Oil and Gas Investor

FEBRUARY 2022

Operators stack up in the Midcontinent.

HARTENERGY

CENTERED IN TRUST AND LONG-TERM RELATIONSHIPS

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
KIMBELL ROYALTY PARTNERS	KIMBELL ROYALTY PARTNERS	KIMBELL ROYALTY PARTNERS	**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	PRIVATE FINANCING STATISTICS
~$2.4 Billion	~$11.4 Billion
Aggregate Transaction Volume Since 2017	Aggregate Capital Raised Since 2009
15 Closed Transactions Since 2017	35 Closed Transactions since 2009

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For the most recent list of our transactions, visit **stephens.com/buildingblocks**

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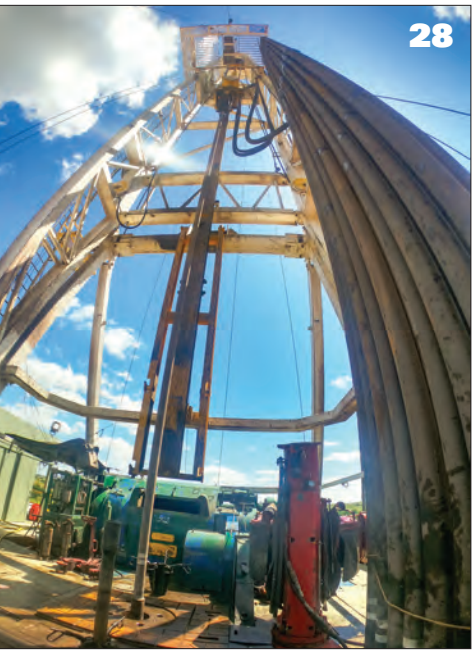
FEBRUARY 2022/VOLUME 42/NUMBER 2



Oil and Gas Investor

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COLUMNS

DEPARTMENTS

ABOUT THE COVER: Oklahoma's all rigged up for markets' renewed demand for oil, gas and NGL. Illustration by Robert D. Avila

Oil and Gas Investor (ISSN 0744-5881, PM40036185) is published monthly by Hart Energy Publishing, LP, 1616 S. Voss Rd., Suite 1000, Houston, Texas 77057. Periodicals postage paid at Houston, TX. Ride-along enclosed. Advertising rates furnished upon request. **POSTMASTER: Send address changes to Oil and Gas Investor, PO Box 5020, Brentwood, TN 37024**. Address all correspondence to Oil and Gas Investor, 1616 S. Voss Rd., Suite 1000, Houston, Texas 77057. Telephone: +1.713.260.6400. Fax: +1.713.840.8585. oilandgasinvestor@hartenergy.com

Subscription rates: United States and Canada: 1 year (12 issues) US$297; 2 years (24 issues) US$478; all other countries: 1 year (12 issues) US$387; 2 years (24 issues) US$649. Single copies: US$30 (prepayment required). Denver residents add 7.3%; suburbs, 3.8%; other Colorado, 3%.

LATEST CONTENT

Chesapeake Achieves ESG 'First' For Legacy Haynesville Shale Gas Operations

By Hart Energy Staff

Chesapeake Energy Corp. is the first shale producer to certify Haynesville natural gas operations jointly under the MiQ methane standard and the EO100 standard for responsible energy development, according to a company release.

Assembling Houstonians To Spur The Energy Transition

By Madison Ratcliff, Associate Editor

Professionals from many different spaces in the energy sector must come together to lead the energy transition, industry leaders say.

US Shale Producer SM Energy Sets New Environmental Targets, Zero Routine Flaring

By Hart Energy Staff

The new environmental targets set by SM Energy, whose operations are focused in the Permian Basin and Eagle Ford shale plays, were largely driven by the company's shareholders, president and CEO Herb Vogel says.

Tackling The New Cyber Threats To The Oil And Gas Industry

By Madison Ratcliff, Associate Editor

DNV and Applied Risk have merged to help companies increase cybersecurity and protect against online threats.

Lucid To Develop Largest CCS Project In The Permian Basin

By Hart Energy Staff

Lucid Energy Group received EPA approval on Jan. 11 for its plan for the sequestering of CO_2 from its Red Hills gas processing complex in New Mexico's Lea County.

ONLINE EXCLUSIVES

Executive Q&A: The New Private Equity Route To Oil, Gas Ownership

By Mary Holcomb, Associate Editor

EnergyFunders CEO Laura Pommer spoke with Hart Energy about a new private equity model for oil and gas that also offers access to bitcoin mining.

Upstream Deal Values Rise In 2021 Despite M&A's Slow End

By Darren Barbee, Senior Editor

The Haynesville Shale and the Permian's Delaware Basin were the two most active plays of 2021's final quarter, combining for 80% of the quarter's deal value, a new report by Enverus says.

Nonprofits, Energy Companies Partner To Promote STEM Education

By Velda Addison, Senior Editor

As efforts to encourage more students to embrace STEM go virtual, businesses and organizations aim to extend their reach to keep talent pipelines for the energy sector filled.

Hart Energy's Unconventional Activity Tracker

By Larry Prado, Activity Editor

Updated weekly, Hart Energy's exclusive rig counts measure drilling intensity. They exclude units classified as rigging up or rigging down, and also exclude rigs drilling injection wells, disposal wells or geothermal wells. They are designed to offer the most accurate picture of what is actually occurring in the field.

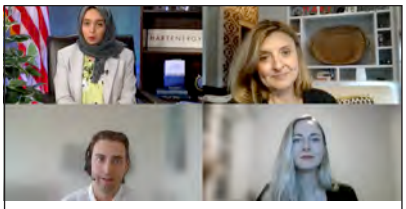
HART ENERGY VIDEOS

hartenergy.com/videos/

Forty Under 40 Honoree Interviews

For your introduction to these role models, we invite you to enjoy these video and audio interviews, extended narratives and personal insights.

hartenergy.com/fortyunder40



ESG Oil And Gas Outlook 2022: 'It's Here To Stay'

In this exclusive roundtable, executives from Enverus, KPMG and Rystad Energy discuss key trends, opportunities and challenges that are expected to shape ESG in the oil and gas sector in 2022.

www.hartenergy.com/exclusives/esg-oil-and-gas-outlook-2022-its-here-stay-198230

DUG East: Toby Rice Talks Sen. Warren, LNG, Energy Crisis And Marcellus Gas

EQT Corp. CEO Toby Rice took Sen. Elizabeth Warren to task over her corporate greed accusations against the oil and gas industry in his first interview after releasing his public rebuttal. Here's what he had to say.

hartenergy.com/exclusives/dug-east-toby-rice-talks-sen-warren-lng-energy-crisis-and-natural-gas-marcellus-197842

CONFERENCE & EXHIBITION

DUG MIDCONTINENT

March 1-3, 2022
Oklahoma City Convention Center
Oklahoma City, OK

AN OKLAHOMA RIG REVIVAL

Returning to OKC in person, the **2022 DUG Midcontinent Conference & Exhibition** promises to be the Oklahoma shale event of the year. Don't miss this valuable opportunity to hear directly from operators and experts as they share news of how the SCOOP, STACK, Merge and more Oklahoma plays are well "in the money".

DUG™ conference sessions and related exhibits historically attract a well-qualified group of professionals eager to network with like-minded peers and colleagues. The atmosphere fosters multiple ways to share the latest trends and technology applications. Attendees can expect to walk away with actionable intelligence for managing successful operations within Oklahoma shale plays.

INDUSTRY LEADING SPEAKERS:

LUKE ESSMAN
President & CEO
Canyon Creek Energy

TIM HELMS
Chief Financial Officer
Citizen Energy

PETER ALLEN
Senior Vice President, Operations
Eagle Resources Group

DEREK DETRING
President
Detring Energy Advisors

CALVIN CAHILL
President & CEO
Calyx Energy III LLC

SETH MOORE
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HART ENERGY ESTABLISHES STEVE TOON ENDOWED SCHOLARSHIP AT

BAYLOR UNIVERSITY

The Steve Toon Endowed Scholarship in Journalism has been established by Hart Energy and *Oil and Gas Investor* magazine, in memory of friend and colleague Steve Toon. This endowed scholarship fund provides assistance to deserving students attending Steve's alma mater, Baylor University, in Waco, Texas, who are pursuing their degree in journalism.

Born in Dallas, Texas, on Dec. 17, 1963, Steve grew up in Houston. He attended CY Fair ISD schools until he entered Baylor University and earned his bachelor's degree in communications and journalism. From the day he graduated from Baylor in 1986, Steve supported himself (and later his family) as a journalist, writer and editor.

Across a career spanning nearly 35 years, Steve prided himself on being a quick study, developing networks of contacts, and communicating effectively and intelligently with his readers. He researched and wrote about health and fitness, medical devices, occupational safety and real estate before turning his considerable talents to covering all facets of the oil and gas industry after 2007.

His work earned honors from the American Heart Association and Texas Medical Association, the Council for Advancement and Support of Education, the National Real Estate Investors Association, the American Society of Business Publication Editors, Media Industry News Best of the Web & Digital Awards, as well as numerous Hart Energy awards. He served on the board of directors for the nation's second largest real estate investment association and the Houston Producers Forum.

Family was the most important part of Steve's life. He and his wife, Cheryl, whom he met and married in 1999, proudly reared three children: a son, Blake, and twin daughters, Lexy and Leah. He spent countless hours tracking family history and discovering connections. Photography was another passion. Never without his camera, he documented every moment for future generations.

Hart energy reports oil and gas industry companies and individuals have already contributed to the scholarship fund.

WHERE TO DONATE

Those wishing to also contribute can do so at: **https://bit.ly/3Emi9iy**

A STARK WARNING ON ENERGY AFFORDABILITY

LEN VERMILLION, EDITORIAL DIRECTOR

The recent uprising in Kazakhstan was certainly about more than LPG prices (liquefied petroleum gas)—let's not fool ourselves—but it serves as a stark warning of how ingrained the energy sector is in any society. It's also a stark warning to those of us in the west that any sudden disruption to energy affordability and availability has a profound effect on people's day-to-day lives.

So it's no surprise that unaffordable fuel would end up triggering protests that led to an uprising that led to a dangerous response from a government that led to, unfortunately, violence and deaths. Given those protest may or may not have been spontaneous, or planned in advance—that's a discussion for more informed geopolitical pundits and reporters—it's clear, as it has always been, energy policy decisions are best made by those who understand the market and not inside the walls of presidential palaces, parliaments, congressional offices and certainly not by activists with weapons and pent-up angst just waiting to explode.

The Kazakh government's decision to discontinue subsidizing LPG, the main fuel for cars in the western part of the country, caused an immediate doubling of prices, leaving fuel unaffordable in a country already simmering over corruption, economic inequality and a questionable human rights history. It's easy to say the authoritarian government of a former USSR republic that maintains as cozy relationship with the Kremlin is a much different situation than the U.S. or the countries of Western Europe. Of course, there's no doubt about it. But is it such a stretch to believe that when it comes the politicized nature of the energy transition, the same couldn't happen in the west?

People plunged into darkness can get quite ornery. Many of us in Texas found ourselves frustratingly plunged into the cold and dark for merely a week last February, and that was a dangerous enough situation for people. Frankly, I never thought I'd find myself scooping water out of a dirty swimming pool to flush a toilet, but I did. Thankfully, good ol' gasoline kept me warm as I spent my days in my car, and then nights under clothing and blankets manufactured with, you guessed it, oil. Now, take that away and who knows?

The bottom line: Playing political games with energy affects people dramatically. It turns them into pawns regardless of whether they are in Houston or Almaty. There's no doubt we need energy reform around the world. Let's face it, neither the Kazakh protests nor the independence of the Texas power grid have anything to do with solving climate change or improving the lives of people. They are simply about political power and money.

Maybe it's time we put the good of people and their well-being at the top of energy policy debate. A week of blackouts is one thing. Violence and death are completely different story. It's not one I want to be a part, of course. How about you?

Join me at **HartEnergy.com/Vermillion-Feb2022** where I have much more to discuss about energy transition policy and investment, the anniversary of the Texas power grid failure, a curious quote of the month and six guesses or less as to why I gave into the Wordle craze.

M&A IS THE BOMB

DARREN BARBEE,
SENIOR EDITOR

Consider the ampersand: that curvy wire that bonds together the undefusable explosive power contained within M&A. The ampersand even has a tiny fuse-like protuberance sitting at its bottom, ready to be lit.

Most analysts expect another year of high-intensity firepower from deals, largely directed at the Permian Basin, as well as the Marcellus and Haynesville shales. The recent Enterprise Products Partners LP announcement of Navitas Midstream Partners LLC for $3.25 billion only served to draw the Midland Basin in stronger contrast with its rival basins.

But the trajectory of 2022 deals will almost certainly cause different impacts than last year.

If commodity prices hold, investors will have to choose between the desire to decarbonize and the reality that the E&P industry will offer almost unmatched capital returns to investors while swiftly adapting to ESG needs—with a few notable exceptions.

Demand for oil and gas also goes against the grain of the financial sector in which banks and asset managers representing 40% of the world's financial assets have pledged to align their portfolios with "science-based net-zero targets," Moody's Investors Service noted in a Jan. 6 report.

Unless a company has large-scale wind and solar farms, it isn't likely to even be in the conversation. A June Investopedia article listed four oil companies as protecting the environment, all of them European and dabbling in renewables: Royal Dutch Shell Plc, TotalEnergies SE, Repsol SA and Equinor.

Despite that, as EQT Corp. CEO Toby Rice recently pointed out, "U.S. LNG powered by the Marcellus Shale is the biggest green initiative on the planet."

As if to vindicate Rice, in early January, numerous news agencies reported that the European Union, suffering gas shortages, was planning to classify some natural gas and nuclear projects as "green" investments. Some Europeans activists were outraged at both natural gas and nuclear power even as they tolerate 25% of Germany's power generation coming from burning coal, according to NPR.

In the U.S., consolidation could lead to benefits beyond company-specific scale and cost synergies. While public companies have taken pains to portray a "clean up their act" position on ESG, private companies are continuing to amp production and, as a result, drive emissions growth in 2022, Moody's said.

Among the 100 largest oil and gas producers in the U.S., nine of the Top 10 greenhouse-gas emission-intensity producers are private, according to a report from the Clean Air Task Force and Ceres, a sustainability-focused think tank that Moody's cited.

Consolidation can enhance the quality and durability of an E&P company's drilling inventory and reserves, improve its product mix or basin diversification and help advance its long-term environmental objectives, Nymia Almeida, Moody's senior vice president, said. "Financially speaking, consolidation can improve market access, reduce overall cost of capital, increase price realizations and lower breakeven costs," she added.

Look for 2022 to also be a grittier, cash-heavy process. Deals will likely include more bolt-on acquisitions with private or small-cap companies. Larger companies will also look to monetize their noncore and Tier 2 acreage as they prune their portfolios.

Moody's sees a shift from the zero premium mergers that have dominated for more than a year.

"Buyers will likely have to pay a premium and more cash in future transactions," the report said, "rather than the no-premium and all-equity deals of 2020, when valuations at cyclical lows left sellers without bargaining power."

In the oil-weighted universe, the Permian Basin will naturally remain a dominate force. Several private and small companies remain with cost and infrastructure advantages as well as additional inventory, Moody's said.

"Permian production has fully recovered to record levels as more companies diverted capital toward that basin in 2021. Volumes in other nearby basins still trail their pre-pandemic highs," Moody's said.

With plenty of free cash to burn, E&Ps will be looking at two alternatives: add high-quality inventory or return cash to shareholders.

For natural gas deals, higher prices and improved access to capital will allow larger gas-focused producers to chase M&A more easily in 2022. But the same higher valuations found in the oil patch will likely to be a motivator for sellers to engage "actively" with potential buyers.

For the remainder of 2022, look for deals to rain down like fireworks. The fuse is lit.

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Connecting You to the Global Energy Industry

TRIPLE THREAT: UNCERTAINTY, UNCERTAINTY, UNCERTAINTY

JACK BELCHER, CORNERSTONE GOVERNMENT AFFAIRS

Sometimes in life it's the quieter, less obvious things that are actually more impactful. Toward the end of last year there was a lot of activity in Congress that was potentially impactful to the oil and gas industry. Much of the news focused on the big pieces of legislation moving through Congress, such as the Bipartisan Infrastructure Bill that President Biden signed into law and the budget reconciliation package known as Build Back Better (BBB) bill that stalled in the Senate after Sen. Joe Manchin (D-WV) said he could not support it.

The infrastructure bill directed a whole slew of government spending toward things such as the power grid, carbon capture and storage and electric vehicle recharging. BBB was originally going to remove several long-held tax deductions (percentage depletion allowance, deduction of geological and geophysical expenses, deduction of intangible drilling costs), but the version introduced in the House dropped those provisions. What it contained was a fee on methane emissions and an extension of the 45Q tax credit for carbon capture and storage.

So with these warnings averted, what are the biggest threats out of Washington? The three biggest factors negatively impacting the oil and gas industry today are regulatory uncertainty, investment capital uncertainty and inflationary uncertainty. Government policy is impacting all three.

With the legislative threats minimized, the regulatory threats and uncertainty come into view. The Biden administration has backed away from its early efforts to slow leasing on federal lands and waters and block new permitting for drilling. Other initiatives that would negatively impact oil and gas E&P are underway.

For example, the Interior Department is expected to raise royalty rates, further disincentivizing activities on federal lands. Additionally, while most larger producers already have efforts underway to detect and mitigate methane emissions, as they should, many smaller producers that haven't will pay more to comply with the latest rendition of the methane rule. And, while the BBB and its accompanying methane fee have seemingly stalled, the government is expected to find ways to impose fees for methane emissions both onshore and offshore.

Over at the Federal Energy Regulatory Commission (FERC), the new makeup of the commission is not going to make permitting pipelines any easier, as the "public interest" standard is tested and perhaps revised to include a climate impact test. FERC permitting for LNG export facilities seems unthreatened for now but certainly less secure than under previous administrations.

These ongoing and anticipated regulatory efforts coupled with antidevelopment and often inconsistent rhetoric contributes to overall uncertainty, which plagues the industry overall. As a result, the energy industry is less apt to invest in new E&P, even when oil and gas prices are high.

Which brings us to the issue of investment capital uncertainty. We all know that prevailing attitudes by investment funds have helped drive capital away from fossil fuel development. In reality, more capital should be flowing to chase these critical commodities for which the world has not lost its need, as underscored by recent accusations by Congress and the administration that industry is purposefully holding back exploration as they plead with Saudi Arabia to bring more barrels to market. It is indeed an unusual dichotomy when investment dollars are slow to feed near certain returns.

While likely temporary, the current dynamics are not without consequences. Let's remember that oil and gas discoveries in 2021 fell to their lowest level in 75 years but not because we are running out of hydrocarbons. We aren't even close to that happening. Instead, discoveries plummeted because exploration budgets, cut during the pandemic, have failed to recover due in part to uncertainty over access to investment capital.

The final critical factor is high inflation or inflationary uncertainty. High energy prices are one of the factors feeding inflation, and inflation is also making oil and gas more expensive to produce. It's a vicious cycle that must ultimately be addressed through monetary policy in the form of higher interest rates, the removal of excess dollars out of the economy and significantly sound energy policy that gets the U.S. producing more of its own energy.

So it's pretty clear that we have three uncertainties—regulatory uncertainty, investment capital uncertainty and inflationary uncertainty—that are hurting our domestic energy industry and hurting the U.S. economy. Current government policies are moving us in the wrong direction. We need to sound the alarm and make our leaders aware that with the right government policies, all three areas of uncertainty can be fixed.

EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2022				
NAPE Summit	Feb. 8-11	Houston	George R. Brown Conv. Ctr.	napeexpo.com
The Energy Venture Investment Summit	Feb. 16-17	Golden, CO	The Colorado School of Mines	theenergyventuresummit.com
DUG Midcontinent	**March 1-3**	**Oklahoma City**	**Oklahoma City Conv. Ctr.**	**dugmidcontinent.com**
LOGA Annual Meeting	March 7-8	Lake Charles, LA	Golden Nugget Hotel & Casino	loga.la
CERAWeek by IHS Markit	March 7-11	Houston	Hilton Americas-Houston	ceraweek.com
EnerCom Dallas	April 6-7	Dallas	Dallas Petroleum Club	enercomdallas.com
Mineral & Royalty Conference	April 18-19	Houston	Post Oak Hotel	mineralconference.com
Energy ESG Conference	**April 26-27**	**Dallas**	**Omni Dallas**	**hartenergyconferences.com**
Women In Energy	**April 29**	**Houston**	**Marriott Marquis**	**hartenergyconferences.com**
Offshore Technology Conference	May 2-5	Houston	NRG Park	2022.otcnet.org
Energy Transition Capital Conference	**May 10**	**Houston**	**Omni Houston**	**hartenergyconferences.com**
Carbon Management Conference	**May 16**	**Fort Worth, TX**	**Fort Worth Convention Center**	**hartenergyconferences.com**
DUG Permian/Eagle Ford	**May 16-18**	**Fort Worth, TX**	**Fort Worth Convention Center**	**dugpermian.com**
Louisiana Energy Conference	May 24-27	New Orleans	The Ritz-Carlton, New Orleans	louisianaenergyconference.com
DUG Haynesville	**May 25-26**	**Shreveport, LA**	**Shreveport Convention Center**	**dughaynesville.com**
Mexico Gas Summit	June 1-2	San Antonio	St. Anthony Hotel	mexicogassummit.com
CIPA Annual Meeting	June 9	Carlsbad, CA	TBD	cipa.org
DUG East	**June 13-15**	**Pittsburgh**	**David L. Lawrence Conv. Ctr.**	**dugeast.com**
Unconventional Resources Technology Conference	June 20-22	Houston	George R. Brown Conv. Ctr.	urtec.org
DUG Bakken and Rockies	**June 28-29**	**Denver**	**Colorado Convention Center**	**hartenergyconferences.com**
IPAA Annual Meeting	July 20-22	Colorado Springs, CO	The Broadmoor	ipaa.org
EnerCom Denver	Aug. 8-11	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. 14-15	Wichita, KS	Hyatt Regency	kioga.org
American Natural Gas Conference	**Sept. 28-29**	**Dallas**	**TBD**	**hartenergyconferences.com**
Energy ESG Conference	**Oct. 11-12**	**Houston**	**TBD**	**hartenergyconferences.com**
Energy Capital Conference	**Oct. 25**	**Houston**	**Omni Houston**	**hartenergyconferences.com**
A&D Strategies and Opportunities Conference	**Oct. 26**	**Dallas**	**Fairmont Hotel**	**adstrategiesconference.com**
North American Gas Forum	Oct. 25-27	Washington, D.C.	Hilton Washington, D.C.	energy-dialogues.com/nagf/
Executive Oil Conference	**Nov. 15-16**	**Midland, TX**	**Midland County Horseshoe Pavilion**	**executiveoilconference.com**
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Thursday, 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.com
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.

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25 INFLUENTIAL Women IN ENERGY

NOW ACCEPTING NOMINATIONS FOR 2023

Oil and Gas Investor invites you to nominate an exceptional industry executive for its 6th Annual **25 Influential Women in Energy** program. Help us celebrate women who have risen to the top of their professions and achieved outstanding success in the oil and gas industry.

Past honorees have included professional women from entrepreneurs to producers, midstream operators, service companies and the financial community. They've represented varied disciplines including engineering, finance, operations, banking, engineering, law, accounting, corporate development, human resources, trade association management and more across the upstream and midstream sectors. All nominees will be profiled in a special report that will mail to *Oil and Gas Investor* subscribers in April 2023.

The deadline for nominations is December 16, 2022

HARTENERGY

Oil and Gas Investor

InfluentialWomenInEnergy.com

In dance of bears and bulls, oil execs see no need for sudden movements

Suddenly E&Ps are seeing variables that go up and not just down.

E&Ps are facing inflation, management teams expect oil prices to rise and overall the oil and gas industry saw a moderate expansion of activity to close out fourth-quarter 2021, according to a newly released survey of producers in several states including Colorado, Oklahoma, Wyoming and northern New Mexico.

Results of the survey by the Federal Reserve Bank of Kansas released Jan. 7 also show activity continued to outpace levels from a year ago.

"District drilling and business activity continued to grow through the end of 2021," said Chad Wilkerson, Oklahoma City branch executive and economist at the Kansas Fed. He added in the release that oil and gas companies' revenues have risen along with higher wages and benefits for workers.

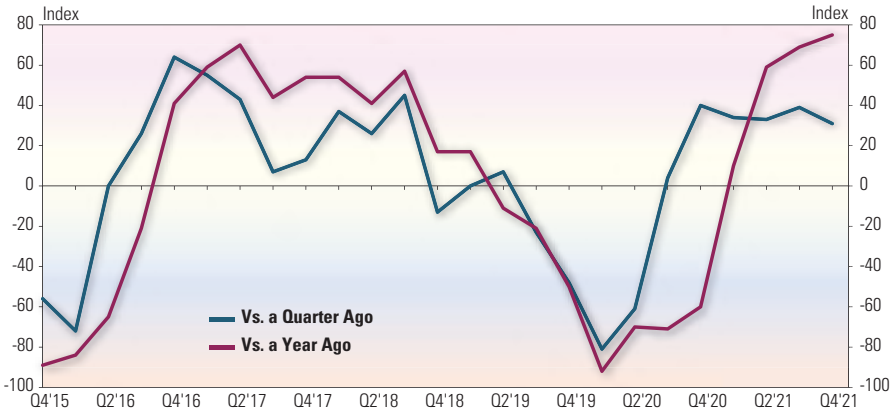
Survey respondents also said they plan to spend more in 2022 than they did last year, citing inflation and possible increased activity.

Oil and gas firms reported that oil prices needed to average $73/bbl for a substantial increase in drilling to occur and natural gas prices at $4.27/MMBtu.

In December, WTI prices were forecast to average $66.42/bbl in 2022, according to the U.S. Energy Information Administration (EIA).

