forward to an estimated $25 billion a year in tax revenue.

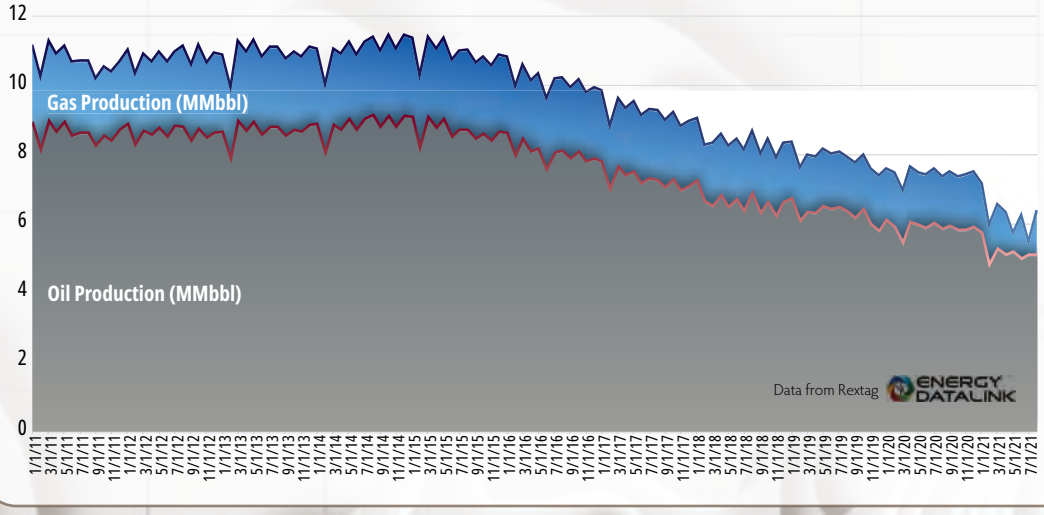
Still, companies such as Aera Energy, California Resources Corp. and Chevron Corp. continue to produce hydrocarbons in the 1,750-square-mile Monterey, albeit in shrinking volumes year-over-year. Six counties host oil and gas operations—Kern, Santa Barbara, Kings, San Luis Obispo, Fresno and Monterey—but Kern dominates the play, with other counties offering miniscule production.

The challenge in the Monterey has never been about volume. Geologists estimate oil reserves to be about 38 Bbbl. Getting to it is another matter.

Compared to the Bakken and Eagle Ford shales, the Monterey is thicker and hydrocarbon deposits are deeper, at 8,000 ft to 14,000 ft. Layers are also highly folded, not flat as in "cake layer" plays like the Bakken, so long laterals are not of much use.

Producers also must navigate a rigorous permitting process in a state that has taken a leadership role in moving away from fossil fuels. Gov. Gavin Newsom's 2020 executive order directed the California Air Resources Board to devise regulations to ensure that all in-state sales of passenger cars and trucks be zero emissions by 2035.

Monterey Shale Monthly Oil And Gas Production



DIAMONDBACK'S STICE SWEARS OFF MAJOR ACQUISITIONS

The strange case of **Diamondback Energy Inc.**'s trailing stock performance among its peers, a point of fixation among analysts, appears to have its roots in the Permian Basin operator's slightly less aggressive framework for rewarding shareholders and its reputation as a "serial acquirer."

It's not a reputation without merit. Over the years, even a cursory glance at Diamondback's acquisitions lends some credence to that view. Since 2017, the company has closed four deals valued at $1 billion or more. That includes its 2021 acquisition of QEP Resources for $2.2 billion. Its largest deal during that span was its 2018 acquisition of Energen Corp. for $9.2 billion worth of stock.

But the company is now publicly holding firm to a lower-key acquisition strategy that won't include the massive deals that have built it into one of the largest operators in the Permian Basin.

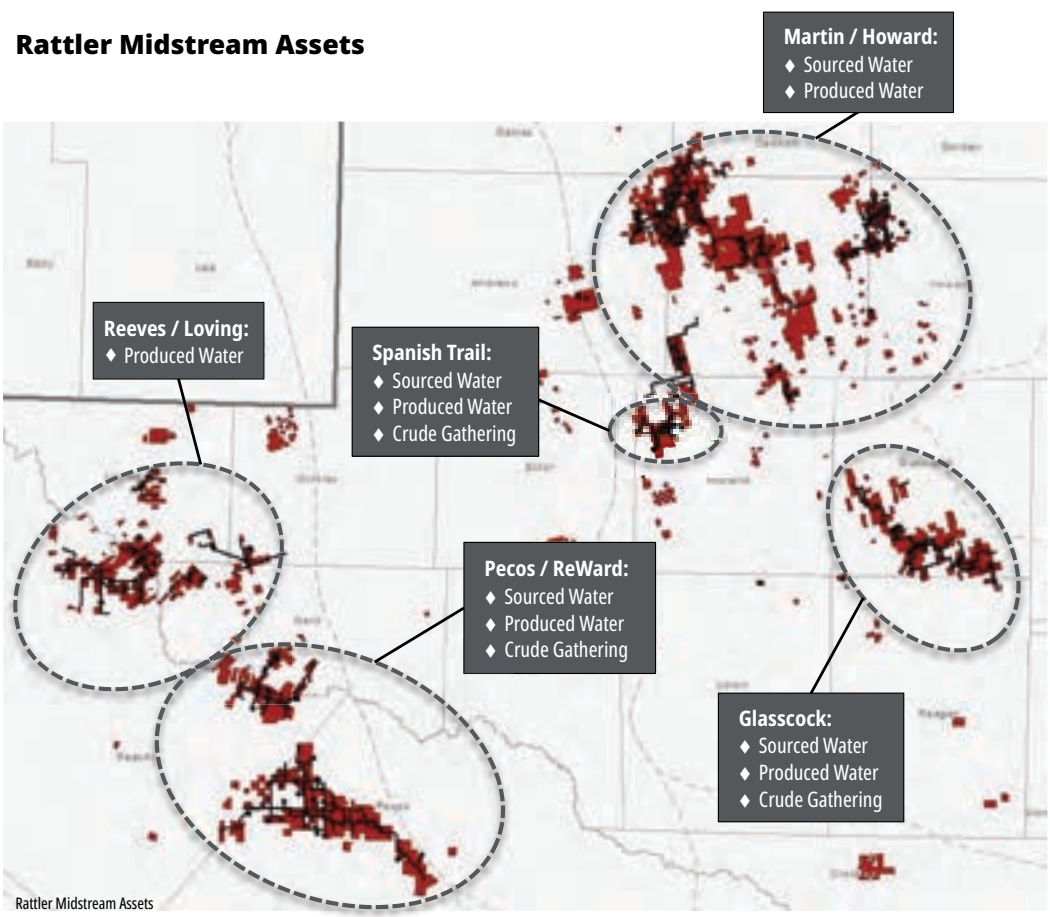
And the company's deal activity has been muted so far this year.

In early May, Diamondback announced that it had acquired 6,200 net acres in the Delaware Basin for $230 million using cash on hand. The Ward County, Texas, acreage gives the company an additional 58 gross long-lateral locations with an 85% net revenue interest in what Stice called a "high rate of return area." The seller was not disclosed. **Kirkland & Ellis** served as Diamondback's legal adviser.

"In fact, we've already begun drilling the position, but do not expect to have production until late this year," said Diamondback CEO Travis Stice.

More recently, the company said on May 16 it would acquire all publicly held common units it didn't already own in its midstream MLP, **Rattler Midstream LP**, in a stock-for-unit deal valued at $575.2 million. The deal gave Rattler unit holders roughly a 17% premium.

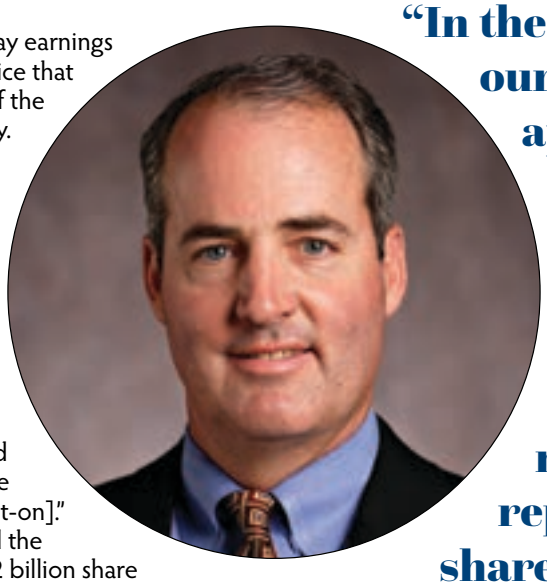
Rattler Midstream Assets



Rattler Midstream Assets

But during a mid-May earnings call, Stice repeated twice that "large-scale M&A is off the table" for the company.

"We do hear a lot about this narrative that Diamondback is a serial acquirer and let me just put it simply: Large-scale M&A today is quite frankly off the table," he said. "We've got nothing on our deal sheet that's considered more than a tuck-in like the [Ward County bolt-on]."



Stice also addressed the company's planned $2 billion share buybacks, which he said are evaluated along the same vein as leasehold acquisitions.

Nitin Kumar, senior equity analyst at **Wells Fargo**, said Diamondback management also "espoused a counter-cyclical view of cash returns, focusing on buybacks and base dividend growth rather than variable dividends."

Kumar added, "We believe the longer-term investment case for the company that is anchored in its counter-cyclical and differentiated cash return strategy remains strong."

Stice said Diamondback has taken its foot off the buyback pedal because of rising share prices. A buyback must generate a return well in excess of the company's weighted average cost of capital, assuming a reasonable mid-cycle oil price, he said.

"In the first quarter, our price debt was approximately $60 a barrel, and as such, we were able to take advantage of some of the volatility in the new market and repurchased 57,000 shares at an average price of $117 a share," he said. "Through the end of the first quarter, we've spent about $440 million, or 22% of the $2 billion program our board authorized last September."

Still, **JP Morgan**, **Goldman Sachs** and Wells Fargo analysts all expressed some degree of concern, either their own or of the market's, that amid a large number of assets being marketed in the Permian Basin, Diamondback may be tempted.

As JP Morgan analyst Arun Jayarm noted during the company's earnings call, the "market appears to be concerned about Diamondback executing perhaps a pro-cyclical type of M&A deal." Wells Fargo similarly shared, "Concerns that FANG [Diamondback] may be an acquirer of assets in 2H22, although management has downplayed the role of M&A in its strategic plans."

Goldman Sachs analysts wrote on May 26 that the company's stock performance has lagged its large-cap peers, including **EOG Resources Inc.**, **Continental Resources Inc.**, **Devon Energy Corp.** and **Pioneer Natural Resources Co.** Diamondback's value has grown by about 35% amid the commodity price bonanza compared to its cousins, which have seen a 54% increase in valuation.

"In the first quarter, our price debt was approximately $60 a barrel, and as such, we were able to take advantage of some of the volatility in the new market and repurchased 57,000 shares at an average price of $117 a share."

—Travis Stice,
Diamondback Energy Inc.

"There are concerns that the company has slowed down its share repurchase program due to its intent to pursue large-scale M&A. However, the company has indicated that any M&A would be more bolt-on in nature and has reiterated its commitment to returning 50%-plus of its FCF [free cash flow] to shareholders," the Goldman Sachs report said.

On the call, Stice said Diamondback said the M&A environment "remains a seller's market, and we're not going to underwrite M&A at today's oil prices, just like we're not going to underwrite repurchasing stocks at today's oil prices."

As for its Rattler Midstream roll-up, David Deckelbaum, an analyst at **Cowen**, said the transaction won't "move the needle much" for Diamondback but makes sense from a couple of different perspectives.

Rattler's unit holder received an 8% dividend compared to the 2% fixed dividend for Diamondback, giving the deal "an inherent arbitrage in cost of capital."

Consolidating the midstream assets, which Diamondback went public with in 2019, is about 2% dilutive of the company's stock. But it will allow for greater simplicity and more direct reporting of the midstream company's $340 million EBITDA for 2022.

Rattler Midstream's debt and credit facility, about $730 million total, is already reported on Diamondback's balance sheet.

"Considering that the midstream business is effectively fully built out and FANG does not intend on growing, consolidating as much of the business as possible follows sound logic of simplifying reporting and maximizing FCF to FANG holders that trades at a current discount. Further, FANG certainly does not need to rely on RTLR as a financing vehicle and the move should be well received as an inevitable evolution of the business model," Deckelbaum wrote.

Diamondback Energy did not respond to a request for comment.

—Darren Barbee

DEVON ENERGY'S RIMROCK ACQUISITION HIGHLIGHTS STRENGTH OF DIVERSIFICATION

News of a **Devon Energy Corp.** acquisition might have had investors expecting an expansion in the Permian Basin.

Instead, Devon's $865 million Bakken bolt-on of **RimRock Oil and Gas LP**, announced on June 8, highlights the strategic value of a diversified asset base, said David Deckelbaum, an analyst at **Cowen**. In addition to its Delaware Basin "franchise growth asset," Devon holds positions in the Anadarko and Powder River basins and the Eagle Ford Shale.

RimRock's bolt-on overlaps and is adjacent to Devon's Bakken position, "makes logical sense and paints an interesting picture of FCF accretive bolt-ons that can be arbitraged by diversified E&Ps to more rapidly grow FCF distributions per share."

Devon agreed to acquire more than 100 "highly economic drilling locations" from RimRock, a **Warbug Pincus** portfolio company, Deckelbaum said. Rimrock's wells produce more oil and a higher percentage of cash flow than Devon's.

The RimRock transaction also addresses any potential runway concerns Devon may have had in the Williston Basin, **Goldman Sachs** analyst Neil Mehta said in a June 8 report.

"The transaction should enable the company to stem natural production declines and keep production flat in the basin over the next four to five years," Mehta said. "Per management, RimRock's assets produced 15 Mboe/d in 1Q22 and are expected to increase to 20 Mboe/d over the course of the next year."

Devon said that the acquisition is accretive enough that it will increase its fixed quarterly dividend to 13% when the transaction closes, likely in the third quarter.

"The company noted that the transaction implies ~2.2x cash flow at current 12-month strip prices (~$110/bbl WTI and ~$8/MMBtu Henry Hub) and that the acquisition will be accretive to earnings/cash flow per share metrics in the first year," Mehta said. "Management forecasts FCF yield of greater than 25% at current strip pricing."

Devon Energy's fixed dividend increase raises its divvy to about $0.18/share, Mehta said. The company's first-quarter dividend payout was a record $1.27 per share. The Devon board of directors has also approved, after expansion, a $2 billion share buyback.

The all-cash deal also means Devon will maintain its "top-tier" balance sheet with expected net debt-to-EBITDAX of 0.2x by year-end 2022.

—Darren Barbee

Read the full article here:

PERMIAN OPERATORS COLGATE, CENTENNIAL TO MERGE IN $7 BILLION DEAL

Colgate Energy agreed on May 19 to combine with **Centennial Resource Development Inc.**, quashing recent rumors that Colgate was seeking an IPO.

The $7 billion "merger of equals" transaction will create the largest pure-play E&P company in the Delaware Basin of the Permian with approximately 180,000 net leasehold acres and 135,000 boe/d of current production.

"This transformative combination significantly increases scale and drives accretion across all our key financial and operating metrics. Colgate's complementary, high-margin assets are a natural fit for Centennial, creating the largest pure-play E&P company in the Delaware Basin," Centennial CEO Sean Smith commented in a joint company release.

"Importantly," Smith added, "the combined company is expected to provide shareholders with an accelerated capital return program through a fixed dividend coupled with a share repurchase plan."

Colgate Energy is a privately held independent based in Midland, Texas, founded in 2015 that has played the long game in acquisitions, with roughly $1 billion in announced deals in the past four years. Backed by **Pearl Energy Investments** and **NGP**, Colgate, however, was reported to be considering an IPO last December that sources said would value the company at around $4 billion.

Centennial Resource Development is a Denver-based independent that went public in 2016 following its merger with **Silver Run Acquisition Corp.**, a blank-check company led by industry icon Mark Papa who would go on to lead Centennial until his retirement in 2020.

Upon closing, the combined company will have over 15-years of drilling inventory, assuming its current drilling pace, the companies expect will generate over $1 billion of free cash flow in 2023 at current strip prices.

The merger values Colgate at about $3.9 billion and consists of 269.3 million shares of Centennial stock, $525 million of cash and the assumption of about $1.4 billion of Colgate's outstanding net debt.

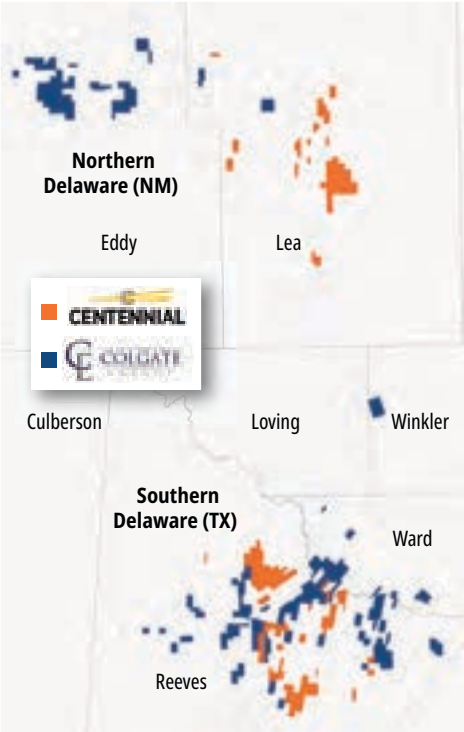
The cash consideration and the repayment of Colgate's outstanding credit facility borrowings at closing are expected to be funded with cash on hand and borrowings under an upsized revolving credit facility. Further, the combined company's net debt-to-LTM EBITDAX ratio at closing is predicted to be approximately 1.0x, given existing cash balances and interim free cash flow.

The combined company will be headquartered in Midland and led by Colgate co-founders Will Hickey and James Walter as co-CEOs. The remaining key positions will be filled by representatives from both companies, according to the release. Centennial CEO Smith will serve as executive chair of the board of directors of the newly combined business.

The combined company will also operate under a new name and stock ticker symbol, which are expected to be announced prior to closing.

Commenting on the transaction, Hickey said: "The Colgate and Centennial teams have each demonstrated a track record of execution through the years, and we are excited to assume leadership roles in the new company to build upon that success and guide the next phase of value creation. Both companies have established strong financial and operational cultures, and we expect the combined company will be a top-tier, low-cost operator that is able to deliver better margins and shareholder returns."

Centennial And Colgate Combined Delaware Assets



Source: Colgate Energy; Centennial Resource Development Inc.

Upon closing, the combined company will have one of the largest management ownership interests of any public E&P company, according to the release, with the management team owning about 12% of the pro forma total shares outstanding. The companies expect that this will result in a higher focus on increasing shareholder value.

Existing Centennial shareholders are expected to own approximately 53% of the combined company, and existing Colgate owners will own approximately 47% of the combined company.

Following the merger, Centennial's board of directors will be expanded to 11 directors. In addition to Smith, Hickey and Walter, plus six independent directors, the new Centennial board will include Robert Tichio, partner of **Riverstone Holdings LLC**—Centennial's largest shareholder, and William Quinn, founder and managing partner of Pearl.

"Centennial and Colgate are a clear strategic fit, combining two complementary acreage footprints in the core of the Delaware Basin," Quinn said. "We are firm believers in the combined management team and their strategy, and we look forward to creating additional long-term value for stakeholders."

The closing of the merger is subject to customary closing conditions, including approval by Centennial shareholders and regulatory approvals.

Citi is financial adviser, and **Latham & Watkins LLP** is legal adviser to Centennial for the transaction. **Credit Suisse Securities (USA) LLC** and **Jefferies LLC** are financial advisers, and **Kirkland & Ellis LLP** is legal adviser to Colgate.

—Emily Patsy

GREY ROCK AGREES TO $1.3 BILLION COMBINATION WITH PAUL RYAN-BACKED SPAC

Grey Rock Investment Partners agreed on May 16 to a $1.3 billion business combination with **Executive Network Partnering Corp.** (ENPC), a special purpose acquisition company (SPAC) backed by former U.S. House Speaker Paul Ryan.

Based in Dallas, Grey Rock is a private equity firm with more than $525 million of committed capital under management and interests in more than 2,500 wells in core areas of the Permian's Midland and Delaware basins, as well as the Bakken, Eagle Ford, Denver-Julesburg and Haynesville plays.

"This transaction with Grey Rock reflects our philosophy and commitment to matching accomplished, proven executives and great assets, with the proper capital structure to maximize results and value creation," commented Ryan, who serves as chairman of ENPC, in a joint release in May.

In connection with this transaction, Grey Rock will contribute oil and gas assets currently held in its Fund I, Fund II and Fund III portfolios to form **Granite Ridge Resources Inc.** in exchange for equity.

Subject to approval by the ENPC stockholders and customary regulatory requirements, Granite Ridge intends to be listed on the NYSE under ticker symbol "GRNT" upon closing, which is expected to occur later this year. Grey Rock will not receive any cash proceeds as part of this transaction and will roll all of its equity into the pro forma company.

Granite Ridge will be led by CEO Luke Brandenberg, formerly with **Vortus Investment Advisors LLC**, **Grey Rock Energy Partners** and **EnCap Investment LP**, and CFO Tyler Farquharson, previously vice president, CFO and treasurer of **EXCO Resources**. The company is estimated to produce 20,500 boe/d with EBITDA of $425 million and free cash flow of $240 million in 2022, according to an investor presentation.

"As hydrocarbons continue to play an important role in the global energy mix, we are confident that Granite Ridge, led by a world-class team with deep operational, technical, and financial expertise, is a compelling opportunity for investors looking to participate in the energy space," Ryan added in the release.

Brandenberg previously served as a managing director of Vortus. Prior to joining Vortus, he had worked at Grey Rock Energy Partners as well as EnCap Investments LP.

Farquharson joins Grey Rock from EXCO where he served as vice president, CFO and treasurer. Farquharson joined EXCO in August 2005 as a financial analyst.

"I look forward to leading Granite Ridge as we enter the public market and seize the opportunities presented by today's energy environment," Brandenberg said.

Upon closing, Granite Ridge will maintain a seven-person board, which will include three independent directors as well as a committee dedicated to strong ESG practices, according to the company release.

Evercore is exclusive financial and capital markets adviser to Grey Rock, and **Stephens Inc.** is acting as financial adviser to ENPC. **Holland & Knight LLP** is providing legal counsel to Grey Rock, and **Kirkland & Ellis LLP** is acting as legal counsel to ENPC.

—Emily Patsy

Read the full article here:

NORTHERN OIL & GAS TO ACQUIRE WILLISTON BASIN BOLT-ON FOR $170 MILLION

Northern Oil and Gas Inc. agreed to pay up to $175 million to acquire a Williston Basin bolt-on, the company said in a June 7 release.

"While the Permian continues to be a source of growth, we continue to find significant opportunities to grow our Williston Basin position," Northern president Adam Dirlam commented in the release.

Based in Minnetonka, Minn., Northern aims to be the go-to resource for operators that want to offload nonoperated working interests in leasehold. Originally focused in the Williston Basin, the company has also expanded into the Marcellus Shale and Permian Basin through over $1 billion worth of acquisitions in 2021.

The acquisition announced on June 7 includes nonoperated interests in the Williston Basin for an initial purchase price of $170 million in cash. Per the transaction agreement, the undisclosed seller may earn an additional $5 million in contingent payments in 2023 if WTI oil prices exceed $92.50 on Dec. 30, 2022.

The acquired assets are primarily located in Dunn, McKenzie and Williams counties, N.D., and include approximately 3,500 acres, 9.2 net producing wells, 2.6 net wells-in-process and 14.9 net engineered economic undeveloped locations.

Northern expects 0.8 net wells to be turned-in-line in 2022 post-closing. The assets are operated primarily by **Marathon Oil Corp.**, **Continental Resources Inc.** and **ConocoPhillips Co.**, and Northern owns existing interests in approximately 50% of the acquired property value.

According to the release, the properties have operating costs lower than Northern's corporate average on its Williston Basin properties.

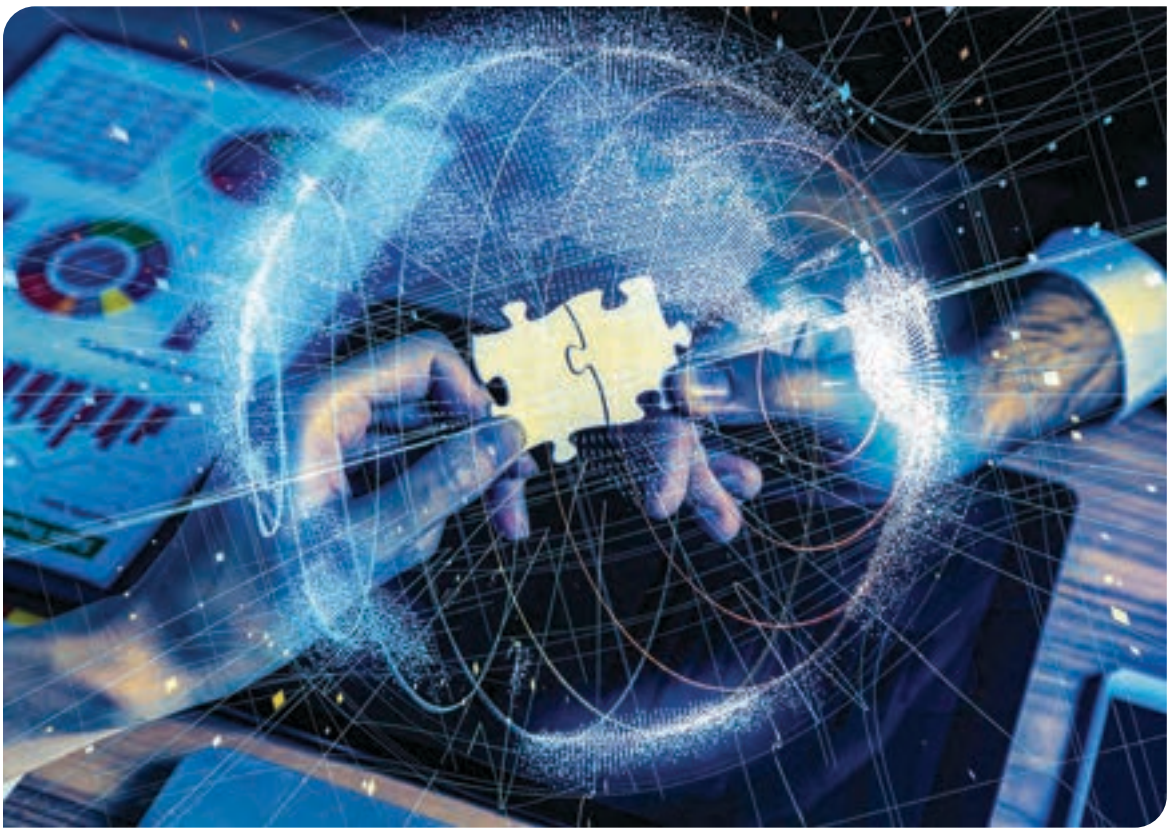
"Anchored by significant inventory, high oil cuts, strong margins and existing ownership in over 50% of the properties, this bolt-on transaction fits perfectly with our strategy," Dirlam added.

Northern plans to fund the bolt-on acquisition with cash on hand, operating free cash flow and borrowings under the company's revolving credit facility.

The effective date for the bolt-on transaction is April 1, and Northern expects to close the transaction in August.

—Hart Energy Staff

BEACHWOOD HELIX TEASES TWIN TRANSACTIONS VALUED AT $863 MILLION



Beachwood Helix Corp., a new energy asset marketplace, is teasing two deals by a private buyer that are set to close in July for about $863 million.

The assets are located in the Lower 48. Beachwood president and founder Joshua Robbins said in an interview that he had spoken to the buyer on June 2 and could not provide additional details.

Robbins said details, including the name of the buyer, would be released after closing because of the "volatile market" and "lack of energy-friendly financing."

Beachwood offers a web-based platform called the Helix consisting of a fully customizable web3 network that delivers deals that match buyers' criteria with the goal of "saving the time of sorting through millions of wells and finding the assets that fit the buyer's target parameters," the company said.

Transactions on the Helix are made through a decentralized database that allows for transparency of price, data and communication between buyers and sellers. About 170 oil and gas companies use the Helix platform daily, according to the company.

The company officially opened its virtual doors in January as an off-market source for deals "specifically for these companies," and, since Jan. 1, has evaluated 206 deals, Robbins said.

While the types of sellers vary, the company offers family companies that may not engage with the A&D space a way to understand the true value of their assets.

"They need some consulting in order to really understand why their assets are valued the way they're valued" even though the price of oil and gas may be elevated, Robbins said. Beachwood walks them through the metrics of their assets and explains the metrics buyers are using in order to make a transaction.

"The buyers and sellers … really like our consulting aspect, where we outline really what their expectations should be," he added.

Beachwood's team includes Carol Gonzalez, a senior reservoir engineer, who has more than 40 years of experience evaluating assets for companies such as **Texaco**, **BHP Billiton**, **Rosetta Resources**, **Pioneer Natural Resources** and **Chesapeake Energy**, according to Beachwood.

"She's been valuing assets since before computers," Robbins said of Gonzalez. "Now we have software that really takes out all of the legwork of reservoir engineering."

Robbins said Beachwood Helix buyers are less oriented toward a particular basin and more toward returns. Some are investors that are looking to quickly reinvest money from the sale of a commercial property into another asset in order to avoid capital gains taxes.

"We outline some strategic advantages for the buyers or the investors" that may want to invest between $15 million and $150 million, he continued. "The return on investment in the bank is zero. So, they want to get some assets that provide income. It really gives them a good platform in which to do it."

Beachwood Helix said its two major transactions have set the stage for the Helix. Both deals are scheduled to close by July 1.

—Darren Barbee

RANGER OIL UNVEILS THREE 'BOLT-ON' ACQUISITIONS TOTALING $64 MILLION

Ranger Oil Corp. agreed to add 17,000 net acres to its Eagle Ford position through three "bolt-on" acquisitions for a total purchase price of roughly $64 million in cash, the pure-play Eagle Ford Shale producer said on May 3.

"As consolidation in the Eagle Ford continues, we see additional attractive opportunities that, at the right valuation, could add both immediate and long-term value to shareholders," Darrin Henke, Ranger's president and CEO, commented in a release.

Based in Houston, Ranger Oil is a pure-play independent oil and gas company engaged in the development and production of oil, NGL and natural gas, with operations in the Eagle Ford Shale in South Texas. Previously known as Penn Virginia, the company rebranded last October following an all-stock combination with Lonestar Resources US Inc.

On May 3, Ranger Oil said it signed separate agreements to acquire the three "bolt-on" oil producing properties in the Eagle Ford Shale contiguous to Ranger's existing assets. With the addition of approximately 17,000 net acres at closing, Ranger will have more than 155,000 net acres, a greater than 10% increase from year-end 2021, according to the company release

Ranger noted it had identified significant and highly economic near-term development opportunities in the bolt-on acquisitions with approximately 19 miles of shared lease lines with Ranger's current acreage enhancing existing development plans through longer-lateral wells and increased working interest. The substantial operational synergies also mitigate the need for additional rigs and services, further strengthening capital returns, the company added.

"These strategic and accretive acquisitions of adjacent oil-weighted assets further demonstrate the strength of our business and our strategy of delivering shareholder value through a variety of avenues," Henke said.

The acquisitions are expected to close early in the third quarter, subject to customary closing conditions. The sellers involved were not disclosed.

The acquisitions are expected to close early in the third quarter, subject to customary closing conditions.

Upon closing, Ranger expects a low decline, stable production of approximately 1,000 boe/d (65% oil / 87% liquids) that it said creates a solid free cash flow profile, maintaining its strong capital structure and enhancing Ranger's framework to return cash to shareholders.

—Emily Patsy

Read the full article here:

GULF COAST

Unit Corp. said it agreed to sell its Gulf Coast oil and gas assets for $56 million. The company will also end its bid to sell its remaining assets and instead seize the opportunity from rising commodity prices to increase its share buyback program.

Based in Tulsa, Okla., Unit began a divestiture program in early 2021 to sell its noncore oil and gas assets. In January, the company engaged **Tudor, Pickering, Holt & Co.** (TPH) to sell its oil and gas properties and reserves. However, in a June 10 release, Unit said it ended its agreement with TPH due to changes in the price of oil, natural gas and NGL and "general volatility in the market."

In March, Unit did close on the sale of certain noncore wells and related leases located near the Oklahoma Panhandle for cash proceeds of $4.1 million, according to regulatory filings. It also sold other noncore oil and natural gas assets for net proceeds of $500,000 in the first quarter.

Unit said its Gulf Coast asset sale is set to close on July 1.

Additionally, Unit announced on June 10 the authorization by its board of a stock repurchase increase of $100 million, up from a previously announced buyback of $50 million. The company intends to fund repurchases from available liquidity.

CALIFORNIA

After more than three decades in California, **National Fuel Gas Co.** said its E&P segment will exit the state, noting the deal would add to its financial flexibility and offer a considerable reduction in emissions.

In a May 5 earnings release, National Fuel said that its E&P arm, Houston's **Seneca Resources Co. LLC**, would sell its California portfolio for up to $310 million.

It was not by coincidence that National Fuel touted the environmental benefits of the sale. In a company presentation, National Fuel said the Seneca divestiture would "significantly reduce the company's emissions," including a 55% reduction in CO_2 equivalent.

ESG remains top of mind for dealmakers, said Clint Rancher, an attorney with **Baker Botts** who advises on M&A transactions. Rancher made his comments generally and was not involved in the Seneca Resources deal.

"Every deal needs to make economic sense, but sometimes ESG considerations can push a marginal deal over the finish line if it advances other company goals," Rancher said.

Under the terms of the deal, buyer **Sentinel Peak Resources California LLC** will pay $280 million in cash at closing and up to three annual contingent payments, potentially totaling $30 million, from 2023 to 2025. The assets produce about 40 MMcfe/d, of which 92% is oil.

National Fuel noted that it will receive about $47,000 per boe/d for what it called "primarily higher cost, steam flood heavy oil production."

Kirkland & Ellis LLP served as the legal adviser to National Fuel, and **Lazard Capital** served as its financial adviser in connection with the transaction.

The Kirkland team was led by corporate partners David Castro Jr. and Chad Smith and associates Will Eiland and Jonathan Strom; environmental transactions partner Jon Kidwell and of counsel Jennifer Cornejo; and tax partner David Wheat and associate David Gilbert.

MINERALS & ROYALTIES

■ **Desert Peak Minerals** and **Falcon Minerals Corp.** completed their merger on June 7, creating a new company called **Sitio Royalties Corp**.

"Sitio is guided by its commitments to best-in-class leadership and governance standards, capital discipline and a thoughtful approach to value-maximizing M&A," said Chris Conoscenti, CEO of Sitio, who previously served as CEO of Desert Peak.

Desert Peak and Falcon Minerals had announced the merger agreement earlier this year to combine in an all-stock transaction. At the time of the announcement in January, the combined company was expected to have a significant Permian and Eagle Ford footprint and an enterprise value of $1.9 billion.

Sitio Resources holds more than 140,000 net royalty acres, normalized to a one-eighth royalty equivalent, over 105,000 of which are located in the Permian Basin. The company is projected to produce approximately 13,500 to 14,500 boe/d in first-half 2022 on a combined basis.

The deal also marked the next chapter for Falcon, which formed in 2018 through an $800 million combination involving its predecessor—a blank-check company—and **Blackstone**'s royalty business.

As part of the merger agreement between Desert Peak and Falcon, Desert Peak became a subsidiary of Falcon's operating partnership (OpCo). Then, on June 3, Falcon effected a four-to-one reverse stock split of Falcon's Class A common stock and Class C common stock and formally rebranded as Sitio Royalties Corp.

Desert Peak's equity holders received about 61.9 million shares of Sitio's Class C common stock and a corresponding number of common units representing limited partner interests in the OpCo.

As previously announced, Sitio is managed by the Desert Peak team and led by Conoscenti.

■ **Andros Capital Partners LLC** unveiled a new mineral platform following an initial acquisition of mineral and royalty interests for $122 million, according to a June 7 news release.

Andros Minerals LLC, the firm's newly launched direct mineral and royalty acquisition platform, entered an agreement with an undisclosed private seller to acquire a portfolio located in the Eagle Ford Shale and Permian's Midland and Delaware sub-basins.

"We are excited to establish Andros Minerals as a direct mineral and royalty acquisition platform with this initial acquisition," Andros founder and managing partner Phillip A. Gayle Jr. commented in the release.

Andros Capital Partners is a private investment firm based in Houston that targets private equity investments, credit opportunities and direct asset-level investments across the energy sector.

The firm closed its inaugural fund at its $250 million hard cap in August 2020. At the time, Andros said it was primarily focused on middle-market transactions requiring between $25 million and $200 million of equity, with an ability to make much larger commitments through co-investments from its limited partners.

Gibson Dunn & Crutcher LLP acted as legal counsel to Andros for the transaction.

EAGLE FORD

SilverBow Resources Inc. closed its cash-and-stock acquisition valued

at roughly $71 million of **SandPoint Operating LLC**, marking the Houston-based company's latest purchase in the Eagle Ford Shale.

Backed by **Carnelian Energy Capital Management LP**, SandPoint is an independent oil and gas company focused in the Eagle Ford. The SandPoint assets add meaningful production, inventory and reserves across a highly contiguous acreage position in La Salle and McMullen counties in South Texas, according to SilverBow CEO Sean Woolverton.

"This is the fourth deal we have closed since August of last year as we continue to execute on our strategic objectives," Woolverton commented in a company release on May 11.

The company announced in April it had entered separate agreements to acquire certain assets from SandPoint Operating, a subsidiary of **SandPoint Resources LLC**, for substantially all of the assets of **Sundance Energy Inc.**, both operators in the Eagle Ford Shale. These deals, worth a combined $440 million including contingent payments, marked the fourth and fifth SilverBow announced since the second half of 2021.

Purchase consideration for the SandPoint acquisition consisted of approximately $31 million in cash and 1.3 million shares of SilverBow's common stock. The cash portion of the purchase was funded with cash on hand and borrowings under the company's revolving credit facility.

Latham & Watkins LLP served as legal adviser to SandPoint for the transaction. **Barclays** is financial adviser to SilverBow on the Sundance transaction. **Gibson, Dunn & Crutcher LLP** is serving as legal adviser to SilverBow on both transactions.

Piper Sandler & Co. and **TD Securities (USA) LLC** are financial advisers to Sundance. **Kirkland & Ellis LLP** is serving as legal adviser to Sundance.

DENVER-JULESBURG

PDC Energy Inc. announced the completion of its $1.3 billion cash-and-stock acquisition of privately held **Great Western Petroleum LLC** in the Denver-Julesburg (D-J) Basin.

"We are excited to close the Great Western acquisition, which is accretive to our operating, ESG and financial metrics. We look forward to providing the market with updated guidance by early next month as we work to integrate Great Western's operations," Bart Brookman, president and CEO of PDC, commented in a May 6 news release.

The acquisition of Great Western boosts PDC Energy's D-J Basin position to roughly 230,000 net acres. PDC also holds some 25,000 net acres in the Delaware Basin in the Permian. Great Western's D-J Basin acreage stretches across Adams, Larimer and Weld counties in Colorado.

Analysts with **Tudor, Pickering, Holt & Co.** said the Great Western acquisition adds much-needed inventory in Wattenberg Field to PDC Energy's D-J Basin portfolio, according to a note by the firm when the deal was first announced in February.

WHO'S WHO IN E&P A&D: PETER J. PAMPALONE

Peter J. Pampalone's career in oil and gas spans nearly a decade and four separate seats in the CFO position, including his current job at Beech Resources LLC.

To that title, Pampalone also adds dealmaker.

Beech, a small Marcellus Shale operator, founded by former Markwest Energy Partners president, CEO and chairman John Fox, holds 8,500 leasehold acres in Lycoming County, Pa. Beech began its acquisition stage in 2016 and has since pursued a continuous leasing program.

"We leased that up organically," he said. "So we continue to acquire acreage."

Despite its size and modest drilling program, the company continues to scout for assets as it builds a fledging operation into what the company intends to be a first-class operator.

"We are always talking to people in the area and in the neighborhood to try to see if there might be some, some interest to work together," Pampalone said.

Even with price volatility, Pampalone said the A&D market has loosened up at least a bit, and buyers are beginning to again place value on undeveloped locations.

"You're not going to get 50% or more value valuation on PUDs [proven undeveloped reserves], but what you are kind of seeing is a maybe a PV-30 on your undeveloped locations, regardless of whether it's a probable possible [reserves] or a PUD, and then they're applying kind of a discount on, in addition [of] maybe a 30% to 50% discount," he said. "So you're getting some value. You're not getting a real robust value for those undeveloped locations, but, you know, you're getting something."

Beech Resources' goal is to develop a company that eventually either attracts a potential acquirer or finds an opportunity to merge with one of its neighbors and gain enough scale to potentially enter the public markets through an IPO.

"That opportunity as an exit strategy is definitely on our radar screen," he said, "although right now what we're trying to do is develop through the drill bit and increase our production, increase our cash flow."

As of April, the company was producing about 15,000 Mcf/d with expectations to grow that year-over-year by 50,000 Mcf/d. The company is in the midst of a four-year, $40 million drilling program.

And, as CFO, Pampalone orchestrated the financing to make the drilling program possible in 2021, as the world was still shaking off the mothballs from the pandemic.

"It was a very difficult time to be the market raising capital," he said. "We raised it through multiple sources" including an RBL as well as more than $20 million in equity capital.

Beech Resources is now in operational mode, drilling wells. In April, the company was about halfway through its drilling program.

"We're all pretty excited for how they could come out," he said. And, as the results come in, "we are always talking to people in the area ... to see if there might be some interest in working together." OGI

Scan to see our entire Who's Who in E&P A&D database.

THE NARRATIVE SHIFTS; THE INDUSTRY RESPONDS

JAMES WEST
EVERCORE ISI

James West is a senior managing director at Evercore ISI and responsible for research coverage of the sustainable technologies and clean energy and the oil service, equipment and drilling industries.

Market Watchers

The terrible events unfolding in Ukraine quickly shifted the narrative on global energy from "energy transition" to "energy security," although we view the current period more as one of "energy scarcity." A confluence of factors had the market headed toward energy scarcity in the developed world before the invasion of Ukraine (energy poverty exists in the developing world); plummeting costs for renewable energy sources and energy storage, government-led clean energy policy mandates and conscious consumers driving corporations to commit to net-zero policies had sent the world into a green frenzy with unrealistic near- and medium-term ambitions.

These themes, coupled with a misunderstanding by most of the population and many government leaders about the incredibly important and integrated role fossil fuels play in almost all aspects of the modern economy, from energy production to agriculture to pharmaceuticals, led to underinvestment unfolding at a dramatic level. At the same time, oil and gas companies were disincentivized to invest in fossil fuel production, especially oil and natural gas production. This underinvestment is manifesting in dramatically higher oil and gas prices. The recent period of relatively low fossil fuel prices is over, and a period of high energy costs will persist at least for the medium term.

We see an era of heavy investment in "all of the above," from fossil fuels to renewables to carbon mitigation technologies unfolding. The world is short on hydrocarbons and electrons, and the energy and power companies are responding. This includes both oil and gas, new energy technologies and major growth in electrification, especially of mobility. The traditional energy industry is increasingly investing in clean energy technologies, which we see as natural. The clean energy companies tend to be small, while the oil and gas industry has scale, technology prowess and can innovate at scale. Embracing each other's skill sets should lead to a flurry of joint ventures, technology partnerships and potentially M&A.

We believe the alignment of hydrocarbon businesses with renewables is in the early stages and will be a defining trend in the planet's move toward a lower carbon future. We also applaud the oil and gas industry for its rapid embrace of carbon capture, utilization and storage outside of use for EOR, as this technical skill set and carbon capture itself is the main mitigation technology in the push to decarbonize the industry.

We entered 2022 with the view that E&P spending would grow in the mid-teens year-over-year. This is now likely closer to 20%. The spike in prices has led to three major shifts. First, private operators in North America have more cash flow to spend, and while these entities are bumping up against oil service capacity, they will increase spending by 50% to 70% compared to the previous 40%.

Second, international oil companies, in particular those in the Middle East and North Africa, are also increasing budgets and adjusting their oil price forecasts to $60 to $80/bbl from the previous $45 to $60/bbl. Now, these companies will boost E&P spending by 30% to 35% versus initial forecasts of 20%.

And lastly, offshore activity is being pulled forward in both the shallow and deep water. Large projects in the Golden Triangle, some recent exploration success in areas such as Namibia and a major ramp up in shallow-water drilling in the Middle East are all contributing to this expansion.

In short, a major cycle is now underway. The oil service industry is leaner and meaner this time and armed with better, more digital technology. A very large percentage of investors have yet to see a commodities cycle and true operating leverage—in metals, mining, materials and hydrocarbons. This will change world market thinking and positioning and usher in a new era of investing in oil, gas and renewables. This will likely be on a scale never witnessed before. OGI

Read the full column on HartEnergy.com.

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CARBON MANAGEMENT TRANSPARENCY IS CHANGING

EIV Capital's David Finan shares how investors are deciding which carbon management practices are worth pursuing, as well as the trillions of dollars of capital needed to reach net zero.

ARTICLE BY

MADISON RATCLIFF

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Relying solely on carbon offsets to hit net-zero targets isn't going to cut it anymore, according to energy investors.

With a swelling number of corporations purchasing carbon offsets as a main source of reducing their carbon footprint, EIV Capital partner David Finan said a rising offset demand is coinciding with higher amount of capital that needs to be allocated to the business.

"If you think about the number of companies that are in the S&P 500 that have signed on for a net-zero commitment by 2040, that's a tenfold increase in the amount of offsets that are needed from today to 2040," Finan shared at Hart Energy's Carbon Management Conference on May 16.

To acquire the necessary capital, corporations will need to do more for their emissions reduction goals than buying carbon offsets; they need to make more substantial moves toward reducing their carbon footprint and increasing transparency with investors.

According to Finan, investors are now more interested in the specifics of emissions reductions. They are no longer looking just for percentages of expected emissions reductions and offsets but also where the offsets are coming from—and the more transparent the data, the better.

Shift in driving forces

Ahead of the curve, EIV Capital was one of the first investment firms to look into the clean energy space, making its first renewable deal in 2010, its first carbon-negative deal in 2017 and its first upstream deal in 2021.

Where other investors saw an area with limited profitability, EIV saw an untapped marketplace. Now, other firms are entering the space as the business of renewables and carbon management has snowballed into a sustainably lucrative business.

"Within eight years, you've seen the world go from, 'We're not going to invest in you because you did renewables' to 'We did our first upstream deal last year,'" Finan said. "When we did it in 2010, it was on the back of commercial contracts that we had a 20-year PPA [power purchase agreement] that allowed us to underwrite, no assumption other than the cash, we're going to come in the door."