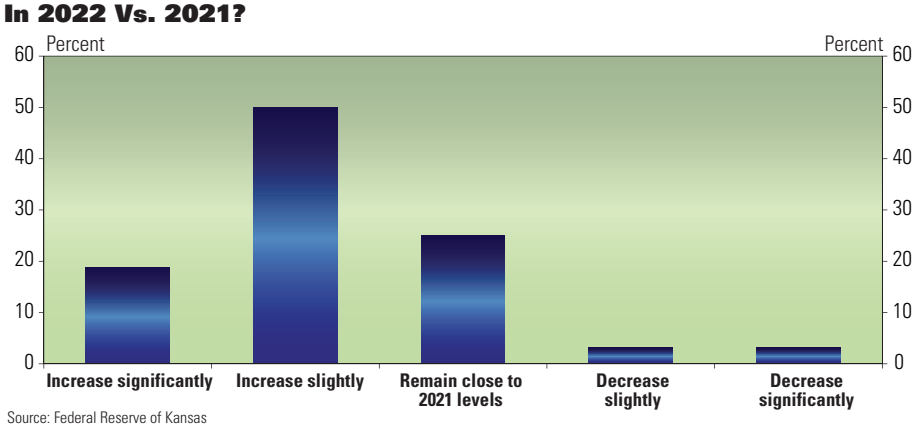
Among 33 respondents, the average price for WTI predicted is $73/bbl.

Drilling/Business Activity Index Vs. Quarter Ago



Source: Federal Reserve of Kansas

What Are Your Expectations For Your Firm's Capital Spending Plans In 2022 Vs. 2021?



Source: Federal Reserve of Kansas

Confidence in WTI pricing increased despite perceived late-year setbacks amid fears of the Omicron variant of COVID-19.

"Oil price expectations increased to the highest levels since the survey began this question in 2017," the Kansas Fed reported. However, natural gas price expectations declined.

Some producers predicted that the scarcity of investment would lead to shrinking supply, echoing comments made by Hess Corp. CEO John Hess in December.

"Investment is the greatest challenge the oil industry faces today," Hess said at the World Petroleum Congress.

One executive told the Fed survey, similarly, that "there is not enough investment for replacement barrels [of oil]. Supply may shrink, and demand will stay similar or even grow."

Robert Yawger, director of energy futures at Mizuho Securities USA LLC, said in a Jan. 7 report that crude oil storage has dipped lower for six consecutive weeks. The U.S. also sold off about 18 MMbbl of oil from the Strategic Petroleum Reserve in December.

Other respondents, who were surveyed between Dec. 15 and Jan. 3, said that capital discipline will continue to moderate activity.

"Pressure to moderate spending from investors," an executive said.

Firms also said they were feeling the effects of inflation, with about 50% of firms expecting a slight increase in spending and another 20% a significant increase. About one-quarter of firms expected 2022 capital spending to remain close to 2021 levels.

"Several firms reported that inflation has driven higher capital spending costs from services and materials," according to the survey. "Other [respondents] reported increased capital spending plans to expand drilling and production."

"Inflation is hitting the equipment purchases for new wells," an executive surveyed told the Fed.

The survey also reaches out to producers in Nebraska and western Missouri.

—Darren Barbee

Upstream A&D 2022 outlook: All about commodity prices

Consolidation will continue to be the driving storyline in 2022 as oil and gas companies tilt toward scale and synergies through A&D, although deals will face headwinds from policy uncertainty and a focus on renewable energy.

Seenu Akunuri, leader of PwC's U.S. energy and mining valuation practice, told Hart Energy he expects 2022 to look similar to last year.

"A lot of the deals in 2021 primarily happened because of the lessons learned in the previous downturn and COVID-19's impact," he said. "Companies, especially on the exploration and production side, were all focused on how they could reduce breakeven margins so that they could continue to generate free cash flow, even if commodity prices were lower than what we're seeing currently."

With the current commodity price environment, "we do expect there will be continued demand for consolidations. Secondly, we also think some of the majors and IOCs will continue to focus on divesting some of their noncore assets given the growing focus on ESG and pressures to reduce carbon footprints."

As commodity prices have stabilized—or even fallen into a rut—the relatively strong price tape will allow deal activity to remain elevated through the year, though upstream E&Ps are strengthening their resolve on delivering dividends and buybacks and placing less focus on exploration and the drill bit, according to a December outlook by PwC.

Private equity funds are also apparently likely to stay on the sidelines as several larger funds have pledged to reduce or eliminate fossil fuel holdings.

"This means they are unlikely to be major buyers of traditional energy assets in the future. However, we expect private equity funds to continue making strategic acquisitions around renewables, clean tech and other places within the energy transition value chain to better balance existing portfolios," PwC said.

Despite the growing focus on low-carbon assets, most of the world's energy still derives from oil, natural gas and coal, PwC said. Forecasts show oil supplies and demand growing in 2022, creating an opportunity for producers to profit from short-term price increases.

"As a result, we expect deals around traditional energy assets that were prevalent in 2021 to continue into 2022. Still, the outlook for pure E&P deals will be tempered by the shift toward renewables amid a growing focus on ESG investing," PwC said.

The new year comes after 12 months of activity rebounded to pre-pandemic levels, with 152 announced deals valued at $133 billion. Volume increased in the second half, up 34%, while

values grew by 30%. Upstream accounted for most of the growth, with 42 deals valued at $47 billion, PwC said.

While the Permian Basin largely ruled large-scale transactions again, Akunuri sees various scenarios for basins that weren't part of the after-pandemic deal blitz of 2021.

In the Eagle Ford, Akunuri said the shale play will generate interest based on the assets that are available and their breakeven margins.

"While the Permian Basin is on the lower side of the breakeven market, the Eagle Ford is not too far behind, so we do expect to see continued interest in all three basins," he said.

Companies may especially be eying the Eagle Ford because of current commodity prices that are poised to generate significant free cash flow.

"Recent demand in natural gas prices has generated a renewed interest both domestically and to support LNG exports," he said

In other basins, the Haynesville, which generated a number of natural gas transactions, is likely to continue its A&D activity as long as natural gas prices stay above $3/Mcf.

The Midcontinent remains a trickier proposition. While the assets range from fair to good quality, breakevens due to uneven pipeline access and wells costs create challenges, though if gas prices hold interest will continue in the play.

The Denver-Julesburg and Powder River basins also remain in play, though they have higher breakeven prices and are further from coastal LNG off ramps.

"Companies will tend to be a little more cautious in making investments. There also might be smaller deal activity with private companies who are looking to consolidate and acquire additional acreage, but we may not see large-scale mergers and acquisitions," Akunuri said.

Finally, will companies look for alternative exits, such as the contemplated IPO of Colgate Energy? Akunuri said it will vary based on management team expectations.

Companies may go the IPO route if they see long-term opportunities to grow the company and not simply monetize acreage.

"However, if companies believe that they're in a good position to exit and sell to another company, they'll take it," he said. "In addition, given the public and investor sentiment mostly unfavorable light being shone on fossil fuel companies, there are definitely some concerns about new IPOs."

A key to a successful IPO will be a clear strategy for ESG and the E&Ps' "journey toward a carbon neutral strategy may get more favorable reception in the public markets."

—Darren Barbee

Does ESG really matter for the oil and gas industry?

By now the oil and gas industry has probably heard the term ESG quite a bit and learned about its significance.

Across several sectors, businesses are rushing to embrace ESG metrics to measure

progress toward their goals. Companies are also looking at innovative low-carbon solutions to gain competitive advantages in a lower-carbon economy. Announcements from companies committing to net-zero carbon emissions are now a regular occurrence.

But does ESG really matter for oil and gas? The short answer is yes.

From investor calls to board meetings, ESG continues to revolutionize how oil and gas businesses are managed, measured and operated. And this isn't slowing down any time soon. This megatrend has begun influencing capital markets and more specifically security prices, and will continue impacting access to capital for oil and gas companies, according to Andrew McConn, head of commercial intelligence at Enverus.

"Company-level ESG differentiation does matter; it's not just a sector level trend to attract investors back to the oil and gas industry at large…ESG will trend in the direction of mattering more, moving forward," McConn said speaking at Hart Energy's Energy ESG Conference.

He went on to explain one of the ways to measure the significance of ESG is to analyze how often the term "ESG" is mentioned by the analyst community.

"Starting effectively with zero mentions of ESG just a few years ago, it has ramped up significantly in the recent years and now averages about twice per investor call every quarter for the top 50 oil and gas companies," he said.

In addition, he noted that the financial community is largely driving the ESG push, adding that the start of ESG investing can be loosely tied to the United Nations Principles for Responsible investment (UNPRI) that has been around for a decade but has ramped up in recent years.

Launched in April 2006 with support from the UN, the PRI had over 2,700 participating financial institutions as of August. These institutions participate by becoming signatories to the PRI's six key principles and then filing regular reports on their progress.

The first principle is a pledge that states, "We will incorporate ESG issues into investment analysis and decision-making processes."

"This [pledge] is an explicit way of saying ESG matters," McConn said, adding that there are currently over 4,000 different ESG-focused funds managing over $ 130 trillion.

Although there is no agreed-upon ESG standard yet, McConn noted that the key to accurate measurement of ESG goals is high-quality disclosures.

"There are always going to be other ways to measure ESG components … but disclosures directly from companies themselves will be the most accurate and useful sources of ESG data," he said.

Even though disclosures are not required yet, according to McConn there is a significant increase in voluntary disclosures from oil and gas companies that conform to identities like Sustainability Accounting Standards Board (SASB) and Global Reporting Initiative (GRI).

ESG is a broad term, but the best way to define it is putting ESG into quantifiable metrics for each of the three categories, McConn explained.

"The 'E' category, for instance, includes proprietary GHG [greenhouse gas] emissions including methane leakage, flaring rates, water consumption, spill rates and energy usage. These are the hardest to quantify in a comprehensive and standardized manner."

"That puts [Enverus] in a unique position to help companies understand what's going on because these metrics are important but also very difficult to measure," he added.

Enverus has created a first-of-its-kind objective scoring system that combines ESG analytics with operational and economic performance, providing a complete end-to-end solution for all market participants.

McConn outlined three elements of devising a winning ESG strategy: flaring and methane emissions, more ESG disclosures and aligning incentives with shareholders.

Even though all three elements are extremely critical for oil producers to achieve their ESG goals and attract investments, the "E" in ESG in most important for oil and gas companies, McConn said, adding that U.S.-based companies have been significantly reducing emissions over the past five years.

"Since 2020, we estimate that the volume of flared gas in the U.S. has reduced by 60% ... Even as activity and production have ramped back up after COVID, producers have been more deliberate in reducing flaring," McConn said.

He continued, "The market recognizes that [reducing methane emissions] is a low hanging fruit on which companies have significant control and is moving the needle on climate change."

Secondly, he said it's best for oil and gas companies to disclose their climate, environmental, social and sustainability activities.

"At this stage, without firmer and more standardized requirements from regulatory agencies, it is best to disclose as much as possible," McConn said.

"Investors recognize that ESG is complicated and it's hard to conform to all the different standards," he continued, "but to conform to optional frameworks that already exist helps in building trust with stakeholders and investor community."

Unfortunately, the oil and gas sector for a long time did not have a great reputation with aligning incentives with shareholders. "It was the whole production growth versus returns paradox," noted McConn.

"It took a while to overcome this, and we are still feeling the headwinds of that mentality, but we don't want to repeat the same thing with ESG…if investors care about ESG, we need to make sure invectives are in place to make that a reality at the management level," he said.

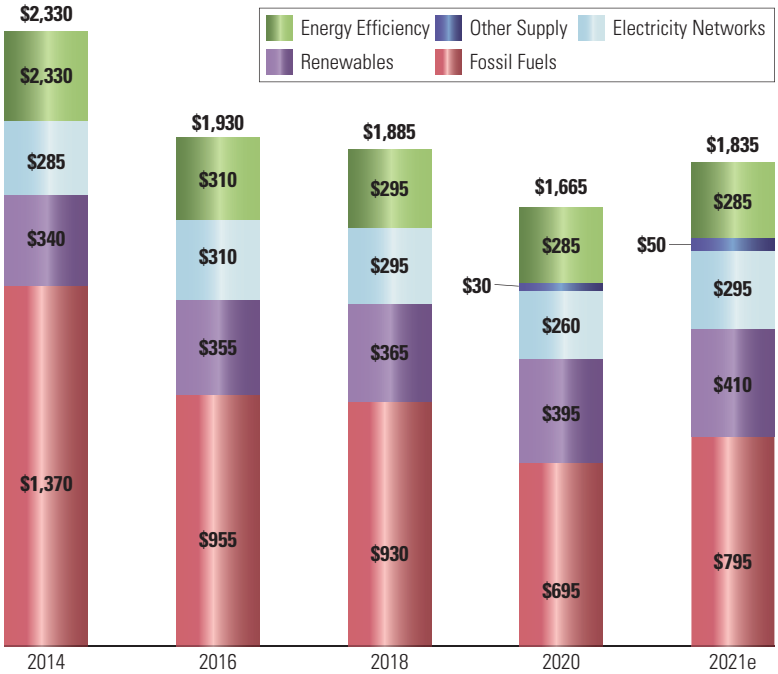
—Faiza Rizvi

Could natural gas be heading for a super cycle?

At Hart Energy's DUG East conference in December, the future of natural gas prices was dissected, extrapolated, guessed at and some speakers even suggested that the whims of the weather gods could be a deciding factor.

Chris Kalnin, CEO of BKV Corp., took a more pragmatic approach, one that his company

Global Energy Investment US$B



Source: IEA World Outlook 2021

has used as it has made a number of gas-focused acquisitions—first in the Marcellus Shale and more recently in the Barnett Shale.

Kalnin said even basic price indicators suggest natural gas prices will fall between $3/MMcf and $4/MMcf of natural gas. Lower 48 natural gas storage levels are about 90 Bcf below the five-year average, according to data from the Energy Information Administration.

But he also mused that an energy price super cycle could be in the works due to population growth, energy demand and underinvestment.

Kalnin noted, for instance, that years of low energy investments simply haven't kept up with demand. In 2014, global fossil fuel investment was roughly $1.4 trillion. In 2021, the International Energy Agency (IEA) estimated it was roughly $795 billion, up slightly from 2020.

But all forms of energy investment have lagged while even renewable energy has remained essentially flat.

Kalnin said that systemic underinvestment will have consequences.

"When you invest less in producing energy and your energy demand is growing ... you're going to have a price response," he said.

Increasing demand is a reality of population growth as the planet heads toward supporting 10 billion people in the next 30 years. IEA's global energy demand shows a sharp increase in expected power needs between now and 2040.

As a matter of first principles, the world's population is a primary driver in energy needs.

"Between more people, more mouths to feed, there is more energy consumption," he said.

With those factors alone, Kalnin wonders if a new super cycle of demand will appear and noted that both Henry Hub and WTI prices have spiked in the past 12 months as the world resumes normal working order during the pandemic.

"The question I ask is 'are we entering a new super cycle?' And what I meant by that is you look over the last sort of five, 10 years, the unconventional boom has led to, at least in the U.S., a very comfortable situation from the supply perspective," he said. "Are we now in a period of time where because we're underinvesting in energy, energy's going be tougher to come by? And it's going to cost more?"

For natural gas, Kalnin sees a robust future for prices, though with caveats.

First, E&Ps face an uphill battle as some investors consider the oil and gas sector as a profitable "sunset industry" with a limited shelf life, he said.

Publicly traded oil and gas companies have seen their values steadily tick up since December 2020, but despite now throwing off cash returns to investors they lag behind other sectors—even those "green" companies that may not produce revenue or income.

And he also said the most direct way to predict natural gas prices is to look at the way in which E&Ps spend money in the coming months.

Even demand doesn't matter from a pricing perspective, he said.

"What really matters is how E&P companies redeploy their money. That is the single biggest factor," he said, noting that the nation is only capable of supporting so much natural gas through LNG.

"The key to watch is the reinvestment rates. This will tell you where you're going to end up," he said. "If everybody loses self-control and puts all their money back into the ground we are going to see crash prices again.

"However, if we're all hanging around the party, not rushing the buffet and just put about half of the money back into the ground, things are going to be really good."

—Darren Barbee

Here's why US shale producers could face tighter margins in 2022

As a result of rising oil prices and lower costs, North America's oil and gas companies generated a generous surplus of cash in 2021. A closer look at 28 North American shale-focused oil and gas producers shows almost $40 billion reported in revenues during the first three quarters of the year—the highest level since 2014.

However, three converging trends could tighten margins of shale producers in 2022, according to a recent report by the Institute for Energy Economics and Financial Analysis (IEEFA).

The first trend is the depletion of the industry's DUCs. For several years, operators drilled more wells than they completed. But when global oil prices collapsed in 2020, the industry reversed course, completing more wells than it drilled. As a result, the oil and gas industry rapidly depleted the massive DUC inventory it had built up over the preceding years, the IEEFA analysts wrote.

Using DUCs allowed the industry to cut spending on drilling. The U.S. Energy Information Administration (EIA) reported that domestic producers relied on DUCs for a little more than 1,000 newly

completed wells in 2020, and about 2,900 in 2021, saving as much as $10 billion in drilling expenditures over two years.

However, these savings are unlikely to last. The DUC inventory has now reached its lowest level since 2014, according to the IEEFA. The problem is that the industry must always keep some DUCs on hand to schedule their completions efficiently. If drillers want to maintain current levels of production, they may soon have little choice but to increase the pace of drilling, which in turn would mean more drilling rigs in operation and more spending to keep them running.

IEEFA expects some basins to respond to the shrinking DUC inventories sooner than others since DUC inventories vary by region. The Permian Basin, which hosts about half the drilling activity in the U.S. and is also the largest oil-producing region, has slightly less than four months of DUC inventory, or about half its five-year average.

In contrast, the Haynesville's current DUC inventory of seven months is in line with the region's five-year average.

Inflation is also likely to boost capital spending in 2022. Preliminary data show that drilling costs have risen 7% since January 2021. Even if costs remain flat for the coming year, the industry will still face higher capital expenses next year compared to the 2021 average.

"Oilfield service costs tend to keep pace with oil and gas prices, so a rapid decline in oil and gas prices could ease price pressures. Yet falling prices would also crimp revenues, hurting the industry's bottom line," according to IEEFA analysts.

A gradual increase in the pace of well completions may also boost capital costs in 2022. The U.S. oil and gas industry completed an average of 772 wells per month in the first half of 2021, which increased to 868 wells per month from July through November, the EIA reported. As production gradually rebounds, the industry will face higher total costs for bringing new wells into production, further boosting capital spending.

According to the IEEFA, the first two factors—the exhaustion of DUC inventories and inflation—could boost next year's capital costs by 10% without any change in the number of wells completed.

"Costs will rise still higher if the industry continues to complete more wells. If oil and gas prices fall next year, as future markets now predict, the oil and gas industry will be pinched between rising costs and falling revenues, jeopardizing its ability to generate cash in the coming year," the IEEFA analysts said in the report.

Producers kept spending in check even as prices for oil and natural gas rose to their highest level in years. But 2022 could see a reverse trend, with costs rising and energy prices moderating.

—Faiza Rizvi

High Appalachian gas production will stay that way analysts say

Appalachia is producing record levels of natural gas and producers should be able to maintain or grow that output without the significant investment in wells required in past years, Rystad Energy analysts said during Hart Energy's recent DUG East/

Marcellus-Utica Midstream Conference.

Analysts also said they expect total U.S. gas production to return to pre-COVID levels in 2022. The recent plunge in the Henry Hub price of natural gas from well over $5/MMBtu to below $4 can be attributed to milder weather and a winter forecast for warmer-than-usual temperatures for most of the country, according to the National Oceanic and Atmospheric Administration. Whether it's a sunny day or a snowstorm tomorrow, it won't alter the Rystad forecast, though.

"We see around $3 to $4 all the way through 2030, which would be kind of the sweet spot in terms of economic feasibility at the asset level," said Emily McClain, a senior analyst covering the North American gas market for Rystad. "But it also helps to ensure that the U.S. will remain a key contributor and really take on a primary role in the energy supplies in the long run."

That's because the energy transition toward electrification and lower emissions position gas to supplant coal in the power generation fuel mix. In particular, Australia relies on coal for 45% of its electricity generation, while coal makes up 55% of Asia's power generation mix. That creates an opportunity for natural gas, McClain said, and not just domestically produced gas in those regions but imports from North America.

In the U.S., use of natural gas in power generation will increase to remove coal from the picture by 2040. Rystad's analysis has gas peaking in the U.S. power generation mix during the 2030s but continuing to play a critical role by 2050 because projected output from wind and solar will be insufficient to meet domestic electricity demand.

The energy struggles of 2021 have been a harsh reminder of how critical gas is in the energy system, McClain said.

"Depending on the timing of the energy transition and the speed at which this occurs, we could potentially see more energy crises like this," she said. "Europe is a great example of a region that has significant renewable resources in their energy mix. But when push comes to shove, and we come into a situation like this year, you see that crumble."

Rystad sees regions like Europe and Asia needing higher levels of LNG to meet power demand and keep to greenhouse gas emissions targets. Russia and the U.S. producers will compete intensely in those markets, but the U.S. maintains an advantage in supply and Russia will experience a steeper decline curve from the mid-2030s to 2050.

Global LNG demand will likely peak at about 718 metric tonnes per year in the early 2040s, McClain said. At the moment, the LNG market is relatively tight as the U.S. awaits completion of export terminals. It's possible for supply to reach 700 metric tonnes by 2040, but that requires LNG export terminal projects to move forward in a timely fashion, she said.

In terms of production growth, there's Goodrich Petroleum Corp. and everybody else. The Houston-based producer that recently agreed to a merger with

an affiliate of Paloma Resources LLC, issued guidance for a 44% hike in gas production in fourth-quarter 2021 vs. the same time period in 2020.

"Obviously, there's nobody in Appalachia with that same sort of 44% in percentage terms growth as Goodrich has," said Matthew Bernstein, an upstream analyst at Rystad. "They're still running a very aggressive program … but you still see some pretty strong numbers from some of the Appalachian producers and some of the diversified producers," he said, citing Comstock Resources Inc. (19%), Chesapeake Energy Corp. (11%), CNX Resources Corp. (10%) and Southwestern Energy (2%).

Appalachian producers enjoyed a faster seasonal acceleration in the third quarter, which buoyed plans for the fourth quarter. Bernstein pointed to record capital efficiencies, resulting in more gas produced despite the smaller number of wells in production, quarter after quarter.

Productivity hovered around 1 Bcf/d in 2014 to 2016, plateaued at around 2 Bcf/d in 2019, then shot up to the 2.2 Bcf/d to 2.4 Bcf/d range in 2020 and rose again in the first half of 2021.

"So, the question now becomes whether these type curves are sustainable and whether we can continue to see this productivity and still be able to grow, or at least maintain gas output without having to invest in the same amount of wells per quarter of a few years ago," Bernstein said. "And our answer to that is a pretty solid yes."

Well productivity gains have remained at a fairly stable level, he said, but not just because the operators are drilling better acreage. Output from Tier 1 and Tier 2 locations in 2016 to 2017 was lower. "That leads us to believe that this learning curve continues to be extremely steep and that the operators are really realizing these capital efficiency gains," Bernstein said.

That is not to dismiss the takeaway and regulatory constraints of the Northeast region. But even if those hurdles keep Appalachia from growing at the same rate as the Permian or Haynesville, that doesn't diminish the stature of the Marcellus and Utica.

"We still see Appalachia retaining its status as the top producer at a very commercially competitive pace," Bernstein said. "As long as there is commercial inventory, we'll have to drill."

—Joseph Markman

Oil, gas companies face growing pressure to address climate concerns

Amid pressure to go green, institutional investors say having energy transition plans is not enough for oil and gas companies; clarity is needed, targets must be hit and low-carbon ventures must create value, according to analysis of results of Boston Consulting Group's (BCG) latest survey of oil and gas investors.

Near-term optimism was abundant, however, when it came to expectations for robust oil prices. About 70% of the respondents believe Brent will stay above $60/bbl through 2024, up from projections between $40/bbl and $60/bbl in BCG's 2020 survey.

Though companies have no control on the oil or gas price, higher prices help pave the way toward profitability and payout—two things that appease investors, said Rebecca Fitz, senior director for BCG's Center for Energy Impact. A third leg exists, she added, that's aggressiveness in terms of the environment and transparency on long-term strategies.

"The takeaway is profitability and payout are essential, but they're not sufficient if the environmental side or the emissions side of the strategy is not effectively laid out," Fitz told Hart Energy. "There will be skepticism if that third pillar is not effectively addressed in the strategy."

The insight, gleaned from 250 oil and gas institutional investors in October, was shared Jan. 6 as companies continue missions to fight climate change by injecting CO_2 underground, producing and using lower-carbon fuels, eliminating routine flaring or producing renewable energy among other tactics. Many companies, including in the U.S. onshore, are near the beginning of what is expected to be long environmental journeys as the world tries to decarbonize.

About 60% of investors surveyed believe peak oil demand will occur by 2030, driven by climate change concerns and the energy transition. The survey also showed that investors are upbeat on natural gas, with 85% saying it will play a critical role as a bridge fuel between traditional hydrocarbons and renewable energy sources.

In addition, about 70% say they want oil and gas companies to pursue growth in natural gas. That's up from nearly 60% in 2020.

BCG noted the response gives a "clear signal" for continued investment in natural gas.

"We already see the bigger integrated companies leaning heavily into natural gas as an investment driver for the next decade," Fitz said. "I think the low-price environment in 2020-2021 obviously made large investment decisions quite hard to make but strategically, there's already a commitment to really investing along the gas value chain as part of their energy transition approach."

The narrative is different in the U.S., where companies for the most part are either oil-focused or gas-focused, according to Fitz, who doesn't foresee that changing.

"It's more fit for purpose. Either you're an oil pure-play or a gas pure play," she said.

That consistency perhaps shows focus and helps maintain capital discipline, a plus in the eyes of investors.

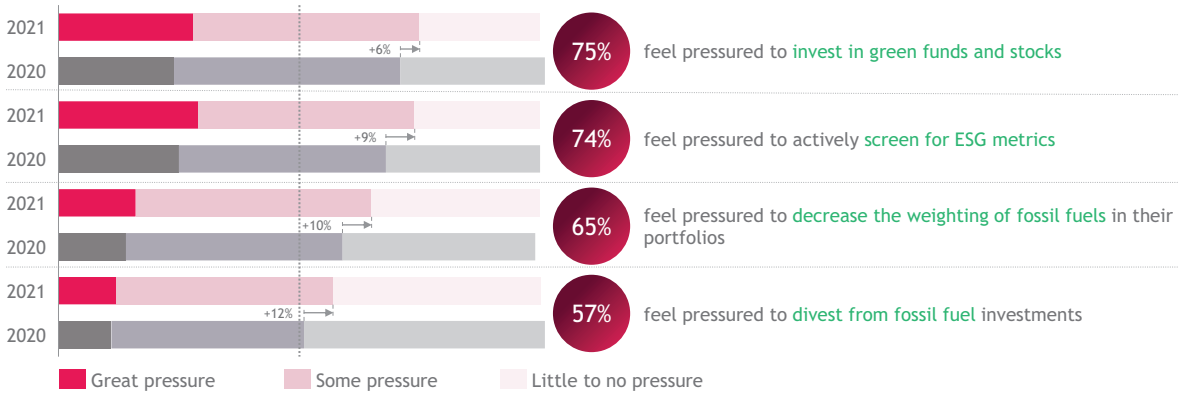
There were some results from the survey that Fitz found interesting or surprising:

Emissions targets: Investors showed strong support for not only Scope 1 and Scope 2 emissions targets but also addressing Scope 3 emissions. Results revealed 81% found Scope 1 targets important; 57%, Scope 2; and 59%, Scope 3.