While a large number of American operators have been basing their emissions targets around the Paris Agreement, Finan has seen a shift in who dictates how much needs to be reduced and by when. In March, the U.S. Securities and Exchange Commission (SEC) proposed new guidelines that would require energy companies to disclose Scope 1, 2 and 3 emissions to investors.

"These proposals for GHG [greenhouse-gas] emissions disclosures would provide investors with decision-useful information to assess a registrant's exposure to, and management of, climate-related risks, and in particular transition risks," the SEC report stated.

To proceed with these SEC proposals, Finan said that the businesses often go through the process as though they were being audited. They collect emissions data to determine if it is "accretive or dilutive" to the company's key performance indicators (KPIs) as they would when looking to buy or sell an asset.

More capital, more change

With greater attention and investment into the clean energy space must come more capital spending, according to Finan. Even ardent supporters of the energy transition have admitted to only spending half the capital necessary to reach their goals.

One-third of annual capital spent still falls to high-emission forms of energy. Furthermore, it is estimated that an increase of about $3.5 trillion is needed to get the funds needed to secure net-zero targets globally. Taking inflation into account, the rising costs could climb even higher.

With both global energy consumption and the human population escalating at a rapid pace, many are rethinking how quickly they can achieve net-zero emissions, if at all. However, Finan believes that alongside the growing need for energy is a growing number of people committed to lowering emissions and tackling the daunting task of achieving net zero. OGI

Read the full article here:

NEW FINANCINGS

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount ($MM)	Comments
Inspiration Mobility LLC	N/A	Washington, D.C.	$215	Secured an additional commitment of capital from new strategic partners **Macquarie Asset Management** and global infrastructure company **Ferrovial SA**, joining existing lead investor **ArcLight Capital Partners LLC**. New funding brings the total investable capital raised to date to $415 million, enabling the company to accelerate its work electrifying commercial fleets.
Laredo Petroleum Inc.	NYSE: LPI	Tulsa, Okla.	$200	Announced a two-year, $200 million share repurchase program authorized by its board of directors through May 27, 2024. The company may purchase shares in accordance with applicable securities laws from time to time in open market or privately negotiated transactions. The company intends to fund repurchases from available working capital and cash provided by operating activities.
Unit Corp.	OTC Pink: UNTC	Tulsa, Okla.	$100	Announced authorization by its board to increase from $50 million to $100 million the aggregate value of shares of common stock that the company may repurchase under its stock repurchase program initially announced on July 13, 2021, and increased on Oct. 8, 2021. Repurchases will continue to be made from time to time at the company's discretion through open market purchases, privately negotiated transactions or other available means. Repurchases will be funded from available liquidity. As of June 10, the company repurchased about 1.3 million shares for approximately $41 million under the repurchase program.
Kinetik Holdings Inc.	NASDAQ: KNTK	Houston; Midland, Texas	N/A	Announced a two-for-one split of the company's common stock in the form of a stock dividend approved and declared by the board of directors. The stock split will be accomplished by distributing one additional share of Class A common stock for each share of Class A stock outstanding and one additional share of Class C stock for each share of Class C stock outstanding. After giving effect to the stock split, Kinetik expects to have in total approximately 135 million shares of common stock outstanding.
Magnolia Oil & Gas Corp.	NYSE: MGY	Houston	N/A	Announced the proposed underwritten block trade of 7.5 million shares of the company's Class A common stock by certain affiliates of **EnerVest Ltd**. Magnolia will not sell any shares of its Class A common stock in the offering and will not receive any proceeds from the sale. In connection with the offering, the company intends to purchase from the selling stockholders 2 million shares of the company's Class B common stock at a price per share equal to the price per share at which the underwriter purchases shares of the company's Class A common stock in the offering. Following close, the selling stockholders will own about 10.9 million Class A and 28.7 million Class B shares of the company, or approximately 18% of the total outstanding shares of the company. **Morgan Stanley** was the sole book-running manager.

DEBT

Company	Exchange/ Symbol	Headquarters	Amount ($MM)	Comments
Occidental Petroleum Corp.	NYSE: OXY	Houston	$3,765	Commenced cash tender offers to purchase for cash outstanding notes in three separate pools. Occidental's obligation to accept for purchase and pay for notes that are validly tendered and not validly withdrawn is limited to an aggregate amount of $700 million, increased to $725 million, for all the pool 1 notes; $650 million, increased to $790 million, for all the pool 2 notes; $650 million, increased to $2.25 billion, for all the pool 3 notes. The offers expired on May 20.
Earthstone Energy Inc.	NYSE: ESTE	The Woodlands, Texas	$1,400	Entered into an amendment to the company's senior secured revolving credit facility, extending the maturity of the credit facility to June 2027, increasing the borrowing base from $1.325 billion to $1.4 billion and reducing the interest rate for amounts outstanding, amongst other things. Elected commitments under the credit facility remain at $800 million.
ChampionX Corp.	NASDAQ: CHX	The Woodlands, Texas	$1,325	Announced that it refinanced its existing credit facilities with a restated senior secured credit facility, amending and restating its 2018 senior secured credit facility. Restated agreement provides a $625 million seven-year term loan B and a $700 million five-year revolving credit facility. Proceeds will be used to repay outstanding amounts under its 2018 senior secured credit facility and repay and terminate its 2020 term loan facility, and to redeem all outstanding 6.375% senior notes due 2026. Proceeds from future draws of the revolving credit facility will be used for working capital and other general corporate purposes.

Company	Exchange/ Symbol	Headquarters	Amount ($MM)	Comments
Northern Oil and Gas Inc.	NYSE: NOG	Minnetonka, Minn.	$1,300	Entered into an amended and restated credit agreement on June 7 governing its reserves-based revolving credit facility with **Wells Fargo**, as administrative agent, and a syndicate of 14 lenders. The borrowing base under the facility has been increased to $1.3 billion from $850 million. The facility maturity has been extended from November 2024 to June 2027. NOG has chosen to increase the elected commitment amount to $850 million from $750 million.
Equitrans Midstream Corp.	NYSE: ETRN	Canonsburg, Pa.	$1,000	Launched an offering of $500 million aggregate principal amount of its 7.50% senior notes due 2027 and $500 million aggregate principal amount of its 7.50% senior notes due 2030, representing an increase of $200 million in combined aggregate principal amount of the notes from a previously announced amount. Notes will be issued at a price of par. Proceeds will be used to purchase a portion of its outstanding indebtedness as part of tender offers for all of its outstanding 4.750% senior notes due 2023 and its 6.000% senior notes due 2025 and its 4.000% senior notes due 2024.
Kinetik Holdings Inc.	NASDAQ: KNTK	Houston; Midland, Texas	$1,000	Launched an offering of sustainability-linked senior notes due 2030 priced at 99.588% of par. The notes pay interest at the rate of 5.875% per year and are payable on June 15 and Dec. 15 of each year beginning on Dec. 25, 2022. The interest rate on the notes is linked to Kinetik's performance against sustainability performance targets related to GHG and methane emissions reduction targets and the representation of women in corporate officer positions. The targets are set forth in Kinetik's recently published sustainability-linked financing framework. Proceeds will be used, together with borrowings under a new three-year term loan facility with a group of commercial banks, to refinance all of its existing consolidated indebtedness.
Ranger Oil Corp.	NASDAQ: ROCC	Houston	$875	Announced that its borrowing base under its revolving credit facility was increased 20% to $875 million. The elected commitment under the facility remains at $400 million. This is the second announced increase this year for a total of approximately 45%.
Equitrans Midstream Corp.	NYSE: ETRN	Canonsburg, Pa.	$800	Announced that its wholly owned subsidiary, **EQM Midstream Partners LP**, commenced tender offers to purchase for cash any and all of its outstanding 4.750% notes due 2023 and its 6.000% notes due 2025 and its 4.000% notes due 2024 up to an aggregate principal amount of $200 million.
Callon Petroleum Co.	NYSE: CPE	Houston	$779.9	Delivered a redemption notice on June 9 with respect to all $460.2 million of its outstanding 6.125% senior notes due 2024 and all $319.7 million of its outstanding 9.00% second lien senior secured notes due 2025. Proceeds from its $600 million private debt offering, along with borrowings under the senior secured revolving credit facility, are expected to be used to redeem all of the 2024 notes and all of the second lien notes.
Callon Petroleum Co.	NYSE: CPE	Houston	$600	Launched a private offering of $600 million aggregate principal amount of senior unsecured notes due 2030. Proceeds will be used, together with borrowings under the senior secured revolving credit facility, to redeem all $460.2 million of the company's existing 6.125% senior notes due 2024 and all $319.7 million of its existing 9.00% second lien senior secured notes due 2025.
Tellurian Inc.	NYSE American: TELL	Houston	$500	Executed definitive agreements to sell $500 million principal amount of senior secured convertible notes, bearing interest at 6.0% per annum, expiring May 1, 2025. The notes will be convertible into shares of Tellurian common stock at an initial conversion price of $5.724, subject to customary adjustments. **Roth Capital Partners** and **Citigroup** served as placement agents.
Diversified Energy Co. Plc	LSE: DEC	Birmingham, Ala.	$445	Closed an asset backed securitization (ABS) of substantially all remaining unsecuritized upstream producing natural gas and oil Appalachia assets linked to key performance indicators based on emissions reduction targets. Represents the company's third ESG-aligned ABS in 2022. The assets were previously pledged as collateral under the company's RBL.
Diversified Energy Co. Plc	LSE: DEC	Birmingham, Ala.	$300	In conjunction with the closing of the $445 million ABS and reflective of the transfer of the collateral, Diversified's 16-member bank group, led by **KeyBank National Association**, redetermined the company's====== RBL borrowing base at $300 million. The ABS proceeds will be used to repay all outstanding borrowings under its RBL and for general corporate purposes, resulting in liquidity of approximately $500 million pro forma as of March 31.
Service Compression LLC	N/A	Lubbock, Texas	$215	Closed on a commitment of first lien senior secured credit facilities with **Crestline Investors Inc.** Proceeds will be used for the acquisition of incremental wellhead compression in the Permian Basin and the kickoff of a newbuild electric-driven wellhead compression program. The acquisition will grow the company's fleet to about 239,000 hp serving blue chip customers in the Permian Basin, Midcontinent, Barnett Shale and Ark-La-Tex regions. **Imperial Capital LLC** served as exclusive financial adviser and **Baker Botts LLP** as legal counsel to Service Compression. **Haynes and Boone LLP** served as legal counsel to Crestline.

Scan to see the New Financings database.

OIL & GAS COMPANIES CONTINUE TO HEDGE

Here's a survey of the 30 largest public oil and gas companies and their hedging activities as disclosed in their Dec. 21, 2021, 10-K filings.

ARTICLE BY
JOSH SCHULTE, JEFF NICHOLSON AND REECE LAMBERT

Hedging remains a mainstay activity for many oil and gas producers to protect cash flows and manage operating budgets. However, these hedge programs and coverage levels were in place before price increases that occurred in early 2022. This resulted in the 30 largest public oil and gas E&P companies recording an overall total derivative liability of $26.8 billion as of March 31, 2022.

Price volatility is ever-present in oil and gas markets and encourages producers to have an effective hedging program in place. Other than a couple of short-lived dips, prices for Nymex WTI futures climbed steadily through 2021. The lowest futures price for oil in 2021 was over $47/bbl. Natural gas prices made strong gains in 2021, even trading above $6/MMBtu for multiple days in October 2021. The average natural gas spot price in 2021 was $3.72/MMBtu, which is nearly $1.60/MMBtu higher than the 2020 average.

The following is a survey of the 30 largest public E&P companies and their hedging activities as disclosed in their Dec. 31, 2021, 10-K filings. It also includes comparisons to the same survey done in the prior year.

The following survey provides as much information as possible based on what was disclosed in regulatory filings. U.S. GAAP accounting rules form the minimum disclosures companies must provide in their filings to provide users with an understanding of:

- An entity's use of hedges;
- How the hedges and the hedged production are accounted for in the filing; and
- How the hedges affect the financial statements.

While the accounting rules require entities to disclose the level of an entity's derivative activity, there can be variance in practice as to how much information a company discloses about the instrument types, the volume of production hedged and the average hedge price.

Why hedge?

Upstream oil and gas companies have

relatively straightforward objectives, which are to search for, develop and extract hydrocarbons. These activities are very capital intensive and require large amounts of cash. Companies need enough cash flow not only to support a level of capex and exploration activity to ensure that oil and gas continue to flow, but also to make debt payments, comply with debt covenants and support the general and administrative costs. Hedging programs at upstream companies are developed with the primary purpose of providing a level of cash flow to increase the likelihood of meeting those needs.

Without the protection of an effective hedging program, an upstream company's cash flows are subject to the volatility of the market. An upstream company without hedges will benefit from higher market prices, but they may need to adjust their operations when market prices decline for an extended time.

The following outlines the percentage of companies in the survey that maintained hedges as of Dec. 31, 2021, for crude, natural gas or NGL. Consistent with prior years, it is clear that the majority of public oil and gas producers maintain hedging programs.

Companies that hedged

Twenty-six of the 30 upstream energy companies surveyed, or 87%, had hedges on the books as of Dec. 31, 2021. This is similar to the 90% figure on Dec. 31, 2020, and is consistent with most prior year survey results. At the end of 2021, 73% of the surveyed companies had crude hedges in place, and 73% had gas hedges in place.

Instrument types

Investors should carefully consider the types of instruments utilized in their hedging program. Hedging strategies can provide different levels of downside protection based on the combination of hedging instruments used. The following notes the number of companies holding various instrument types in their hedging portfolio.

For a producer, swaps provide the highest amount of downside protection. However, swaps limit upside price participation. This leads producers to utilize purchased puts, which can be costly, or costless collars, which allows the producer to participate within a range of price movements. Other instruments noted in the survey were swaptions and three-way options.

Swaptions, often used to raise a strike price by allowing a counterparty to increase the volume or lengthen the tenor of the contract at their discretion, continue to represent a minority of the instrument types utilized by the public companies.

Three-way options (sometimes called three-way collars) are also used to raise the window of strike price participation between the purchased put and sold call that generally straddles the current market prices in the costless collar strategy by using the premium received from selling a put below current market prices. This strategy can backfire if market prices fall below the sold put.

Of the public oil and gas companies reviewed, swaps continue to be the preferred instrument for both natural gas and crude. A strategy utilizing both swaps and collars was common for both crude and natural gas, which is generally consistent with the prior year.

Length of hedging

When executing a hedging program, many companies are challenged with how far out to hedge their production. If the prices increase over time, they largely give up the upside. However, if the prices drop, it allows the company to weather the storm for a longer period. Based on the survey results, it is common for companies to hedge some level of the prompt 12-month period representing 2022. About half of the companies with crude or gas hedges held hedges in 2023 as of Dec. 31, 2021. Similar to last year, only a handful of companies held hedges for crude in 2024 (36 months out). More companies held gas hedges in the two- to four-year range as of Dec. 31, 2021, than the previous year.

Price levels

As a hedging program is intended to increase cash flow predictability, the price level at which companies execute hedges is often heavily influenced by operating budgets and debt compliance.

For the companies that disclosed their average floor prices for WTI Cushing crude, Henry Hub natural gas, or both, the average swap price for crude was $54.17/bbl for 2022 and $56.16/bbl for 2023 and natural gas was $2.95/MMBtu for 2022 and $2.94/MMBtu for 2023. The average put price (non-three way) for crude was $51.60/bbl for 2022 and $51.29/bbl for 2023, and natural gas was $2.94/MMBtu for 2022 and $2.91/MMBtu for 2023.

Hedge coverage

Consistent with the prior year's survey, few companies disclosed the amount of their forecasted production that was hedged as of Dec. 31, 2021. Only six companies disclosed a percentage of forecasted production hedged. For the companies that did disclose this information, the average hedge level for crude was 51% of forecasted 2022 production and, for natural gas, was 54% of forecasted 2022 production. Note that these hedge levels include coverage provided by three-way options.

In summary, the implementation of an effective hedging program can be a tool that helps ensure certainty of cash flow and provide a longer reaction time in the event of a market price collapse. Management teams are encouraged to consider the various hedging alternatives and strategies available to them.

Josh Schulte is a manager in Opportune LLP's commodity risk management advisory group. He assists companies with developing and executing complex risk management programs. Jeff Nicholson is a senior consultant in Opportune LLP's derivative reporting practice, in which he assists companies with the reporting and analysis of derivatives and complex securities. Reece Lambert is a senior consultant in Opportune LLP's derivative valuation practice based in Tulsa, Okla.

Voices

"Our high-quality assets, top-tier margins, unhedged oil position drove significant free cash flow generation during the first quarter of more than $2.3 billion, of which we are returning $2 billion to the shareholders."

—Scott Sheffield, *Pioneer Natural Resources Co. CEO, during a conference call with analysts in May.*

Oil and gas leaders address how hedging strategies may evolve during a tumultuous year.

"We're decent as an industry in understanding the long-term supply demand fundamentals. We're all pretty bad at understanding what's going to happen next month with the price. That's just not our game."

—Nick Dell'Osso, *Chesapeake Energy Corp. CEO, to Bloomberg during CERAWeek by S&P Global in March.*

"We don't have take-in-kind rights for all of our gas, but we do have full assurance for all of our gas. So we are exposed to Waha. We've hedged much of our exposure in 2023. And we think that's the tight spot."

—Kaes Van't Hof, *Diamondback Energy Inc. president and CFO, reporting on the firm's early 2022 performance in May.*

Read more on Diamondback's business strategies.

IMPACT OF CONTINUOUS EMISSIONS MONITORING ON SHALE

Bear Givhan, CEO and co-founder of Colorado-based Earthview, discusses why continuous monitoring technologies have emerged as the most scalable and affordable ESG solution for oil and gas operators.

ARTICLE BY

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Faiza Rizvi: *Tell us more about Earthview's BluBird continuous methane monitoring platform, and what makes it different from similar technologies in the market?*

Bear Givhan: The BluBird system is a continuous emissions monitoring platform. What makes it unique are both the hardware and software components. Our hardware is simple, accurate and robust. It's ready to work 24/7 in the oil field. The next part of the Earthview equation is our software.

This is really what differentiates Earthview from its competitors. The BluBird software uses sophisticated algorithms to accurately identify, locate, and quantify emissions on any location.

Together, these components make BluBird an inexpensive but highly accurate monitoring solution. Recently, an independent third-party testing demonstrated that our system achieved 90% probability of detection at emission rates as low as 10 kg/hr. The data we received from this testing proved that we are well within the range required by the Environmental Protection Agency (EPA) and various certification agencies.

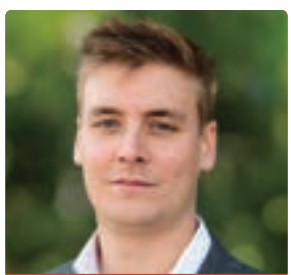
FR: *How are you helping operators achieve their ESG goals?*

BG: We're mostly engineers and scientists here at Earthview, so we like to quantify our impact for operators. As one example, we recently caught a 4-Mcf-per-hour emission on an operator's location.

On a three-month inspection cycle, that might have emitted 8,640 Mcf before being corrected. At $9/Mcf, that's nearly $78,000 in lost revenue! And according to the EPA's greenhouse-gas equivalency calculator, correcting that emission is the same as not driving a car a million miles, or planting nearly 8,000 saplings and letting them grow for 10 years.

That's real impact, from one emission on one location. We're looking forward to helping many operators achieve their ESG and financial goals.

> **"We're mostly engineers and scientists here at Earthview, so we like to quantify our impact for operators."**



For the oil and gas sector, the path to lowering emissions can often be complex and challenging.

To overcome the drawbacks of manual inspections, continuous monitoring for leak detection has emerged as a popular tool for oil and gas operators to meet their sustainability commitments and achieve ESG goals.

Faiza Rivzi, Hart Energy's senior editor, ESG, recently caught up with Bear Givhan, CEO and co-founder of Colorado-based Earthview, to talk about the company's continuous monitoring platform and why this technology has emerged as the most accurate, scalable and affordable monitoring solution in the market today.

Founded in 2019, Earthview has developed a vast network of field-ready air quality sensors that are being deployed by operators across Colorado, Permian Basin, Barnett Shale and Appalachian Basin. The idea for the company, according to Givhan, came from frustrations with existing methods for surveying oil and gas infrastructure for natural gas leaks and the imitations associated with these methods.

FR: *As drilling ramps up, are you seeing increased interest from oil and gas operators to deploy new emissions monitoring technologies?*

BG: We are currently seeing increased interest in Earthview's BluBird emissions monitoring system. We sense that the interest isn't driven by increased drilling activity; rather, we believe that operators are realizing that, at our price point, the system pays for itself by keeping more methane in the sales line and less in the atmosphere. OGI

WORK THAT MATTERS

Four years after picking up a Haynesville, Eagle Ford and Delaware Basin package for $10.5 billion, bpx energy is delivering $1 billion a year in free cash flow to parent bp Plc. The 2022 outlook? More.

bp Plc came around to putting together a sizeable U.S. shale portfolio later than other operators. But it wasn't late in terms of the price paid in 2018, and the value the properties are returning.

It gained 190,000 boe/d (45% liquids) from BHP Group Ltd., gaining 470,000 net acres in the Haynesville, Eagle Ford and Delaware Basin for $10.5 billion—the largest bp acquisition in more than 20 years.

The Delaware portion was 83,000 net with some 3,400 gross drilling locations and existing production of some 40,000 boe/d (70% liquids). In the Eagle Ford, it picked up 194,000 acres and 1,400 locations in the oil and wet gas windows, producing 90,000 boe/d (70% liquids).

In the Haynesville, it added 194,000 acres with 720 locations, more than tripling its pre-existing position in the play and producing 60,000 boe/d (100% gas).

bp had put its onshore U.S. upstream business into a new unit, bpx energy, in 2014, consisting of some 315,000 boe/d from seven basins in five states that it eventually divested and named Dave Lawler the new unit's CEO.

Lawler, who is now also chairman and president of bp America Inc., began his career in 1990, joining Conoco and Burlington Resources and then Shell E&P Co. He was president and CEO of independent PostRock Energy Corp. before joining SandRidge Energy Inc. as COO.

Among the bpx energy attributes he's proud of is the company's culture. Printed on the coffee cups in the community cafe at Denver headquarters is the slogan, "You belong here."

"It's my hope that society views bp in this same way—that bp belongs—because we are fully committed to helping the world achieve net zero. It's a massive challenge, but our teams are in action, and we are sincere about playing a meaningful role in the energy transition."

Executive editor-at-large Nissa Darbonne visited with Lawler in May.

RICARDO MERENDONI

ARTICLE BY

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Nissa Darbonne: ***It's been four years since the acquisition. How's it going?***

Dave Lawler: Our goal was to create a business model that could deliver material free cash flow on a consistent basis and compete for capital across the globe.

With the premium BHP assets, we secured a multidecade development position in some of the highest performing reservoirs within the Haynesville, Eagle Ford and Permian. When combined with our exceptional team, all our objectives have been achieved.

In 2021, we exceeded $1 billion of free cash flow and simultaneously improved our safety and environmental performance.

ND: ***The $1 billion in free cash in 2021. That was from bpx in particular?***

DL: Yes. That was just bpx. In 2021, the aggregate IRR of our capital program exceeded 100%.

ND: ***As both oil and gas prices have improved dramatically this year, what might the 2022 results be?***

DL: In the first quarter, [parent bp] delivered about $8.2 billion in operating cash flow. bpx was an important part of that.

We spent about $1 billion in capex last year. This year we'll spend about $1.5 billion to $1.7 billion. So we anticipate free cash flow will again be significant because the teams are delivering some outstanding wells.