"That can be a challenge for some; it could be an opportunity also," Fitz said of the latter.

As defined by the U.S. EPA, Scope 3 greenhouse-gas emissions result from activities from assets that the reporting company doesn't own or control but indirectly impacts its value chain. Scope 2 emissions are indirect emissions from sources owned or controlled by the company, while Scope 1 emissions are direct emissions from sources owned or controlled by the company.

Survey Question: Do You Feel Increased Pressure In Your Investment Choices To Pursue Any Of The Following?



Source: Boston Consulting Group

Low-carbon investments: There was a higher level of comfort for investing in renewable electricity and battery storage, which are technologically scaled up industries, Fitz said, noting that makes the investment proposition clearer.

Results showed 80% of investors found renewable electricity value accretive with short- or long-term payouts. The percentage was 72% for battery storage. Less confidence in value add was evident for technologies such as hydrogen, 49%; advanced mobility, 49%; and carbon capture, utilization and storage (CCUS), 37%.

Technological maturity appeared to be the determining factor.

"Renewable power generation, it's scaled. It's understood. You know what you're getting," Fitz said. "CCUS: it's immature. It's been around for a long time, but it's certainly not commercially scaled."

Climate risk and valuations: Of the investors surveyed, only 12% factor climate risk as a critical focus into their valuations of oil and gas companies. This compares to 40% who are beginning to consider factoring climate risk and 27% who factor climate risk but not yet as a critical focus.

"I would imagine when we do it next year, that number grows," Fitz said.

And, of the companies that factor climate risks into their models, 70% said they don't believe they impact valuations.

Many oil and gas companies are in early environmental stewardship conversations with their investors on setting targets. Fitz called that a good start, an essential first step that signals these issues are taken seriously.

BCG works with many E&Ps on setting targets.

"We need to get it to a point where you can benchmark targets across companies and measure progress toward targets and have total transparency about what target means what," Fitz said. "We do this benchmarking, and it's very difficult to actually compare Company A, Company B, Company C. … This is going to be an ongoing discussion where targets get clearer and get more transparent. They get more benchmarkable and investors are going to be part of saying 'yes, I agree' or 'no, I don't agree with that.'"

Survey results showed that about three-quarters of the investors feel pressured to invest in green funds and stocks as well as to actively screen for ESG metrics, while 65% said they feel pressured to decrease the weighting of fossil fuels in their portfolios and 57% pressured to divest from fossil fuel investments.

BCG said most investors acknowledge that oil and gas companies have taken some initial steps to improve their environmental performance, but they want to see results "hitting emissions reduction targets and showing EBITDA growth from companies."

—Velda Addison

Why the energy transition doesn't call for oil, gas divestment

The global push for net-zero emissions has generated several misconceptions about the energy transition, most notably, over whether oil and gas will be exiled by investors, according to finance experts with Citi and J.P. Morgan.

"A lot of folks equate transition with divestment," said Val Smith, chief sustainability officer at Citi, speaking on a panel at the 23rd World Petroleum Congress (WPC) held in December. However, Smith noted that when Citi announced its net-zero commitment last March, the firm was precise with the language it used to oil and gas clients.

"We intend to work relentlessly with our clients to help them transition, and we'll transition together to net zero or lower carbon," she said on the WPC panel that focused on aligning business performance and ESG reporting.

Alongside the continued focus on sustainability that has led many in the oil and gas sector to be more transparent about its ESG efforts, a working relationship with the banking sector will be just as critical as the energy transition unfolds.

"We really need to focus on identifying opportunities to decarbonize, not on divesting… divesting does not really change the math on greenhouse-gas emissions in the atmosphere at all," Smith continued. "Our job is to marry these two intentions, to be really committed to the sector and also the transition. Done right, I think there's an opportunity for all of us."

A report by the U.N. said the world population will reach 9.7 billion people by 2050 and the energy demand is expected to increase significantly over that time period. While renewable energy will account for a bigger piece of the energy mix to meet this demand, the U.S. Energy Information Administration said nearly 50% of the world's energy will come from natural gas and oil in 2040.

"We are going to have a very disruptive transition if divestment

is part of that conversation," Smith said.

"We don't think there's a path to a successful transition that involves firing our clients," echoed Jonathan Cox, global co-head of energy investment banking at J.P. Morgan Securities LLC.

J.P. Morgan has been active through the different eras of energy—onshore vertical drilling, offshore exploration, horizontal drilling and shale.

"I'm going to make a prediction that J.P. Morgan will be lending more money to the energy industry in 10 years … the energy industry won't be limited to oil and gas," Cox said.

Instead of divestment, J.P. Morgan is putting a higher priority on today's transactions to demonstrate its environmental stewardship, according to Cox.

"If we think about energy narrowly in yesterday's or today's definition, then we're denying ourselves the opportunity to evolve, transform and innovate," he said. "Let's not think in today's fishbowl and hold that constant as the world changes around us."

J.P. Morgan's loan portfolio will focus on investing with winners, which Cox defined as businesses that factor in elements of environmental stewardship.

"If good companies, regardless of their carbon intensity, see a motive for their stakeholders to transition and invest in new technologies, then we want to help do that. We want to help finance it and we want to help accelerate it…and I think we will need a lot of people on the boat to do that," he said.

In Europe, green bonds—financial instruments to fund sustainable projects—have become the primary form of climate-focused finance. The issuance of green bonds reached $452.2 billion in 2021, a 46% increase from $270 billion issued in 2020, according to the Climate Bonds Initiative.

Given the pressure placed on attaining sustainability, investors are using green bonds and sustainability-linked loan principles to draw in the oil and gas market. Sustainability-linked loans require the borrower and lender to identify sustainability key performance indicators (KPIs).

KPIs are defined as material to the borrower's core sustainability and business strategy that addresses relevant ESG challenges of the industry sector, and from those, the lender and borrower set and calibrate ambitious and meaningful sustainability performance targets. Once met, the borrower is awarded with a small incremental pricing benefit.

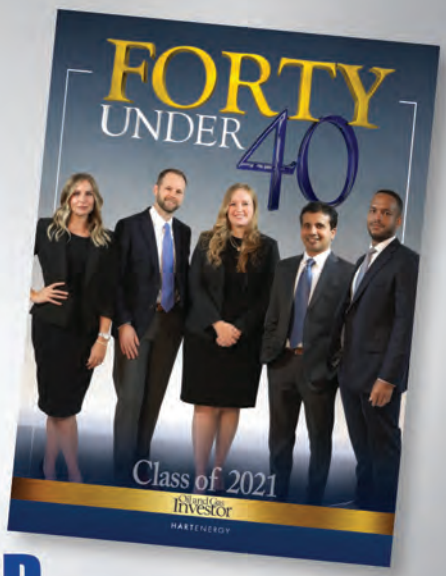
These loans rely on the borrower to be transparent about the company's emissions data.

Finding that less than 30% of Citi's clients report this data, Smith said "data is your friend." She added that disclosures can be used to reflect performance and also drive performance when the information comes back underwhelming.

"Try to get comfortable with the measurement and reporting of your direct emissions data because that is a step forward to begin to disclose and share more information with your financial institutions about where you are today and then that can open up conversations around what things look like tomorrow," she said.

—Mary Holcomb

FORTY UNDER 40



We invite you to NOMINATE those that are
MOVING INDUSTRY FORWARD

Oil and Gas Investor is accepting nominations for the **2022 Forty Under 40 in Energy awards**. We encourage you to nominate yourself or a colleague who exhibits entrepreneurial spirit, creative energy and intellectual skills that set them apart. Nominees can be in E&P, finance, A&D, oilfield service, or midstream. Help us honor exceptional young professionals in oil and gas.

Honorees will be profiled in a special report that ships with the November issue of *Oil and Gas Investor* and on HartEnergy.com.

Nominees should display:

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

Oil and Gas Investor

Deadline for submissions is June 1, 2022

HARTENERGY

'IN THE MONEY' IN OKLAHOMA

Margins are strong in the multi-stream SCOOP, STACK and Merge where operators are dialing up the hydrocarbon weighting they want from any given rig. Yet, any stream—oil, gas, NGL—will make the numbers these days.

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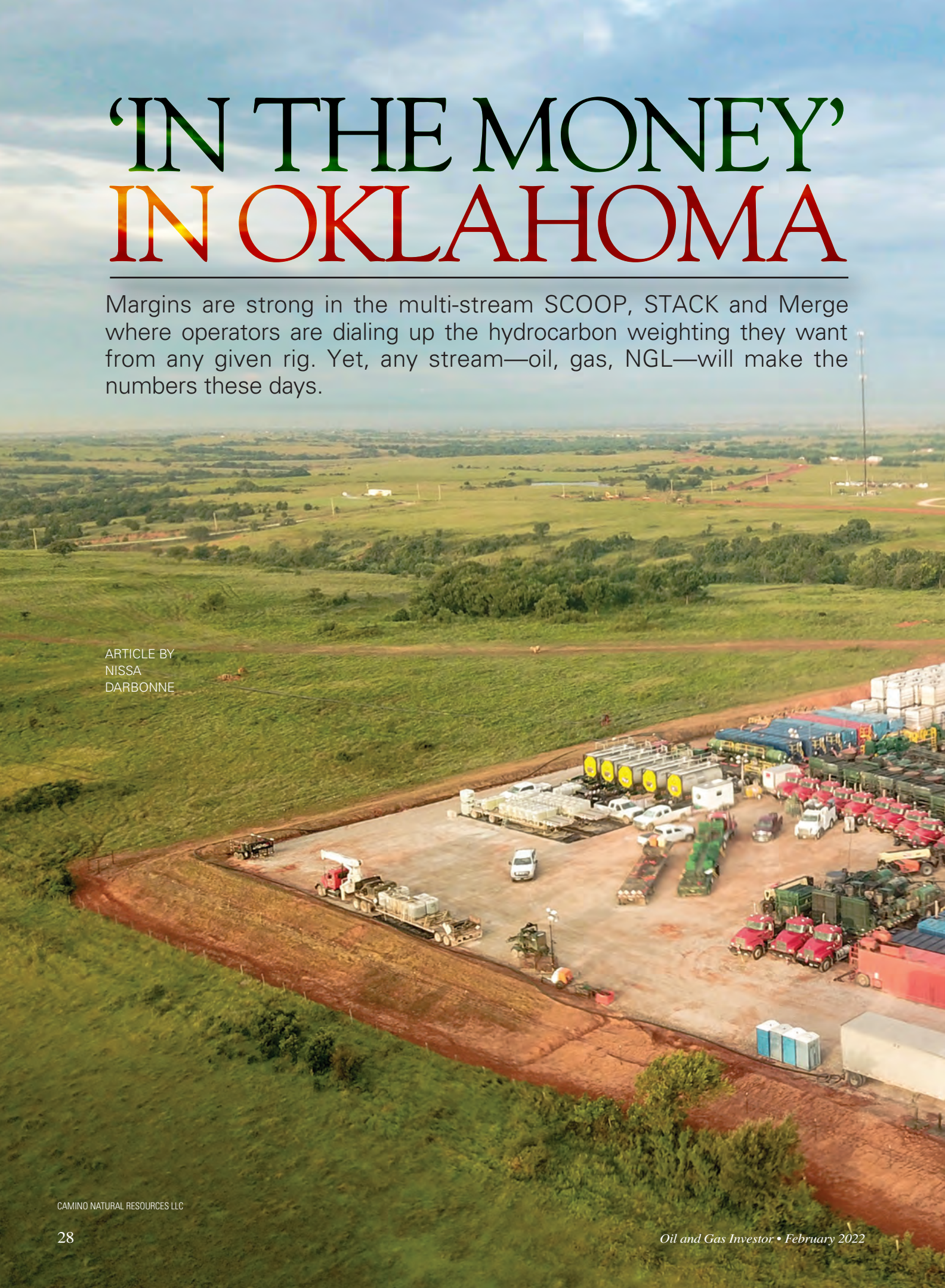


CAMINO NATURAL RESOURCES LLC


Nine

"This basin really works," said Ward Polzin, CEO, Camino Natural Resources LLC.

While 2020 and first-half 2021 were overwhelmingly challenging for oil and gas producers, it had been difficult even in 2019 for Oklahoma producers.

Many rely on decent—at least—natural gas and NGL prices in addition to a decent oil price.

Exiting 2020 and into 2021, natural gas and NGL prices became better than decent, though. Some 60 rigs were drilling in the Anadarko Basin this past December, up from about 23 as 2021 began and about 40 pre-COVID, according to Enverus' count.

The Anadarko Basin and the Haynesville play (also 60) were the only two in the Lower 48 to post a higher rig count exiting 2021 than pre-COVID.

In the Midcontinent's hot spot—the SCOOP/STACK/Merge fairway—there had been as few as about nine rigs at work at the bottom, said Ward Polzin, CEO, Camino Natural Resources LLC. "So we've dramatically improved."

Denver-based Camino was among the few producers who continued to drill. It has three rigs at work; Citizen Energy III LLC has four. Polzin said, "We're the two largest [Oklahoma] privates and doing more out there than many of the largest operators other than Continental [Resources Inc.]."

As major SCOOP/STACK/Merge-driven M&A for leasehold has settled in the past half-decade, remaining operators are harvesting their minerals somewhat quietly. The late 2010s produced a slew of bankruptcies as the eastern reach of the STACK play didn't pan out.

Tim Helms, CFO of Tulsa-based Citizen Energy III, said, "Where people have painted Oklahoma with a broad brush from past poor-performing companies in the basin, there's a lot to be said about the successes we and others have had both technically and financially here, and the business case for continued investment in the region.

"The asset is a great one and one that, in the right hands, can generate a great profit."

Over at Camino, Polzin said, "Everybody's happy. We get the growth, do it all within cash flow and dividend back to our owners."

Camino paid $90 million to private equity partner NGP's investors in 2021. "We're not taking new equity, we're not taking new debt, we can grow production at 10% a year with [our] three rigs, still keep debt below 1.0x EBITDA and still dividend significant money back to NGP," Polzin said.

"This basin really works."

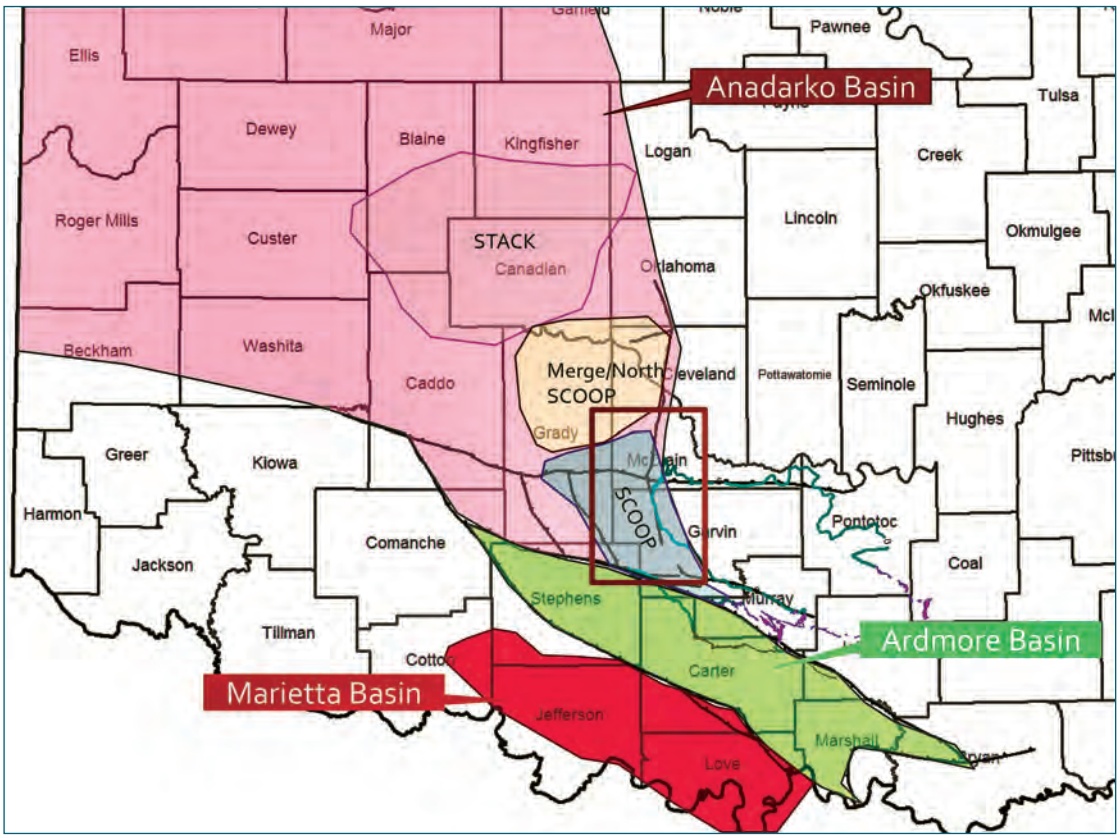
What's driving it?

The commodity mix in the Anadarko Basin can be 1:1:1 oil, gas and NGL. While the gas content drives greater oil recovery, basin economics need strong prices.

A perception about the basin has been, "That place is too gassy," Polzin said. "But you get more gas because we have a lot more pressure in the system and, therefore, a lot more productivity from the wells."

It's a lower oil content than, say, the Permian Basin, "for sure. But, on an absolute basis, during a well's first year, we get about 85% of the oil out than a Midland well gets out. And we get five times the gas."

The NGL composite price—natural gasoline, isobutane, butane, propane, ethane—was about $12/MMBtu in early 2014 as the SCOOP, STACK and other new Oklahoma plays were appearing, according to Energy



Source: Casillas Petroleum Corp.

Overleaf, a zipper frac is underway at Camino Natural Resources LLC's John Phillips 0905 31-6-1MXH and Robbers Cave 0905 31-30-1WXH wells in the Merge in Grady County, Okla.

Facing page, a stand of pipe at Camino's Kimber 0707 17-20-1MHR well in the SCOOP in Grady County, Okla.

CAMINO NATURAL RESOURCES LLC

MARIETTA BASIN

Drilling continues in the Marietta Basin, primarily by Exxon Mobil Corp. unit XTO Energy Inc.

The major reported this past spring that its Marietta-Woodford, Ardmore and Arkoma basins' holdings produce 26,000 bbl/d of liquids and 178 MMcf/d net. Working interest ranges from 70% to 80% on its more than 300,000 net acres.

It had one rig drilling the Marietta Basin at year-end. Another operator, Trailhead Exploration LLC, was drilling as well.

Seth Urruty, president of Oklahoma operator Camino Natural Resources LLC, said XTO continued drilling the Marietta through the pandemic. "It's a fascinating basin. It's similar to the Ardmore position [Camino has]. It's not as vast in areal extent and depositional extent. It's relatively localized."

XTO dominates in the deep core where there is significant overpressuring. "So they're expensive wells, a lot of long days drilling," Urruty said. Total vertical depth can be more than 15,000 ft, but the production is robust.

"It's an interesting area. But for Camino it's a bit challenging in terms of competing for capital for now."

Information Administration (EIA) data.

Propane at Mont Belvieu on the Texas coast, for example, was about $1.60 a gallon.

But the NGL composite fell to less than $4 two years later, according to EIA data, while crude oil also plummeted.

NGL rebounded to about $11 in mid-2018 and began tumbling again to about $4 pre-COVID. Crude oil was still more than $50 at the time. But, depending on where an Oklahoma well is producing, oil might be only a third of production.

By April of 2020, NGL was less than $3. Natural gas was less than $2. Propane was less than 25 cents—a low not seen since before this century, according to the EIA.

In late 2020, NGL began to rebound, finding more than $10 by this past fall and settling in there into year-end.

A 1,500 bbl/d NGL well

Camino was formed to focus on Oklahoma with a first acquisition in 2017. Seth Urruty, president, said, "The previous high mark was at the end of 2018. We were in a kind of downward realized price market all through 2019, all through 2020."

Camino has leasehold throughout the central Oklahoma fairway for the SCOOP, STACK and Merge. It's focusing one of its rigs currently on the far southern end in what's being called "South SCOOP."

The gas is 1,200 Btu to 1,400 Btu. "When we're looking at $3 natural gas, we're thrilled to death, quite frankly," Polzin said. "And then $4 and $5 gas is just kind of off the charts."

Urruty said a $1 bump in natural gas and a $5 to $8 bump in NGL, makes margins "double, triple, quadruple quickly from how low we were."

Camino is getting between $35 and $40 for its NGL per barrel now. "Most of our wells IP at 1,000 to 1,500 barrels in NGL per day. So it's a huge contribution."

For natural gas, a Camino well may come in with between 2 MMcf and 20 MMcf a day. A typical well is 6 million to 8 million a day. The eastern side of its leasehold is oiler; the western, gassier.

The wellhead yield is typically between 150 bbl and 200 bbl per MMcf of NGL. "It's a real positive and unique to this play at these depths and pressures. The NGL yields are really high," Urruty said.

"We have some wells with initial flowback of over 2,000 barrels. It's a really unique high-pressure rate with substantial NGL production."

'They make hole'

Citizen Energy's assets are entirely in Oklahoma as well—some 240,000 net acres, about 97% HBP, producing some 70,000 boe/d.

CAMINO NATURAL RESOURCES LLC

Drillpipe for Camino's Cora Mae 0506 10-15-1MH in the SCOOP in Grady County, Okla.

RYAN EUSTACE, CAMINO DRILLING CONSULTANT

The sun sets as the Cactus 145 drills Camino's Toby Keith 1108 #7-18-1MXH well in Canadian County, Okla., in early January.

"We're Anadarko Basin specialists, if you will," Helms said. "We've got a lot of years of expertise operating in this area.

"We're not against going to other areas, but this is where we've had a lot of success."

Backed by Warburg Pincus, its focus is primarily in the Merge at the intersection of the Stack north and the Scoop south, assembled largely by privately held Citizen Energy II. That iteration merged its assets with those of Linn Energy LLC to form publicly held Roan Resources LLC in 2017. The Citizen team bought Roan out in 2019 and took it private as Citizen Energy III.

Of its four rigs at year-end, three were at work in the Merge; one, in the STACK. At the time, it wasn't drilling in its SCOOP leasehold.

Revenue is about a third gas, third NGL, third oil, Helms said. So higher natural gas and NGL prices "help, for certain."

Having leasehold throughout central Oklahoma, "we do like the diversity we have that gives a lot of flexibility to move rigs to the location that best suits the conditions at the time—whether it be prevailing prices for gas versus oil or vice versa."

For Citizen, moving a rig northeast that's updip will get it more oil; south and west, more gas. "We span the gamut of phase windows from dry gas on our far western flank, as you get to the deepest depth of our position, all the way up to a pretty heavy oil concentration on the other side of the play."

The company minds that it isn't pushing the envelope far. "I would say we're probably not the most exciting from a new technology standpoint. We stay with the tried and true," Helms said.

As it's worked the region for more than a decade now, "we've optimized frack design and we've optimized landing zones, etc., to minimize cost and improve productivity and hit that inflection point as best we see fit."

Cost control has resulted in sustained, continuous activity in the basin by putting fewer dollars at risk for any given well, he said.

"A lot of the technologies that we see out there may work great in other areas. We've got rigs that aren't the newest and shiniest, but they make hole," he said. "And the dayrate is very competitive."

The team is seeing higher steel prices in the field. But dayrates haven't escalated as much yet, he said.

Adding midstream

Citizen looks at adding leasehold "as it makes sense. We've done a few different acquisitions over the years."

In Oklahoma, "competitors" for leasehold are "actually really great partners. We work with each other pretty effectively in trading in and out of acreage to improve our own net interest and vice versa."

Still, "we win some and lose some." But Citizen sticks to its valuation. "I think we won't ever get out of our skis from paying for acreage," Helms said.

Meanwhile, though, "we do have about a decade's worth of inventory at our four-rig cadence. So there's no need for us to [buy]."

Something it did purchase in 2020 was one of its primary midstream providers, Blue Mountain Midstream LLC, giving Citizen an integrated system, including gas-gathering and -processing infrastructure.

"We're not against going to other areas, but this is where we've had a lot of success," said Tim Helms, CFO of Citizen Energy III.

McGIRT

The U.S. Supreme Court declined in November to reconsider its 2020 decision in the case of *McGirt vs. Oklahoma*. In that, the court ruled that most of the eastern half of Oklahoma is ruled by the state's tribes.

Oklahoma Gov. Kevin Stitt had requested reconsideration at the recommendation of his Commission on Cooperative Sovereignty, chaired by Devon Energy Corp. co-founder Larry Nichols and including Continental Resources Inc. founder Harold Hamm and The Williams Cos. president and CEO Alan Armstrong.

In 2020, the Oklahoma Corporation Commission ordered that it reigns over oil and gas activities on the Five Tribes' land.

Tim Helms, CFO of Tulsa-based producer Citizen Energy III LLC, told *Oil and Gas Investor* that Citizen's properties aren't within the disputed area. "But, certainly, there are ramifications for" others.

"It hasn't directly affected us. But it's something we're obviously keeping a close eye on."

Meanwhile, the governor's brother, Keith, has filed suit that a speeding ticket he received can't be heard by the Tulsa municipal court, citing the McGirt ruling, according to Tulsa World.

The Stitt brothers are members of the Cherokee Nation, having at least one ancestor who was a tribe member. Keith Stitt's attorney, meanwhile, is a member of the Pawnee Nation.

Cherokee Nation Attorney General Sara Hill told Tulsa World in January of sorting out the go-forward plan, "I hope we're at the acceptance phase of the process."

"The SCOOP/STACK/Merge is a combo play—oil, gas, NGL. It's not all oil, and it's not all gas. It's a little bit of everything," said Seth Urruty, president, Camino Natural Resources LLC.

"That's really improved our operating margins as well."