ND: ***You're getting these results from just three properties.***

DL: Yes. I don't think our valuation reflects that these are core positions in world-class basins. For example, we're in Reeves County [in the Delaware Basin] with probably the strongest production and richest hydrocarbon saturation in the Permian, or at least one of the very top areas.

The same is true of our position in the Eagle Ford. And then we have what we think is some of the very best rock in the Haynesville.

ND: ***I hear you're making enormous step-outs in the Eagle Ford.***

DL: Last year, the team drilled and completed a step-out that is on track to an EUR more than three times as large as already-strong offsets and is expected to deliver a 5.2 value investment ratio (VIR = net present value/well cost), which is one of the primary metrics we utilize to deploy capital across the business.

That's just a world-class economic outcome. We're still discovering zones and areas that we hadn't even priced in the original deal.

ND: ***Where is it? In the gas fairway?***

DL: We weren't going to disclose that for now. But our acreage straddles the dry-gas and liquids windows, so we have optionality within the trend itself. There's a spectrum of opportunities within the whole Eagle Ford trend.

ND: ***Are you looking to buy?***

DL: We are pleased with our current position and have no plans to pursue a material acquisition. We are always open to strategic additions that fit well with our current operations.

ND: ***Natgas strip was $2.84 when the deal with BHP closed. Today, it's more than $7. It seems there was only one place for bpx's returns to go: up. So the deal had upside no matter what, right?***

DL: The price of gas certainly was an upside, but we didn't count on that to support the deal. We did have the strong liquids component, which was a key focus for future development. In addition, there were numerous undeveloped areas and zones and key synergies that we knew provided significant upside.

bpx energy's Grand Slam facility in Orla, Texas, in the northern Delaware Basin is an electrified oil, gas and water-handling facility that reduces operational emissions.

BPX ENERGY/MARC MORRISON

BPX ENERGY/MARC MORRISON

The electric Independence Contract Drilling Rig 212 drills for bpx in the northern Delaware Basin in May.

Naturally, the improvement in prices have helped. But even at deal metrics, the wells in the Haynesville are best-in-class. We brought on a two-well pad last year that was getting close to pushing 50 MMcf/d total. And we have a massive inventory.

But we're also really optimizing our completions, getting the longest laterals possible and optimizing the stages and the sand and fluid pumped. We have dynamic analytics that are working well for us.

We're pleased with the results that have come in—and at any price environment. I want to make sure this is appreciated. Some might say, "Well, you had a strong year in terms of prices." Without a doubt, that's true. But even at moderate-to-lower prices, these assets are very strong.

ND: ***In the spring of 2021, before the situation in Europe this year, I saw natgas futures elevate across the board, even diminishing the shoulder-versus-winter difference and possibly because 20 Bcf/d is being exported now. Do you think that at least a $4 or $5 strip going forward is likely?***

DL: I won't speculate on prices. But if you look at the investment profile over the last few years, you'll see a significant reduction in capex deployed on gas development. This decline, combined with demand for gas supporting the energy transition, creates an environment for gas that is different than in previous cycles.

Gas is important to society. When combined with emissions reduction technologies, carbon capture and storage, and for potential use in hydrogen, we have a reason to be excited about our gas position in the Haynesville. We have somewhere on the order of 11 Tcf of total resource. So gas is very important to our portfolio going forward.

ND: ***Tell us about your work in the energy transition.***

DL: bpx, in addition to delivering free cash flow to bp Plc, is going to be very integrated in the energy transition. We have the subsurface expertise and the drilling expertise that will play a leading role in the carbon-capture aspect of the business. We will drill several appraisal wells for the company in 2022.

We're also going through a process of independently certifying our gas as low-methane intensity.

ND: ***Your career began in 1990. Could you have imagined then that 2- and 3-mile, multi-frac-stage laterals in tight rock onshore the U.S. and the U.S. becoming the world's No. 1 oil and gas producer again is where we would be today?***

DL: I actually started my drilling career working for Rick Muncrief, now the CEO of Devon [Energy Corp.], at Burlington Resources. We were drilling single-mile horizontal wells, intersecting fractures in the Bakken [in the early 1990s] well before today's frac technology. Rick is an exceptional

leader and a dear friend to this day.

When I got out of the [Colorado] School of Mines in 1990, it was still a conventional oil and gas business, evolving into deep water. Then the industry evolved into unconventional development, unlocking significant production and reserves. And now the energy transition, where gas will be a source of blue hydrogen transportation fuel.

It's been an exciting career to see all these different phases. But I can tell you this latest one is the most exciting.

ND: ***The energy transition?***

DL: Yes. bp aims to spend $4 billion to $6 billion per year on low-carbon projects by 2030. There's just so much going on in the space, and it's work that matters to society. We listen hard, [and] it is clear what is being asked of us globally: People want clean, reliable and affordable energy. bp was and remains at the forefront of responding to that request.

We'll still be in the oil and gas business, but, globally, production will be 40% lower by the end of the decade as we high-grade the business. However, bpx and the Gulf of Mexico production will probably be growing over that period. In fact, we'll play a very important role in funding the transition and producing what we call "resilient hydrocarbons."

But if you told me in 1990 that I would have the opportunity to work with all the amazing people and take on all these generational challenges, it would have been hard to process all that change. It's exciting to be a part of and to continue to grow into new areas.

ND: ***One of bp's clean energy projects is solar in Pueblo, Colo.***

DL: We're a 50:50 partner. It powers an electric arc furnace in a steel mill that recycles steel. This is a clear example of a circular green economy.

It's amazing that a steel mill that had been in operation since the late 1800s has found a way to evolve so it can remain an important part of the community and the economy in Pueblo.

ND: ***What else should* Oil and Gas Investor*'s readers know about bpx?***

RICARDO MERENDONI

DL: We're proud that we've reduced flaring from roughly 16% when we acquired our assets to less than 0.5% today, all while bringing new production online.

And we are in the process of electrifying the field. At our new well sites, there are no tanks, no flares. It's just power lines. And it's nearly silent.

We plan to spend about $1.3 billion total to install a state-of-the-art gathering system in the Permian Basin. This all-electric strategy is well underway in Reeves County. We've installed 2,200-megawatt substations that power most of our field. We currently utilize about 23 MW, for which we purchase renewable energy credits.

We also expect to achieve zero routine flaring well ahead of our target of 2025.

If you invest correctly, you will get a strong rate of return and by doing it right. So, we're delivering exceptional wells, generating a significant amount of cash for the company, and, at the same time, decarbonizing. So, it can be done.

My hope and message is that we can perform while we transform for the future, decarbonizing oil and gas production, all while investing in and developing technologies that will help the world reach net zero.

I'm very excited about the future. OGI

U.K. SHALE, AGAIN

Finding itself short oil and gas in the midst of soaring global prices, the U.K. is looking again at its shale—and this time, no matter how often protesters glue themselves to public buildings.

ARTICLE BY

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The U.K. has a new head of business and energy, and he means oil and gas—in addition to other fuels. Secretary Kwasi Kwarteng ordered a new shale development report from the British Geological Survey (BGS) on April 5.

Nothing fancy. Something quick. It was due at the end of this past month.

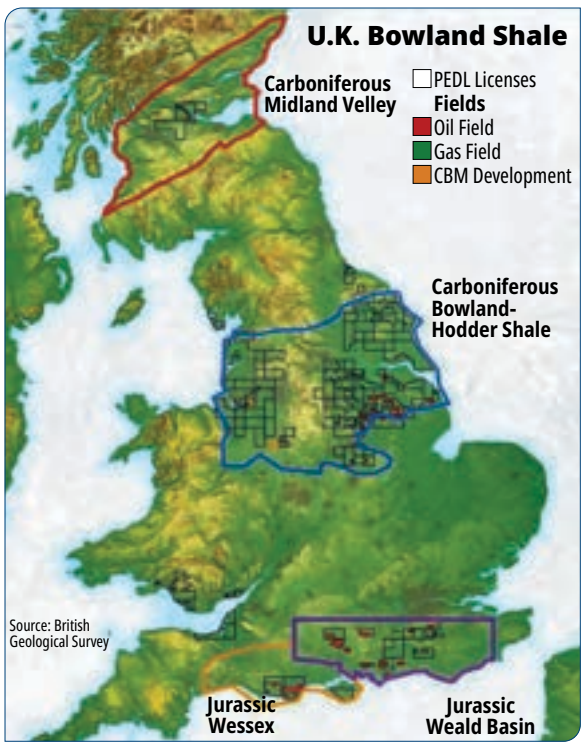
"I want to be clear that this should be a desk-based exercise," he wrote to the BGS. He wasn't asking for more test wells or additional seismic monitoring. "The aim would be to assess any progress in the scientific understanding … to consider next steps."

As for fossil-fuel protesters, he tweeted on April 13: "My message to XR [Extinction Rebellion] activists gluing themselves … to my department [building]: You cannot—and we won't—switch off domestic oil and gas production. Doing so would put energy security, jobs and industries at risk and would simply increase foreign imports, not reduce demand."

It's a turnabout from a U.K. energy policy that retreated just a few years ago when confronted by protesters, such as fashion designer Joe Corre, son of designer and activist Dame Vivienne Westwood. Kwarteng presented to one of his alma maters, Harvard Kennedy School, the day he wrote to the BGS. "Transforming our energy system is no longer just about hitting net-zero targets and tackling climate change—as important as they are. It is also about national security," he said.

"The Bowland has the same kind of characteristics as the Fayetteville and Barnett. It's in the dry-gas window, which is actually good."

—Kent Bowker



Among those leading exploration of U.K. shale this past decade was Sir Jim Ratcliffe, founder and chairman of privately held, London-based chemicals manufacturer Ineos.

He wrote in The Daily Telegraph on April 10: "The sad reality of the short history of the U.K. shale industry was that the science was totally ignored, and our politicians reacted to a false public perception of the so-called dangers by introducing a moratorium on development. Apparently the influential voice of a fashion designer carries more weight than any number of scientific experts."

Dan Steward and Kent Bowker, geologists who were part of the Mitchell Energy & Development Corp. team that cracked the code on the Barnett Shale in the late 1990s, were consulting to Ineos as it drilled shale tests.

Also part of the consulting group was Nick Steinsberger, the lead Mitchell petroleum engineer.

Bowker told *Oil and Gas Investor*, "I've got to say, if you read [Ratcliffe's] letter,

NORTH SEA CONVENTIONAL

While suddenly actively encouraging oil and gas development, the U.K. has also proposed a windfall-profit tax on energy companies.

According to Reuters, the 25% tax plan is expected to come with a nearly 100% tax break for capital spent on new oil and gas projects.

Reuters quoted Rishi Sunak, the British chancellor, "The more a company invests, the less tax they will pay."

Also this spring, the U.K. approved a Shell Oil Co. gas development, Jackdaw, after having rejected it in October. Jackdaw had been licensed since 1970.

Reuters reported that "Shell's new plan changed the way it processes gas at the Shearwater hub" in regards to handling naturally occurring CO_2.

U.K. Secretary of State for Business, Energy and Industrial Strategy Kwasi Kwarteng tweeted about the Jackdaw approval, "We're turbocharging renewables and nuclear, but we are also realistic about our energy needs now.

"Let's source more of the gas we need from British waters to protect energy security."

he gets about as feisty as I've ever seen him in public."

The U.K. is paying more than $30/MMBtu of natural gas and more than $120/bbl for oil. It's a net importer of both.

Steward said, "They are desperate for something. They are looking at possibly giving tight reservoirs another chance. Possibly. Putin made them rethink things."

What shale?

The U.K. has four onshore areas with shale gas development potential, according to the BGS: the Bowland Shale-Hodder mudstone (Carboniferous) in northern England; the Midland Valley (Carboniferous) in southern Scotland; and the Weald Basin (Jurassic) and Wessex area (Jurassic) in southern England.

The BGS estimates 1,300 Tcf of gas in place (P50) in the Bowland and 4.4 Bbbl of oil in place in the Weald. The shale in southern Scotland might contain 80 Tcf and 6 Bbbl. An estimate was not made for the Wessex area due to insufficient data.

The Bowland, which was deposited during the Visean and Namurian stages of the Carboniferous period when the U.K. was located at the equator, extends offshore too—west under the Irish Sea and east under the North Sea. Gas in place for it and the Hodder is between 822 Tcf and 2,281 Tcf based on one analysis, the BGS reported; another analysis suggests it might be 140 Tcf.

In southern Scotland in the Midland Valley, the shale has 2% to 6% organic carbon content. The BGS reports an estimate of between 49 Tcf and 137 Tcf of gas in place.

The Bowland is also found on England's southern coast. But the potential is unknown, according to the BGS.

Halted

Shale tests were halted in the U.K. in 2019 after a 2.9 magnitude earthquake was measured as U.K.-based E&P Cuadrilla Resources Ltd. completed in the Bowland at Preston New Roads about 6 miles from the Irish Sea.

"There, it's completely different geologically," Bowker said. "Where they are, the Bowland is very thick, but it's also very faulted. Ineos had the opportunity to be in that area, but Dan and I suggested they stay out of there mainly because it's faulted."

Faults are where you "lose your frac." Bowker said, "It's not going to work well. Our friends at Cuadrilla induced some earthquakes. And that's what stopped the process in the whole country."

The geology to the east, where Ineos was testing in its leasehold and in some leasehold operated by a joint-venture partner, U.K.-based IGas Energy Plc, "is more benign," though.

"It's not structurally complex. And we believe it's a lot quieter tectonically. Induced seismicity should be much less of a threat where Ineos is."

Ineos' tests found the Bowland to be good rock. And it also found a tight-gas sandstone, the Millstone Grit, similar to, "though not at the same scale," as the Mesaverde of the Piceance Basin and the Morrow/Springer sands of the Oklahoma portion of the Anadarko Basin.

"In fact, they are the same geologic age: Lower Pennsylvanian. It's a massive basin-center gas deposit. It's not shale, but it's possibly very productive," Bowker said.

In both the shale and the sandstone, "we know the gas is there because we did all the science and the drilling to show that it's there. Now, we weren't allowed to try to produce it. We weren't allowed any kind of completion. So we don't know exactly how much of it we're going to produce. We just know there's a lot there."

The combination of resource in place and areal extent—possibly hundreds of square kilometers—might make it a Fayetteville-size producer, Bowker estimates.

Steward said, "When you consider Britain's

"[The Bowland] isn't going to be a huge game changer, like the Marcellus and the Haynesville have been in the U.S. But for the U.K., it's plenty big."

—Dan Steward

gas requirements are substantially less than ours, it means quite a bit of gas."

The U.K.'s natural gas consumption in 2019 was 2.9 Tcf; production was 1.4 Tcf, according to the U.S. Energy Information Administration. In contrast, U.S. gas consumption in 2019 was 32 Tcf; production was 35 Tcf.

U.S. consumption this year is trending to 35 Tcf, with some 7.3 Tcf of that "consumed" by exports via LNG and pipe.

For Europe as a whole, the Bowland "isn't going to be a huge game changer, like the Marcellus and the Haynesville have been in the U.S.," Steward said. "But for the U.K., it's plenty big."

Resembles

Bowland gas in place closely resembles that of the Barnett and Fayetteville shales, Bowker said. "The Fayetteville has thousands of wells with sandstones above it that are gas-saturated. The Fayetteville always seemed to me to be the most proper analog," he said.

The Fayetteville is Mississippian-age. Bowker said, "The Mississippian/Pennsylvanian stratigraphy gets complicated in the U.K.; that's probably why they call the whole thing Carboniferous.

"But the Bowland has the same kind of characteristics as the Fayetteville and Barnett," Bowker said. "It's in the dry-gas window, which is actually good. And there might be some liquids like some parts of the Barnett Shale."

As for the Bowland's permeability, porosity and organic content, these are similar to the Barnett.

In terms of the number of benches for stacking horizontals, "I think there'll be one in the shale play where Ineos is," Bowker said. "I don't think there will be multiple ones."

But in the basin-centered sandstone play above it, there are multiple intervals. He likens it to Jonah and Pinedale fields.

"We've got sandstones that are just chock full of gas, and they're tight. They're going to require stimulation. And they don't really produce a lot of water."

Incomplete completion

Bruce Walker, Enverus regional manager, Europe and Middle East, summarized the shale development attempts in a 2019 blog post. Cuadrilla drilled four Bowland tests between 2010 and 2012, resuming in 2017 at Lancashire in eastern England. One of the wells, Preston New Road, tested up to 0.2 MMcf/d.

It was underwhelming, but "this was despite only fully fracking and completing two out of 41 planned frac stages in the Bowland." Also, the well was only a vertical.

Meanwhile, the IGas-Ineos partnership found "excellent shale gas potential" in the Millstone Grit above the Bowland in its Tinker Lane well at Nottinghamshire, Walker added.

Another IGas-Ineos' well, Springs Road, showed 250 meters (820 ft) of the Bowland "and further gas indications in the Millstone Grit and the deeper Arundian Shale."

In 2016, the U.K. awarded more than 12,000 square kilometers of prospective shale acreage with Ineos getting the most; it had applied for 30 permits.

Walker added that Britain's Centrica Plc and France's Engie SA and TotalEnergies SE were, at the time, "waiting in the wings."

Delineation

What's needed next is delineation: drilling additional wells across the play, Bowker said. Ineos drilled only two wells before the U.K. shut it down, "but the two wells at least showed there is plenty of gas in place.

"An engineer will tell you, 'That's great. But are you going to be able to produce it?' We weren't allowed to prove that we could produce it.

"But Dan and I know from our work in the Barnett and all the other plays that we've been involved in that the engineering know-how is there to get the gas out.

"But again, we weren't allowed to do it."

He added that resuming tests "to get it out is, politically speaking, a no-brainer."

Steward noted that, essentially, Ineos wants to use its own money to science the U.K.'s indigenous natural gas—for the U.K. "It's almost a gimme that the government should say, 'Yes.'"

At stake

This past February, Cuadrilla plugged its two wells in Lancashire as ordered by the government, according to The Guardian, adding that Cuadrilla's CEO called the order "ridiculous" while Europe was confronting a gas crisis.

This was four days before Russia invaded Ukraine.

It's believed that, like in the Marcellus, Putin seeded U.K. anti-fracking campaigns. Interestingly, all have backfired. The U.S. is the world's No. 1 producer of natural gas and is shipping to the U.K. some of its surplus, while U.S. experts are instructing the U.K. on how it can develop its shale.

Ineos itself is a direct recipient of U.S. shale development, having built tankers to receive Marcellus ethane at an Atlantic terminal and to receive other U.S. ethane from the Houston Ship Channel.

Steward said that, if the U.K. had proceeded with shale development in the past decade, "I don't think they would be in the position they're in today."

Now, possibly, "they have learned enough to start getting enough gas out to take care of themselves."

But the U.K. has additional surface issues to overcome, Steward added. "When Kent and I first got there, the government was proud to tell us they could issue a permit in a year, whereas it used to take two years.

"And we told them, 'Look, if it takes a year to get a permit, you're never going to have a development program.'"

'You're the highest price'

Bowker said, "It's interesting that [in Nottinghamshire] not too far away from where we drilled the Springs Road well is a statue that is a twin to one in Ardmore, Okla. The statue commemorates the importation of U.S. drilling crews from southern Oklahoma during World War II."

ENERGY SECURITY

U.K. Secretary of State for Business, Energy and Industrial Strategy Kwasi Kwarteng's tweets this spring about energy are emphatic that oil and gas development are essential to the country's future.

The statue, "The Oil Patch Warrior," was dedicated in 1991. During WWII, Ardmore-based Noble Corp. drilled for oil in the U.K.'s Sherwood Forest to surface fuel for the U.S. ally.

"At one time, the U.K. had a vibrant onshore oil and gas industry," Bowker said. "It still produces oil onshore. It's not anywhere near what it used to be. But it's interesting that the citizenry in the U.K. at one time actually celebrated oil and gas."

The noisemakers are few, though, he added. Out in the countryside, "when we would talk to folks in the restaurants and pubs, most of them understood what we were doing and were supportive.

"As long as you don't shake their China cabinets," Bowker said.

Steward added, "When you get away from the radicals, they're good with it. And I'm sure they would be now, given the price they're having to pay for fuel."

Bowker added that an easily dispelled myth circulating in the U.K. is that Ineos "will just export the gas to get the highest price.

"I'm like, 'But *you're* the highest price.'"

Besides that, "there's no way to export the gas from the U.K. All the pipelines flow *into* the U.K."

Industrial revolution

Chris Wright presented to the House of Lords in 2014 on how fracking is safely done in the U.S. He was among 1990s frac-design team members involved with eventual breakthroughs on economically completing U.S. shale wells.

He went on to found pressure-pumping operator Liberty Energy Inc., where he is chairman and CEO.

He noted in an *Oil and Gas Investor* interview at Hart Energy's DUG Haynesville Conference last year that the Bowland Shale "runs right through the Midlands of England, literally where the industrial revolution began.

"I know the folks and companies in this room, if they brought their technology over to the U.K., could have a shale revolution right there."

The attempt to develop the shale in the past decade was welcomed by the U.K. manufacturing industry, he added, "and protesters of fewer than a hundred people were able to prevent wells from being drilled and fracked."

Meanwhile, in Liverpool, which sits on top of the Bowland and is the birthplace of the industrial revolution, "one in three households is without a single employed person living in them," Wright said.

'Flick of a political switch'

In his op-ed April 10, Ineos' Ratcliffe wrote, "The U.K. is in the midst of an energy crisis. … How have we ended up in this situation?"

The North Sea and nuclear power had given the U.K. "an enviable degree of energy independence. … All of that has disappeared, with successive governments of all political colors having no coherent energy policy. Energy policy is a long game."

But the U.K. has had 27 secretaries of state during the past 50 years, "hardly a recipe for long-term thinking."

The U.K. now imports 50% of its gas. "We are buying strategic gas supplies for the country on spot deals at the whim of global markets and are reliant for supply on foreign governments with whom we may have fundamental differences."

In addition, he wrote, U.K. storage capacity is 2% of annual demand. (For comparison, U.S. gas storage is about 14% of domestic demand, excluding exports to Mexico and as LNG, and about 11% of gross demand.)

"Our £250 million investment [in shale tests] did not even get us to first base. We identified significant reserves of gas across the whole of the north of England, but were not allowed to develop a single test well to prove that the technology could be operated safely," Ratcliffe wrote.

"[This] £250 million of investment [was] destroyed with the flick of a political switch, with no offer of compensation and not even the decency of an apology."

Shale development takes time, he noted, so if it had not been halted in 2019, "it would, indeed, be having a positive impact today."

Today, it can only be helpful in countering the next British energy crisis. "Unless we act now, we will be in the same parlous position then." OGI

CYBER INSECURITY

While it's impossible to defend all operational technology assets from cyberattacks, companies who prioritize cybersecurity are more likely to prevent or survive an attack.

ARTICLE BY

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While many energy professionals believe cyberattacks could cause harm in the next two years, investments in security aren't necessarily being made.

Concerns about the security around operational technology (OT) have escalated, particularly since the 2021 ransomware attack on the Colonial Pipeline. Even so, one of the challenges is what appears to be a "wait-and-see" approach to OT cybersecurity, according to DNV's "The Cyber Priority: The state of cybersecurity in the energy sector" report published in May.

Companies need to understand it's possible to minimize risk even if it is unrealistic to expect to protect all assets from the threat of a cyberattack, according to cybersecurity experts. They also need both a good cybersecurity defense system as well as a playbook for what to do during an attack.

Chief among the actions energy companies need to take are allocating sufficient funds to cybersecurity and training as well as knowing what the OT vulnerabilities are, said Trond Solberg, managing director of cybersecurity at DNV.

The research, carried out in February and March 2022, surveyed more than 940 energy professionals involved in a range of functions within the industry, including those with in-depth knowledge of cybersecurity, engineers, general managers and C-suite executives.

Respondents were in Europe, the Americas, the Middle East and Africa, and Asia Pacific.

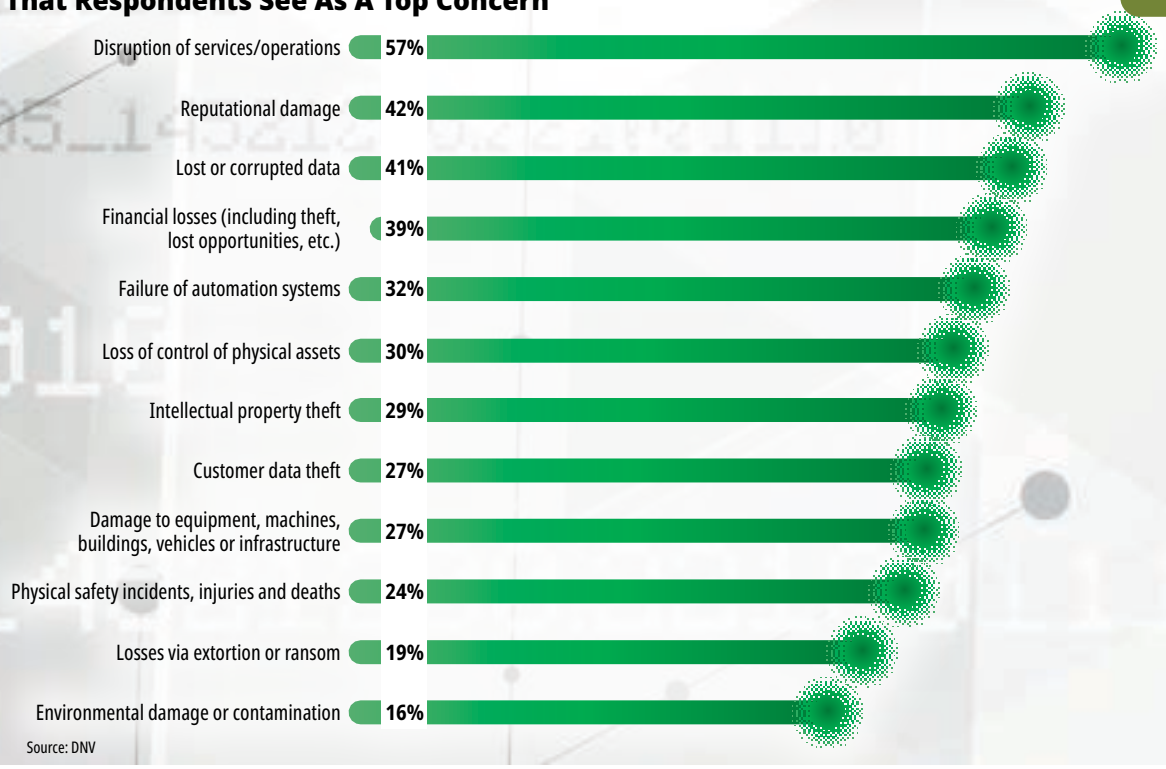
The results of the research "confirmed a suspicion we had," Solberg said.

The research revealed that energy professionals believe cyberattacks on the industry are likely to cause harm to life, property and the environment in the next two years, with 85% of respondents expecting an attack to cause operational shutdowns, 84% expecting physical damage to assets, 74% expecting an attack to harm the environment and 57% anticipating loss of life.

> "It is concerning to find that some energy firms may be taking a 'hope for the best' approach to cybersecurity rather than actively addressing emerging cyber threats."
>
> —Trond Solberg, *DNV*

DNV raised concern about two other results. Only 47% of respondents believe the security of their OT—the control systems managing, monitoring and controlling industrial operations—is as robust as their information technology (IT) security, and only 44% of the industry's C-suite executives see the

Cyberattack Consequences That Respondents See As A Top Concern



Source: DNV

need for urgent improvements to prevent a serious attack on their business, despite emerging threats.

Solberg said the consequences of OT attacks are "much higher" than those around IT and info security attacks.

"Unlike information security, with OT there are physical consequences," he said, which could include pollution, accidents and damage to life and property.

The concern, he added, is that attacks are becoming more sophisticated and seeking results beyond what can be achieved with ransomware.

"As OT becomes more networked and connected to IT systems, attackers can access and control systems operating critical infrastructure such as power grids, wind farms, pipelines and refineries," he said.

What makes this particularly worrisome is the fact that the industry hasn't made the necessary investments to defend against OT cyberattacks, Solberg said.

"The maturity of the energy business is not where it should be in terms of investment," he said.

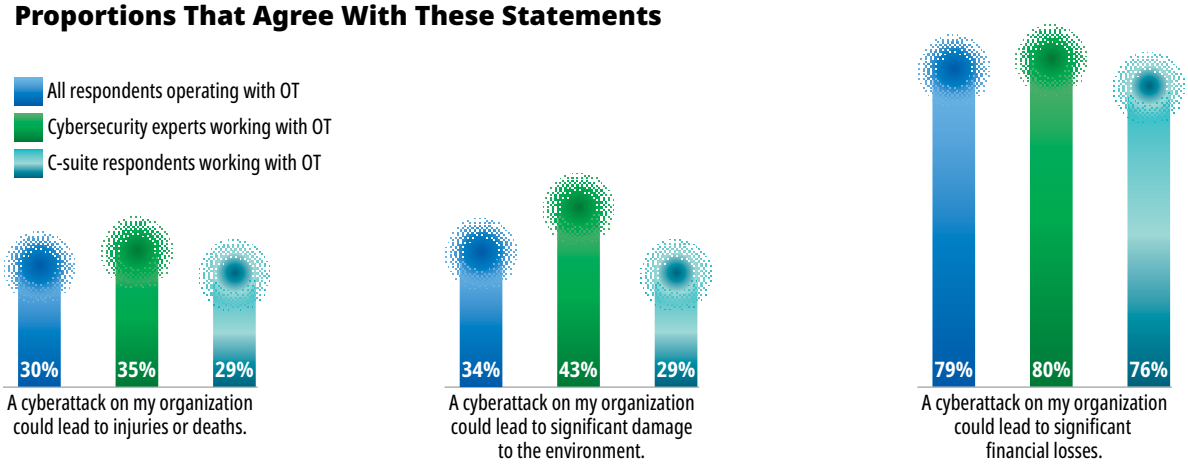
Instead, Solberg added, it appears the industry is taking a "wait-and-see" attitude.

The research revealed that 44% of C-suite respondents believe they need to make urgent improvements in the next few years to prevent a serious attack on their business, and 35% of energy professionals say their company would need to be impacted by a serious incident before investing in their defenses.

"It is concerning to find that some energy firms may be taking a 'hope for the best' approach to cybersecurity rather than actively addressing emerging cyber threats. This draws distinct parallels to the gradual adoption of physical safety practices in the energy industry over the past 50 years," Solberg said.

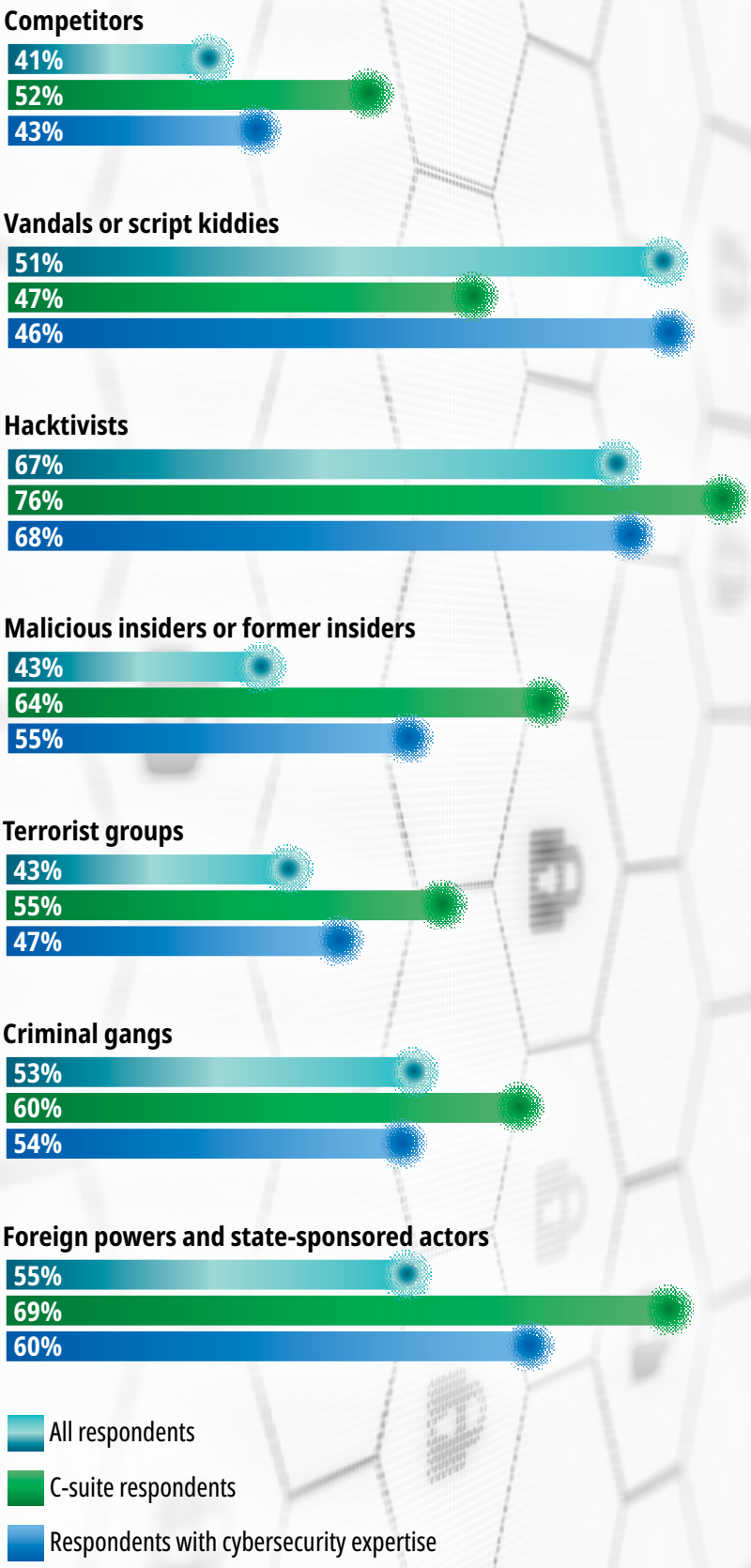
DNV suggested some companies may hesitate to invest in cybersecurity because most respondents believe their

Proportions That Agree With These Statements



Source: DNV

Most Concerned Threat Factors Of Respondents



Source: DNV

organization has so far avoided a major cyberattack and only 22% suspect their organization has been subject to a serious breach in the past five years.

"We need to fight the 'wait-and-see' attitude," Solberg said.

An undeclared war

It's unrealistic to expect to protect all assets from the threat of a cyberattack, but it is possible to minimize risk, Nicholas Andersen, chief operating officer at Invictus International Consulting, said during "The Cyber War Among Us" executive dialogue at the Offshore Technology Conference in Houston.

"You're not going to protect everything all the time," he said.

Instead, he said, companies can prioritize protection for areas that could have the "highest consequences" if a cyberattack succeeded and then build layers of defense around that.

And the entire industry is facing a cyberwar.

"Each of you is on the front lines of this war that was never declared," Andersen said.

It may not have been declared, but attacks are constantly evolving, and it would behoove the industry to have a community of people with whom they share information, he added.

"With cybersecurity, what affects you today is going to affect me tomorrow," he said. "New vulnerabilities and attack methods are being discovered every day."

One method is to breach a system and linger hidden for some time as they work to gain influence, he said.

"It doesn't matter that you don't see them today. They don't want you to see them today. They want to lay in wait until a time of their choosing," he said.

Andersen said IT and OT teams should work much more closely together. The conversation needs to start with prioritizing potential consequences and should have risk owners "who can drive change on the OT and IT sides."

Groups like Linking the Oil and Gas Industry to Improve Cybersecurity can help with things such as teasing out root cause analysis, he said.

While the industry has a strong focus on safety, Andersen said cybersecurity should be just as integral.

"Cybersecurity needs to be baked into that safety conversation," he said.

Good defense and a playbook

As the upstream energy industry becomes increasingly connected through IT, OT and the Internet of Things, the number of entry points into a system increases. There are several challenges to planning an effective cybersecurity strategy, and companies must understand their vulnerabilities and the potential damage a successful attack could

wreak, as well as have a trained plan for how to respond, experts said during the AWS Energy Symposium in May.

Ben Miller, vice president of service and R&D at Dragos, said the threat landscape in cybersecurity is only increasing. The proliferation of connections for OT equipment is one reason, he said.

"Traditional IT approaches have not worked. It's not a technology problem. It's a strategy problem."

—Leo Simonovich, *Siemens Energy*

"You can't get less connected; that's just not happening," he said. And all of those connections are potential entry points for a cyberattack, he said.

"No adversary is out there saying, 'I'm not going to attack OT systems,'" Miller added.

Leo Simonovich, global head of industrial cyber and digital security at Siemens Energy, said the company asked people who were responsible for OT about their experiences with cyber threats.

"What we found was really disturbing," he said. "Most are experiencing at least one major event per year" that's causing problems, and some are experiencing even more each year.

The points of entry are increasing, and cyberattack strategies are evolving, but there are additional challenges the energy industry faces when it comes to securing their assets and networks.

Miller said there can be limited data collection or analysis of that data, partly because coordination between internal teams can be lacking. That lack of coordination and sharing of information inside organizations can lead to attempts to defend a system in isolation, he said.

If existing information isn't shared quickly, it can mean a company doesn't have sufficient time to plan a defense or response, he said.

Simonovich highlighted some other reasons that it can be difficult to secure a network or asset in a "hyperconnected digital space."

First, there can be a problem with visibility, he said.

"Visibility is the most overused word in cybersecurity," he said. "But it's still important."

That's because if a company doesn't know how exposed the network or asset is, it's hard to protect it, he said. And it's necessary to identify those vulnerabilities that, if exploited, could have "real-world consequences," he added.

He cited other factors that make cybersecurity more challenging, such as the existence of brownfield legacy assets. If they've been undermaintained for a while, securing those assets can be difficult, especially if they are being connected at an accelerated pace, he said.

At the same time, he said, "The traditional boundaries between OT and IT are beginning to blur."

A new approach is necessary, Simonovich said.

"Traditional IT approaches have not worked," he said. "It's not a technology problem. It's a strategy problem."

Miller said a world-class cybersecurity program needs five elements: a defensible architecture, monitoring of the industrial control systems network, remote access authentication, vulnerability management programs and disaster recovery plan.

And Simonovich emphasized that companies need to know how to respond and train that response, he said. The playbook should guide the company to take a proportionate response to an attack, ranging from mitigating efforts on up to "pulling the plug" as a last resort, Simonovich said.

"You can automate it and simplify it, but you cannot avoid training it."

While digital controls are enabling a system that's in flux to operate more efficiently, it's disrupting companies who are trying to make sense of the digital transformation, Simonovich said.

The companies that win, he said, "will have to become more digital and embrace cybersecurity as a core competitive advantage." OGJ

OIL BOOM CYCLE OPPOSITE 'IN EVERY WAY'

In an industry of cycles, here's why the current oil and gas boom is unique and what experts say operators need to figure out before the next bust.

ARTICLE BY

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The current oil and gas boom cycle may differ from past up markets, but the industry must improve how it manages the cycles.

A unique set of circumstances paved the way to the upmarket the industry is enjoying, but supply chain tightness and inflation are a large part of the picture. At the same time, operators are concerned about maintaining competence of rig site personnel through boom and bust cycles, speakers said during the IADC Drilling Onshore Conference and Exhibition on May 19.

The current upmarket in oil and gas is completely different than the one the industry was riding in 2007 and 2008, according to Ian Macpherson, senior research analyst at Piper Sandler.

Back in 2007 and 2008, "we were into a well-lubricated growth mode" with the expectation that prices would be "stronger for longer," he said. "What we have now is the opposite of that in every way."

Piper Sandler projects $100 WTI through 2025.

DUC piggy bank

One reason is that global oil demand is currently over 101 MMbbl/d and expected to climb to 104 MMbbl/d by the second half of this year or sometime next year. The key variable, he said, is when China's reopening spurs increases in demand.

At the same time, supply was tight even before Russia—which had over 10% of the supply stack—invaded Ukraine, he said. Now, supply deficits are "too wide to fill with shale" and other sources, Macpherson said.

Yet shale is expected to grow by 500,000 bbl/d this year over last year's production, he said.

"Shale activity is surging, but production growth will be labored," he said.

A major problem is the DUC well deficit. "We robbed the piggy bank of DUCs," which "significantly depleted our DUC inventory," Macpherson said.

At the same time, companies want to drill. Rig counts are going up, but that is causing its own knock-on effects.

According to Piper Sandler data, rig counts for the Lower 48 in March 2019 were 1,013, 750 in March 2020 and 377 in March 2021. March 2022 rig count was estimated at 614, and March 2023 counts were estimated to be 709.

"Our probability of making it through 2023 without a recession is going down daily."

—Russell Evans, *Economic Research and Policy Institute at Oklahoma City University*

"We're going to consume most of our reserves of good quality rig stocks that can be reactivated," Macpherson said.

And if enough can't be reactivated, newbuilds will be up for consideration, he said. That, however, is not necessarily appealing because they will bring "a different level of sticker shock than what they're seeing now."

As such, he said, "There's only one way for prices to go from here."

If day rates for a super-spec rig are currently $30,000, he projected they'll be at $35,000 per day by the end of the year. A newbuild would likely need a multiyear contract with a $40,000 per day rate to be considered viable, he added.

"That's not a conversation that's happening now, but I think it's a conversation that's going to emerge starting next year," he said.

Good supply chain news

Supply chain disruptions should create upward pressure on commodity prices, which is good news for the oil and gas sector, according to Russell Evans, executive director for the Economic Research

and Policy Institute at Oklahoma City University.

His expectation is that commodity prices should remain up in the near term, and that the industry will make it through 2022 without a recession.

"Our probability of making it through 2023 without a recession is going down daily," he added.

The world is "coming off a period of exaggerated economic strength," Evans said, and "the economy on its own is not as strong as the numbers" suggest.

The reason, he said, is that trillions of dollars of economic policy have influenced current market conditions. That approach was used back in 2010 when the world was coming out of the Great Recession.

"It was a unique policy to offset economic weakness," he said of the decision to help "bump personal incomes" through an until-then "unfathomable" trillion-dollar policy. Criticism at the time was whether it was enough to move the needle, he added.

Then, with the COVID-19 pandemic, even larger trillion-dollar packages funneled money into household balance sheets, he said. Personal incomes were going up, stock markets were returning 20% and real estate was up 25%, he said. Capital looking for returns sought out cryptocurrency and non-fungible tokens (NFTs), he said.

"That was only possible against the backdrop of the policy environment we were living in," Evans said.

But that strong economic policy meant a lot of extra capital that was seeking out fewer goods due to supply chain disruptions, he said.

"Inflation was really the only thing that could happen," he said. The resulting inflationary period will likely persist throughout the rest of this year and into 2023, he predicted.

"There's no fast way to move that inflation out of the system," he said.

But he does expect supply chain behavior to change moving forward and for companies to reconsider vertical integration. Companies may be willing to "pay a little extra for inputs in the supply chain if they can get it from a trusted partner," Evans said.

'An industry of cycles'

And when it comes to supply chain issues, Kyle Eastman, drilling operations manager, Chevron North America E&P Co., said operators aren't just focused on making sure they have a rig available for drilling.

"Do you have the stuff you need to construct your well? Oil country tubular goods, cement, mud, directional drilling equipment, sand, perforating charges and trucking?" he said.

As prices for goods and services rise,

"As prices for goods and services rise, different groups have to 'compete for capital within our own company.'"

—Kyle Eastman,
Chevron North America E&P Co.

Eastman said different groups have to "compete for capital within our own company" as the operator focuses on capitalizing on current energy prices while mitigating against future market adjustments.

At the same time, he said the industry needs to do a better job of improving the work experience for the field-based workforce. This is important because of the costs of turnover from safety and training perspectives as well as the potential effect it can have on barrels of production that may be delayed or foregone, he continued.

Part of that answer may lie in technology, which "is not a means to necessarily eliminate labor" but to "allow you to more effectively use the labor on site and to get more consistent results with less experienced people," Eastman said.

John Willis, vice president of drilling and completions at Occidental Oil & Gas, said more mechanization on a rig will mean the need for more people, not fewer, on a rig site.

"You've got the same amount of work, and it's crammed into fewer days," he said. So more people will be needed to help carry out tasks like getting casing ready and handling logistics.

But it's also important to remember that the oil and gas industry is an industry of cycles.

"We're going to be up for a while, and we're going to be down for a while," he said. This is particularly true with shale plays, which have such fast declines, he said. "We need to look at how to better go up and down even more than we used to in the past."

Capturing knowledge in automated systems could make it possible to scale when rig count rises and not lose the knowledge when counts decline, he said.

Relying on remote experts could also mean fewer people that would need to be retained during downturns, he added. This might mean changing the competency profile of people who are on the work site, he said, such as making sure they have some management experience.

Such an approach might also make it "not a disaster for them when they get laid off," Willis said. "We can be better skilled at managing the ups and downs in our industry." OGJ

"We can be better skilled at managing the ups and downs in our industry."

—John Willis,
Occidental Oil & Gas

REPUBLIC SERVICES TALKS RNG

The waste management company and energy producer teamed with Archaea Energy to invest $1.1 billion to develop 39 renewable natural gas projects across the U.S.

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With the sprawling downtown Houston skyline as a backdrop and hundreds of birds hovering overhead, the humming of trucks and a drilling rig on site signal progress at the 300-ft hill.

One could hardly notice the faint smell of garbage lingering in the air as Republic Services turns trash picked up from the curbs of neighborhoods, restaurants and other facilities across the fourth most populous city in the U.S. into renewable natural gas (RNG) at the McCarty Road Landfill.