Camino has taken a stake in its midstream partner too, Iron Horse Midstream, which has a 225 MMcf/d plant in the middle of the SCOOP/STACK/Merge in Grady County and more than 250 miles of gathering.

Urruty said, "That gives us a lot of see-through into how our residue gas is marketed. And we have a lot of input and collaboration on what we're doing on the NGL side.

"That's allowed us to gain access to markets that we thought were going to be favorable and, it turns out, have been *more than* favorable."

Upstream, Camino took in a central Delaware Basin operation that had been held by Luxe Energy LLC, another member of the NGP portfolio, in 2020. Luxe was sold in 2021 to Colgate Energy Partners III LLC, which is part of the Pearl Energy Investments and NGP portfolios, for equity.

In Oklahoma, Camino took in NGP member 89 Energy II LLC.

Camino's founding assets were purchases of Ward Petroleum Corp.'s SCOOP position and Chesapeake Energy Corp.'s Merge position, as well as those of NGP portfolio companies Rebellion Energy II LLC and 89 Energy LLC, both operators in the Merge and SCOOP.

(At press time, Reuters reported Colgate is preparing to file its S-1 to IPO. Luxe co-founder Lance Langford has formed Langford Energy Partners LLC. And Kayne Anderson Energy Funds consolidated three Anadarko Basin portfolio companies into newly formed 89 Energy III LLC.)

'Perception'

Polzin said the challenge for the Anadarko Basin "is just perception." There are three reasons why it's been negative, starting with that several operators went bankrupt. "So markets thought the SCOOP, STACK and Merge must be bad, right?"

But "100% of these bankruptcies were not in the core of the play," he added. They were in what was hoped to be an economic STACK extension north of the core.

"Those areas up there are not as core," Polzin said. "And why are they not core? They have lower pressure and they have thinner source rock. You just don't get the quality of well.

"I think people got misled that those bankruptcies from the noncore were indicative of the core."

Another source of a negative view among generalist investors is that operators were, naturally, looking early on for what number of wells could be put in a drilling spacing unit (DSU) for the best rate of return.

"We the industry assumed we could drill 10 to 16 wells per DSU among the zones. And, just like in every other basin, we the industry assumed too much."

Many pads were overdrilled. Camino and others have determined that DSUs are best with between six and eight wells. With that recipe, "our parent/child relationship is great," Polzin said.

"We're limiting the impact on the parents with these child wells. We just have to space it correctly."

The third source of a poor image is generalist investors' misunderstanding of the benefits of the strong volume of central Oklahoma's solution-gas drive.

"The SCOOP/STACK/Merge is a combo play—oil, gas, NGL. It's not all oil, and it's not all gas. It's a little bit of everything," Urruty said.

And it comes with access to markets—oil to Cushing; NGL to Conway, Kan., and Mont Belvieu; and gas to local markets and west, north and south, all "at a pretty low differential."

"We sell gas to [Gulf Coast LNG] liquefaction companies as well," Urruty said. "Oklahoma's in a really good position in terms of infrastructure that's already built out."

Overall, the past six or more months "have exceeded the highest wellhead realized dollar for wet gas that we've seen. The previous high mark was at the end of 2018."

2,000 bbl/d Ardmore

Camino's net production is some 50,000 boe/d, more than 90% operated, from 90 wells. Its roughly 150,000 net acres are throughout central Oklahoma.

CAMINO NATURAL RESOURCES LLC

A view of springtime from the drilling rig at Camino's Cora Mae 0506 10-15-1MH in the SCOOP in Grady County, Okla.

2022 estimated field-level cash flow is some $450 million. After paying $90 million in dividends in 2021, Camino estimates distributing between $150 million and $200 million this year.

Continuing its three-rig program is expected to grow production between 10% and 15% per year. Camino has more than 20 years of inventory. At $55 oil and $2.75 gas, its top 300 locations in inventory are estimated to bring a roughly 95% IRR; another 700-plus locations would generate more than 20%.

The current leasehold has some 180 DSUs and "a very small number of those are fully developed," Urruty said.

"We have, in my mind, the cleanest fairway of undeveloped acreage in the core and as much remaining inventory on that core fairway as anybody in the basin—public or private."

The leasehold stretches from Blaine and Kingfisher counties down to Love in the Marietta Basin. It had a rig in late 2021 drilling in Canadian and Grady counties in the Anadarko Basin and one at the intersection of Stephens, Garvin and Carter counties in South SCOOP in the Ardmore Basin.

South SCOOP is Continental Resources Inc.'s southern extension of its Springboard project. That far south, the primary operators are just Camino and Continental, each with one rig. Also operating there are Citation Oil & Gas Corp. and Cheyenne Petroleum Co.

Camino has drilled nine wells in the Ardmore to date. The last two that were brought online each averaged 30-day IPs of 2,000 bbl/d. "Not boe," Polzin said. "That's 2,000 barrels of oil."

To date, the wells appear to also have a flatter decline rate.

"The Ardmore's a perfect example where you have a lot of oil and actually a lot less gas. Our GORs [gas-oil ratio] down there are relatively low."

'Dial it in'

In Oklahoma, "you can kind of dial it in," Urruty said, depending on the hydrocarbon that's getting the best price. "It's a little bit of everything in Oklahoma."

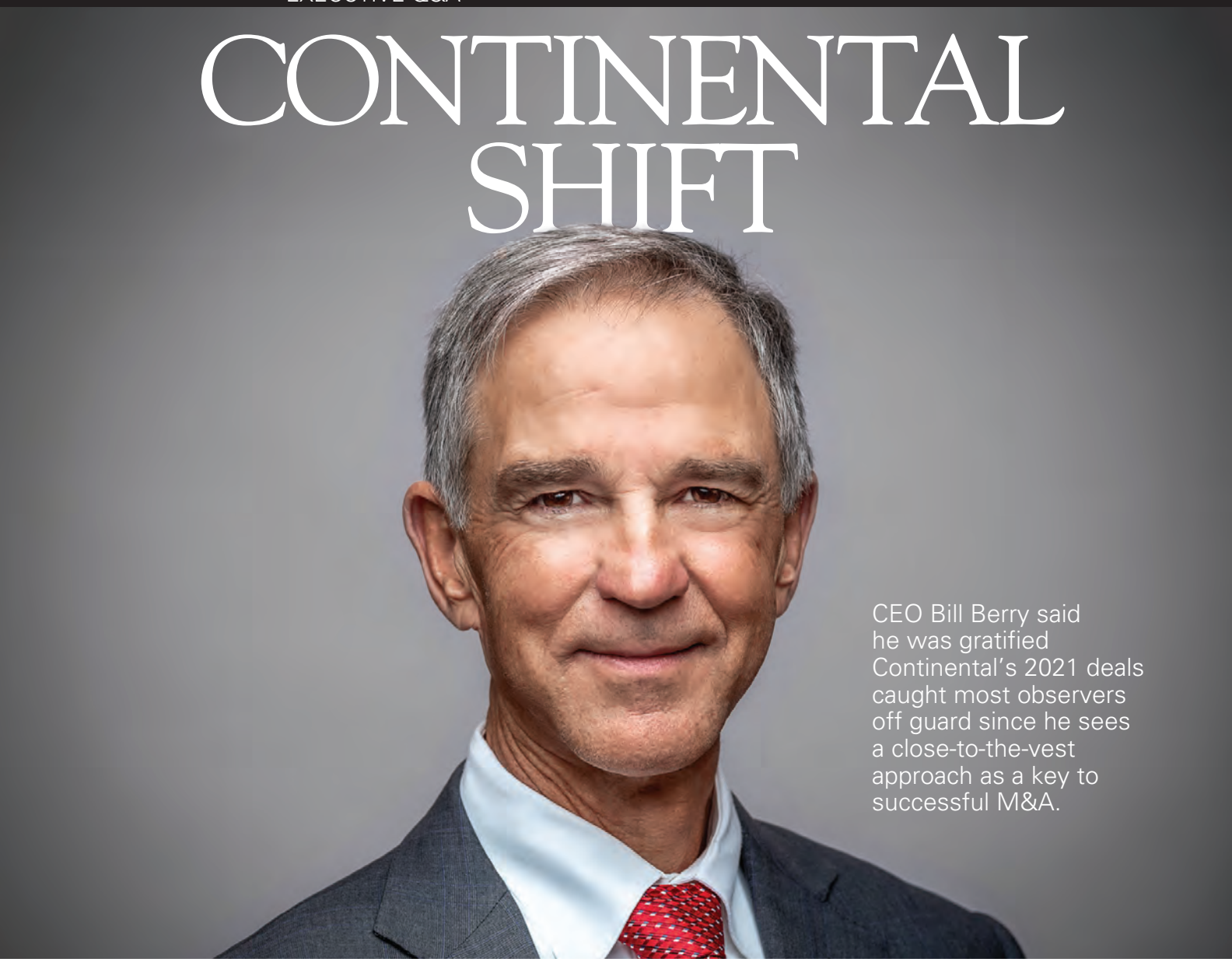
Citizen's Helms said, "Oklahoma has a rich heritage of being a great oil- and gas-producing region. We have seen more than our fair share of people come and go in the basin and not have financial success."

As the state's most active private operator, "I think [Citizen has] a well-established track record of proving that the asset is a great one and one that, in the right hands, can be managed effectively and generate a great profit."

Camino's Polzin added, "Our wells are getting better. Not every well's better than the one before, but the next five are better than the previous five."

Camino has "just kind of quietly turned into a big private company. And life's pretty good." □

CONTINENTAL SHIFT



CEO Bill Berry said he was gratified Continental's 2021 deals caught most observers off guard since he sees a close-to-the-vest approach as a key to successful M&A.

INTERVIEW BY DARREN BARBEE

Continental Resources Inc. has long made a name—and lots of money—as a stalwart of Oklahoma and the Bakken. Then, in a move that surprised many analysts, the company turned unexpectedly to the south, buying up Pioneer Natural Resources Co.'s Delaware Basin assets for $3.2 billion. The company had also recently made acquisitions in the Powder River Basin.

And the company isn't finished. It's prepared to spend in excess of $300 million on additional deals, all while continuing to raise dividends and lower costs.

With some of the dust settled, Oil and Gas Investor *spoke with Continental CEO William Berry about the company's strategy and the rationale for its expansion.*

Darren Barbee: Given how sensitive the markets are to pandemic news and the fact that Wells Fargo recently described you as a 'combo player' with oil and gas production, how do you strategically balance business decisions?

William Berry: It always starts off with what one's company's perspective is on the fundamentals and where you think those are going. At Continental, we've described for the last couple of years that we think there are a couple of things going on. One is that oil supply and demand was not in balance, and that's why in February of 2020 we went out and said that we need to start paring back production growth. We think it's inappropriate to overproduce into an oversupplied market, specifically on the crude side.

If you look back to that time period, there were a lot of folks that were starting to worry that it must be a company inventory issue, the reason these guys are slowing down. A few months later, of course, COVID hit and grabbed everyone's attention, and then we started hearing more people say, "Maybe we should start slowing down."

There was a worldwide crude inventory overhang that was significant. We're talking about approximately 1 billion barrels that were out there. And then there's a production capacity

side, and there was a real significant overhang on that as well. It was probably in the 7 million barrels a day range.

What's happened since February of 2020 is that, that inventory has been gradually worked off, and the pundits are throwing numbers out, Q1, Q2; somewhere in 2022, you're going to see, probably in the first half, that we're starting to see supply and demand balance. That's our expectation on the oil side. I think you're seeing that manifest itself with Biden's comments where he went out and asked OPEC and Russia to increase their production.

As you may have seen, Harold Hamm did an interview where he suggested that Biden could accomplish the same thing by not even having to make those long-distance calls; he could make a local call by just calling us. That's kind of our hope is that the Biden administration realizes, acknowledges and supports the essential role the American petroleum industry plays in underpinning the strength of the United States.

All that to say, I think we're going to see strengthening supply and demand fundamentals through '22 on the oil side.

Now switch to gas, and that's kind of a reflection of what you see with the Wells Fargo combo (oil and gas) company comments. We actually described ourselves that way, and Wells Fargo wrote about us that way. Last year we ended up saying we think that the gas actually was on the other side. It was going to be a little bit tight, and we intentionally shifted the majority of our drilling from oil to gas.

We had a couple rigs running up in the Bakken because even under COVID oil prices, we said we just need to keep up activity, keep the service industry busy, keep it active and keep supporting them as we go out and do a little bit. And so we slowed down considerably in 2020, but we put the marginal additional rig on gas.

It was our expectation that the supply/demand balance in gas was going to be very constructive and supported actually putting more drilling on gas. We did that, and we did see gas prices strengthening. We articulated that through the words of commodity optionality. We really liked that. We continue to like that optionality.

DB: We're seeing in the U.K. speculation of another lockdown there. As you approach 2022, are you feeling like you have to be extremely conservative and very nimble as these things move, or do you rely on a conservative production plan?

WB: I think you would describe it as conservative. We've said, and particularly with respect to crude, that we see no reason for companies to be overproducing into an oversupplied market and no reason to be growing more than low single digits. So 3% to 5% production growth are probably reasonable numbers as

CONTINENTAL RESOURCES INC.

we go into looking at what the world probably could use [this] year. As we all know, with this coronavirus, there is so much ignorance in the world, and that's not a negative statement. It's a statement of fact that we're all learning, the medical profession especially, and so whether your glass is half full or half empty, Omicron is going to be widespread but not as deadly. The good news is that the longer we go, the higher percentage of the world population is vaccinated, the less capability for the virus to mutate because it has less laboratories to mutate in, meaning bodies, and the more people that catch it through natural immunity that this thing hopefully will temper itself.

As we have said, hope is not a strategy. So, you do have to plan that it could go the other way. The word you used is the word we often describe ourselves with: nimble. We have a very nimble organization. It's a function of the, if you will, secret sauce of how we run our business and also the function of our ownership structure that we can make quick decisions and move on a dime as we see opportunities present themselves.

DB: Continental has made some interesting deals lately. I am curious what made the company decide it was the right time to step out with the acquisitions you made, both with the Powder River Basin acquisition and the much larger Permian deal.

WB: I'd probably start at the high level and say that we view it as a positive and maybe even as a compliment that this was a surprise to the market. When you talk about M&A or A&D, the way to be successful in that is to be confident in how you're approaching things. If companies go out there with a well-described M&A or A&D strategy, quite often it's difficult to execute.

We are foundationally built on strong exploration and geologic skills and subsurface capability, and we've got a really good understanding of the basins we're in and basins we're not in. I know when we bought the Samson acreages (in the Powder River Basin), we did hear from folks asking why we were entering a new basin, and then again when we made the move into the Permian.

And so just to put it into context our first transaction that we looked at in the Permian, we almost completed, was at the turn of the century, so over 20 years ago. When you think of the Permian Basin, most people don't think of Continental Resources. We actually came really, really close back around 2000 to putting a deal together.

Geologically, we studied it, understood it, and as you know, the case for any type of activity around the country is having a good understanding of the rocks, and this team has a really, really good understanding of the rocks.

The definition of success is when opportunity meets capability, and we feel both in the Powder and the Permian that probably describes us. We had this opportunity meeting our capability, and we're really comfortable that they're going to be good successes for the company.

"We are foundationally built on strong exploration and geologic skills and subsurface capability, and we've got a really good understanding of the basins we're in and basins we're not in."

The other benefit is that there was a little bit of, if you will, an indication of what we were looking at in probably Q1, Q2 of 2020, maybe Q3 also. My comments on the earnings call was we'd be interested in a third leg of the stool, and so looking for other opportunities.

Part of that is because the only way you can manage political risk is through diversification and, of course, everybody saw what was going on with [Dakota Access Pipeline] and the issues there. By having geographic diversification and geological diversification and commodity diversification, that provides you with optionality. We strongly believe that's a strength, that's something that we subscribe to, and I think that's a little bit of what you're seeing with our activities.

DB: Should these acquisitions tell us anything about the Bakken?

WB: The question that's begged is what do these acquisitions mean for the Bakken? A couple of things just for some data points to help put it in perspective, for probably the last couple of years, we've gone out, again we mentioned this on our earnings call, and Jack Stark, our president, has done a really good job on describing them to the market. He said that we have an inventory, and this would just be the Bakken and Oklahoma, that's adequate to grow this company 5% per year for the next 10 years and still have significant inventory left over.

There's not an inventory issue with the existing assets we have. If you look at probably the best reflection of inventory and inventory capability is the drilling activity, and in the Bakken right now we've got nine rigs running. We're three times the activity of our next closest competitor up there.

So there's still a lot of good inventory in the Bakken, and it's still a key part. The other attribute, and I'll call it enabler if you will, is the reason we were able to do things like going into the Powder and into the Permian is because of the strong cash flow generating capabilities of the Bakken and Oklahoma. Oklahoma is also a pretty significant driver of this company. We're the No.1 producer in each of those locations.

DB: We saw a lot of Permian transactions in 2020 where the buyer didn't ascribe much value to the undeveloped reserves. Here, I think we saw some upside ascribed to that. As you worked through this deal, did you evaluate it from an inventory perspective or cash flow, repeatability, inventory? Whatever metrics were important to you?

WB: Yeah. A little bit of scene setting. We actually in advance of this had identified this

"We are foundationally built on strong exploration and geologic skills and subsurface capability, and we've got a really good understanding of the basins we're in and basins we're not in."

area geologically as something that, again, is the definition of success where we think that if an opportunity presents itself, matching up with our capabilities, which we thought were transferable from an operational basis and geological basis. This is a deep oily area. It's one that's hand-in-glove with the things we've demonstrated with our capabilities in the Oklahoma area.

We have a strong desire to have assets where we have the ability to drive the performance. This is 98% operated area. It's 90% held by production. As you know, it's got 50,000 acres of royalties, which drives your NRI [net revenue interest] up to about 80%. It's also got surface acreage and good, extensive water infrastructure. All those together pretty much describe our other assets, if you look at where we are in North Dakota, you look at Oklahoma, we have really strong water assets, which drives your operating cost because you're in control and you're able to make sure you're operating at maximum efficiency.

We've got relatively good NRIs but, again, it's in a significant working interest and a significant operator lead position. All that really fits hand-in-glove with where we are. Then it all starts and ends with the rocks. We like the rocks.

DB: Pioneer Resources CEO Scott Sheffield has made it clear his preference is to be the Midland Basin. Did you get a sense of how they viewed the asset during negotiations?
WB: I'm not sure what drove Pioneer's perspective on deciding to sell this really good asset. We're seeing this year all over the world, people sometimes have different needs for different reasons versus cash, versus geological perspective, and we've all seen over and over again, if you want different geology, get a different geologist. That's kind of how the world works.

I remember early in my career, we were exploring in Norway, and this is when everybody said there's no oil and gas in Norway's offshore continental shelf. Sure enough, folks came in and had the first discovery in 1969. As you'll recall, when Harold [Hamm] went up to the Bakken, there was a lot of discussion about there is no way you can produce oil from shale and, fortunately, Harold didn't read that book, and said, "Well, let's go figure it out."

Like I said, this is a company that's always been based on strong geologic capabilities. You see it today. I've had a chance to work with a lot of companies, either working for or with through my 40-plus-year career, and the subsurface team here is as good as any in the industry.

DB: Continental has also discussed spending perhaps $350 million to $375 million in other deals, and some analysts have said they were confused or unclear what your strategy was for M&A. Is there something that needs to be clarified? What is the strategy that you guys are looking at? Are you looking to block up additional areas in these two acquisition areas or even in the Bakken?
WB: There's some clarity and some lack of clarity that is probably beneficial in answering that. The clarity is that there's a strategy. The strategy part that we have articulated is we're in some areas where we're the No. 1 producer in Oklahoma [and] the No. 1 producer in North Dakota. We think that brings strength to us [and] capability to us because we're transferring operating efficiencies across the basin. Clearly that's something that we focus on to have that kind of materiality. A strategy of materiality is definitely key, and you'll see that manifest itself in how we do our business.

The other strategy is that, again, we're real subsurface focused, and so there probably will be things we do that from an asset basis may surprise people. We may build some acreage positions before we come out with a declaration of those positions, people will say, "Oh, we didn't know they were doing that" and, "What are they doing?"

But you pretty much have to do it that way in this business. Like I said, if you show all your cards, you're at a competitive disadvantage, and we're pretty good about keeping close to our vest or at least we try to.

DB: On the Samson deal, which you've closed, are you already seeing the fruits of that acquisition? How is that progressing?
WB: I'm going to probably just share with you that what we've seen so far is meeting our expectations. We have actually closed on a follow-up transaction there. We now have approximately 215,000 acres that we've ended up with in the Powder River.

DB: How do you view the results there so far?
WB: The Powder is in early innings. People are still trying to understand it. Again, for competitive reasons, I think the best way to describe our thoughts on this is that it's consistent with our expectations.

DB: You already mentioned your inventory in the Bakken and Anadarko Basin. You've reported consistently lower operating costs and an increase in shareholder dividends. What is the main way you have been able to squeeze more production out of fewer dollars?
WB: I'll share with you a conversation I had with Harold when I first joined the board about seven years ago and started looking at the company. I told Harold that he had created something really special here. It's a culture that is a combination of very, very strong cost stewardship and caring. Putting both of those in one package is pretty rare in a company. You get companies that care a lot, and they're not real frugal. We get companies that are real frugal that don't manifest that they really care about their employees.

He has just really created something special here. It's unique. That frugality and, again, it starts with the founder and that's kind of how it was built, "Hey, this is something that we're going to look at every penny." You know, a penny on our lease operating cost per barrel, that's a million dollars. That's a lot of money. What you

have when you have a culture like that, people are proud of it [and say], "Hey, look what I did to be frugal, look what I did to be frugal."

Once you have that culture, it's easy to perpetuate. I've been associated with companies that have the opposite culture. It's hard to change. A lot of that is frugality and capability. There's a really, really strong technical team here that runs the operations, and they're looking for every single thing they can do. That said, it starts and ends with safety and keeping people safe. We're really pleased with the safety performance that we've actually been able to deliver. We set a record last year. Knock on wood, we're on pace to set an additional record this year.

DB: You recently announced your third consecutive quarter of the dividend going up. Do you see that continuing?

WB: This company is more aligned with its shareholders than any other company in the industry. We've got four of the Top 20 owners that work for this company. We focus every day as much as anyone on what is the right way to steward this company for the benefit of our shareholders, and shareholder return is a big part of that.

As you look at what's out there, philosophically, we've described we want to be competitive on the fixed dividend side of things. The share buyback is a big part of it. We had a billion-dollar program that was put in place a few years ago by the board, and we still have about $600 million to go on that. We think share buybacks are a very appropriate vehicle.

There are other things, the arrows in the quiver, so to speak, that could be used and all of those are on the table. We talk and discuss those all the time. The capability of the company to be able to deliver that dividend, I think that's where you're really focusing the question is, the sustainability of it. We introduced it, and then we had to pause it during COVID. That was a lot of the angst on our part going through that as to whether that was the right thing to do. But our philosophy on dividends, and most companies are this way, is that you put in a fixed dividend, you want it to be sustainable, and that's where we are. Sustainable and competitive is our approach to dividend and shareholder return.

You've seen us talk about reinvestment rates of 65%, 75%. I mean, that's a mid-cycle number, and we're well, well below that with where we are with the commodity prices right now.

DB: How does that tie into what the company is doing regarding ESG?

WB: We've been trying to do the things that I think everybody in the industry is trying to do the right things on and from an ESG perspective. We've actually reduced our methane emissions since 2016 by 59%. So a lot of companies are out there talking about reducing by 50% by 2025, 2030. We're already there, and we're looking at taking it further.

In both the major basins that we operate, so Oklahoma and North Dakota, we're the No. 1 gas capture company and continue to try to look for ways to do that. We wholeheartedly do not subscribe to routine flaring. All that comes into perspective. For example, this year, we have basically deferred $40 million worth of production—and this is oil and gas production—that could have been produced, but it didn't meet our operational threshold for ESG. So in other words, we could have produced it within regulatory footprints that were out there, but we would have had excess flaring that did not meet our standards, so we deferred that production and revenue.

It's real dollars that we're putting into not only spending but also revenue deferral to make sure that we're not in excess of a flaring "goal."

We were honored to be recognized by Hart Energy this year with the Energy ESG Top Performer Award. We appreciate you recognizing the efforts companies like ours are taking to be leaders in this space.

DB: ESG is top of mind for the industry, but there's also been a lot of discussion regarding carbon capture. Is that something that you're looking at?

WB: Yeah. If you're in the methane business world, you really are in the electron business and in an electron world, you need to understand what your competition is, meaning all the types of ways to generate electricity. And if you're in the methane world, you have to look at your waste byproduct, and that's CO_2.

I'm ecstatic that the industry is doing a robust and thorough review/analysis, actually activity, to see some things going on in the space of carbon capture. Yes, we look at it and consider it every day as to what's the right vehicle, what's the right approach for us and the industry.

I do believe that carbon capture is going to be an essential and integral part of the energy future for the petroleum industry. □

CONTINENTAL RESOURCES INC.

ENERGY CAPITAL: WHERE'S THE MONEY?

The energy capital landscape is changing, and providers are becoming more selective about which companies to support, but opportunities remain.

ARTICLE BY
ANNA KACHKOVA

"We destroyed so much capital over the last six years, so investors have become disenchanted, to say the least, with oil companies," said Haynes and Boone LLP partner Buddy Clark.

The energy capital landscape is in a state of flux, with further volatility expected in oil and gas markets as the world continues to deal with the fallout from the COVID-19 pandemic. Meanwhile, the rise of ESG priorities poses ongoing risks that look set to continue constraining capital availability.

Haynes and Boone LLP partner Buddy Clark said public companies in particular are facing more constraints.

"We destroyed so much capital over the last six years, so investors have become disenchanted, to say the least, with oil companies," he said.

This disenchantment is playing out in various ways. Kyle Kafka, a partner at private equity firm EnCap Investments LP, said that while the high-yield market has remained fairly consistent for E&Ps, the equity market has "significantly" shrunk.

"The cumulative amount of money raised in the equity markets for E&P since 2018 is less than the total amount of money raised in 2017 alone and less than a fifth of what was raised in 2016," he said. "You're seeing this shrink take place in both the lesser amounts of follow-on offerings as well as the lack of IPOs in the last few years."

Stephen Trauber, a vice chairman and co-global head of natural resources and clean energy transition at investment bank Citi, sees the energy capital landscape as being "in the early stages of some significant changes." The cost of capital is rising, while the availability of both debt and equity capital is becoming much scarcer than it has been over the past decade, he said.