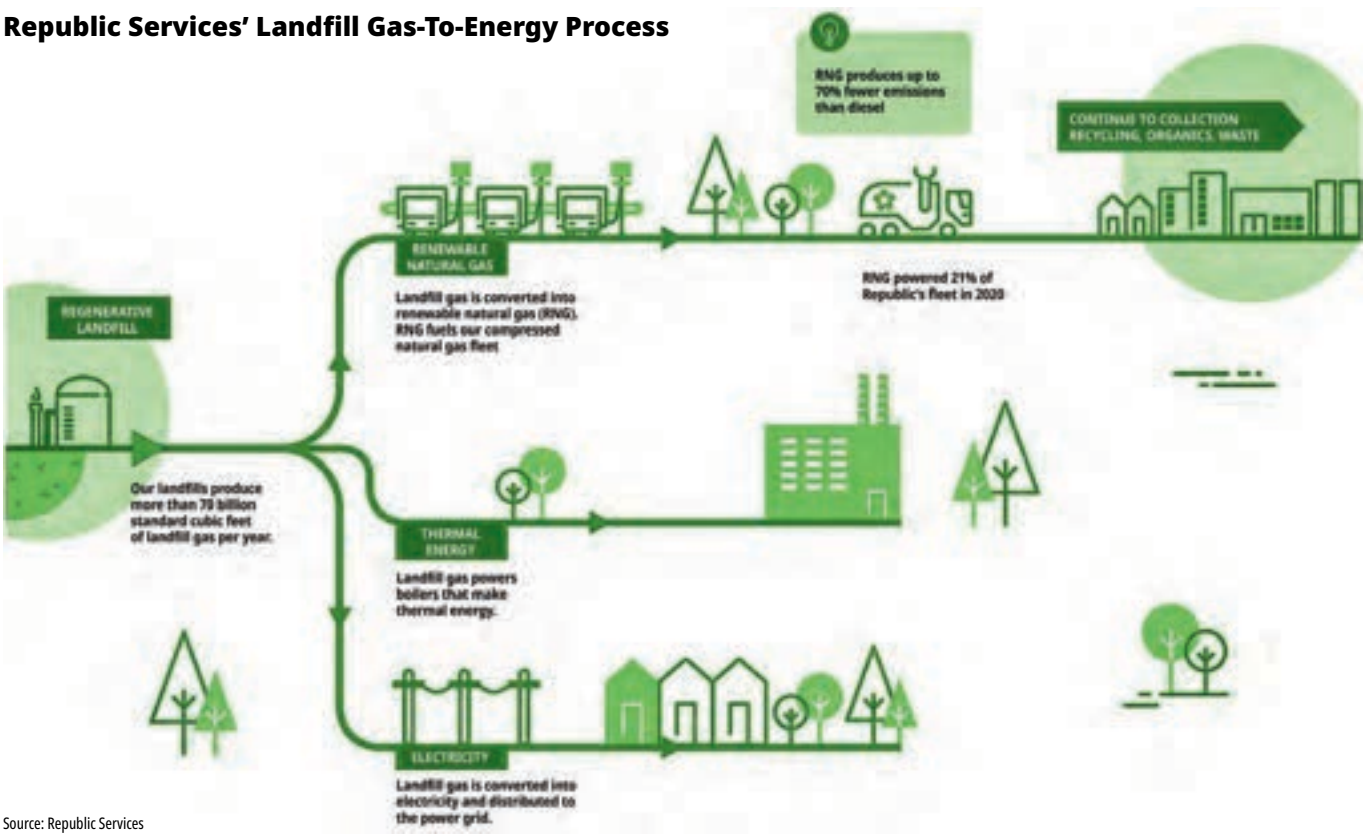
Here, the South Texas heat and humidity are welcomed.

"That helps the trash break down," Modesto Dominguez, the landfill's general manager, said, noting how lots of pressure is also needed to help the trash decompose and produce a mix of gases that mostly include methane.

The process, which transforms what is essentially biogas at 50% methane into pipeline-quality gas of at least 96% methane, involves drilling holes to form a network of wells—some horizontal, others vertical—about 150 ft deep more or less depending on how high the landfill is at the time, he explained. The perforated pipes connect to other pipelines around the landfill. Blowers suck the gas like a vacuum from the landfill into one of the two gas plants on site, where moisture and other unwanted gases are reduced or removed to yield RNG.

RNG's appealing carbon profile—it's less carbon intensive than diesel—coupled with access to carbon credits is attracting investment as the energy transition picks up pace. Naturally occurring methane in places like landfills, dairy farms and other sources is being tapped

Republic Services' Landfill Gas-To-Energy Process



Source: Republic Services

VELDA ADDISON/HART ENERGY

Trucks move along the dirt roads at Republic Services' McCarty Road Landfill in Houston where methane is captured and turned into renewable natural gas.

for gas capture, and demand for bountiful supplies is growing.

The RNG supply market is only about 185 MMcf/d in the U.S. today, but it has a four-year compounded annual growth rate of 29%, according to Enverus. The energy data firm said it expects RNG demand to grow at least 4.6 times by 2030 to 855 MMcf/d. Only about 83 Bcf/d is consumed by the U.S. domestic market today.

"We believe landfills represent the highest volumetric RNG potential and estimate about 1,030 MMcf/d of total possible capacity in the U.S.," Enverus said, "with a potential of 870 MMcf/d from landfills with either planned projects or are within 5 miles of existing gas infrastructure."

Republic Services is moving deeper into the action, having announced in May a joint venture with RNG producer Archaea Energy. As part of the $1.1 billion investment, 39 RNG projects will be developed in 19 states across the U.S. starting in late 2022. When fully operational, the projects are expected to generate more than 12.5 MMBtu of RNG annually. Republic's existing RNG, or high Btu, projects generate about 15 MMBtu of energy per year.

Early adopter

Phoenix-headquartered Republic has been in renewable energy for more than 25 years; however, most of its legacy landfill waste to gas plants were geared toward electricity, not RNG. The tide is beginning to turn, giving potential for the carbon-neutral fuel sourced from decaying feedstock to push the company closer toward its sustainability goals. Of Republic's 76 existing renewable energy projects, about eight are solar and 68 are landfill gas-to-energy, Pete Keller, vice president of recycling and sustainability, told Hart Energy.

"When we first got into it, it was about utilizing an available resource to generate energy. It wasn't necessarily about carbon intensity or climate change or those types of things," said Keller. "We were just early adopters using a resource, but now it's really about opportunities to decarbonize, to clean up grids [and] to clean up pipelines. It's just been an evolution in the landscape."

Roughly 73 billion standard cf of biogas is utilized across Republic's existing 68 projects. When gas is captured at company sites without renewable projects, Keller explained that it is flared or, technically, thermally oxidized. The process converts methane into CO_2, "which is still not awesome, but it's far better for the environment than releasing that methane into the atmosphere."

Methane is more than 25 times as potent as CO_2 at trapping heat in the atmosphere, according to the U.S. Environmental Protection Agency.

The amount of methane captured at Republic's sites with landfill gas to energy projects vary depending on the age, climate, types of waste going into systems and the density of the wells.

"Generally speaking, you're somewhere between 75% and 99% capture," he said.

The company has four landfill gas-to-energy plants in the Houston area, where it takes in about 13,000 tons per day but spikes when there are major events. Two of the four landfill-to-gas energy plants are located at the McCarty Road Landfill, which takes in about 6,500 tons per day, Dominguez said.

"We can sell all the RNG that we produce without even trying. Demand far outstrips supply."

—Pete Keller,
Republic Services

The projects pull the methane equivalent of what 1.26 million acres of trees would pull from the air, or about 109 million gallons of gas per year, he added.

Developing RNG, despite the advantages, is not without challenges.

To make projects economically viable, a minimum amount of flow is needed and location matters.

"If your site is 20 miles from the nearest pipeline, getting gas into distribution can be a challenge," Keller said. "There are some systems out there where you can pressurize a tanker truck, and then you get to haul that truck down to an injection point 20 miles away. But that can be a challenge."

Getting bigger

The technology that separates the gases, however, is "pretty tried and true," said Keller, who spoke briefly about the pressure swing adsorption process with carbon molecular sieve. The process, used at McCarty, separates different gaseous species by the size of their molecules.

With solid technology and infrastructure in place as decarbonization and sustainability goals drive change both within and outside the industry, the time seemed right for Republic to expand further into RNG.

"Some of the smaller projects that historically have not been economically viable now make a lot of economic sense just because of the change in the energy sector," Keller said. "Then there's some other incentives in the marketplace that you may be familiar with—the Federal Renewable Fuels Standard or California's Low Carbon Fuel Standard (LCFS). Those can add value to projects."

Under the Renewable Fuel Standard, RNG qualifies as an advanced biofuel.

RNG projects' access to carbon credits, such as the federal government's cellulosic biofuel renewable identification number (D3 RIN) and California's LCFS credits, can push realized prices to anywhere from $30/MMBtu to more than $100, according to Enverus. That compares to Henry Hub's recent decade-high price of about $8.50/MMBtu.

"While historically folks hadn't always had confidence that those schemes would be around over the long term, I think there's increasing confidence in the marketplace that those types of incentives are going to exist for the foreseeable future," Keller said. "That creates more confidence for the investments."

The partnership will enable the company to scale up quickly.

Of the dozen or so developers Republic considered for the joint venture, Houston-based Archaea, one of the largest RNG producers in the U.S., stood out in part because the company has its own crews.

"We didn't see that in any other developers; other developers would require an outside construction firm, an outside engineering firm. Archaea has all that capability in-house," said Keller. "When we think about bringing projects to market with speed, we just thought that was a really good offering."

The companies hope to have all 39 projects, including six in Texas, complete by 2027 with RNG in the marketplace.

The projects are expected to help Republic hit sustainability goals, including increased beneficial reuse of biogas, something Keller admits has been "a little lumpy in the last few years."

Using 2017 as a baseline, the company aims to increase beneficial reuse of biogas by 50% by 2030.

"We've increased our usage of biogas as an organization by about 5% since 2017. So not necessarily on the trajectory that we want to be on," he said. "With the partnership with Archaea, we've got a clear line of sight to those 39 projects. Again, we expect most of them to be online by 2027, so we feel really good about our ability to achieve that goal."

Looking ahead

Though RNG makes up less than 1% of what's in pipelines today, Keller called demand robust.

"We can sell all the RNG that we produce without even trying," he said. "Demand far outstrips supply."

Besides the environmental pluses, fuel credits are adding value on top of the RNG value itself, which is typically priced identical to fossil fuel.

Like other industry insiders, Keller sees value potential from the voluntary market, specifically large institutions willing to pay market plus premium for RNG as they work to hit their own sustainability goals on the utility usage side.

Republic doesn't plan to stop with the latest 39 RNG projects.

"I think there's going to be more near-term development just because the economics are so attractive," Keller said. "We're going to look to continue to try to find opportunity beyond 39 sites, and the partnership allows us to do that."

Plus, there are additional opportunities, looking at the company's existing portfolio.

He sees growth ahead, not just for RNG produced at landfills, but industrywide investment growth of RNG produced at wastewater treatment plants and agricultural RNG markets such as dairy and swine farms over the next five to 10 years due to strong demand and compelling economics.

What could change the positive outlook?

"Certainly, if some of the regulatory frameworks—the incentives—in the transportation world went away, that could alter that outlook," Keller said. "On the utility side, I don't foresee a world that's less interested in lower carbon fuels. So, the demand from that side will continue to be strong, and there'll be adequate premiums in that marketplace to justify these projects." OGI

Damian Lopez, operations manager at the McCarty Road Landfill, explains how gas wells work at the site. The well is one of 190 gas wells at the site.

VELDA ADDISON/HART ENERGY

THE EVOLUTION OF ESG REPORTING

Developing SEC requirements and market pressure push E&P companies to meet disclosure demands.

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Attitudes toward ESG metrics have been shifting for some time. As ESG becomes more of a priority for the oil and gas industry, the way these metrics are reported has also evolved. Pressure from different kinds of stakeholders has played into how E&P companies report on ESG, and it also depends on the nature of the company in question. Generally speaking, though, it is the environmental aspect that has been the main focus by far.

"The 'E' takes most of the oxygen in the ESG conversation, partially because it is easier to agree on how to measure. The 'S' and 'G' tend to be more subjective," Nick Volkmer, Enverus' director of product, ESG, told Hart Energy.

This has translated into companies beginning to set various targets, including reaching net-zero greenhouse-gas (GHG) emissions over the long term in some cases, to report their ESG achievements. Progress has been mixed to date, and efforts to develop a more unified approach are now underway, with various standards emerging and gaining popularity in recent years.

Standardization is set to be accelerated further still when the U.S. Securities and Exchange Commission (SEC) brings in new rules relating to disclosure of climate-related risks for publicly listed companies. The rules are still being finalized, with a public comment period on the SEC's proposals closing on June 17. But even with changes being made to the initial proposals, the implications are expected to be far-reaching.

"We view this as the most seminal rulemaking to come down in probably decades, and the amount of disclosures that it compels for public companies is a real game changer," Stephen Grant, a partner at Haynes and Boone, told Hart Energy.

There is still uncertainty over what the picture will look like once the SEC's rules are adopted, but it is clear that the industry can expect reporting to become more widespread and requirements to become more stringent.

Seismic shift

The volume of ESG reporting currently illustrates that overall, the industry has embraced the need for it. Enverus estimates that over 85% of companies representing roughly 94% of the market capitalization of the XOP, a key oil and gas E&P index, now publish annual corporate sustainability reports.

"It is safe to say ESG reporting is now the standard across the industry," said Volkmer. "Each year, we see more disclosure and better standardization, helping facilitate ESG comparisons."

Meanwhile, the spring 2022 edition of Haynes and Boone's Oil & Gas ESG Tracker, on which the firm collaborates with EnerCom, found out of 30 U.S.-listed middle market onshore oil and gas producers, 97% have made ESG-related disclosures. This was up from 70% in the spring 2021 edition of the publication.

The report showed that to date, the majority of ESG disclosures among its sample of companies were to be found on company websites and in corporate sustainability reports rather than in SEC filings. This means "most ESG disclosures are not subject to the full range of liability and other investor protections that help elicit more complete and accurate disclosures," according to the report. Also, what is published on companies' own websites can vary considerably.

"U.S. firms generally issue sustainability reports and recognize the need for disclosure. The issue is comparability," Morningstar's director of equity research, energy and utilities, Dave Meats, told Hart Energy. "For example, the E&Ps we cover break down Scope 1 emissions by carbon dioxide and methane (some included nitrous oxide, which generally made up a negligibly small proportion of aggregate emissions)," he continued. "Reporting Scope 1 emissions via process is optional; many chose to give a distribution via source (i.e. flaring, venting, combustion, etc.). Some don't, and the ones that do often use distinct categorization methods (i.e. the combination of venting/flaring into one number, or the addition of an 'other' category). Neither Scope 2 nor Scope 3 emissions seem to be required."

As well as differences in how operators reported such numbers, Meats pointed to differences in when they disclosed them.

"There also lacks clear disclosure for the timing of sustainability reports," he said. "For example, some firms released 2021 reports detailing 2020 data in November of 2021. It would be better for investors if the timing of sustainability reports were closer aligned to the timing of annual reports, if possible."

Publicly listed operators are not alone in making more disclosures, with portfolio companies and other private operators increasingly concerned with what their sustainability reports look like on both the macro and micro levels, according to an Akin Gump corporate partner and climate change group co-leader Cynthia Mabry. The shift now underway is that operators are viewing ESG reporting as just part of doing business, rather than something that they would only do if required to, Mabry told Hart Energy.

Drivers

In the absence of regulations requiring ESG disclosures, pressure from investors is seen as a major driver in bringing the industry's reporting to where it is today.

"We believe institutional pressure was the main catalyst behind expanded ESG reporting seen over the last few years," said Volkmer. "Operators understand regulations from the SEC and other government entities are likely around the corner and are preparing for that possibility, but the abundance of voluntary disclosure to date is mostly to satisfy investors."

However, pressure to make ESG disclosures has also come from a variety of other stakeholders, and this mix continues to change.

"The reporting that our individual companies do has been continuously evolving," Aaron Padilla, vice president of corporate policy at API, told Hart Energy. "It grows in its comprehensiveness, and it grows in the different types of audiences to which it's oriented."

Padilla noted that some of the more traditional audiences in the earlier years of reporting included employees and communities, as well as governments in countries that were hosting the oil and gas industry. On top of this, he cited the expectations of the marketplace.

Mabry also pointed to a variety of stakeholders whose involvement has helped shape ESG reporting.

"What has developed from these sustainability reports or ESG reports has been based on stakeholder engagement, and that includes investors, but it also includes NGOs [non-government organizations] and other sorts of activism, as well as shifting government regulation and peer benchmarking," Mabry said. ESG reporting frameworks have evolved in part as a result of operators "looking to see what their industry and aspirational peers are doing and ensuring that what they are putting to the market is consistent or as good or as robust as their peers," she added.

This push for greater consistency has resulted in the emergence of certain frameworks and approaches that have become popular. For example, the API has collaborated with two other industry groups, the International Petroleum Industry Environmental Conservation Association (IPIECA) and the International Association of Oil & Gas Producers (IOGP), to produce sustainability reporting guidance for the oil and gas industry.

"The latest version that we produced in 2020, like previous updates before that, reflected common and good practices and reporting and relevant issues across the industry," said Padilla. "That guidance document is shaped by our member companies, which produce it, so it's by nature a reflection of the reporting that they do, or the reporting that they aspire to. It has established a framework that a lot of other oil and gas companies across the sector that aren't necessarily members of API, IPIECA or IOGP also follow."

Padilla added that the API has also produced a complementary guide on GHG reporting.

"Each year, we see more disclosure and better standardization, helping facilitate ESG comparisons."

—Nick Volkmer, *Enverus*

"We view this as the most seminal rulemaking to come down in probably decades, and the amount of disclosures that it compels for public companies is a real game changer."

—Stephen Grant, *Haynes and Boone*

"We've defined more tightly the boundaries and the definitions for a core set of indicators, such that it will work in conjunction with our other guidance document to promote more consistent and comparable reporting from one individual company to the next," he said. "We as an industry recognize the need for financial sector organizations in particular to have consistent and comparable reporting from one company to the next. And we have really aspired to define a standard set of indicators that will drive that and voluntary reporting by companies."

In order to meet financial sector expectations for this sort of reporting, Padilla said the API had engaged with some of the world's largest institutional investors, commercial banks and credit rating agencies.

"We're very attuned to that stakeholder group for this reporting," he said.

Stepping up

Now, the SEC is trying to improve consistency further still. The commission's proposals would require publicly listed companies to disclose information about their governance of climate-related risks and their processes for managing those risks. And for those companies that already have climate-related targets or goals in place, certain disclosures would be required.

The proposals would require companies to disclose their direct, or Scope 1, GHG emissions, as well as indirect emissions from purchased electricity or other forms of energy, or Scope 2. Scope 3 emissions, which include those generated by end use of the operators' products by their customers, are also included in the proposals, though only if they are considered "material" or if a given company has set a target that includes Scope 3.

Haynes and Boone's Grant said he saw the SEC's Scope 3 proposals as attracting a lot of attention and potentially subject to modification in the final rules.

"If those aspects of the proposed rules are adopted in the final rules, I'm curious to see if companies continue to [set Scope 3 targets], or if they back off from making those forecasts because in doing so companies would also be required to disclose historical Scope 3 emissions data," Grant said. "In addition, the SEC's position is if you have set a target or goal, you need to disclose it. You need to disclose how you intend to achieve that goal, and on an annual basis, you have to provide updates on how you're doing."

Few operators have Scope 3 targets and disclosures to date, and while this number had been expected to rise, it cannot be ruled out that additional SEC regulations could have an impact on the uptake of such targets. This comes as companies are already grappling with the questions of how best to quantify and minimize Scope 3 emissions, which represent a far greater challenge than Scopes 1 and 2.

"Only a quarter of the ~100 energy companies we track disclose Scope 3 emissions," said Volkmer. "It is a tricky number to triangulate on and, with oil and gas companies, the majority of Scope 3 emissions are from the consumer using the product. This will make any Scope 3 net-zero commitment difficult, but not impossible, to achieve for any energy company. The majority of net-zero targets are centred around Scope 1 and 2 emissions, or those directly sourced from the company."

As the energy transition accelerates, though, additional pressure to include Scope 3 in targets and disclosures can be expected.

Akin Gump's Mabry noted that investors in a particular company

"U.S. firms generally issue sustainability reports and recognize the need for disclosure. The issue is comparability."

—Dave Meats, *Morningstar*

could demand that it go further on Scope 3 than whatever is ultimately required by the SEC. This can be seen in the rise of shareholder proposals demanding tougher targets on decarbonization, which in some cases have included Scope 3 emissions. While such proposals may be defeated, as was the case with a recent effort to make ConocoPhillips Co. adopt Scope 3 targets as part of a more ambitious decarbonization plan, the pressure will not come from the SEC alone.

"Companies should consider that at some point they will likely be disclosing Scope 3 emissions," said Mabry. "Disclosures may not be in 2022, but companies should have a path toward disclosing those emissions in the future whether or not technically required under the SEC rules."

There are other changes that are also expected to come about once the SEC rules are finalized, including the use of third parties to audit emissions disclosures.

"One of the major differences between the proposed SEC requirements and current sustainability report information is that emissions under the SEC will need to be audited by a third party," said Volkmer. "Emissions are inherently hard to track and measure and third-party auditing will pose a new challenge. The question will be how different the SEC emissions guidelines will be compared to the current EPA [Environmental Protection Agency] system, which producers have years of experience with."

"We as an industry recognize the need for financial sector organisations in particular to have consistent and comparable reporting from one company to the next."

—Aaron Padilla, *API*

Next steps

The SEC announced in early May that it was extending the public comment period on the proposed rules until June 17.

"We suspect that's because they're receiving a significant amount of commentary from stakeholders as well as industry participants," said Grant.

Indeed, Padilla said the API was preparing comments to submit by the SEC's deadline.

"We will be specific in our letter to delineate aspects of what the SEC has proposed that we as an industry view as highly problematic and that we think should be rescinded and taken out of the comprehensiveness of disclosures that the SEC has proposed that each company should have to report," he said. "And we'll also delineate in our comment letter a better alternative, a narrower set of much more relevant and effective requirements for dimensions of climate reporting that we think would be more appropriate."

Padilla added that, whatever shape the SEC's rule will ultimately take, it will have an effect.

"And what we want is for it to have a positive effect," he said.

Ultimately, efforts to standardize ESG reporting will continue, via the SEC and elsewhere. Morningstar's Meats cautioned, however, that standardization alone is not enough but needs to be pursued in a certain way in order to be useful.

"The usefulness of standardized reporting is itself predicated on both the regulation and veracity of how exactly emissions data is gathered and measured, or perhaps in the case of Scope 3 emissions, estimated," he said. "Investors could also benefit from emissions data from an asset-by-asset or project-by-project basis, if attainable. Investors should also have more clarity with regards to the purchase or utilization of carbon offsets in order to achieve emissions reductions or a net-zero target."

Haynes and Boone and EnerCom's Oil & Gas ESG Tracker found that institutional investors tend to favor companies that disclose their ESG targets. As time passes, and even more companies step up ESG disclosures, it seems likely that additional pressure will also emerge on companies to achieve those targets as well.

"Investors really like disclosure just by itself; they want to know what's going on," said Grant. "But they also want to see progress, and they want to see goals being met." OGJ

"Companies should consider that at some point they will likely be disclosing Scope 3 emissions."

—Cynthia Mabry, *Akin Gump*

THE NETWORKING CHALLENGE OF AN ISOLATED ENGINEER

How does an asset development and completion operation expert connect with others like her when there are so few like her?

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Nabila Lazreg is outstanding in her field. She is an educated, experienced and highly skilled engineer. How does she advance in her career?

The simple answer is to network, but not all situations are that simple. Lazreg is a woman of color in an oil and gas industry dominated by white males. She is an immigrant from North Africa and non-native English speaker living in North America. And she is an engineer stationed in the oilfield, far from corporate headquarters.

"Women of color do have unique challenges in the field," Katie Mehnert, founder and CEO of Ally Energy, told Hart Energy. "You don't see as many, if not many at all."

Mehnert also offered two salient points for those working in the field:

- ***You've got to be there:*** "If women are going to get to the top of the house, they do need operations experience, absolutely, because it helps broaden a person's resume and background, and gives them a greater chance of being competitive for the executive roles."
- ***You've got to leave:*** "There's only so far you can get in the field on the ladder to the top. If you're not in the corporate office, you may not have that ability to move up the ladder because of the access to the people, access to the information."

'Strong personality'

Lazreg grew up in Algeria during that country's 1991-2002 civil war between the government and Islamist extremist rebel groups. Had they succeeded,

(SOURCE: HART ENERGY; YELYZAVETA MINAIEVA, NANO-STOCKER, FREEZERAMES/SHUTTERSTOCK.COM)

How does an experienced, skilled woman advance in her career when her workplace is the oil field?

the Islamists' theocratic approach to governance would have harshly restricted the rights of women.

"Islamists were against women in the street and studying, but I did not quit," she said in an email to Hart Energy. Lazreg was the only woman in her class at the École Nationale Polytechnique in Algiers to study mechanical engineering. When she graduated in 1996, she was one of only two women to complete a rigorous recruiting process and be hired by Schlumberger.

Lazreg was sent to Italy for training before returning to Algeria, a member of OPEC, to work in the field. It wasn't an easy assignment. Women working alongside men runs counter to custom in that region and she was routinely cursed by co-workers. Even today, women only account for 20% of the Algerian workforce.

After five years, her performance earned her a relocation overseas where she landed in the Permian Basin. Eventually, her knowledge of hydraulic fracturing and shale reservoirs established her as one of Schlumberger's subject matter experts in those areas. She has since moved on to work for an upstream producer and is based in Canada, specializing in asset development and completion operation.

The attitudes of her male colleagues in Texas and Canada do not compare to how she was treated in Algeria, but they do pose challenges. Few women choose careers that put them so close to the wellhead, nor are there many women like her in senior technical roles giving orders to men who are her subordinates.

"You had to build a strong personality to earn respect and have authority on site," she said. "These projects are high-dollar value, very sensitive to safety and reputation. One mistake and we can kill people or lose a multimillion dollar asset, or hurt the company's reputation. I had to be strong and assertive and firm to ensure people follow directions."

Only one in the room

There are few women in the industry in fracking roles, and Lazreg has never worked with another in her 23-year career. That may be because, of those she has encountered, most do not work at the sites and supervise shale completion operations, as she does.

And that work status often places her in the position of the only woman in the room. It hasn't kept her from expressing her thoughts in meetings, she said, because she draws on her experience in the field and is accustomed to asserting herself with men.

But still, she is the only woman in the room. That, in itself, speaks to the workforce composition of the oil and gas industry.

Of the 20 industries evaluated in the 2019 Women in the Workplace report by McKinsey & Co. and LeanIn.org, the talent pipeline in oil and gas was the weakest. Women constituted 38% of entry-level recruits in oil and gas. Only "technology: hardware," "IT services and telecom," and "industrial engineering and manufacturing" had lower percentages.

"It is a big issue in in the energy sector," Trent Aulbaugh, a partner who leads the North American Industrial Practice Group at energy executive search firm Egon Zehnder, told Hart Energy. "For whatever reason, for whatever historical reason, the E&P space, particularly on the technical side, is underrepresented with minorities, and it's underrepresented with women."

"Women of color do have unique challenges in the field. You don't see as many, if not many at all."

— Katie Mehnert, *Ally Energy*

It's not a new issue, he added, and while progress has been made, "the pace isn't nearly as fast as I think most organizations would prefer it to be."

The data reflecting the ability of women to move up the corporate ladder also put the industry in a poor light:

- Second-worst at the manager level;
- Third-worst at the senior manager level;
- Dead last at the vice president level;
- In a three-way tie for fourth from the bottom at the senior vice president level; and
- Dead last in the C-suite.

(Full disclosure: Hart Energy, which annually honors the 25 Influential Women in Energy and, in 2021, published a Diversity in Energy special report, has no women and only one person of color among the 11 members of its senior leadership team.)

More opportunities

"I know that feeling of being the only," Mehnert said. "Thank God, it's changing since I was in the field, but there are a lot of resources out there, particularly with larger companies."

Thanks to advances in technology and, to some extent, the arrival of COVID-19, the opportunities for career advancement are easier than ever, she said.

"If I look back at five, 10 years ago, content was limited, connectivity was limited," Mehnert said. "Sure, we had social media and the internet, things like that, but we were not hyperconnected like we are now. We have COVID to thank for that. We became a Zoom community overnight because we were forced to go online."

Women took a significant hit during the pandemic, she said, because they often had to choose their families over their jobs. That's part of the reason that people are slow to return to pre-COVID work habits. They are accustomed to the flexibility and the way of life they created during that time.

> **"From my experience, many women leaders in the USA and Canada have mastered great soft skills. Not many women take the technical path and grow into leadership."**
> —Nabila Lazreg, *Engineer*

To Mehnert, that's an opportunity for the industry to attract talent if companies are realistic about which jobs absolutely need to be filled by someone in the office five days a week. Even if warnings about a coming recession are correct, hybrid working is here to stay, she said, because it's made people happier and more productive to have that flexibility.

Of course, that only applies to office positions, not field work.

"Unfortunately, in field assignments, there's not going to be that flexibility because of the demands of the job," Mehnert said. During COVID, many field workers went to work. They were in plants and in harm's way when it came to COVID because they had to be present physically at an asset.

"It makes it difficult if you're in a field role to have the time to network because your job is operations," Mehnert said. "When I had an operations job, I couldn't go to a lunch meeting about women in energy. Actually, I'd get laughed at—'you're going to what?'"

Times have changed and companies are expected to commit to issues like diversity and inclusion, and to giving their employees the time they need to build their networks and advance their careers, she said. They are also investing in creating affinity groups to bring women and people of color together in energy.

Talent drain

They need to, particularly when it comes to engineering talent. Other industries, particularly tech and financial services, have been poaching talent from oil and gas for years, luring people with competitive compensation and an attractive culture. Once they leave for Apple, Google or Meta, Mehnert said, they don't come back. The cyclical nature of oil and gas, in which waves of employees are let go during price slumps, doesn't help. The renewable and power sectors are also pursuing oil and gas technical employees.

Of course, this struggle to attract and retain young talent comes as older employees continue to depart, taking their experience and institutional knowledge with them.

Meanwhile, Lazreg continues her work in the Canadian oil fields. She's good at what she does, and this is where she wants to be. It's limiting, though, which speaks to Mehnert's point about the need to leave the field and serve in the corporate office to get ahead.

She has tried the conventional networking path but attending meetings is difficult in her current location. She has also found that most of the women attaining lofty positions in the industry tend to occupy non-technical roles in human resources, finance and law.

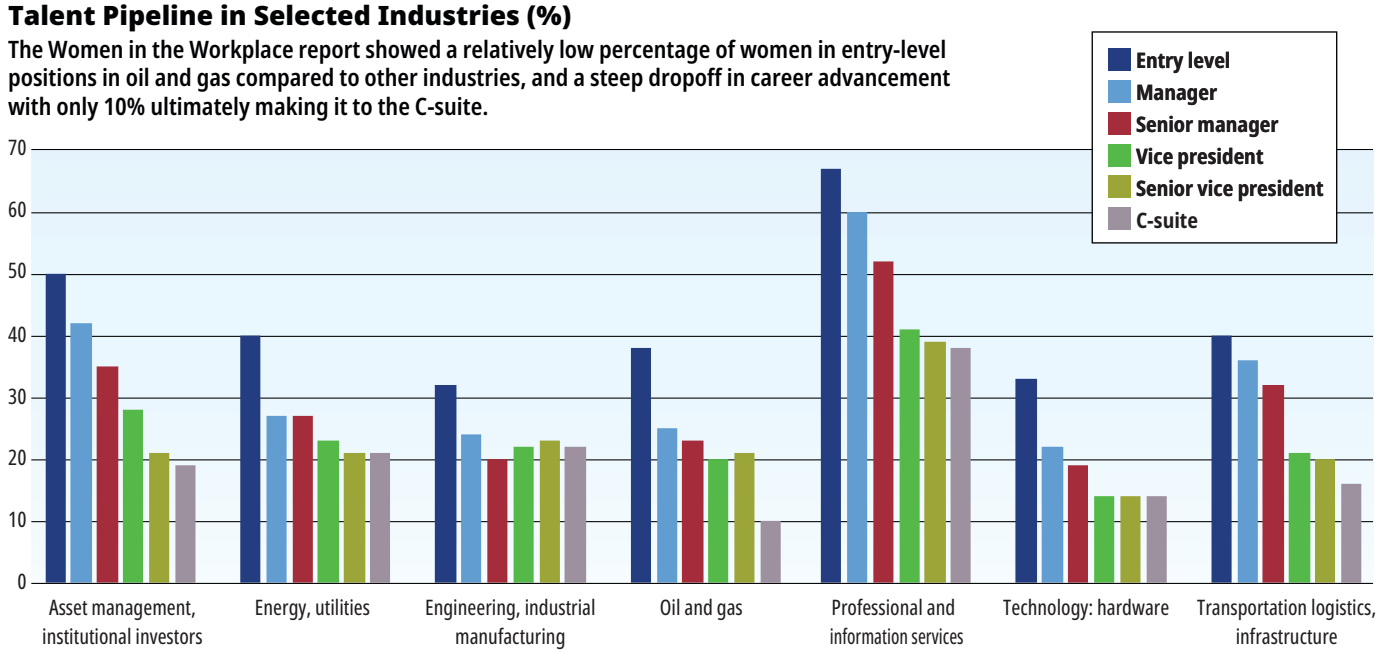
"From my experience, many women leaders in the USA and Canada have mastered great soft skills," Lazreg said. "Not many women take the technical path and grow into leadership."

Of course, that has long been the culture of the oil and gas industry for both men and women. Operations people have always left the field for the corporate office to move up in their careers. Domestic people have always sought international roles to move up in their careers.

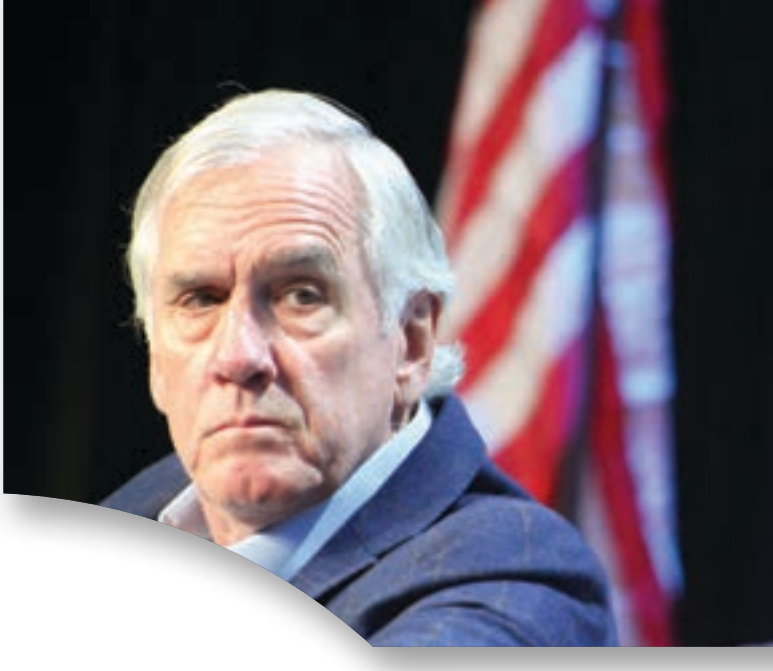
And then there is Nabila Lazreg. Outstanding in her field. Alone. Hoping to connect. OGI

Talent Pipeline in Selected Industries (%)

The Women in the Workplace report showed a relatively low percentage of women in entry-level positions in oil and gas compared to other industries, and a steep dropoff in career advancement with only 10% ultimately making it to the C-suite.



(Source: McKinsey & Co., LeanIn.org)



SHALE, SHALE, THE GANG'S ALL HERE

A distinguished slate of experts addressed a full house at the fifth DUG Haynesville Conference and Exhibition at the Shreveport, La., Convention Center on May 25 to 26. **Top:** The U.S. flag welcomes attendees outside the venue; Dick Stoneburner of Pine Brook Partners listens to Rob Turnham of Goodrich Petroleum Corp. during the frac-side chat of the play's founders; Nick Racik of Welltec; **Middle:** Founders Steve Dixon of Chesapeake Energy, Stoneburner, Turnham and their moderator, Hart Energy's Nissa Darbonne; William Standifird of Intelligent Wellhead; **Bottom:** Hart Energy's Brian Walzel and Jay Salitza of KeyBanc Capital Markets; Grant Butkus of RBC Capital Markets; Good morning, Shreveport.

SCAN ME

Photos by Joseph Markman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SHREVEPORT CONVENTION

USING DATA TO DRIVE SHALE PERFORMANCE

BPX Energy is driving innovation in the Haynesville Shale by thinking differently and "smarter," executive Kyle Koontz told DUG Haynesville Conference attendees.

ARTICLE BY

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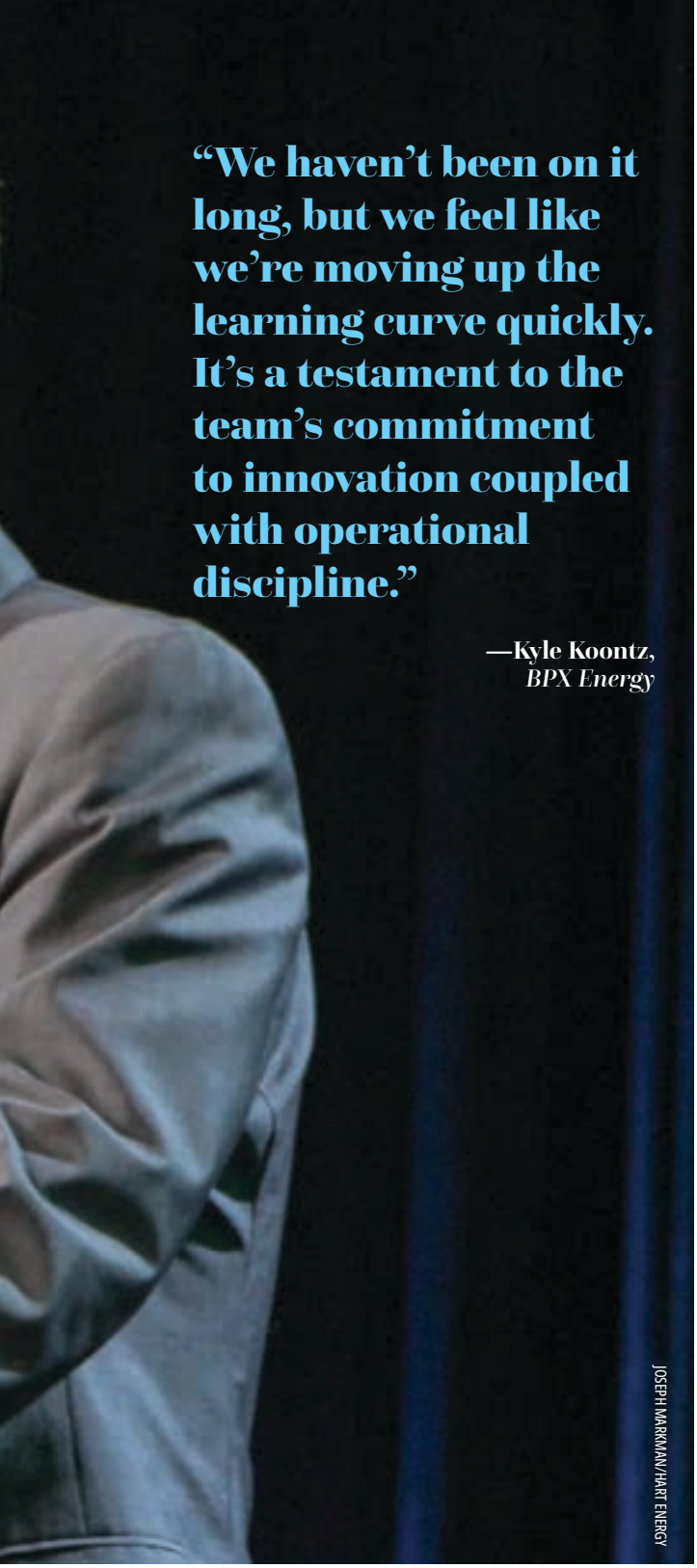
BPX Energy is thinking differently and smarter in the Haynesville, using data and analytics to drive decisions to boost stimulated rock volumes and increase production.

"We're trying to get out of the old way of thinking—pumping a big frac job and praying it works—and try to get more prescriptive, using more modern technology coupled with analytics that have been prevalent in other industries into how we develop better investments and make smarter decisions," said Kyle Koontz, chief development officer for BPX Energy.

Speaking to attendees of Hart Energy's DUG Haynesville Conference and Exhibition on May 26, Koontz shared how BPX is using digital technology to help guide decisions such as on where to drill the next well, how to complete it and whether to choke back production.

BPX, a wholly owned subsidiary of bp Plc, took over operations in the Haynesville in early 2019 after acquiring the shale assets from BHP as part of a $10.5 billion deal that also included acreage in the Eagle Ford Shale and Permian Basin. The company has 537,000 net acres in



JOSEPH MARKMAN/HART ENERGY

"We haven't been on it long, but we feel like we're moving up the learning curve quickly. It's a testament to the team's commitment to innovation coupled with operational discipline."

—Kyle Koontz, *BPX Energy*

the Haynesville, where it is running three rigs and one frac spread on the Louisiana side of the play.

"We haven't been on it long, but we feel like we're moving up the learning curve quickly," Koontz said. "It's a testament to the team's commitment to innovation coupled with operational discipline."

Known for its prolific production of natural gas, seen as a bridge fuel in decarbonization, Haynesville is positioned to play a critical role in the energy transition. Data from the U.S. Energy Information Administration show Haynesville gas production is forecast to rise 239 MMcf/d to 15.1 Bcf/d in June.

Producers like BPX are working to keep the gas flowing.

"If we don't achieve that first milestone in getting stimulated rock volume, it really doesn't matter how fast we produce the wells," Koontz said. "We're going to be limited in the type of recovery and the types of economics we can get."

Decisions are typically based on experience and science, he said. But oftentimes, he said, decisions are based on experiences from other plays and that may not always fit situations at hand.

BPX developed a platform that enables its team to make more data-based decisions using raw data inputs that generate information on which the team can act. Blending classical statistics with modern data analytics and traditional oil and gas analysis workflows leads to intelligent, data-driven predictions, he said, adding that in turn leads to new wells with premiere results.

"Each time we work through this workflow, it gets smarter and smarter," Koontz said.

A series of ID plots were developed to help drive decisions and evaluate investments. Using 2019 as its baseline, he explained how the company aimed to maximize its SRV and boost recovery using the data-driven platform. The company also incorporated rate transient analytics and other analytical tools to improve completions.

"We can use a series in this workflow, the diagnostic tool, to isolate variables and decide which decisions we need to drive improvement, which are more effective, without having to rely on a lot of production history to determine if we're successful," Koontz explained. "After we establish our reservoir contact, we have to look at the production strategy."

The company uses a real-time automated algorithm that calculates productivity downhole as the well is producing. "This runs in the background so that our reservoir engineers and our production engineers can make informed decisions on choke strategy and rate of production," he said.

Well results indicate how the approach is paying off.

The M&M 39-27 #2 well is BPX's best well to date with a maximum production rate of 40 MMcf/d.

Other wells highlighted included a pair of super extended laterals at Crestview Woods located in the northern part of the Louisiana Haynesville play. Drilled to a total depth of 15,000 ft, the wells will come online this summer, he said.

BPX also marked its first Haynesville-Bossier stack with the MUR 21-28-33 No. 1 and No. 2 wells. "We started expanding beyond just the Haynesville, looking at all development scenarios in order to understand how these reservoirs are reacting with one another," Koontz said. "They're also the first wells where we've had site electrification."

Development comes amid improved natural gas prices. Koontz said returns are strong in the Haynesville at today's prices; however, the company must be profitable without relying only on gas prices.

"We want to make sure that doesn't slip our mindset into a state of complacency," he said. "We have to continue to drive innovation and see how good we can become." OGI

DESPITE BOOM, OIL AND GAS STOCKS STILL UNDERVALUED

With oil and gas prices and exports both rising, KeyBanc's Jay Salitza sees plenty of reason for optimism.

ARTICLE BY

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Capital discipline is the secret sauce that has vaulted the oil and gas sector ahead of all others in the stock market this year, but from a relative value perspective, energy companies are still trading fairly modestly, a market expert said May 26.

Energy companies as a whole are trading at 8x EBITDA and account for about 5% of the S&P 500 index, said Jay Salitza, managing director for oil and gas at KeyBanc Capital Markets Inc., at Hart Energy's DUG Haynesville Conference and Exhibition. By contrast, the technology sector trades at 17x EBITDA and constitutes about 25% of the index.

"So, you're either going to see a lot more running room for gas stocks or further compression from the tech space over time," Salitza said. "Oil and gas, in our opinion, continues to show the ability to return capital to shareholders."

There are challenges, though. Companies in the sector, like every entity in this economy, are struggling in an environment of high inflation, he said. Interest rates are also rising.

"For the near term, it seems to be modest to flat growth and preservation of capital, as opposed to more significant growth aspects," Salitza said.

He also noted how private equity firms have been forced to pivot their strategies significantly in the last two years.

"Historically, they've always been very IRR [internal rate of return]-based in their approach," Salitza said. Now, investments are made with an eye toward the longer term and free cash flow.

The $9 misnomer

The lofty price of natural gas, which lingered above $9/MMBtu for most of the day on May 26, pervaded the atmosphere at DUG Haynesville. Gas actually

> **"That market doesn't seem to be slowing any time soon. It's going to be continuing to grow for many, many more years to come."**
>
> **—Jay Salitza,**
> ***KeyBanc Capital Markets Inc.***

closed down more than 12 cents to $8.785/MMBtu at the close of trading, but rose as high as $9.38 at mid-morning.

But Salitza cautioned against irrational exuberance.

"It's hard to not be optimistic when you see a $9 price tag on the strip, but you have to think about the fundamentals of the natural gas space," he said.

Part of the issue is that, in the day-to-day energy business, $9 isn't always $9.

"Most companies have production fairly well-hedged for 2022," Salitza said. "In most cases, 60% to 70% of production is hedged. In some cases, there is expected production beyond that. So, although you see $9 on the screen, a lot of companies are not enjoying the benefit of $9 to their cash flow."

They're certainly seeing a premium cash flow, he added, but not always $9, or what the high price of the day happens to be.

Another aspect of fundamentals, however, is storage. Natural gas inventories have been trending 15% to 20% below the five-year average for storage, which is a key metric for traders. Tight storage combined with a spike of consumption caused by a cold winter could send prices soaring. To Salitza, it's an indicator that natural gas prices will show relative strength for quite some time.

Exports are another cause for optimism. Shipments of pipelined gas and LNG rose 30% in 2019 from 2018. Despite the pandemic, 2020 still experienced a 15% increase in exports, and 2021 registered a 25% increase over 2020.

"That market doesn't seem to be slowing any time soon," he said. "It's going to be continuing to grow for many, many more years to come." OGI

JOSEPH MARKMAN/HART ENERGY

WHY THE HAYNESVILLE HAS AN A&D PROBLEM

While E&P operators all trail their commodity underpinned values, natural gas-weighted producers take the hardest hit, trading at a 55% discount to Henry Hub prices.

ARTICLE BY

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A&D, particularly in the Haynesville, is in a bind. Partly, that's the fault of a suddenly giddy natural gas price environment that has blown in gale force headwinds for deal makers.

Despite high gas prices, A&D has been left in the lurch, particularly in the Haynesville where the gas-rich shale will play a central role in the U.S. LNG, provided operators have the inventory they need.

With A&D hampered by a wide bid-ask spread, market factors may instead push companies toward more mergers or deals featuring stock-heavy consideration. And public companies are gravitating toward deals as they look to build runway—with the added danger of being hard-pressed to pay strip value for what they need.