Nonetheless, various sources of capital for public and private E&P players alike will still be needed, and the appetite to help fund U.S. oil and gas production could bounce back if energy demand continues to grow as is expected. That said, providers of capital for both public and private producers are becoming more selective about which companies to support, and some E&P firms stand to do better than others as a result.

Shrinking role

Recently the pool of energy capital sources has been shrinking across the board. This includes banks—traditionally a major source of capital for the E&P sector—on both the commercial and investment side. Clark estimates that at least two dozen banks were actively building a book of energy loans around five years ago but that this has since shrunk to around a dozen today, of which only half are still actively seeking to increase their book.

"The energy industry is adjusting to the reality of an energy lending bank market with less capacity as a result of several banks exiting the energy lending market over the last few years," said Bryan Chapman, the market president of energy lending at Iberiabank. Some banks already exited in 2018 to 2019, but following the 2020 collapse in oil prices, banks "experienced unprecedented losses on energy loans due to the need to restructure balance sheets in a market where secondary/tertiary sources of repayment were not functioning as they did in prior downturns," Chapman added.

Even as oil prices strengthened steadily over most of 2021, many U.S. E&P companies insisted on maintaining a cautious approach, part of which entailed keeping their spending within cash flow.

"The trend/focus on spending within cash flow has a few implications for investment banks," said Trauber. "First and foremost, it means that there will be less capital required by the upstream companies and therefore makes it much more challenging for banks to generate returns on the capital provided by the banks. Most banks do not generate adequate returns for their own shareholders based solely on lending. Therefore, banks seek to enhance their returns based on ancillary business such as public equity and/or debt issuance."

What's still needed

Trauber expects this to force more banks out of the sector as upstream becomes a less attractive space for them to lend to. Despite this, though, banks are still needed, and he believes that most of the upstream sector will still require some credit facilities, albeit likely smaller in size than before.

"The sector does remain highly cyclical and unpredictable, and we would not advise companies to solely rely on cash flows," he said. "There will almost always be a need for credit facilities provided by the banks as a backup liquidity line in case of unpredictable events."

Christina Kitchens, principal and managing partner at advisory firm 3P Energy Capital, agreed that while some E&Ps are able to operate within cash flows, most would have additional capital liquidity needs. She said that, ironically, those firms that are likely to be less reliant on outside capital—including the majors and middle-market firms such as Pioneer Natural Resources Co. or EQT Corp.—are those that can most easily access it due to the scale and quality of their assets.

Among other options, upstream operators are likely to keep looking to reserve-based lending (RBL) to meet some of their capital needs. Haynes and Boone's Clark said that when capital was more easily available, E&Ps used RBLs as a "war chest for opportunistic acquisitions" while relying more on second lien and public debt offerings to fund drilling.

"Until those markets come back, the RBL I think will become even more important than it was in 2014 through 2020," Clark said.

Indeed, Chapman said that as the market improved in 2021, a number of companies were able to increase their reserve-based loans. "Loan terms have made a definite shift to be more conservative after March 2020," he added. "Banks are looking to increase resilience and reduce volatility by requiring more hedging, typically 18 to 24 months at a minimum," Chapman said.

"For many firms, there will remain a need for RBLs for liquidity management, but I believe going forward there will be less reliance on RBLs as a primary source of capital for an acquisition financing or for capital-intensive projects (asset growth), as we have seen in recent past," Kitchens said. "RBLs will be a smaller portion of that funding with its structures tightened and less competition and capacity in the banking market."

Private equity pivot

Similar to banks, private equity (PE) firms have remained a significant source of E&P capital but have stepped back somewhat in recent years.

"For the private companies, the market evolved over the last 20 years to where you really don't have true independence; you have portfolio companies that are managed by private equity investors," said Clark. And PE funds also destroyed capital in recent years, causing their investors to want to pull back from oil and gas, he continued.

EnCap's Kafka also sees PE firms pulling back.

"Many of the large generalist PE firms are pivoting out of the E&P space through either a wind down of existing funds or by not seeking to raise any future funds focused on E&P," said Kafka. "Capital from energy-focused PE firms is also shrinking, with some firms winding down and others looking to raise smaller capital amounts. Current upstream private equity dry powder is estimated to be down 50% compared to 2018."

As a result, Kafka believes that the landscape for raising capital will be tight and competitive for private companies as well as public ones. However, he sees certain advantages for those companies that are still able to obtain PE funding, especially when compared with their public counterparts.

"If you have access to capital, you are extremely well-positioned as the competitive landscape has significantly shrunk. There are fewer PE-backed companies than there used to be, and typically with smaller commitments than have seen in previous years," Kafka said. "Public companies are constrained by the need to make any acquisitions be metric-accretive, specifically on free cash flow, and thus are not as focused on growth-oriented acquisitions for cash. This should result in great opportunities to make acquisitions for PE firms that have access to capital."

Alternative capital

While the overall pool of capital sources shrinks, its mix is evolving, and there are still some new entrants into the energy capital space.

"We believe that ESG and political pressures will limit many capital providers from participating in the E&P space in the near term," said Kyle Kafka, partner, EnCap Investments LP.

"The sector does remain highly cyclical and unpredictable, and we would not advise companies to solely rely on cash flows," said Stephen Trauber, vice chairman at Citi.

"The energy industry is adjusting to the reality of an energy lending bank market with less capacity as a result of several banks exiting the energy lending market over the last few years," said Bryan Chapman, market president of energy lending, Iberiabank.

"This time around, the new entrants are largely private capital, family offices and insurance firms, and they are fewer in number and smaller in scale," said Christina Kitchens, principal and managing partner, 3P Energy Capital.

"As far as new entrants to energy capital go, they are not as numerous as in prior downturns," 3P's Kitchens said. "Previous cycles had community and regional banks enter along with expansion of new fundraising in equity and fund adaptations to specialize so to seize recovery opportunities. This time around, the community banks have largely deserted lending to E&P."

Kitchens has seen a similar trend play out among regional, mid-scale banks, which she said are limited from being a strong source of new capital by shareholder pressure and prior losses experience, among other factors.

"This time around, the new entrants are largely private capital, family offices and insurance firms, and they are fewer in number and smaller in scale," she said. "For many of these new entrants, they are on the front end of their investment thesis in navigating new investment opportunities, have not yet committed large dollars of new capital and are strongly contrarian in beliefs, looking for trades created by others' misconceptions."

Such new entrants are not necessarily looking for outperformers, according to Kitchens, but are instead seeking out "asset realignments, distress caused by capital rotations and places where a fixed-rate structure would work well—looking for low risks with access to steady distributions."

Alternative lenders can benefit from accessing "equity-like returns with a senior position in a credit structure with lower-risk profiles," Kitchens said.

"These opportunities are available due to less capital availability broadly across the space and more exits to come, the higher pricing of debt and credit enhancement requirements in ESG standards, hedging and lower debt/cap in structures," she added.

The borrower, meanwhile, benefits from accessing capital that may not have been available otherwise, though Kitchens noted that top-performing middle-market firms and majors would likely have continued access to the public debt market if their acquisitions or projects are judged to be of value. But for many others, alternative capital may be a more readily available option and could also be a better fit to the underlying capital need.

"Most alternative capital will be highly customized to the underlying investment," Kitchens said.

Changes in the future

There appears to be a general consensus that capital providers of all kinds are becoming more selective about the companies they choose to fund. The growing focus on ESG could accelerate this trend.

"I fully anticipate that all E&P firms will be expected to adopt ESG reporting standards and for those that don't or for some reason can't demonstrate some degree of year-on-year improvements, then they will be treated harshly across their capital stack in the years to come," Kitchens said.

However, Haynes and Boone's Clark said that oil and gas is set to come bouncing back in the relatively near future as growing energy demand collides with supply shortages caused by the relative lack of exploration and new development in recent years.

As this plays out, leading to a "mad rush" back into oil and gas, Clark anticipates that capital providers will also return to E&P once there is money to be made in the space again.

"If you can make money in oil and gas then you can issue public bonds, and people will buy them up," Clark said, adding that he had similar expectations for the return of IPOs and various types of lenders.

The relative lack of new drilling in recent years was also flagged up by Kitchens, who noted that many of the companies that have been able to operate within cash flow and pay down debt relied mainly on DUCs.

"This reliance on DUC completions has masked the actual capital levels needed on the horizon to replace and add to reserves going forward," she said. "A capital-intensive industry does not change its stripes overnight and with demand forecasted for continued growth, new reserves have to come from somewhere and redeployment of operators' cash flow will likely not cover reserves' replacement, let alone additions."

Citi's Trauber agreed that the upstream sector is needed to meet growing demand, and said decarbonization efforts would help address some of the headwinds affecting the attractiveness of the sector from an environmental standpoint over time.

"I think we are in the early innings of the sector remaking itself into a higher-return and stronger cash flow-generating sector," he said. "The valuations attributable to the sector today remain very low relative to many other sectors and as investors begin to see improved returns and cash flow, I believe they will move back into the energy sector."

EnCap's Kafka expressed similar expectations.

"We believe that ESG and political pressures will limit many capital providers from participating in the E&P space in the near term," he said. "On a longer-term basis though, once it becomes apparent that attractive returns are achievable in the space and can be done safely and responsibly, we anticipate that a large number of those capital providers will ultimately return to the space." □

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FATAL FLAWS: IS ERCOT STILL BROKEN?

In February 2021, Winter Storm Uri caused an immense power generation outage in Texas, leaving more than 4.5 million homes without electricity. Has the Electric Reliability Council of Texas learned its lesson?

ARTICLE BY
JOHN HARPOLE

Editor's note: Thirty-two years ago, John Harpole authored his first magazine article for the Hart Energy family of publications. That article was titled "December of 89." Coincidentally, it dealt with another major storm that wreaked havoc on the Northeast U.S. during December of 1989.

Harpole described firsthand his experiences as a natural gas buyer for General Electric (GE) industrial plants. A weather-induced shortage of interstate natural gas pipeline capacity nearly sent 12,000 GE plant workers home for an early Christmas.

Harpole brings more than thirty years of market insight to this story in an effort to describe, in day-to-day terms, what happened in Texas last year.

Harpole's company, Mercator Energy, brokers the sale of natural gas for producers and manages the purchasing of natural gas for industrial plants from Louisiana to California. A thorough understanding of natural gas pipeline capacity and how natural gas flows in and on a particular pipeline is a central offering to Mercator's clients.

Freezing in energy-rich Texas is the equivalent of starving in a grocery store.

The emotional, financial and political repercussions from last year's historic electrical outage in Texas will be felt for decades, far beyond the big state's border. Recognition of the need for legislative atonement may take longer.

After a year's worth of reflection on the events surrounding Winter Storm Uri, we continue to ponder some key questions:

- Can anyone reasonably claim that the Texas deregulated electricity market is functioning properly?
- Can the February blackout ultimately be blamed on the Texas-sized gravy train of renewable tax credits/abatements, mandates and incentives?
- Has the Texas State Legislature adequately assessed the anti-competitive impact of renewable tax credits on the Electric Reliability Council of Texas (ERCOT) model?
- Are electric generation providers equally incentivized to perform, especially on a peak day of demand?
- And perhaps of greatest concern: Does the experience in Texas foreshadow larger challenges for a U.S. electric grid in transition?

The hundreds of lives lost in the largest forced outage of electricity in human history deserve a thorough exploration of those big questions. And we will get to that. But in summary, the facts in the case point to simple answers of no, no, no and no. And for that last question of greatest concern—the near certainty of future problems—the answer has to be none other than a big, frightening yes.

FORGE PRODUCTIONS / SHUTTERSTOCK.COM

Most of the discussions of the above questions would fall into what we call the "first order macro" category of the Texas power grid problem. We noticed in the last year that most of the experts involved in fixing the problem (and hopefully averting future disastrous outages) focused disproportionately on the "second order micro" category of issues. While those issues certainly command attention, the macro items should require the most attention moving forward. We need to examine the cost-benefit of federal production tax credits, subsidies for renewable energy, competitive renewable energy zones and more.

According to the most conservative measurements, over 200 people lost their lives as a result of ERCOT's failures. On the early morning of Feb. 15, the grid came within 4 1/2 minutes of a complete system-wide failure. That type of "meltdown" would have required what the electric utility refers to as a "black start."

"We came dangerously close to losing the entire electric system," said Curt Morgan of Vistra Corp., in testimony to a post-Uri storm legislative hearing. Vistra Corp. owns and operates one of the largest fleets of thermal generation (natural gas and coal) units in Texas.

Let's remember: By "close," we are talking about minutes, and by "dangerously," we are talking about a situation that could have resulted in the loss of thousands or tens of thousands of lives.

Some experts estimate that it could have taken at least two months to recover from such an outage. Few backup power generator systems are expected to run longer than three days. Imagine having to life flight every ICU patient to a hospital in a neighboring state due to a lack of electricity. That helicopter flight would only be possible if the typical electric-powered refueling pumps had backup diesel generators.

The cost

In a Nov. 2, 2021, press release, Texas Comptroller Glen Hegar estimated that the financial fallout from Winter Storm Uri falls in the range of $80 billion to $130 billion. According to a survey conducted by the University of Houston, "more than two out of three, or 69%, of Texans lost power at some point during Feb. 14 to Feb. 20, and almost half, or about 49%, had disruptions in water service."

In yet another Uri-related jolt, the Texas Railroad Commission voted in November 2021 to give approval to the Texas Public Finance Authority to issue $3.4 billion in state-backed bonds to compensate natural gas utilities for extraordinary expenses related to the storm. Rather than absorbing that financial shock in one monthly billing cycle, Texas ratepayers will be paying off that bond in monthly increments for decades.

Even after last February's debacle, the degree to which Texas relies on dispatchable thermal

Fresh snow covered the state capitol in Austin, Texas, after a winter storm in February of 2021.

Q&A WITH TEXAS RAILROAD COMMISSIONER JIM WRIGHT

Elected to the Texas Railroad Commission for the first time in November 2020, Jim Wright is a fifth-generation rancher who surprisingly unseated the incumbent and gained the voters' attention with his emphasis on transparency and ethics within the energy industry and peripheral to it. We had the opportunity to discuss with him some of the more sensitive issues in connection with the Winter Storm Uri disaster.

Do you believe that the Texas Legislature assumes the Railroad Commission has a disproportionate responsibility for resolving Electric Reliability Council of Texas' (ERCOT) failures last year?

Jim Wright: Possibly. I think legislators heard a narrative that the underlying failure of the grid was natural gas, and to some extent, they zeroed in on that in their subsequent legislation. The natural gas system could have performed better, but I think to place the bulk of the blame on the doorstep of our natural gas industry was perhaps a convenient sidestep.

Clearly a whole host of issues contributed to the events of last February. Some of those, such as weatherization of electrical power plants, stemmed from ERCOT and the power generators themselves. Many of the issues that were the result of process failures in February were addressed in Senate Bill 3, but there are some overarching issues as it relates to our Texas electrical grid that remain unresolved namely the underlying and systemic imbalances in our market structure.

Look, I understand the Legislature has a tough job after an event like Winter Storm Uri. The legislators must cobble together information to construct mandates for an agency or agencies to solve an extremely complex problem, all in a limited amount of time. Imagine trying to coordinate a single piece of legislation to direct two state agencies and one quasi state agency to work together flawlessly—it must be very difficult.

That said, I think both industry and the Railroad Commission (RRC) made it abundantly clear that natural gas played a redeeming role in Winter Storm Uri; not one of fault.

How would you rate the Railroad Commission's statutory ability to address and solve ERCOT's problems?

JW: The RRC has primary regulatory jurisdiction over the oil and natural gas industry, pipeline transporters, the natural gas and hazardous liquid pipeline industry, natural gas utilities, the LPG industry, and coal and uranium mining operations. In addition, the RRC has exclusive original jurisdiction over natural gas utility service rates in certain parts of Texas but has no jurisdiction over the commodity price of oil or natural gas, which is wholly market-determined. Most importantly for this question, however, the RRC has absolutely no jurisdiction over the regulation of the generation, transmission or distribution of electricity in Texas. In short, the RRC has no statutory authority to address or solve the problems encountered or created by ERCOT. The RRC can, however, work to ensure that certain natural gas facilities are properly designated as critical and also weatherized so that the flow of natural gas to electrical generating facilities is predictable and sufficient.

Is the larger issue in Texas a market-structure issue exacerbated by renewable energy tax incentives that have virtually eliminated competitiveness for thermal generation in the ERCOT market?

JW: Absolutely, yes. This is one of the underlying issues that I believe caused the downward spiral of blackouts during Winter Storm Uri. Wind and solar power generation is increasingly augmenting our power portfolio, which can be a good thing. In fact, the Texas Legislature effectively guarantees that wind and solar can supply up to 20% of the electrical generation without any competition. That means

or fossil fuels for electric generation is not understood by most Texans. To begin with, most people fail to consider that storage of electricity at a utility scale is currently impossible. One day of U.S. electricity demand would require 500 years of battery production from Tesla's largest 5.3 million square foot Gigafactory in Nevada. So how will our electric grid perform when the wind doesn't blow and the sun doesn't shine? Without utility-scale electricity storage, it simply can't.

In simplest terms, electricity is either being produced, transmitted or consumed.

The scale and needs of the U.S. electric grid are rarely mentioned in the "decarbonization" campaigns that routinely win politicians and hedge fund managers favor. Ironically, the winning campaign teams at capitol buildings and in hearing rooms never have to operate the electric grid after the campaign is won. For them, the work is done and the financial compensation is collected. That compensation during the first three months of the most recent Texas Legislative session amounted to $24 million in payments from energy industry participants to over 300 newly minted energy lobbyists. For certain advocacy groups, the energy transition from fossils to 100% renewable energy is a foregone conclusion. Renewable energy is the only solution allowed.

In economic terms, I would classify this new "era of renewables" as a classic economic clash between socialism and free-market capitalism. Some might call it crony-corporatism (socialize the cost while privatizing the profits) rather than socialism, but no reasonable economist would identify the Texas Public Utilities Commission's (PUC) deregulated market design as a truly free market. That market has been distorted in large part thanks to federal tax subsidies.

Under the current market reality in Texas, wind operators have a complete advantage over their thermal generation competitors. Thanks to the federal production tax credit, wind operators can actually bid into the ERCOT market at negative power prices and still make money. The federal production tax credit of .023 cents per kilowatt-hour is equal to $23 per megawatt-hour (MWh) which, when converted into

when the wind is blowing and the sun is shining, thermal electrical generation sources like natural gas and coal have to come offline, making it difficult for those industries to compete. That is one part of the problem. The other is that, due to federal incentives, wind and solar operations can discount the cost of the electricity that they provide and still turn a profit.

It is this combination of state policy and federal tax incentives that best explains the absence of new gas-fired electrical generation facilities constructed in Texas in the last few years, even though the power needs in the state have increased dramatically. All power generation sources need to be on a level playing field to provide actual competition. When the sun is shining and the wind is blowing, having that renewable power generation is a benefit to Texas. However, since the renewables are at the mercy of the weather, they cannot be counted on to be there whenever needed. For that reason, nothing beats the instant-on reliable power that natural gas provides.

Does the Railroad Commission have statutory authority to mandate weatherization to/for the natural gas industry?

JW: Yes. Two specific pieces of legislation, House Bill 3648 and Senate Bill 3, collectively mandate the RRC to designate certain natural gas facilities as critical and require those facilities to weatherize. The proposed critical designation rule and corresponding forms were recently adopted at a Nov. 30, 2021, RRC conference after extensive workshops and comment periods. Much of the Senate Bill 3 requirements will be completed in 2022, including rulemaking for weatherization for critical natural gas facilities.

However, while we have the authority to mandate weatherization requirements, the RRC can't require or force production. I mentioned this at the most recent open meeting, and I continue to emphasize the need for electrical generators to secure firm gas supplies and transportation. I believe the best safeguard against extreme weather events, whether winter storms, hurricanes or summer heat, is an abundance of gas storage. Storage in salt caverns or depleted fields is advantageous in these situations, because unlike gas from the wellhead, gas from storage has already been processed and is ready for use.

So if that weatherization mandate is enforced, won't that further erode the competitiveness between renewable and thermal generators to the benefit of the renewable industry?

JW: It certainly could. I don't know if wind and solar are being made to weatherize and, if so, what the cost of that weatherization might be. I do know that natural gas storage facilities in Texas did a fantastic job of weatherizing prior to this year, and they performed flawlessly during Winter Storm Uri. Because it can have a serious financial effect on individual wells, it simply doesn't make sense to require full weatherization on marginal assets, such as oil wells that only provide small volumes of casinghead gas or gas wells near their economic limit.

The critical designation rule addresses this issue by dividing the natural gas facilities in Texas into three separate groups: (1) "Super-critical" natural gas facilities, which supply approximately 80% of the daily gas required in Texas, are so important that they will not be allowed to opt out of the weatherization rules; (2) "Non-critical" natural gas facilities, which produce little to no natural gas and are thus automatically exempt from the weatherization requirements, provide good opportunities for initial load shed during an extreme weather event; and finally (3) "Marginally-critical" natural gas facilities, which may choose to request to opt out of the weatherization rules, will have to provide the RRC with a reasonable basis and justification for doing so.

Do you think there should be some form of capacity market for at least firm supplies on a peak demand day on ERCOT?

JW: While this question is well outside the RRC's jurisdiction as an oil and gas regulator, I do think there should be at least some sort of incentivization for power generators to contract for firm supply and transport for peak demand volumes, at least during the winter months.

I understand that PUC (Public Utilities Commission) is looking at this issue and reviewing potential solutions to address these concerns. I have already begun to put wheels in motion to enhance the market for our natural gas to ensure electricity is available for distribution onto the grid while further utilizing gas that is currently flared.

I first wrote about this in an op-ed published by the Houston Chronicle back in August. Since that time, I have been working with Congressman Michael Burgess (TX-26) on legislation (H.R. 6146) The Stranded Gas Recovery & Utilization Act to further strengthen our ability to get natural gas to market.

This isn't simply a Texas problem. Just recently, New England's power grid operator raised concerns that several issues, including natural gas pipeline constraints, could impact the area's power system.

a heating unit of natural gas, is roughly equal to more than $6/MMBtu. Essentially, the natural gas industry can't compete against the huge advantage given to the wind energy developers and producers through a federal tax incentive. The prevailing first of the month price for electricity in February 2021 averaged $25/MWh. Thermal generators simply could not compete. But more importantly, any incentive to compete at any time, let alone during peak demand, had been eliminated by the tax incentive for renewable energy.

What used to be a competitive ERCOT market is now characterized by a situation where dispatchable generation is apparently only required when the wind doesn't blow. It is difficult to identify or find a natural gas-fired generator that will publicly admit that they don't hold upstream firm transportation pipeline capacity to meet ERCOT's potential peak day requirements for all of their individual gas fired generation units.

It doesn't make economic sense for a gas-fired generator to hold year-round firm transportation capacity on a natural gas pipeline when they are only competitive a handful of days per year against subsidized wind generation. There is no market incentive to do so.

It is the moral equivalent of asking the natural gas industry to run a 100-yard dash every 15 minutes, 24 hours per day, 365 days per year. Their competitor, in this case the wind energy industry, gets an 80-yard head start in every race. The only chance the natural gas industry has to win the race is when their competitor fails to show up or falls flat on their face. The real question for the natural gas industry is why even train or prepare for such a race?

In a recent Washington Examiner article, Stephen Moore, a well-known economist and former editorial board member for the Wall Street Journal, posed the question, "How much would the solar, wind and electric vehicle companies get in federal handouts and tax loopholes in President Joe Biden's 'Build Back Better' bill?" Although the bill never made it out of Congress, it would have been well over $100 billion in taxpayer largesse. If all the tax credits had been included, that number would have reached half a trillion dollars. No other

WHEN FORCE MAJEURE BECOMES PRICE MAJEURE

The Permian Basin currently accounts for approximately 15% of total U.S. natural gas production. Ten years ago, it was about one-third of today's nearly 12 Bcf generated on a daily basis in the Permian Basin. The race to oil and natural gas production, or more accurately, associated natural gas production, in the Permian Basin has sky-rocketed.

Due to increasingly more restrictive air emission regulations implemented by the Texas Commission on Environmental Quality, oil producers had a limited amount of time to flare any natural gas associated with a new producing oil well. In order to expedite their sale of oil, Permian Basin producers almost uniformly responded by dedicating their producing acreage to a third-party natural gas gathering pipeline company. That gathering company would buy the natural gas production "at the wellhead."

In an effort to install the natural gas gathering systems as quickly as possible, midstream companies (again, almost uniformly) bypassed the historic use of natural gas-fired compression and chose electric compression. Electric compression was much easier and quicker to install given state air permit regulations related to natural gas compression emissions.

During the rolling blackouts of February 2021, significant volumes of associated natural gas production were shut in due to a lack of electricity as a result of Electric Reliability Council of Texas (ERCOT) mandated rolling blackouts. It only took an average of two hours for the natural gas to sit in that cold pipe to see the hydrates fall out in solid form and thereby freeze that route to market.

The first of the month price for electricity in February 2021 was roughly $25/MWh. In the midstream natural gas gathering contract executed by the producer, the actual electric costs are treated as "a pass through." Stated another way, whatever the midstream company paid for electricity was passed through by the midstream company to its producer client. That February, at $25/MWh, the electricity cost passed through to the producer on an MMBtu basis was roughly equal to 14 cents to 16 cents per MMBtu in pipeline gathering charges.

The standard midstream provider purchase agreement or contract price for the majority of Permian Basin third-party gathered gas follows an industry standard 80:20 rule. That is, 80% of the gas received a first of the month index price while the remaining 20% received a fluctuating daily price. (For February 2021, the prevailing first of the month index at Waha Hub posted at $2.49/MMBtu.)

On the morning of Feb. 15, when the Texas Public Utility Commission unilaterally set the clearing wholesale price of electricity on ERCOT at $9,000/MWh, that price translated to a $50/MMBtu pass-through charge for natural gas compression electricity.

What producer would accept a price of $2.49/MMBtu but pay a minimum of $50 in gathering fees to receive that price?

The frozen pipes that created a force majeure event ultimately, when the expensive electricity was turned back on, forced a price majeure declaration. Some producers exercised their right to "an economic out-clause" in their midstream gas gathering contract. Should a second rolling blackout occur under similar circumstances, that price majeure declaration will most likely be made by all producers.

It is doubtful that any ERCOT market design ever anticipated or even appreciated those types of upstream natural gas supply issues.