The headwinds are fierce. Gas-weighted public company shares trade far below multiples based on natural gas prices. Sellers, meantime, are unwilling to part with their assets without getting fair value based on current strip prices.

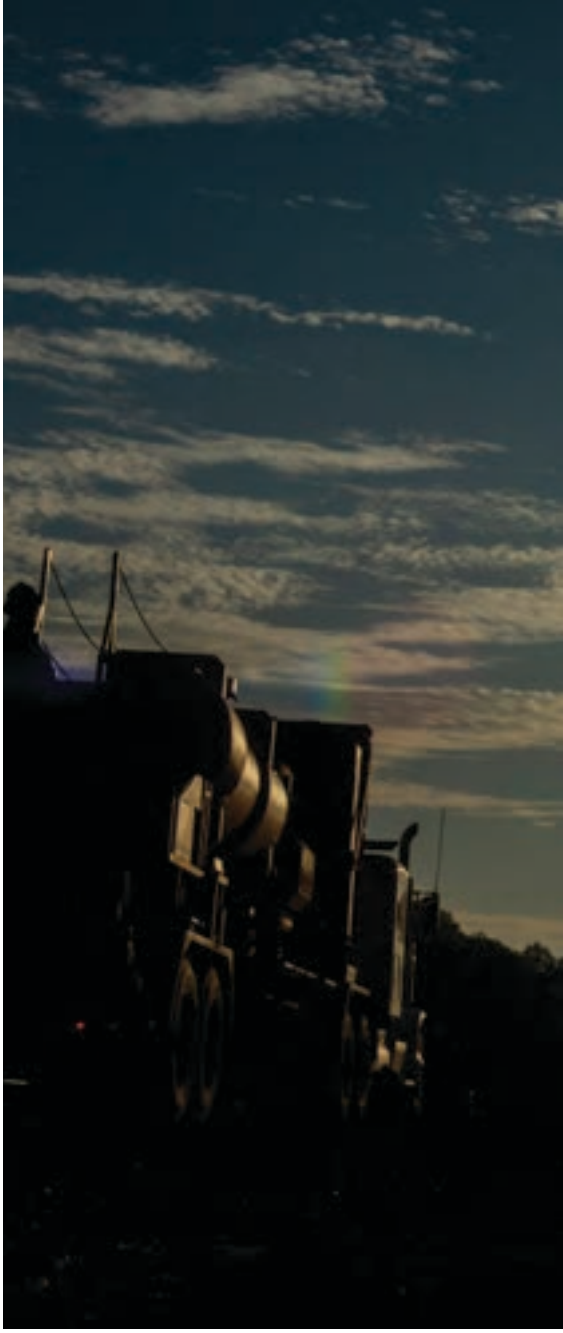
That's put a crimp in dealmaking, with A&D stalling and mergers the more likely way to placate sellers.

The chief villain in the deal market is price dislocation. In the present, prices are up. But years into the future, their value collapses—a phenomenon known as backwardation. As of June 6, natural gas contracts for 2022 were $9.23 per Mcf of natural gas, according to KeyBank National Association. That compares to 2025 contracts that value a Mcf of gas at just $4.58.

The backwardation persists despite recent acknowledgments by policymakers that the economy will rely on natural gas for electrical generation, chemical use and refining diesel.

Even with the rebound in asset-level transactions in 2020 and 2021, transaction levels won't satisfy the long-term inventory needs Haynesville operators need to acquire as they try to keep pace with demand. That demand includes a freshly made commitment to supply Europe with an additional 4.8 Bcf/d of LNG by 2030.

Grant Butkus, a managing director at RBC Richardson Barr where he leads corporate and asset transactions, said the plateau in A&D transactions may leave companies no choice but to use mergers and stock inducements to get deals done.



Speaking on May 26 at Hart Energy's DUG Haynesville Conference and Exhibition in Shreveport, La., Butkus noted that natural gas deal activity and increased investor interest was energized before the Russian invasion of Ukraine brought natural gas into the fore of discussions.

"This is something that's much more structural that's been building over time," he said. "It's really been building over the last couple of years as people start to understand that gas is a much more fundamental part of the overall energy ecosystem and it's going to be that way for a very long period of time.

Recent International Energy Agency (IEA) reports note that the world will still consume a majority of natural gas in 2050, even in zero-carbon or net-zero scenarios.

Both 2021 and 2022 were characterized by outsized energy sector returns,

Read the full article here:

strong commodity prices and a highly active A&D market. Yet natural gas-weighted public companies trail their oily peers.

Large-cap oil companies trade at a 27% discount to WTI prices, according to RBC. Small- and mid-cap companies are at a 37% discount. And natural gas-weighted companies trade at a whopping 55% discount to Henry Hub prices, Butkus said.

And that creates a disconnect between public buyers and private sellers.

"The readthrough on that is most public companies don't get credit for where strip is today," he said. "So, if you're a public company and you go try to buy private assets, the private asset owners, private equity owners, private companies want their assets valued at strip. But you would effectively be valuing their assets above where your assets sit today."

Public companies face a dilemma of buying assets for cash at a cost that exceeds their own inventory.

Instead, public companies will be pushed into making acquisitions by creating relative valuations with their stock.

"So that's either issuing a large amount of stock to private sellers so you're able to acquire at your stock valuation and then as you appreciate the sellers also share in that upside," Butkus said. "Or you're looking at a public company to public company M&A."

But there are some signs that the call on natural gas has caused some investors to wake up to its potential.

"There's going to be a lot of interest from buyers out there," he said. "We're seeing that out there in the processes we're running today."

Butkus said he's seen a sizable amount of new investor interest both from the public equity and private equity markets looking to get into natural gas.

"But to offset that," he added, "we're also seeing an incredibly volatile commodity price which makes it difficult for deals to get ultimately done without trying to find ways that both sides of that transaction can share in the upside as the markets equalize and as we continue to see the back end of the curve start to catch up with where we sit today." OGI

Events Calendar

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

EVENT	DATE	CITY	VENUE	CONTACT
2022				
IPAA Annual Meeting	July 20-22	Colorado Springs, CO	The Broadmoor	ipaa.org
IAEE Annual Conference	July 31-Aug. 4	Tokyo	National Graduate Institute for Policy Studies	iaee2022.org
Energy Workforce & Technology Council Summer Mtg.	Aug. 3-5	Westminster, CO	The Westin Westminster	energyworkforce.org
EnerCom Denver	Aug. 7-10	Denver	The Westin Denver Downtown	enercomdenver.com
Western Energy Alliance Annual Meeting	Aug. 10-11	Beaver Creek, CO	Park Hyatt Beaver Creek	westernenergyalliance.org
KIOGA Annual Convention	Aug. 14-16	Wichita, KS	Hyatt Regency	kioga.org
The Energy Summit	Aug. 23-24	Denver	Denver Center of Performing Arts	coga.org
SEG/AAPG IMAGE Conference	Aug. 28 - Sept. 2	Houston	George R. Brown Conv. Ctr.	imageevent.org
OGA Annual Conference	Aug. 29	Norman, OK	Embassy Suites by Hilton Norman	okgas.org
Energy ESG Conference	**Sept. 8**	**Houston**	**Royal Sonesta**	**hartenergyconferences.com**
GPA Midstream Convention	Sept. 11-14	San Antonio	Marriott Rivercenter	gpamidstreamconvention.org
America's Natural Gas Conference	**Sept. 27**	**Houston**	**Royal Sonesta**	**hartenergyconferences.com**
North American Gas Forum	Oct. 24-26	Washington, D.C.	Park Hyatt Washington, D.C.	energy-dialogues.com/nagf/
Energy Capital Conference	**Oct. 25**	**Dallas**	**Fairmont Hotel**	**hartenergyconferences.com**
A&D Strategies and Opportunities Conference	**Oct. 26**	**Dallas**	**Fairmont Hotel**	**adstrategiesconference.com**
Executive Oil Conference	**Nov. 15-16**	**Midland, TX**	**Midland County Horseshoe Pavilion**	**executiveoilconference.com**
OK Petroleum Alliance Fall Conference	Nov. 16-17	Oklahoma City	TBD	thepetroleumalliance.com
SPE Innovation & Entrepreneurship Summit	Dec. 7-8	Houston	Norris Center City Centre	spegcs.org
2023				
IPAA Private Capital Conference	Jan. 19	Houston	The Post Oak	ipaa.org
NAPE Summit	Feb. 1-3	Houston	George R. Brown Conv. Ctr.	napeexpo.com
CERAWeek by S&P Global	Mar. 6-10	Houston	TBD	ceraweek.com
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Tuesday, odd mos.	Fort Worth	Fort Worth Petroleum Club	adamenergyfortworth.org
ADAM-Greater East Texas	First Wed., even mos.	Tyler, Texas	Willow Brook Country Club	etxadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.com
ADAM-Permian	Bi-monthly	Midland, Texas	Midland Petroleum Club	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.co
ADAM-Rockies	Second Thurs/Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Houston Petroleum Club	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	hefg.net
Houston Producers' Forum	Third Tuesday	Houston	Houston Petroleum Club	houstonproducersforum.org
IPAA-Tipro Speaker Series	Second Wednesday	Houston	Houston Petroleum Club	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.

ENERGY TRANSFER EDGING CLOSER TO FID FOR LNG FACILITY

Energy Transfer LP is the lone company in the project and continues its search for partners.

ARTICLE BY

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Energy Transfer LP has signed five LNG export agreements to date for 5.8 million tons per annum (mtpa) of supply ahead of an anticipated final investment decision (FID) this year regarding a large-scale Lake Charles shipping facility that could see initial tankers setting sail as early as 2026.

"Recent events in Europe highlight the importance of LNG from the United States, a country with abundant natural gas supply and strong geopolitical ties to Europe. We are hopeful that our Lake Charles LNG project will be a significant factor in the long-term solution for global energy needs," Energy Transfer's spokeswoman told Hart Energy on June 10.

Each sale and purchase agreement (SPA) will become fully effective upon the satisfaction of the conditions precedent, including Energy Transfer LNG, an affiliate of Energy Transfer, taking FID, which is anticipated by year-end 2022, Energy Transfer LNG resident Tom Mason said June 5 in a company press release.

The Lake Charles LNG facility is the only brownfield project among those proposed on the U.S. Gulf Coast, providing timeline and cost advantages, according to details provided in Energy Transfer's May 2022 investor presentation. The maximum estimated export capacity could reach up to 16.5 mtpa from three trains or a lower 11 mtpa from two trains.

"They want to FID the full three trains, and they think they will get 90% or so contracted before they take an FID," Bank of America Merrill Lynch oilfield

Lake Charles LNG Proposed Site Rendering

Source: Energy Transfer LP

service analyst Chase Mulvehill told Hart Energy. "There is potential for some majors to step up and sign some offtake … and if a major were to do that, they would actually take on a full train."

Energy Transfer is the lone company in the project, after Shell's departure in 2020. The company continues its search for an equity partner or partners with an aim to sell down up to a 75% interest. It's doubtful it would FID the project without an equity partner, Mulvehill said.

"If they sign a major, that would give them and everybody a lot more confidence that they'll do 16.45 mtpa and the full three trains," he said, adding that Energy Transfer wasn't interested in a phased construction plan and would prefer to do three trains all at once.

At an estimated cost of $550 per ton, according to Bank of America and Merrill Lynch data, the potential cost for the Lake Charles LNG export facility could be between $6 billion to $9 billion.

Dallas-based Energy Transfer's move into the LNG export arena comes after the sale of its Canadian assets to further deleverage its balance sheet and redeploy capital within its massive U.S. footprint.

"High [U.S. LNG] exports are being supported by high international LNG prices, as well as by additional export capacity created by a new U.S. LNG export facility, Calcasieu Pass LNG, which continues to ramp up exports," the U.S. Energy Information Administration announced June 7 in its "Short-Term Energy Outlook."

Expanding export deals

Energy Transfer has signed five LNG SPAs between March and June for a total 5.8 mtpa of LNG supply. Under all the agreements, the shipments will be free-on-board with a purchase price indexed to the Henry Hub benchmark plus a fixed liquefaction charge. The first deliveries are expected as soon as 2026.

Most recently, China Gas Hongda Energy Trading Co. Ltd., a subsidiary of China Gas Holdings Ltd., signed a SPA to receive 0.7 mtpa. The SPA is for 25 years and is China Gas' first long-term contract.

It "strengthens our existing portfolio for the import of LNG and will further enable China Gas to reliably and securely meet our natural gas customers' needs," China Gas Hongda general manager Yalong Qi said June 5 in a press release. "It is also an important step along the path to realizing China's carbon peaking and carbon neutrality goals," he added.

In May, Energy Transfer signed two SPAs.

The first SPA involved Gunvor Singapore Pte Ltd., which signed on for 2 mtpa. The SPA is for 20 years and "a significant step in executing Gunvor's overall strategy of uncovering and securing low-cost resources and implementing competitive and reliable deliveries to our LNG buyers," Gunvor co-head of LNG trading Kalpesh Patel said May 2 in a press release. The second SPA was inked on May 3 and involved SK Gas Trading LLC, which signed on for 0.4 mtpa. SK Gas, which is Energy Transfer's first Korean offtake customer, committed to an 18-year SPA.

In March, Energy Transfer also signed two SPAs, which represent the company's initial deals. ENN Natural Gas and ENN Energy Holdings Limited announced that ENN NG and ENN Energy signed on for 1.8 mtpa and 0.9 mtpa, respectively. Both SPAs are for 20 years.

"The signing of these long-term SPAs will further enrich ENN's LNG resources, expand resource supply channels and improve ENN's natural gas supply capacity to meet the rapidly growing natural gas demand in the domestic market," ENN NG president and vice chairman of the board of directors of ENN Energy Holdings Zheng Hongtao said March 29 in a press release.

Energy Transfer's LNG Sales And Purchase Agreements

Date	Counterpart	Shipping Method	Start Date	Contract Length	Supply
June 5	China Gas Holdings Ltd.	Free-on-board	2026	25 years	0.7 mtpa
May 3	SK Gas Trading LLC	Free-on-board	2026	18 years	0.4 mtpa
May 2	Gunvor Singapore Pte	Free-on-board	2026	20 years	2.0 mtpa
March 29	ENN Natural Gas	Free-on-board	2026	20 years	1.8 mtpa
				Total:	5.8 mtpa

Source: Energy Transfer LP

Lake Charles LNG

Energy Transfer is amongst the largest and most diversified midstream energy companies in North America. The company has a strategic footprint in all of the major U.S. production basins and owns and operates approximately 120,000 miles of pipelines and associated energy infrastructure across 41 states transporting approximately 30% of the U.S.' crude oil and natural gas.

Lake Charles LNG, a wholly-owned Energy Transfer subsidiary, owns an LNG import terminal and regasification facility on Louisiana's Gulf Coast near Lake Charles, La. The terminal has above-ground storage capacity of approximately 9 Bcf and the regasification facility has a send-out capacity of 1.8 Bcf/d.

The Lake Charles LNG facility will be built on the existing brownfield regasification facility. The site spans 152-acres and will capitalize on four existing LNG storage tanks with capacity of 425,000 cubic meters, two deepwater berths that can accommodate ships up to 215,000 cubic meters of capacity and other LNG infrastructure.

The facility will also benefit from its direct connection to Energy Transfer's existing Trunkline pipeline system that connects to multiple intrastate and interstate pipelines, the company said in its annual report, adding that the pipelines allow access to multiple natural gas producing basins, including the Haynesville, the Permian Basin and the Marcellus Shale.

On May 6, the Federal Energy Regulatory Commission granted Lake Charles LNG's and Trunkline's extension of time request to allow for completion of construction and modifications through Dec. 16, 2028. The project as currently designed is fully permitted by federal, state and local authorities and has all necessary export licenses, according to Energy Transfer. OGI

DRONE POISED TO REVOLUTIONIZE OFFSHORE INSPECTIONS

Here are three main technological breakthroughs that SubUAS CEO Javier Diez said made the first multi-domain air-water drone Naviator possible.

ARTICLE BY

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A drone capable of both flight and underwater operations on the same mission could streamline future offshore oil and gas inspection activities.

Cracking the technology that allows a robot to conduct both aquatic and aerial operations on a single trip has been tough. A newly developed drone would be able to fly to an offshore asset, submerge to conduct underwater inspections and return to base or fly to a new destination.

The hardware, however, is only one component of the technology solution. Software and cloud operations both make crucial contributions to the drone's capabilities.

According to SubUAS CEO Javier Diez, most people thought it was either impossible for a single robotic unit to carry out both aquatic and aerial operations, or it would only be possible with a lot of trade-offs. SubUAS's Naviator relies on hybrid aquatic and aerial technologies, he said.

"It looks very simple," Diez said. "But there's a lot of amazing technology that makes this operate in both water and air."

He said three main technological breakthroughs made the Naviator possible. The first and hardest, he said, is a propulsion system that works both in air and water.

The Naviator NV8X water/air drone can operate in water depths to 2,000 ft.

SUBUAS

"We took inspiration from animals that can fly and those that can swim," such as ducks and flying fish, he said. "All these animals can do one very well and one not very well."

The goal was to develop a single propulsion system that did both equally well, he said.

"In this case, we probably beat nature," Diez said. "We can operate equally well in both mediums."

In fact, he said, the propulsion technology used for the Naviator is similar to that being used for the Mars Ingenuity Helicopter, which is designed to operate in a thin atmosphere.

While underwater, the Naviator operates autonomously using navigation aids but is controlled in the air via remote control. When the Naviator emerges from the water, it acquires a GPS location and can also operate autonomously, or a remote operator can resume manual control of the robot.

"This water-to-air transition is what nobody else can do," Diez said.

Second, the robot had to be able to precisely manage propulsion speeds in both aquatic and aerial environments, a challenge he said took close to a decade to solve.

Third, he said, subsea electronics are typically placed in pressure vessels, which can drastically increase the weight of the equipment. Instead of using a pressure vessel, SubUAS is coating the Naviator's electronics with a proprietary material that allows the unit to operate at water depths to 2,000 ft.

The technology that allows the Naviator to carry out operations underwater and in the air on the same mission opens up a host of possibilities for inspection of offshore oil and gas assets, as well as offshore wind facilities.

Defuzzy CEO Adnane ElSoussi said

companies frequently want to take advantage of robots for tasks that are dull, dirty and dangerous.

Offshore inspections are "a dangerous down and dirty operation," ElSoussi said.

They also tend to require multiple assets, including vessels and subsea robots, in addition to personnel, he noted. Using a Naviator, he said, reduces both logistics and operational costs.

"It looks very simple, but there's a lot of amazing technology that makes this operate in both water and air."

—Javier Diez, *SubUAS*

One reason is that a Naviator can be controlled remotely—very remotely.

An early May demonstration of the robot's capabilities saw an operator in the United Arab Emirates (UAE) control a Naviator in New Jersey. In the demonstration, which was carried out during the AWS Energy Symposium in Houston, the unit took off from a point on land, flew to a spot over the water, slowly submerged, navigated about 30 ft underwater, slowly resurfaced, lifted into the air and flew back to shore.

While the collaboration between New Jersey-based SubUAS and UAE-based robotics company Defuzzy originated during a November 2021 meeting in Dubai, a "desert and ocean" separated the two companies for much of their collaboration, said Fuad B. Mekhti, managing partner at Quantum International and advisory board member at Defuzzy.

With few exceptions, Mekhti said, "nobody has seen each other physically," just through digital platforms like Zoom, Teams and others.

But remote operation of the Naviator by the Defuzzy-developed robotic fleet control system specialist, sitting 7,000 miles away, was a major piece of the puzzle, and the distance separating the teams was less important than the common goal, he said.

SubUAS offers Naviators in three payload sizes: the 8-pound workhorse, 30 pounds and 100 pounds. While mission times depend on vehicle size, Diez said, the units can handle about an hour of flight and about two hours of underwater operations. He said the company is exploring technologies like fuel cells to extend the flight time.

The Naviator is controlled by a combination of software and cloud directives. Inspection objectives are issued from a Defuzzy-developed robotic fleet control system. OGJ

Oil and Gas Investor

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'NOPE'

@ CLOSING

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It would be Harold Hamm. The morning of June 14, shortly after seeing Hart Energy's breaking news alert about Hamm bidding to take Continental Resources Inc. private, I received a text.

Someone had replied to a Twitter post about the news, commenting, "Wonder what he's seeing."

Without knowing more details yet, I replied, "Wall Street doesn't want oil and gas producers using equity to grow, so why be public?"

Getting into the Securities and Exchange Commission filing, I read Hamm's letter to employees. Yep, that's his point.

It would be Harold Hamm who would go first to tell Wall Street, "Nope." When he took his already 40-year-old Continental public in 2007, it had found a game-changing treasure in the Bakken Shale and needed access to large amounts of capital to develop it.

"At that time, the public market rewarded companies for both growth and performance," he wrote.

Today, though, Wall Street doesn't want oil and gas producers to spend money; they want to harvest it instead. The ever-fewer public operators out there, Hamm wrote, "is illustrative of a lack of support from the public market, and we believe there is a resulting underappreciation of Continental."

That's how it is in 2022. That's what Hamm sees.

He wrote that private operators have "the freedom to operate." And, like Continental was before May 16, 2007, "aren't limited by public markets."

He concluded, "Continental is a strong company built to last, and our family believes being private will make it even stronger and more competitive."

Immediately, the market appreciated Continental, driving the stock price up well beyond Hamm's $70 per share offer, 16% from the prior-day closing to $74.88.

Nitin Kumar, oil and gas securities analyst for Wells Fargo Securities LLC, said traders might be expecting a rival bid. But the Hamm family isn't interested in selling any of their 83% holding. The other bid would have to be for the 17% alone—essentially a silent partner.

What is certain, though, is that Continental shares are actually worth $80, Kumar said. And that's at only $60 oil.

Meanwhile, it's irresistible (yes, I'm going there) to compare how Harold Hamm makes an offer and how Elon Musk makes an offer.

Clearly Hamm's was contemplated for, well, 15 years, plus four weeks. He wrote in his letter that he's always said that "as long as we were appreciated in the market, we would remain a public company, but if our opportunities were limited by being public, we should look at alternatives."

Meanwhile, Musk's bid for Twitter looks like an accident—a pocket tweet to which he woke the next morning and felt more compelled to follow bad thinking with more bad thinking (oblivious that no one really takes him seriously anymore) than to tweet his usual mea culpa: "Haha."

Hamm bid $70; the stock appreciates to $75.

Musk bid $54.20; the stock tanks to $37.

Hamm and the Hamm family's Continental holding appreciated this year 40% through June 13. Musk's holding—about 15%—in Tesla Inc. depreciated this year 46% through June 13.

Continental likely holds only U.S. dollars. Tesla's quarterly report filed April 25 reported it "invested" $1.5 billion in Bitcoin in the first quarter of 2021. "We believe in the long-term potential of digital assets both as an investment and also as a liquid alternative to cash," it added.

The crypto would have been acquired at between $32,150 and $58,745. One June 14, a Bitcoin was worth $22,000.

I gave a nephew 0.001 Bitcoin last summer for his 10th birthday. It was worth $45 at the time. He said, "I want to sell it." I suggested he hold.

He asked again last November, when it was worth $67. I suggested he continue to hold it. I said something about "you have no better use of the proceeds" and other things that I now see could roughly be translated as "blah blah blah."

Today, a Pokemon card would have been a better investment, after all.

I could learn a lot from a 10 year old.

Elon Musk could learn a lot from an oil and gas producer.

First, all property owned should be real. Second, write a letter to the employees—a nice letter.

Third, do due diligence. Fourth, do this due diligence before making an offer.

Fifth, don't tweet crazy stuff. Sixth, maybe just don't tweet. OGI

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