ERCOT recently reset the maximum electric price cap from $9,000/MWh to $5,000/MWh. That still doesn't solve the potential price majeure problem for natural gas producers that rely on electric compression.

If a similar Winter Storm Uri is encountered in the future, a $5,000/MWh cap would translate to a $28/MMBtu pass through on electric compression gathering charges. That potential $28 gathering fee far exceeds the 10-year average for Waha gas ($2.50/MMBtu) or the highest first of the month price in the past 10 years, which occurred in November 2021 at $5.56/MMBtu.

industry in American history has ever received that lucrative paycheck.

"The folks at the Institute for Energy Research calculated that this would have been on top of the more than $150 billion in subsidies those industries received from Uncle Sam in the last 30 years," he said.

"The umbilical cord to taxpayer wallets never gets cut. Yet, laughably, the left says all these subsidies to 'green energy' are necessary for an 'infant industry.' Really? Does Big Wind or Big Solar ever grow up? You can call it socialism or crony-corporatism, where renewable energy developers socialize the cost and privatize the profit. But whatever you call it, it is not a free market. It is simply a bad economic policy."

Has Europe learned its lesson?

Europe deregulated its electric grid about five years ahead of Texas. At the time of this writing, many experts anticipate the same sort of Texas-forced blackouts throughout Europe in the cold months of January through March of 2022.

Last fall, energy shortages throughout Europe were made worse by a lack of wind in the North Sea, which reduced the availability of electricity for all of Northern Europe. Power prices increased dramatically. European spot natural gas prices were 10 times the cost of U.S. natural gas.

Most European fertilizer plants that utilize natural gas as a feedstock for ammonia were shuttered. Concerns over a shortage of fertilizer and the resultant shortages of crops are raising concerns about food shortages and severe inflation across Europe. During the past five years, Europe has demonstrated an overreliance on renewable energy, shirking the fundamental need for dispatchable thermal energy. However, change is in the wind.

In a recent Substack email from author Michael Shellenberger, he wrote, "Four years ago, the conventional wisdom in Europe was that the continent was transitioning to renewable energies. The cost of electricity from solar panels, wind turbines and natural gas had declined significantly, and lithium batteries could soon replace natural gas to provide energy when the sun wasn't shining and the wind wasn't blowing. And [according to consensus], nuclear energy was going away; the main question was how soon existing nuclear plants could be dismantled.

"Today, the conventional wisdom has changed radically. Energy and electricity prices are at record levels due to Europe's overreliance on renewables, inadequate supplies of nuclear energy and shortages of oil and gas due to underinvestment in oil and gas exploration and production. Carbon emissions in Germany rose 25% in the first half of 2020 due in large part to a 25% decline in wind [energy], underscoring the unreliable nature of weather-dependent renewables. In response, both France and Britain have promised a major expansion of nuclear energy."

Europe is learning an expensive lesson: dispatchable generation (coal-fired plants, natural

gas-fired plants and nuclear plants) must be available at all times for an electric grid to run efficiently and sustainably. Germany recently closed three of its remaining six nuclear plants with plans to shift energy dependency mainly to wind. We will see how that goes, but the data here seem to portend a decades-long setback in that part of Europe.

Back to Texas

Energy issues are globally connected, but the problems in Texas are big enough to absorb all our attention at this point in time. The "meltdown" of the Texas energy grid in February 2021 has generated encyclopedic volumes of documents as experts, politicians, analysts, scientists, media outlets and others debate the whys and wherefores. New information and speculations are added almost weekly, and government bodies in search of solutions keep nudging the ship in slightly different directions.

If we want to prevent a repeat of the Uri disaster, we have to start with the recognition that the myriad of contributing factors fall into the two categories that we mentioned above: macro and micro.

First order macro issues. These include market distorting tax policies (as identified by Bill Peacock with Texas Public Policy Foundation) that overlay all ERCOT/Texas Public Utility market pricing and operating functions such as:

- The Federal Production Tax credits for renewables (in Texas alone worth $16.3 billion),
- CREZ (Competitive Renewable Energy Zones) transmission capital support ($14 billion),
- Federal stimulus funds ($1.6 billion),
- Renewable energy credits ($570 million),
- Interconnection costs ($1 billion),
- 313 property tax limitations ($2.5 billion),
- 312 property tax abatements (?),
- ORDC costs caused by renewables ($2.5 billion); and
- Carbon offset credits/payments (?).

These subsidies, as they run between 2006 and 2029, will amount to more than $36 billion.

Second order micro issues. These are the day-to-day, keep-the-train-running-on-time issues, mostly pertaining to ERCOT market functions.

The boundary lines for assigning blame to the ERCOT blackouts are often gray when analyzing the duties of ERCOT, the Texas PUC, the Texas Railroad Commission and the State Legislature. The Texas Railroad Commission runs front and center in resolving both the macro and micro issues identified above.

Jason Modglin, president of Texas Alliance of Energy Producers, also agreed with Commissioner Wright about the inaccurate targeting of the natural gas industry. He went a step further in suggesting that the natural gas producers "saved lives" (along with the Railroad Commission). He noted that the Railroad Commission identified the need to keep the electric power flowing to natural gas producers, so they could in turn keep the critical natural gas flowing to the generators. This strategy ought to be etched into future tactics.

"By identifying and prioritizing critical components of the natural gas system, operators will supply transmission utilities with the best information to make informed load-shedding decisions and keep more gas flowing to where it is needed," he said. "There is more work to do to build the resiliency of the system by ensuring electric generators have firm pipeline and supply contracts in place and that growing urban areas have the natural gas storage needed to keep the lights and heat on."

As it is, one of the micro issues facing ERCOT is the cyclical nature of the energy failures in an extreme environment such as Winter Storm Uri and how the failures compound one another. A lack of electricity at the natural gas production facility results in a lack of fuel for the electric generation plant at a critical time when that plant needs it the most. And round and round we go.

When power is not available, the micro issues such as "weatherization" of natural gas plants are just as important as the macro issues. But the micro issues can be addressed with a little thought and preparation and with better communication. It seems that the apologists for renewable energy want to focus on these housekeeping issues, completely neglecting more fundamental issues of market design and function. But the key question is: What market incentive can induce private companies or corporations to be available when renewable energy is not available?

In another confounding micro problem that arose during Winter Storm Uri, it turned out (thanks to Texas PUC policies) that electric generators were, in some cases, charging natural gas producers about 20 times in electric costs what the natural gas producers were able to receive to provide the natural gas. See the attached sidebar here for details about how that infuriating disincentive worked. This upside-down economic fluke was like telling the beer vendor at a football game that he had to pay $150 for the privilege of selling a $7.50 beer in the stadium's executive suite.

Some of the following micro issues were just a matter of bad/unlucky timing, and some are easily solved with a proper level of commitment from legislators, regulators and others. But it is important to recognize here that these micro issues all played a role in the disaster:

- **Thermal outage due to planned maintenance**. At the same time that the storm hit, ERCOT reduced thermal capacity by 10 to 12 gigawatts (GW), representing about 15% of the minimum need for the demands of the day.
- **Frozen wells.** There is some dispute over the status of the gas wells—whether they truly froze up, and if so, exactly why it happened and how badly, and at what point it happened in the efforts to "fight" the winter storm. We believe there was some freezing which could be prevented in the future by improvements in weatherization. But the wells can't produce if they

BP

don't have power, which is what happened when the rolling outages began throughout the system.

- **Frozen wind turbines.** Again, we aren't certain how badly the turbines truly "froze." And if they did freeze, enhanced weatherization could solve this micro problem. But the bottom line is they weren't moving, and they weren't going to move because of our final micro issue.
- **Absence of wind.** Again, this was bad timing. Usually, the best winds at the Texas wind farms occur at about 2 a.m. or 3 a.m., and they're usually good for about 6 to 9 GW of power (topping out at about 20 GW). At 2 a.m. on the morning of Feb. 15, wind had dropped to 5.3 GW. At 8 p.m. on Feb. 15, it was at 0.8 GW. At the time Texas needed that wind power the most, the turbines were generating about 0.8 GW, or about 2% of its rated capacity. And that's exactly why dispatchable power is so crucial to the grid system to even out the intermittencies that come with renewables.

As long as we're on the topic of wind-power delivery, it is worth noting that wind power tends to arrive when it is needed the least. It ramps up late at night, when most people are sleeping and using less electricity. This problem is exacerbated, of course, by the minimal electrical storage capability mentioned above.

Texas' impact from the lack of wind power during Winter Storm Uri was greater than those states bordering to the north. The storm resulted in a high-pressure weather system sitting over the central U.S. and its associated low wind velocities that extended all the way up to Canada. This curtailed the wind turbines across the central U.S. plains and resulted in low power generation. However, the electric grids to the north of ERCOT (known as MISO and SWPP) were augmented with dispatchable power from coal-fired units, and similar crisis in power balances were not seen.

Skewed subsidies

The micro issues are numerous, and there are probably others that we could have added. But the macro issues are where we need to direct most of our energies for solutions if we want to have the greatest proportion of success in averting future tragedy over the next five, 10 or even 50 years.

Gregg Goodnight, head of a study team of retired engineers for the organization The Right Climate Stuff, said, "We conclude that there were two major contributing factors that led to the February Texas electrical grid outage: the unusual but not unprecedented weather event and the cumulative impact of long-term public policy, both at the state and federal levels."

He added the following observations:

- The long-term impact of public policy at both the state and national level during the past 20 years has increased and will continue to increase the vulnerability of the Texas grid to outages such as the one seen in February of 2021.
- The Texas grid's safety margin for handling of severe weather events has continued to erode due to policies that reduce the reserve dispatchable (thermal) power available to offset the extreme conditions that we believe made a similar incident inevitable.
- Policies enacted in the early 1990s meant to encourage growth of wind and solar power generation (and meant to be temporary) have not been phased out as intended. They continue to significantly advantage these intermittent sources of power to the near exclusion of new thermal power additions.
- Current power pricing policies in Texas give no credit for reliability and dispatchability. Treating the pricing of "as available" power from wind and solar the same as on-demand peaking power is fundamentally flawed.

The obligation for continuously balancing the ERCOT grid's electrical supply and demand rests exclusively on thermal power sources, but the attendant costs are spread among all grid customers. Instead, these costs should be borne by all electrical producers to the extent they contribute to this intermittency.

In an interview, Bill Peacock with Energy Alliance said, "The Texas electricity market is being overrun by renewable energy generation. Since 2018, 79.3% of all new generation has been intermittent renewable energy. Only 19.1% has come from generation that can be dispatched, and all of that comes from one source—natural gas. The lack of diversity that has resulted from this overreliance on renewables has come at a great cost to Texans."

About $66 billion has been spent building wind and solar capacity in Texas since 2006. During that fateful week in February, according to author and journalist Robert Bryce, "there was no solar production, and of the 31,000 megawatts of wind capacity installed in ERCOT, only about 5,400 megawatts, or roughly 17% of that capacity, was available when the grid operator was shedding load to prevent the state's grid from going dark."

What does the future hold? ERCOT will become increasingly dependent on weather generation powered energy. According to Bryce, "about 24,000 megawatts of solar and 11,000 megawatts of wind capacity are slated to be added to the ERCOT grid between now and 2023. Thus, over the next two years, the amount of renewable capacity in Texas will nearly double."

To Goodnight, the numbers don't add up. His studies show that under current conditions, Texas will expect to be receiving 38% of its energy from renewables by 2025, a number that is far out of whack with reality. Instead, he said, the lesson of Winter Storm Uri is that the system can handle at most 25% renewables on an average basis.

Yet we continue to see the push for subsidized renewables in Washington, D.C., and in state capitols. The federal government has renewed production tax credits more than 20 times during the decades. And in instances where the government can't benefit from

renewables directly with new laws, we see instead a "back door" advocacy through tightening regulations in which the government makes business harder and harder for the dispatchable (natural gas, coal and nuclear) power resources.

It seems that the "100% renewable crowd" is trying to fast-track the elimination of fossil fuels. Without utility-scale storage, that premise is impossible. When the world transitioned from horses to automobiles, the new automobile owners did not go out and shoot their horses.

My current overriding concern is that the mayhem we saw in Texas presages what we will see across the U.S. as statewide renewable energy mandates ratchet up over the next few decades. Unfortunately, "what happens in Texas" will not stay in Texas, as most other states join the "all-renewable bandwagon." We distort true market competition when we mandate renewable energy generation and/or provide tax incentives for it. The mandates and incentives also eliminate any competitive incentive among generators using coal, natural gas or nuclear fuel. Texas is currently suffering through a "distorted market" phase of an energy transition to what some would hope will be an all-renewable supply of energy for the grid.

The distorted market phase resembles a socialistic economy's command and control over the electric grid. The uncertainty of freezing in your own home and waiting for the power to come back on must feel a lot like standing in a breadline hoping for sustenance when it's your turn to buy bread at the counter.

The new era?

Regardless of the economic term used, socialism or crony-corporatism, the net impact on society is the same. If my assertion is correct, Texans (and more specifically ERCOT) face a much larger problem than trying to coerce the natural gas industry to weatherize.

A true functioning free market for electricity would foster, promote and nurture competition between all electric generation participants (nuclear plants, coal plants, natural gas-fired plants, wind and solar).

Competition in today's U.S. electric grid is so skewed by renewable mandates, state utility commission must-take-resource edicts and renewable tax subsidies that most traces of a "free market" characterization have virtually disappeared.

Unfortunately for Texans, that economic reality played out in February 2021 when Winter Storm Uri penetrated Texas and wreaked havoc. Will that same problem continually repeat itself as individual states ratchet up their commitment to renewable energy? I think so. □

A WELL-TIMED HOLIDAY?

A four-day "holiday in trading" occurred just as Winter Storm Uri descended on the Midwest and Texas in February 2021. All natural gas index prices were settled at close of business on Friday, Feb. 12 and were then fixed by the natural gas trade publications and the Intercontinental Exchange for Saturday, Feb. 13 through Tuesday, Feb. 16. If not for that miraculous timing, natural gas index prices in Texas on the trading holiday of Monday, Feb. 15 (President's Day) and Tuesday, Feb. 16 might have otherwise reached $2,500/MMBtu.

That would have been quite a black eye for Texas natural gas producers as accusations of "profiteering" would have been leveled against them by all sides. No doubt, congressional and state legislative hearings would have ensued.

What could have caused natural gas prices to run to $2,500/MMBtu on that frozen Monday and Tuesday?

According to Andrew Barlow, a spokesman for the Texas Public Utility Commission (TPUC), early Monday morning on Feb. 15, the TPUC had identified a "system glitch" as the reason electricity prices remained artificially low at $1,200/MWh. The TPUC couldn't understand why incremental generation did not materialize at the $1,200/MWh price. It just didn't fit their preconceived model.

Therefore, the TPUC unilaterally ordered the Electric Reliability Council of Texas (ERCOT) wholesale price to be immediately and manually fixed at $9,000/MWh. They were attempting to send a price signal to incentivize generators that were possibly still on the sidelines.

It would arguably become known as the single most expensive market error made by regulators in Texas and possibly U.S. history.

The TPUC "experts" fundamentally mistook a lack of available generation (caused by freezing temperatures, frozen pipes and a lack of wind generation) as a market pricing issue and not a scarcity or physical supply issue.

As one Permian Basin pumper said to me, it took them two days to realize that "frozen pipes don't thaw out any quicker at $9,000/MWh than they do at $1,200/MWh."

ERCOT made the unforgivable mistake of leaving that $9,000 wholesale price in place for two full days longer than necessary. ERCOT forced power companies, according to their watchdog, Potomac Economics, to absorb $16 billion in excess wholesale electricity costs.

Those costs have now been wrapped up and put in a nice box or more specifically, a bond issue, that Texas rate payers will be paying off for decades to come.

Had natural gas trades been captured by the Intercontinental Exchange or by Gas Daily publications (which were on the Monday and Tuesday tail end of that four-day holiday), natural gas pricing could have and would have chased the $9,000/MWh TPUC-mandated wholesale price of electricity equivalent.

That $9,000/MWh wholesale price converts to a natural gas price equivalent of $2,640/MMBtu. As it was, record high daily spot prices for Waha hub reached $154/MMBtu during those four days, all predicated on trades that occurred on that Friday, the last day of trading before the Presidents Day four-day weekend.

I'd call that a well-timed holiday.

—John Harpole

THE PICKUP ARTISTS

Mach Resources and financial backer Bayou City Energy announced acquisitions 10 and 11 as they continue to roll up assets down and out in the Midcontinent.

ARTILE BY
DARREN BARBEE

Midcontinent deals in the past couple of years have been the blender variety, consisting of pulped bits of upstream and midstream assets that once showed promised but were pureed by downturns, COVID and bankruptcy.

In this bleak landscape, Mach Resources and backer Bayou City Energy found a natural symbiosis in strategy. In a Christmas Eve conversation in 2017, Mach's Tom Ward and Bayou City's William McMullen, discovered a shared business philosophy: Buy assets shunned by the industry, operate them economically during the downturn and wait for recovery.

The resulting company now boasts more than $100 million in free cash flow per quarter, which the company expects to increase in 2022 while keeping costs low and production gradually increasing.

The keen-eyed acquirers at BCE-Mach, as they refer to their partnership, have seized on distressed and overlooked assets and become one of the few consistent aggregators of assets in Oklahoma, far North Texas and Kansas.

In December, the BCE-Mach combination announced two new acquisitions totaling $66.5 million as it continued its pennies-on-the-dollar approach to buying.

The newest acquisitions—the partnership's 10th and 11th—are expected to add $26.4 million in cash flow in 2022, according to the companies.

One of the deals, a bolt-on centered on the Oklahoma STACK, grabbed additional working interest in 61 wells in Kingfisher County, as well as midstream assets that are prerequisite for most of its transactions.

And in Kansas, BCE-Mach announced its fourth Mississippi Lime acquisition, expanding its operating footprint in Kansas to about 66,000 net acres and 193 operated wells primarily located in Barber County. BCE-Mach also added to its midstream infrastructure with 16 additional disposal wells and associated gathering systems.

Mach's CEO, Ward, said the smaller bolt-on acquisitions are quickly and seamlessly assimilated and, like most of its deals, won't require additional employees beyond a few field employees.

"We have cut LOE by about 30% or more in every acquisition that we have made," said Tom Ward, CEO, Mach Resources.

"We've been able to keep G&A basically flat since 2018," he said.

The additional acreage and interest will plug in to an already sprawling 678,000 net acres held by BCE-Mach at the end of September, with a staggering 97% of its leasehold HBP.

The M&A BCE-Mach has engaged in has come through a close partnership with private equity capital provider Bayou. It's a partnership built on trust and consensus, as the companies watch each other's backs and check each other in every transaction they consider.

Mach is led by Ward, the co-founder of Chesapeake Energy Corp., SandRidge Energy Inc. and Tapstone Energy. Bayou is stewarded by McMullen, the firm's founder and managing partner, who began his career in oil and gas finance at the Global Energy Group at UBS Investment Bank and continued in private equity at Denham Capital and White Deer Energy. He went on to found Bayou City Energy in 2015, which now has approximately $2.7 billion in assets under management. He is also co-founder of Ara Partners.

In a joint interview, Ward and McMullen said that a window may be closing, though slowly, on the Midcontinent's low-valued assets as commodity prices continue to tick upward.

Ward, circumspect about the deals Mach Resources has made, said the notion that the assets the company has purchased were easy pickings is misleading.

"I'd say it's never easy," he said. "Trying to find things that what we believe are discounts is something that requires us to have some knowledge of an area that maybe others don't know and that we see discounted properties where others can't see them. That just goes with our management team's decades of experience through the areas that we work in."

SWAT team

Bayou City and Mach agree the business plan does not stop at simply acquiring cheaply. Ward and his team at Mach Resources, which Ward affectionately calls his "SWAT team" of oil and gas professionals, work to implement cost savings, sometimes even before acquisitions close.

Ward credits his team at Mach, 80% of which has worked with him over the years at Chesapeake, Sandridge or Tapstone. Mach has pur-

chased based on that experience, science and a strong contrarian faith in the Midcontinent that has otherwise been a virtual dead zone for deals in the past two years.

The SWAT team has "tentacles" across the Oklahoma oil and gas complex, from field-level personnel and service providers to regulatory bodies and financial institutions.

"We will not acquire an asset unless there is a Day One plan to cut costs and improve production, thereby making the entry metrics even more attractive than publicly stated. That dynamic really accelerates returns for investors, especially when overlayed with the opportunity to purchase assets at very attractive prices," Ward said. "We have cut LOE by about 30% or more in every acquisition that we have made."

With a unified purpose, Mach and Bayou City have amassed a formidable position in the Midcontinent. That's largely due to a fluid, equal partnership that has resulted in 11 acquisitions and counting.

Ward recalls meeting McMullen in late 2017 when both were considering different ventures and partnerships. But in 2018, Ward said few individuals or private equity groups were aiming to buy in distressed areas and focus on generating free cash flow.

"I wouldn't say Bayou City was unique, but Will individually had the same mindset that I did, that the industry wasn't … at the time necessarily spending their capital correctly and that we were due for a time that maybe there could be opportunities for us," he said.

The partnership that was forged in 2017 became one in which Ward and McMullen talk nearly every day, walk through acquisitions jointly and analyze assets together.

'Unnatural holders'

McMullen said BCE-Mach partnership has flourished, particularly in the past three years, as the upstream sector has been hit by waves of price shocks.

"We wanted to take advantage of that," McMullen said, adding that his expectation was that commodity prices would stabilize and that, particularly for natural gas, demand would rebound.

The Midcontinent was a Death Valley for investors, with stocks becoming worthless, first-lien debtholders wiped out and, McMullen and Ward said, the area was considered un-investable.

Over the course of 11 deals, BCE-Mach acquired $1 billion dollars of infrastructure built by prior owners, including saltwater disposal, gas gathering and processing, crude oil gathering, storage and even an electric grid.

The Midcontinent has what Ward calls an "abundance of unnatural holders" consisting of 2019 and 2020 first and second lien debt holders who took on equity from failing business. Those companies, now seeing higher commodity prices "would like to be out of owning equity, so there is a decent amount of [A&D] opportunity still left."

"Bayou City still has hundreds of millions of dollars of equity that we have behind Tom, incremental equity that we'd like to have put to work over the next couple of years," said William McMullen, founder and managing partner, Bayou City Energy.

MACH RESOURCES

Since 2018, BCE-Mach has acquired $1 billion dollars worth of infrastructure, including saltwater disposal, gas gathering and processing, crude oil gathering, storage and an electric grid.

BCE-Mach's purchase of upstream assets with complimentary midstream infrastructure was the centerpiece of its 2020 deal to buy Alta Mesa Resources for $220 million. The deal included Kingfisher Midstream's 453 miles of gas gathering pipeline and 108 miles of oil pipeline.

McMullen said the Midcontinent is seen as having higher breakeven costs than other basins, but that's largely "because people are looking at it on just the upstream-only economics.

"We wholly own a lot of our gas gathering and processing, our saltwater disposal, compression. I think even in the Miss[issippi] Lime, Tom, we own a little bit of our electric grid up there," he said. "So, when you factor that in and you're able to offset your cost because you integrate other sort of infrastructure systems into your underwriting, that breakeven molecule, whether its oil, NGL or gas, is a lot lower obviously if you've been able to vertically integrate your upstream and midstream systems."

BCE-Mach's strategy was exemplified by its deal to purchase Alta Mesa Resources in April 2020 for $220 million. In addition to upstream assets, Mach also bought control of Kingfisher Midstream, which includes 453 miles of gas gathering pipeline, 108 miles of oil pipeline and gas processing capacity of 350 MMcf/d.

"That does actually make us a low, low-cost producer because we have the benefit of all that infrastructure that comes in line with these assets," McMullen said. "And again, credit to Mach and their teams, but we don't outsource a lot of that capability either. We have all of that in-house. It's Mach's crews that are running the Kingfisher Midstream assets that we purchased from Alta Mesa out of bankruptcy."

Mach's production is split among oil, natural gas and liquids, with oil consisting of 25% of its production but 50% of its revenue, Ward said. Control of the infrastructure allows the company to move commodities to the market to Mach's advantage.

"We have so many synergies being able to send our molecules to our gas gathering plants, processing plants, and then being able to take those molecules to market as we see fit," McMullen said. "Being able to have your finger on all of those different touch points allows us to be able to send the molecules when we want to send them and get really, really good pricing for them because before they leave our ownership, we've already sent them much further down the stream than a lot of other operators."

Ward said every acquisition BCE-Mach makes is an attempt to "find something that we don't give any upside to."

Like the Alta Mesa deal's midstream bonus, Mach's 2018 purchase of Chesapeake's Mississippi Lime assets also included in-place infrastructure.

"So, we continued to have two rigs running currently in the Alta Mesa area that we had in Kingfisher County, and we drilled over 90 wells and will put rigs back to work in the Miss Lime probably in [2022] that both have tremendous upside," Ward said.

The company is generating more than 100% rates of return on its drilling program, as well, by watching costs closely.

"We pinpoint the locations that we choose," he said. "We don't have just continual programs of drilling, but we have very large acreage swaths that we pick specific locations and then with the added benefit of having a midstream system in place."

Mach will likely continue to roll up acreage in and around Oklahoma through bolt-on acquisitions.

"Bayou City still has hundreds of millions of dollars of equity that we have behind Tom, incremental equity that we'd like to have put to work over the next couple of years," McMullen said. "We'll do that on an opportunistic basis. We're not in a hurry to do anything, but again, if something presents itself and it makes sense, we'll evaluate it just like we have been in these past 11 acquisitions."

As commodity prices have increased, Mach is running two rigs in Oklahoma, and the Mississippi Lime is economically viable today due to its ownership of integrated infrastructure.

Mississippi limelight

In every acquisition they consider, Ward and McMullen are talking, usually through multiple conversations.

"We understand what we're both looking for, and if either one of us didn't care for an acquisition, we wouldn't do it," he said.

McMullen said that Bayou City and Mach each have their own engineers who collaborate. Mach passes along a recommendation that he and Ward then discuss.

"It is interesting. Sometimes the recommendation from Mach … Bayou City will say, 'Oh yeah, we feel good about this. Why don't we do a little bit more?'

"Sometimes we say, 'This probably isn't as high on our priority list. So, let's do a little bit less.' But it's extremely collaborative. I think our visions and just our business strategy dating back to late 2017, Tom and I have been perfectly synced up, aligned on that and where we want to take the company."

As commodity prices have improved, Mach has looked inward at its drilling program while still adding leasehold.

The recovery in oil and gas prices through mid-January has allowed Mach to pinpoint specific areas and intervals within its leasehold that have now become economically viable.

"Most of our northeast Kingfisher acreage that we bought from Alta Mesa, both in the Oswego and Osage, is economically viable today," McMullen said. "We've got two rigs running there. The Mississippi Lime is certainly economically viable today, given all of the owned infrastructure that we have, especially given that we own our saltwater disposal systems up there as well. And we're going to look to put out maybe a rig or two early next year on that acreage."

The company now plans to "toggle" between drilling and an opportunistic acquisition strategy. And, because the company's debt is so low, "we do actually have the ability to make that toggle. So, we'll continue going back and forth, I think, just as we said, opportunistically," he said.

Ward said that Mach will also continue to focus on generating free cash flow.

BCE-Mach has also kept its leverage ultra-low. BCE-Mach targets an extremely modest financial leverage of total debt to EBITDA at or below 1.0x, and its development plan relies solely upon cash flows from operations targeting a 25% reinvestment rate, as defined as capex over EBITDA.

Based on its development plan, overall production should increase in 2022. The company produced third-quarter 2021 free cash flow of $111 million on EBITDA of $128 million, with 52,000 boe/d production (45% liquids). BCE-Mach enjoys shallow decline rates of 14% on its base PDP.

"We have a lot of free cash flow to either make distributions or to put into new investments alongside the equity that Bayou City provides," Ward said. "I don't know if it's unique or not, but it's a very good place to be in a strong market that still has, I think, a good amount of opportunity left in it."

One piece at a time

BCE-Mach believes its low-leverage and low-cost structure provide tremendous operational optionality for the business. But the acquisition pipeline has not run dry. Mach will continue to roll up producing acreage.

And with its business plan, BCE-Mach is built to withstand severe price shocks and adapt its month-to-month strategy quickly.

"In high prices, we drill; in low prices, we buy, and in between, we improve the hell out of our assets," McMullen said.

McMullen said that initially, BCE-Mach was able to buy PDP assets at prices of PV-20. Now, even in the Midcontinent, they see assets trading at sub-PDP PV-10.

"Where we've gone then is smaller assets. I think the larger multi-$100 million assets are going to trade very competitively. They're just visible," McMullen said. "It's much easier to buy one 50,000-boe-a-day asset than it is to do what we've done and acquire 11 of them if your goal is simply to own that amount of production."

Bayou City is one of the only private equity funds actively investing in the Midcontinent, but this trend may be changing. Other investors are starting to recognize they cannot ignore the cash flow from the Midcontinent.

"Whatever the underlying driver is, the output is that there's just not a lot of upstream funds focused here anymore," McMullen said. Bayou City and Mach have viewed other firms' absence as their opportunity.

"We have a lot of free cash flow to either make distributions or to put into new investments alongside the equity that Bayou City provides," Ward said. "We're well-positioned with plenty of capital to deploy to be in an active market that still has opportunity left."

Bayou's ability to tap into additional equity gives BCE-Mach an advantage in executing deals, since money remains tight in the oil and gas space.

Ward said it's still a difficult time to find capital, and while there are healthy companies that

In third-quarter 2021, BCE-Mach produced $111 million of free cash flow on EBITDA of $128 million from average production of 52,000 boe/d.

MACH RESOURCES

can take on debt or issue equity, adding new debt into the market, IPO fundings and private equity sponsors are still "nowhere near where it was a few years ago."

McMullen said acquisition capital, whether it comes from public markets or private equity, is especially scarce for assets starting at $100 million.

"A lot of what's been going on in the public space has been debt refinancings … you have seen a good amount of [refinancing] on balance sheets to lower that cost of capital," McMullen said. "From the private landscape, it's going to be exceptionally difficult for private equity funds to raise upstream focused capital."

That may be due to several factors, such as ESG, the focus on the energy transition or investors that still lack the appetite to invest due to the results during the past decade in oil and gas.

"Whatever the underlying driver is, the output is that there's just not a lot of upstream-focused funds anymore," he said.

'Pennies in the dirt'

Mach and Bayou City have centered their acquisitions in Oklahoma and Kansas. With other areas having also been hit by the downturn, Ward and McMullen are away of opportunities but none that fit into the lucrative coexistence of upstream and midstream assets.

That value proposition is difficult to duplicate elsewhere, Ward said.

"We have really focused on cost control. I guess, the motto that our operational team has is that we look for pennies in the dirt," Ward said. "Anything that we take on is really focused on how we can save money."

McMullen said that BCE-Mach does look elsewhere but agrees that from a philosophical and strategic view, the market outside of core Delaware and core Midland Basin assets are too expensive.

"As we were looking to build the Mach enterprise, from the outset, we said, if nobody cares about inventory and the focus is cash flows and PDP assets, then where are PDP assets trading most cheaply? And [we] really didn't care why that was, necessarily, as long as we get diligent and understand why the margins were there," he said.

That largely ties in with infrastructure as a critical ingredient for most transactions.

"Essentially where is our dollar going to go the furthest and being able to acquire as much production as we can so that when our thesis of higher commodity price in the future pans out, where are we going to get the most bang for our buck," McMullen said.

As with the broad view of most energy investors, Bayou City and Mach's shareholders are focused on cash flows and returns and less about growing production through the drill bit.

"It would be a higher bar, I believe, to go out of the basin right now," he said.

Ward said that if the market moves to a point where PDP acquisitions are valued at PV-10 or higher, "we would probably look more to distributing more cash flow and allowing our production to decline some," he said.

"There still is a market here, really across the whole area, the Midcon, that you can find good acquisitions to be made at the metrics that we have chosen to buy at," Ward said. "And again, if that changes, we don't have to make any acquisitions because we've built up a very nice company." □

IMPROVING THE BOTTOM LINE THROUGH TECH INNOVATIONS

Technology trends are helping operators save on costs and generate more production.

ARTICLE BY
BRIAN WALZEL

For the first time in what seems like years–certainly pre-COVID years–a sense of stability has returned to the upstream oil and gas industry. Backed by solid and stable oil and gas prices, as well as tempered growth and spending, producers have seemingly found the sweet spot between generating returns for investors, growing production and navigating the energy transition.

At the core of much of this sustained stability is operational efficiency. Producers have tightened their belts in spending while slowly but steadily growing production. Still, rig counts are far below pre-COVID levels. However, cost savings and lowered capex doesn't always come from decreased activity, nor does all production growth result from drilling new wells.

Both center around the adoption and deployment of technology applications that are enabling operators to identify more pay, cut down on costs and enable greater efficiencies, which in the end results in a healthier bottom line. According to Rystad Energy, the U.S. shale industry is expected to see $4.2 billion in efficiency gains in 2022.

Advances in drilling technology, a better understanding of the subsurface, automating labor-intensive processes and oilfield electrification have all contributed to improved economics in a resurgent and more stable oil and gas industry.

Halliburton has developed technologies that enable improved geosteering and downhole imaging, combined with remote and autonomous capabilities.

HALLIBURTON CO.

Going electric

Callon Petroleum Co. operates more than 180,000 net acres in the Permian Basin and Eagle Ford Shale. Senior vice president and COO Jeff Balmer said Callon differentiates itself from its peers through its approach to technology applications, which starts, he said, with field development planning.

"To be capital efficient and optimize your dollar but maximize your recovery, you have to really take a regional aspect approach and then work it all the way down to the well, and in particular for us at the pad level," he said.

Like most producers, Callon historically relied on diesel power generation to power its well sites. But Balmer explained that by investing capital to connect the company's operations into the local power grid, not only is the company improving its ESG performance, but it's also realizing significant cost savings.

"We look at opportunities for items like electrification in the field, which allows us a very controlled, dependable source of power," he said. "It improves run time on all of our artificial lifting equipment. All of our pump jacks, all of our pump down controllers now utilize a very controlled, very uniform system. And then of course on the emissions side, you

"The role of technology and the importance of continued investments and innovation is paramount to operational success," said Jeff Balmer, senior vice president and COO, Callon Petroleum Co.

are no longer using diesels. So you're cutting down on your emissions. You don't have the truck traffic. You don't have the physical transfer of the fuel on location. And from a savings standpoint, in the Eagle Ford alone, we're going to save half a million dollars a month in operating expenses."

Balmer noted that transitioning from diesel to electric takes upfront capital, but the payout for Callon came in less than a year.

"And then you'll be making money every single day that you have the infrastructure up and running," he said.

And while Callon has committed to significant implementation of electrification of its producing equipment, the company has also tested the waters on e-frac with a three-well pilot with U.S. Well Services. Balmer said that for this year, Callon will be running "very energy efficient, low-emission frackers."

Downhole imaging

In many ways, a producer's fortunes are often only as good as its rock. But improving an understanding of the subsurface, and subsequently the available pay, is paramount to maximizing production and eventually profits.

A focus for many service companies in recent years has been on developing tools and technologies that solve that challenge, and improved downhole imaging is paying off.

Schlumberger Ltd. has deployed technologies that enable multilayer mapping while drilling technologies that allow the operator to optimize geosteering operations and accessing initially bypassed oil or secondary oil targets.

Vera Wibowo, product champion GRM Geology for Schlumberger, explained that reservoir understanding has evolved over the past few decades, beginning with what she described as "reactive geosteering," then the adaptation of downhole imaging emerging about 25 years ago, transitioning to advancements in geosteering and reservoir mapping.

"The breakthrough came when we had the technology to be able to detect the boundaries of the formation so that we knew exactly where to position the wellbore geologically," she said.

The latest advancements from Schlumberger are now in downhole geosteering and mapping.

"It helps operators save costs by ensuring that they are in the best part of the reservoir while drilling, maximizing the reservoir exposure," Wibowo said. "The technology helps the operator to improve the production and the ability to see deeper and then map the multiple layers they don't see. They are basically placing the well in the best part of the reservoir. All of this is basically reducing the costs and also the risk of the well."

Rami Yassine, senior vice president of the Drilling and Evaluation Division at Halliburton Co., explained that improved reservoir mapping has coincided with increased reservoir complexity, particularly in international basins. In response, Halliburton has advanced its LWD platforms to offer a better understanding of reservoirs, which improves geosteering and ultimately increasing pay.

Yassine related that an operator in the North Sea recently ran Halliburton's latest line of LWD technologies and saw significant cost savings through identifying more hydrocarbons in the reservoir.

"They drilled the well, and then post-job, they ran a 3-D reservoir map," he said. "In that reservoir mapping they were able to identify an additional 400 feet of net pay, so that operator decided to go back in and sidetrack the well that we were on. During that sidetrack, they decided to do it while operating the 3-D reservoir mapping in real time. And while they were doing that, they identified an additional 500 feet of net pay. So that ultimately reduced the overall cost per barrel for that operator just through a sidetrack of a well, and they recovered an additional 900 feet of net pay."

Yassine said that deep reservoir mapping was something that historically was very limited, but as the technology has improved, so has the understanding of the reservoir.

"The value that our customers are seeing is understanding the true boundaries of their reservoir and allowing them to adjust their reservoir models accordingly," he said. "Historically, imaging of the reservoir was limited to a few feet from the wellbore. Now, we're able to see close to 300 feet. So it has allowed our customers to better understand their reservoir. In addition, it has allowed more efficient geosteering across the reservoir for accurate well

Reservoir understanding has evolved over the past few decades, said Vera Wibowo, product champion GRM Geology for Schlumberger Ltd.

placement to maximize the production. And that has ultimately improved the amount of recoverable reserves the operators can have."

Drilling advances

Few stages of the well life cycle have seen more technological advancements in recent years than drilling. With improved geosteering, MWD and LWD applications and fully autonomous drilling rigs, the time it takes to drill miles-long horizontal wells has gone from weeks to days.

"Operators are extremely aware that new technology will come at a price, but it will only be applied and adopted if it's going to achieve the targets of lowering the overall cost of completing sections and drilling wells," said Hesham Darwish, Schlumberger product champion of casing drilling and reamers for well construction. "And we've seen over the years how these advances have brought up efficiency and significantly reduced the number of days and times to drill wells."

Schlumberger's casing-while-drilling technologies allow operators to simultaneously case the section of the hole while drilling, which helps eliminate downtime during the drilling process.

"So, in the conventional methods you have to drill the hole first, and then wait for it to be cased, you need to do a certain number of steps that includes tripping out of hole," Darwish said.

"Challenges are faced in the drilling section, which results in high nonproductive time, unplanned costs and delays, and they happen due to the time exposure between drilling the section and casing it," he said. "Those challenges can happen due to different reasons; could be pressure gradient, unstable formation, losses or gains that happened while drilling, and those issues get even more complicated when we are facing challenging directional profiles which require the right mitigation plan in order to avoid nonproductive time delays and unplanned cost.

"[Casing drilling] provides assurance that every foot drilled is cased and secured. All the down time and the wait time associated with pulling out of the well, conditioning, reaming, casing and running are all eliminated in that case."

"The value that our customers are seeing is understanding the true boundaries of their reservoir and allowing them to adjust their reservoir models accordingly," said Rami Yassine, senior vice president, Drilling and Evaluation Division, Halliburton Co.

"Operators are extremely aware that new technology will come at a price, but it will only be applied and adopted if it's going to achieve the targets of lowering the overall cost of completing sections and drilling wells," said Hesham Darwish, product champion, Schlumberger Ltd.

Yassine said that autonomous drilling capabilities have provided more consistency in drilling, more predictability and more reliability. One of Halliburton's drilling automation tools drives itself downhole without surface interaction, which allows it to use high-frequency measurements downhole to maintain trajectory and deliver the proper wellbore placement.

"Compared to a legacy approach, which was always surface commands and multiple commands to the downhole tools to adjust trajectory as needed, now with that downhole automation, tools have the ability to just run on their own," Yassine said. "Think about it as a more advanced Tesla; consider it with the downhole intelligence essentially, running the system and having high-frequency sensors. It can really consume a lot of downhole data and adjust at a high frequency because of advancements that we've put into electronics and automation."

Balancing investments vs. costs

As the oil and gas industry has moved to prioritizing free cash flow over a production-at-all-costs mentality, investments in new technology applications are at risk. Profits now are given back to shareholders, and money is being invested in simply maintaining production at single-digit percentage growth from year to year.

"But the role of technology and the importance of continued investments and innovation is paramount to operational success," Balmer said.

"The technology aspect is the differentiator," he said. "But it's an appropriate level of applied technology. It isn't where you're trying to come up with correlations that don't make any sense. And I think where we as an industry are going is having the type of the people that are evaluating technology and then the implementation of that technology. You don't have to be the first one to have an autonomous drilling operation or a nobody-on-site completions operation. You just want to be able to leverage those technologies when they are proven." □

A CASE FOR DIVERSITY IN ENERGY

Studies of the oil and gas industry's workforce suggest more inclusion leads to better performance.

ARTICLE BY
VELDA ADDISON
AND
BRIAN WALZEL

The Great Crew Change is complete. Much discussed, fretted over and analyzed, the shift in the makeup of the oil and gas industry's workforce that was long portended has come. And for all intents and purposes, it has come and gone.

Look around conference rooms, exhibit halls, cocktail receptions and Zoom meetings, and you'll see the change firsthand. The industry is younger, more diverse, less formal, speaks in buzzwords, understands (mostly) cryptomining, sees printouts as passe, conducts business and does their jobs from their cellphones, and now frequents the office far less.

Much like the sources of energy it procures, the industry workforce has transitioned and continues to do so. It is the "S" in ESG—social responsibility. But while the industry has prioritized the "E"—environmental—with net-zero and other carbon and methane reduction targets, there is still work to be done to complete the ESG picture.

Part of the effort in achieving those end goals is the continued evolution of the industry's workforce, essentially to make it more diverse. A diverse workforce doesn't just make social sense and is the "right thing to do," but it makes for good business, explained Molly Determan, COO with the Energy Workforce & Technology Council.

"The business case is that more diverse companies perform better and have better returns," she said. "But also, as our work changes, as we become more focused on digitalization and AI [artificial intelligence], the people that we need to employ are changing, and we need to be able to attract those people. So the traditional kind of oil and gas industry that wasn't as flexible and wasn't as focused on making sure that there were benefits like parental leave and things like that, that isn't going to attract the type of people that we need in order to be a leader through energy transitions."

In the recent "Diversity Matters" study conducted by McKinsey and Co., one unnamed oil and gas executive described the importance of a diverse workforce simply in terms of staying relevant.

"This is a business decision," he said. "By 2025 we are going to be a millennial and Generation Z workforce that is inclusive and diverse. If your business is not, you are going to get bottom-of-the-barrel workers."

"You've got to convince people to utilize their network and even reach outside of their network to find, identify and attract diverse talent," said Leon Harden, DEI strategy manager, Burns & McDonnell.

Early-stage recruitment

One of the first steps to instilling a more diverse workforce is understanding what diversity means, and what it looks like. Does it mean more ethnically diverse? More women in the workforce? More socio-economic parity?

"What we've done recently is taken a look at how we choose to interpret the words diversity, equity and inclusion [DEI]," said Tana Cashion, senior vice president of human resources with Devon Energy Corp. "With diversity, we talk about it as being foundational to Devon's success and that our team includes people with a variety of backgrounds, perspectives, experiences and abilities. That's how we think about diversity.

She added that equity is also a hiring priority at the company.

"We believe that fairness is at the center of the core of our culture, policies and practices," Cashion said. "We strive for all employees to have equal access to opportunities.

"And then inclusion, we believe in relationships, and we'll ensure all employees are seen, valued, heard and connected," she continued. "If you look at each of those definitions, we try to think very comprehensively about how everybody in the company should be on the same page about what those things mean, because [diversity] can mean a lot of different things."

To build a foundation for diversity in the oil and gas industry workplace, industry associations and companies themselves are starting, in many cases, at the bottom floor: childhood education. It's a long-term play, investing time and resources into programs and outreach efforts to plant the seed of, eventually, a career in the energy industry.

"We're all trying to have a rising tide that lifts all boats," said Leon Harden, DEI strategy manager with Burns & McDonnell. "That's why we're investing in K through 12 education and mentorship. That's why we do over 400 job shadows for high school kids. At Burns &

McDonnell we have a program called Battle of the Brains, where kids come in and we get them interested in STEM really early. Because it's not just enough to recruit at diverse conferences and go to HBCUs [historically Black colleges and universities] and other minority serving institutions, as we do. We have to jump ahead a little bit and get kids interested really early so that they choose to go into STEM-related degree programs that are available to them in most colleges and universities."

Devon Energy has taken a similar approach to early-stage recruitment, having instituted STEM programs at elementary schools since 2016 in the areas in which Devon operates.

"We've been a part of opening more than 100 STEM centers in schools and learning centers," Cashion said. "That's been an amazing experience to see and be a part of, and it has really had an impact on hundreds and hundreds of students exposing them to this, the skills that they will need to have in order to have the types of careers to fill the pipeline of qualified people, ultimately being able to land in this industry."

While making early investments in a potential future employee pool establishes the science- and technology-minded, it takes more to ensure those future employees are also culturally and racially diverse.

Cultivating diversity

In addition to establishing education programs, Harden believes a key component to cultivating diversity in the industry is for companies and associations to create connections and relationships in their communities.

"We all have recruitment teams," he said. "We all have a top-down diversity initiative, but I think it has to be more grassroots than that."

Harden explained that a first step is ensuring total buy-in on diversity and discussing the business case for diversity.

"Once you've gotten there, you've got to convince people to utilize their network and even reach outside of their network to find, identify and attract diverse talent," he said.

Harden noted that a common practice for companies is for them to identify "that diverse person" within their organization and have that person "carry the mantle of diversity."

"I would encourage [organizations] to get our old white guys out there and really be carrying this mantle, because we need everybody to solve this issue, which is that we need more representation within the industry," he said.

Cashion suggested instilling a multifaceted approach to diversity recruitment, explaining that creating a diverse workforce is not enabled through just one strategy.

"If you change your hiring numbers, that doesn't result in a more comprehensively diverse, equitable or inclusive organization," she said. "If you just focus on unconscious bias training, that also isn't a one-shot deal in terms of becoming more sophisticated in diversity, equity and inclusion. It has to be a comprehensive package. So companies have to look at it through the lens of talent practices, in organizational expectations and conversations and areas of emphasis. It takes time and attention to all of those categories of diversity and inclusion."

At Chevron Corp., intentional conversations about diversity and inclusion continue.

"Where we have underrepresentation, we study it and undertake proactive efforts to address this. This could include broader outreach to underrepresented groups, mentoring

"A culture that is built on a common purpose, teamwork, respect and feedback—and rooted in inclusion, trust and empowerment—is essential for everyone to be their best in the workplace," said Josetta Jones, chief diversity and inclusion officer, Chevron Corp.

SODEXO ENERGY & RESOURCES

BP instructors teach, mentor and guide at the company's Houma Operations Learning Center in Louisiana.

"Our continuing goal is to foster an environment where all employees can reach their full potential and improve the advancement of African Americans and other underrepresented minorities," said Dave Lawler, chairman and president, BP America.

programs, investments in the educational pipeline, and assessing and removing potential barriers to hiring or advancement," said Josetta Jones, the company's chief diversity and inclusion officer. "Accountability for these proactive efforts is fundamental to ensuring the proportion of women and minorities at Chevron increases."

The San Ramon, Calif.-headquartered company has been recognized by several diversity organizations, including the American Association of People with Disabilities and the National LGBT Chamber of Commerce, among others, for its diversity and inclusion initiatives.

Chevron's recent initiatives include a program called Welcome Back, which targets individuals who have left the workforce for child or family care, or other reasons. Launched in 2019, "the program is designed to help individuals re-hone their skills and accelerate the process of reentering the workforce," Jones said

The company is also taking aim at goals toward increasing the number of women at senior levels by establishing its Global Women's Leadership Development Program in 2020. The program, Jones said, has three objectives: "provide strategic development planning for high-potential women earlier in their careers; offer access and visibility to influential senior leaders, job owners and personnel development committees; [and] establish resources to support development, including coaching, mentoring and skills growth."

In all, efforts undertaken by Chevron appear to be paying off.

"We continued to develop our diverse leadership pipeline and have increased the percentage of senior-level jobs held by women and racial and ethnic minorities to 44%," Jones said.

The case for diversity

From a societal perspective, diversity and inclusion is viewed as the right thing to do. And, in a sense, that's true too of business and perhaps even more so the oil and gas industry, traditionally one of the least diverse and inclusive industries.

Findings from the "Diversity Matters" report bore this out, at least from a gender equity perspective. For its report, McKinsey analyzed data from 250 companies, evaluated its own data in women in the workplace and interviewed more than 20 current and former CEOs and senior executives.

McKinsey found that companies in the top quartile for women leaders are 15% more likely to have above-industry average financial returns. The company was careful to note that while no casual connection can be proved, it does point to a correlation that suggests "when companies commit themselves to diverse leadership, they are more successful."

Adopting a culture of inclusion and diversity can also help position a company for the rapidly changing makeup of the American population as a whole, Harden said.

"The Census that just came out said that in 2044 the workforce will be minority white," he said. "So for us, this is an opportunity to position ourselves, to be ready for the workforce of the future. This is a trend, and we have to be ahead of it."

Harden added that many of Burns & McDonnell's clients are asking more questions about how the company is attracting, hiring and retaining diverse talent.

"So it's critical that we start to talk about this, that we start to brand this [and] that we start to communicate it not only to our employees but externally as well," he said.

From an operator's perspective, Devon sees diverse talent acquisition as paramount to staying in step with the rapid evolution of the technologies used to grow their operations and business.

SODEXO

Sodexo knows that operational business continuity is essential to clients. Its site level teams are committed to delivering food and facilities management and client service in a safe environment.

"[The business case for diversity] is extremely compelling in that our industry relies upon technology and innovation," Devon's Cashion said. "You cannot move forward in innovation and technology without having a diverse set of skills, experiences and characteristics of the members of your team to really be driving toward the best results or the best outcome possible. It's part of the fabric of how we operate."

Analysis of a study by McKinsey & Co. of more than 1,000 companies across 15 countries shows there is a strong business case for diversity and inclusion, and "the higher the representation, the higher the likelihood of outperformance."

The consulting firm reported in its 2020 "Diversity Wins: How Inclusion Matters" study that companies in the top quartile of gender diversity on executive teams were 25% more likely to see above-average profitability than their peers in the fourth quartile. The finding was based on 2019 analysis and was up from 21% in 2017 and 15% in 2014.

"In the case of ethnic and cultural diversity, the findings are equally compelling. We found that companies in the top quartile outperformed those in the fourth by 36% in terms of profitability in 2019, slightly up from 33% in 2017 and 35% in 2014," McKinsey stated in the report. "And, as we have previously found, there continues to be a higher likelihood of outperformance difference with ethnicity than with gender."

There are plenty of studies that show how a more diverse workforce leads to diversity of thought and more creative solutions, which in turn improves results, according to Stephanie Hertzog, CEO of Sodexo Energy & Resources. However, she has concerns about attracting talent and keeping them.

"Our industry is going through a tough time, and we really need the best and brightest minds helping us through the energy transition," Hertzog said. "While we've historically been able to attract them, we are seeing some of the best and brightest pause on their decisions."

As a mentor to a recent chemical engineering graduate from Texas A&M University, Hertzog faced the possibility of seeing her mentee leave the industry after just entering it.

"She is still there now ... so we'll see. Her concerns are a few fold," Hertzog said. "One is just where this industry is headed and if there are going to be great career opportunities."

The new hire, Hertzog explained, questioned whether oil and gas was the right industry to commit her career to. The timing of the global pandemic created another set of circumstances that compounded those feelings of doubt. Working from home meant little access to and guidance from experienced coworkers, something that was not limited to the energy field.

It helps to have a support network, Hertzog said. Such support systems can be a godsend when facing challenges. It can be helpful to have people, outside of immediate family or workspace, who have gone through similar experiences to talk to, she said.

Hertzog's network of confidantes was called the Alpha Girls, nicknamed by her father, she said after recalling a bad day when motherhood and work duties collided. She found herself out of town on business crying in a Houma, La., restroom having forgotten her breast pump in Houston.

"There are definitely challenges that women face that men just don't," Hertzog said.

Hertzog, who has worked in energy services, pointed out that during her career she has never had a female supervisor and rarely saw women higher than her on the chain unless they worked in human resources or legal.

Research unveiled in 2021 by the Energy Technology & Workforce Council, working with the consulting firm Accenture, on the U.S. oil and gas workforce showed the percentage of women and ethnic minorities in the sector still trails their representations in the overall U.S. workforce.

The study revealed women account for 47% of the overall U.S. workforce, compared to 19% of the U.S. oil and gas workforce (up from 15% in 2018).

The study concluded that ethnic minority representation, the first year the council

CHEVRON CORP.

Volunteers teach children about robotics at the Chevron-sponsored California State University East Bay Science Festival in Hayward, Calif.

BP

A BP employee is pictured at the company's chemical plant in Texas City, Texas. The company has about 43,500 core employees globally.

included the category in the study, within the sector also lags the overall U.S. workforce. In all, Black/ African American, Asian and Hispanic/Latino employees make up 36% of the overall U.S. workforce. For the U.S. oil and gas workforce, it's 28%.

"It's hard when you don't see anyone who looks like you or has gone through similar things you're going through," Hertzog said. "You have no example of someone who made it through. There were definitely times when I felt like I was failing at all of it—I wasn't a good wife, I wasn't a good mother, I wasn't a good employee. But upon reflection, I was typically putting more pressure on myself than anyone else was."

Besides the so-called Alpha Girls, great bosses made the difference for Hertzog.

"I don't think they were necessarily any more understanding of the plight of the working mother than the working father," she said of her supervisors, "but I've been fortunate to work for empathetic leaders, and that's important regardless of gender or race."

Prioritizing inclusion

Support networks have formed at companies that have put DEI among their priorities. These employee networks bring together people with common identities or experiences, providing supportive environments for career development and growth.

Sodexo has nine employee business resource groups, which include gender, race, veterans and disabled employees.

Companies like BP and Marathon Oil Corp. are among the energy companies with similar resource groups. Both have undergone strategic transformations: BP transitioned from an international oil company to an integrated energy company in 2020, while Marathon split into two independent companies in 2011. Diversity has been part of both companies' ambitions, and both have made additions and set new goals recently regarding their DEI efforts.

BP, which published its first DEI report in June 2021, is recognized as having one of the energy industry's most mature programs, according to Tamara Page, BP's head of Western Hemisphere workforce DEI.

"I will say we're still learning. This is a journey for us," Page said during the Offshore Technology Conference in Houston. "We don't have all the answers, and we are continually evolving and reinventing ourselves within the DEI space. When I started way back, it was just the D; it was just diversity. And then it moved into diversity and inclusion, and now it's diversity, equity and inclusion."

One of BP's latest awakenings came in 2020 with the deaths of George Floyd, Ahmaud Arbery and Breonna Taylor. She said the company recognized the need to respond to what was happening in the world because "our people are our biggest assets."

The company held "listening lounges" for its employees to share their experiences with racial injustice. The lounges attracted about 6,000 people, Page said.

"I don't think I'm alone in saying this," Page said. "It was a change in our organization."

While BP has had DEI programs in place for a number of years, the company went further after its shared conversation. Its Framework for Action plan includes focusing on transparency, releasing an annual DEI report; accountability, linking diversity and inclusion progress to performance management; and talent, targeting Black employee development.

The plan includes a goal to double spend with U.S.-based diverse suppliers by 2023, embedding DEI metrics into entity operating plans and the annual performance review process for all employees as well as doubling representation of African Americans in group leadership by 2023.

"To some of you, this may feel like we're focusing on one group of employees over another. To others, these actions will not be enough," Dave Lawler, BP America chairman

and president, said in a statement at the time. "Balance is hard to achieve, but I'm confident this framework is the right path for BP's future. The BPLT, leaders across the U.S. and I are all committed to this important work. This is an ambitious framework, and we will dedicate the resources we need to achieve it."

The year 2020 was marked by a wave of racial unrest in the U.S. that was reignited by the deaths of Floyd, Arbery and Taylor. The deaths sparked protests and again put the spotlight on incidents of systematic racism toward Blacks in the U.S.

In 2020 Chevron evolved its long-term strategy toward improving racial equity. The change came in response to what Jones described as a "convergence of events that include the spread of COVID-19, an economic downturn that led to massive unemployment and social unrest growing out of the death of George Floyd and other Black citizens in the United States."

The company's effort focused on increasing investment and support in the education and development of Black talent and leadership.

"Our racial equity approach includes a $15 million commitment that has four pillars: education, job creation, talent and leadership development, and community and small business partnerships," Jones said. "We are also working to expand our existing relationships with community, business and educational partners such as K-12 science, technology, engineering and mathematics organizations and historically Black colleges and universities."

In 2020 Marathon launched its Black Employees and Allies of Marathon (BEAM) Network, which is open to all employees. The move was not performative, said Shara Hammond, leadership and inclusion manager with Marathon Oil. Speaking during the Houston conference, Hammond said the company started that journey in 2018 because of the gap in psychological safety.

According to Marathon's website, the BEAM Network enables employees to connect to support each other in personal and professional development; encourages Black employees to advance their careers through mentorships, networking and organizational partnerships; creates programs that increase awareness and understanding of different perspectives in the workplace; promotes a diversified workforce including in various job functions; and increases awareness within the Black community of opportunities within the oil and gas industry.

"They've just embraced that by creating dialogue circles where Black employees and allies are able to have conversations about inclusion, differences, commonalities and diversity," Hammond said of Marathon's workforce. "From that, they want to build a strategy so that we then take on leadership behaviors around allyship in our organization."

That year Marathon also partnered with the Chinese American Professionals Group to offer virtual training events on topics such as bystander training, feeling safe in the workplace, psychological safety and moving beyond crisis. The move came as anti-Asian harassment and attacks surged in the U.S. during the COVID-19 pandemic.

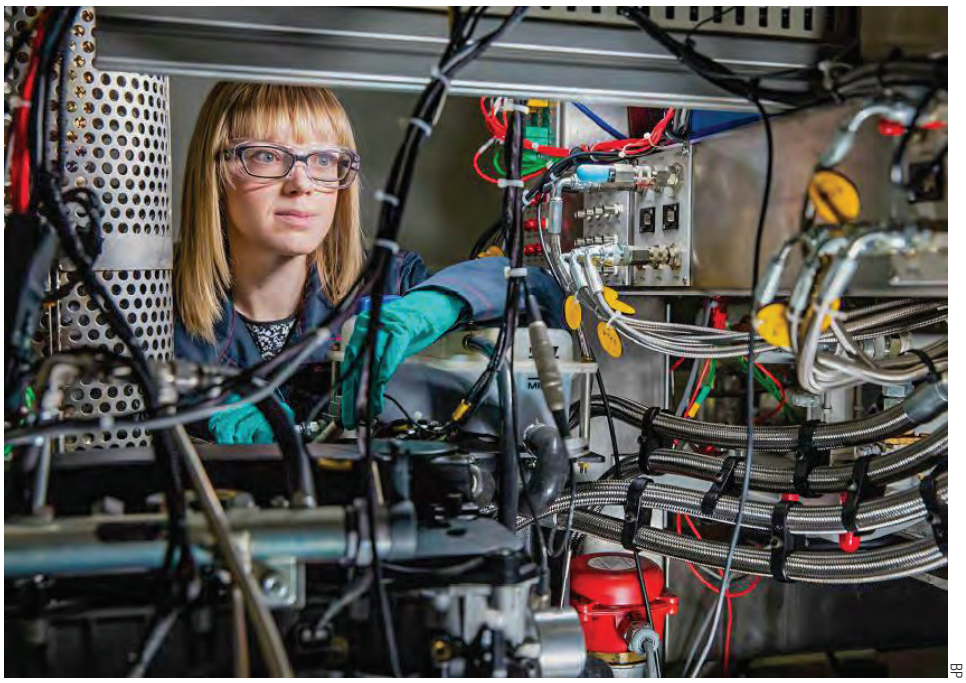
Marathon's actions were a continuation of the company's grassroots, employee-driven DEI efforts. When developing such strategies and forming programs, it might be natural to take a top-down approach, implement best practices and let data drive decisions, Hammond said, but it's important to listen to employees.

"We often start with the data. The data will tell you one story; that's completely fine. We're data-driven people," she said. "But at the end of the day, your employees know exactly where you are and where you may need to go. So that's where you find your next best step, instead of just looking for a best practice."

Diversity, Hertzog said, was not talked about by her previous employer; however, it is "part of the DNA" at Sodexo. The onshore and offshore food and facilities management services company has a workforce that is 55% women. Like some energy companies, Sodexo offers DEI training with participation tied to compensation for executives, and job candidate pools must be diverse. The company also extends its DEI values to suppliers, having committed globally to spend 25% of its purchases with small- and medium-sized businesses with a focus on local and diverse by 2025.

"We have a long way to go on both gender and ethnic diversity," Hertzog said of the energy industry. "The most important thing we can do is be really intentional about it." □

BP reported 38% of its employees in 2019 were female, up from 35% in 2018.



BP

2022 Trends IMPACTING OIL AND GAS

The ongoing need for reliable and affordable energy, ESG considerations, capital discipline and M&A opportunities are expected to drive the energy sector in 2022.

ARTICLE BY
MITCH FANE

ILLUSTRATIONS BY
ROBERT D AVILA

It is increasingly clear that this year—and potentially the next five—in the oil and gas industry will be defined by a push and pull between capital markets' reluctance to invest in oil and gas and the dissonance among government, consumer and investor perceptions about the speed with which oil and gas should or can be replaced.

Market developments in 2021 make structural undersupply of oil and gas commodities self-evident. In prior times, that would mean high returns and a rush to invest, but these are not prior times.

Pressure to decarbonize and the subsequent reaction of capital markets may result in continued structural underinvestment. But 2021 has shown us that the laws of supply and demand haven't changed.

When gas demand in Europe and Asia surged, the spread between natural gas at the Henry Hub and LNG delivered into Asia went from $3/MMBtu to $30/MMBtu, according to Refinitiv.

Moving into this year, there will be increasing risks of tight markets and opportunities for companies willing to make investments in what is increasingly perceived as a sunset industry.

In 2022 and beyond, four trends will shape the energy sector:

1. The ongoing need for reliable, affordable energy.

The oil and gas industry is under relentless pressure. It is perceived as a villain when fuel prices are high and ignored when fuel prices are low. The threat of climate change has only reinforced that image.

Government action to decarbonize the energy complex is increasingly certain, and whatever the destination, the journey will take time and cost trillions. Renewable penetration and electric vehicle adoption are growing, but the impact on oil and gas demand remains imperceptible.

Populations and economies will expand across the globe requiring reliable, affordable energy. Until fossil fuels are displaced at scale, oil and gas demand will also increase.

This presents an opportunity for some companies to create scale and earn superior returns if they're willing to take the risk and can engineer their operations for success. Integration makes a collection of assets more valuable together than they would be individually by connecting them (perhaps virtually) and removing or avoiding obstacles to optimization. This will be a pivotal differentiating factor for energy companies.

Energy value chains are complex, and at each link, there is the possibility of losing value. Many industries have struggled with which parts of the value chain belong together and which parts are best left separate, and oil and gas companies are no exception.

While typically information has proven to be the biggest obstacle to integration, the digital age has created new perspective, and we see great opportunity in the years to come.

2. Response to ESG considerations.

Moreover, response to the ESG imperative will take one of three forms, and the choices that companies make will largely define their overall strategies.

Certain oil and gas companies view ESG excellence as a competitive advantage and will invest proactively to create value. While many oil and gas companies are digitalizing their operations, digitalization is taking on a whole new lens around ESG. As an example, a company might collate the carbon emissions data from a particular business unit, monetize those emissions and trade them via blockchain.

Further, oil and gas companies are increasingly looking to digital twins, data platforms and other technologies to move beyond simply monitoring to emission controls.

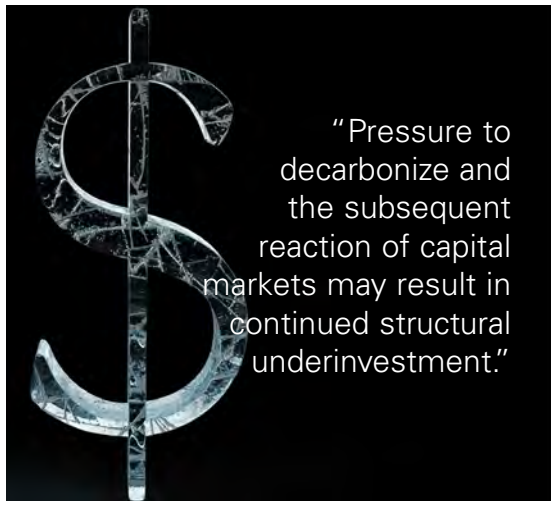
Simultaneously, companies are also evaluating opportunities to invest in decarbonized energy: hydrogen, wind, solar, carbon capture, utilization and storage, geothermal, energy storage and others. Those with command of the technologies will be advantaged.

Others will act now out of a sense of inevitability. ESG won't necessarily be seen by this group as a source of competitive advantage now or ever, but these companies will recognize that transparency is essential. Those companies will be proactively buttoning up their systems, data and ESG reporting processes to keep up.

A third subset of companies carry on as usual. Branding and access to capital can be compartmentalized to some extent in commodity industries that can sustain production with little or no outside investment. This group is waiting for ESG to become a requirement and for Securities & Exchange Commission disclosure mandates to be announced. Regulation may eventually take over, but until it does, competitive advantage will be difficult to see. While there will be some, those organizations will be few and far between.

3. Capital access and discipline.

The oil and gas industry must walk a very fine line as commodity prices increase,



balancing fiscal discipline and progress on ESG issues, while meeting growing demand and shareholder expectations. No matter the ESG strategy that oil and gas companies choose to take, access to capital will be a critical factor in future success.

Capital providers are increasingly aware of sustainability risk. They are calculating their exposure by analyzing their clients' emissions both on an absolute and intensity basis to understand how that rolls into an aggregated view of their portfolio. They are also aware of the capital investments needed to truly fund the energy transition, but many are struggling to determine the realistic measure of funding required to meet mid-century and interim emission targets. Balancing the need for that capital with the realistic expectations for decarbonization outcomes will set the financial and regulatory context for the coming decade.

Further, some investors are concerned that a rush to low-carbon technology will cause overvaluation. As a result, capital access for those organizations that actually need to make this transition will be delayed and bumpy.

Amid less third-party investment, capital discipline and operational excellence will remain a high priority for all oil and gas companies. Digital transformation will lead the way, unlocking efficiencies, cutting costs and enabling new business models. With better data analysis, companies will make better M&A decisions and optimize portfolio risk and returns. Profitability in legacy businesses will need to fund transition investments and keep returns at the corporate level competitive while alternative energy projects find their footing.

4. M&A opportunities emerging.

The combination of a positive return outlook, upward pressure on valuations and the need to decarbonize will have oil companies taking a hard look at their portfolios. That analysis will no doubt lead to portfolio rebalancing and a surge in transaction activity, keeping in mind how access to capital impacts deals.

Forecasts of falling oil demand, targets that would force oil companies to be accountable for not just the production, but the use of oil products (Scope 3 emissions) and questionable economics have led international oil companies to pivot away from U.S. shale properties.

Eventually, the appetite for those assets from publicly traded companies will be exhausted, leaving room for private players, who are large and financially healthy, to step up.

Rig counts are well above where they were last year but are less than half of their pre-pandemic peak, which was less than half of the peak they reached before the 2014 to 2015 downturn, begging the question of what it will take to get more capital into the oil field. Private ownership of U.S. shale properties may turn out to be the answer, though moving the ownership of carbon-emitting assets from company to company will not actually result in less emissions.

Meanwhile, oil and gas companies will seek to placate activist investors, diversify their portfolios and, in some cases, divest fossil fuel assets. Oil companies put over $10 billion into renewable energy projects in each of the last three years. Time will tell if those investments will pay off.

Competition among fossil fuel companies to put down a footprint in clean energy is fierce, projects are selling at a premium and there's a lot of downward pressure on returns. At the same time, there are good questions about the fit between oil company competencies and success factors in the electricity and renewable energy business generally.

The outlook for M&A in 2022 looks strong. Companies will need to cash out on fossil fuels as they cash into renewables. After that comes the drive to meet shareholder expectations of profits, returns and cash flow. ☐

Mitch Fane is a principal at Ernst & Young LLP and serves as the EY Americas energy and resources leader and U.S. oil and gas leader. He has more than 25 years of experience that spans all segments of the oil and gas, petrochemicals, power and utilities, and renewables industries, with experience in mergers, acquisitions, restructurings, fairness opinions, strategic alternative evaluation and collateral purposes.

EDITED BY
DARREN BARBEE

Falcon Swoops Down On Desert Peak In $1.9 Billion Merger

FALCON MINERALS CORP. agreed on Jan. 12 to an all-stock merger with **Desert Peak Minerals**, the largest independent Permian Basin pure-play mineral and royalty company, set to create a mineral and royalty company with a significant Permian and Eagle Ford footprint and an enterprise value of $1.9 billion.

The transaction will mark 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. It also follows a thorough evaluation over the past several months of a number of alternatives to maximize shareholder value, according to Claire Harvey, chair of the Falcon board and the transaction committee.

"Following our comprehensive review, we believe that a combination with Desert Peak represents the best opportunity to maximize value for Falcon's shareholders," Harvey commented in a company release.

Combined, the company will own over 139,000 net royalty acres, normalized to a 1/8th 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.

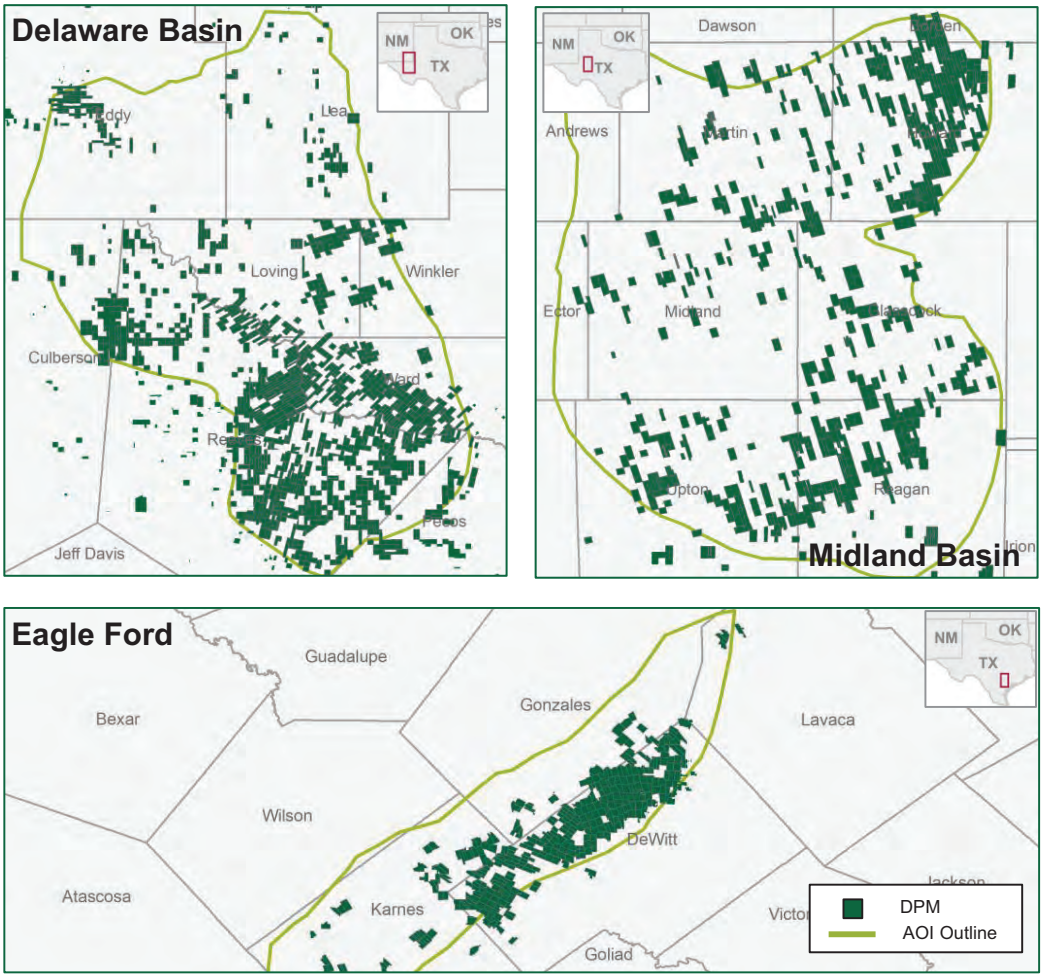
The combined company—to be managed by the Desert Peak team headquartered in Denver—will remain focused on consolidating high-quality mineral and royalty positions in the Permian Basin while optimizing its existing asset base, a company release said.

"We believe the ownership of Permian minerals and royalties is trending toward larger-scale, more efficient institutional ownership," Desert Peak CEO Chris Conoscenti commented, adding that the new company strategy is to be the "leading consolidator" of these assets.

Desert Peak was founded by **Kimmeridge**, a private investment firm focused on energy solutions, to acquire, own and manage high-quality Permian Basin mineral and royalty interests. The company has accumulated its 105,000 net-royalty-acre position in the Permian through the consummation of over 175 acquisitions to date, according to the release.

Meanwhile, Falcon owns mineral, royalty and overriding royalty

Desert Peak Minerals Permian Assets



Source: Falcon Minerals, Desert Peak Minerals

interests covering over 21,000 net royalty acres in the Eagle Ford Shale and Austin Chalk in South Texas. The company also owns over 12,000 net royalty acres in the Marcellus Shale across Pennsylvania, Ohio and West Virginia.

Combined, the company will have approximately 20 net wells normalized to a 5,000-ft basis that have either been spud or permitted. The inventory of line of sight wells provides visibility into attractive organic production over the next 12 months, the company release said.

"As we have previously communicated to our shareholders, we believe scale matters in the minerals business, as it enhances the ability to drive greater consolidation, improves access to capital and reduces volatility caused by asset concentration," added Bryan Gunderson, president and CEO of Falcon, in the release.

Expected to close during the second quarter, Desert Peak will become a subsidiary of Falcon's operating partnership and the combined company will retain Falcon's "Up-C" structure.

Under the terms of the definitive agreement, Falcon will issue 235 million shares of Class C common stock to Desert Peak's equity holders. Falcon's existing shareholders will own approximately 27% of the combined company, and Desert Peak's equity holders will own roughly 73%.

Following closing, the combined company will have a new board of directors consisting of eight members. According to the release, members of the new board are currently expected to be: Noam Lockshin, Christopher Conoscenti, Erik Belz, Allen Li, Claire Harvey, Steven Jones, Morris Clark and Alice Gould. Lockshin, a partner at Kimmeridge, Desert Peak's and the combined company's largest equity holder, will serve as chairman of the new board of directors.

Barclays is serving as lead financial adviser to Falcon's transaction committee, and **Houlihan Lokey** also served as a financial adviser to the transaction committee. **Latham & Watkins LLP** is Falcon's legal counsel, and **White & Case LLP** is serving as legal counsel to the transaction committee. **Vinson & Elkins LLP** is serving as legal counsel to Desert Peak and Kimmeridge.

—Emily Patsy

Lime Rock Resources Kicks Off 2022 With Pair Of Acquisitions

LIME ROCK RESOURCES started 2022 with a pair of acquisitions worth $358.5 million that chairman and CEO Eric Mullins said signals changing market dynamics for upstream A&D.

With a sole focus on acquiring producing oil and gas properties in the U.S., Lime Rock Resources has made over 25 major acquisitions since its inception in 2005. However, until last October, the Houston-based company had been laying low since 2019, according to Mullins.

"We have been patient, acquiring only one small overriding royalty interest in the two years before this past October," he commented in a company release on Jan. 4.

In October, Lime Rock Resources closed on the acquisition of oil and gas properties in the Permian Basin from **Rosehill Resources**. The acquisition, which Mullins had described in a July announcement as a "unique opportunity," was worth $508.3 million.

In total, the Lime Rock Resources team has made over $850 million in total property acquisitions during the past four months.

"We believe that the nearly $1 billion of acquisitions in the last several months," Mullins said, "testifies to changing market dynamics, a robust opportunity set and our ability to work with sellers over many months on transactions that work for all parties."

The two acquisitions announced Jan. 4 included the acquisition of **Abraxas Petroleum Corp.**'s Williston Basin position in North Dakota. Abraxas had previously announced the $87.2 million transaction as part of a restructuring process that would result in it becoming a pure-play Delaware Basin company.

Separately, Lime Rock Resources said it also acquired properties from an undisclosed private seller in the Austin Chalk and Eagle Ford in Texas for $271.3 million.

"With significant on-the-ground operating capability in both Texas and North Dakota," Charlie Adcock, vice chairman of Lime Rock Resources, added in the Jan. 4 release, "we look forward to integrating the new assets into our existing operations and to continue to focus on margins and low-risk development opportunities."

The Williston acquisition from Abraxas consist of approximately 3,500 acres in North Dakota's McKenzie County. Inclusive of the new assets, Lime Rock Resources now manages approximately 19,400 boe/d of net production in North Dakota within the Williston Basin, where it said it has been an active operator since 2014.

The private acquisition in the Austin Chalk and Eagle Ford is of producing properties on approximately 46,000 highly contiguous net acres located in Burleson, Milam and Robertson counties, Texas. The properties produced approximately 7,700 boe/d as of the closing of the acquisition, the Lime Rock release said.

—Emily Patsy

Earthstone To Acquire Permian's Chisholm Energy

EARTHSTONE ENERGY INC. on Dec. 16 agreed to acquire the assets of privately held Permian Basin operator **Chisholm Energy Holdings LLC** in a cash-and-stock transaction worth over $600 million that marks the independent E&P's fifth acquisition within the past 12 months.

"The Chisholm acquisition caps off a series of highly-accretive and value-adding transactions that have dramatically transformed Earthstone during 2021 and further establishes Earthstone as a Permian Basin-focused company with increasing scale," Robert J. Anderson, president and CEO of Earthstone, commented in a company release.

In particular, the acquisition of Chisholm will expand Earthstone's Permian footprint into the Delaware Basin. The company expects the deal will not only increase its net production and adjusted EBITDAX but also roughly double free cash flow in 2022 versus Earthstone standalone.

Chisholm, majority owned by **Warburg Pincus LLC** and its affiliates, operates in the northern Delaware Basin with approximately 36,100 net acres and a drilling inventory of 414 gross (237 net) operated identified locations in New Mexico's Eddy and Lea counties. The company is currently operating a two-rig drilling program, which Earthstone said it plans to maintain, with current net production of about 13,500 boe/d (61% oil, 79% liquids).

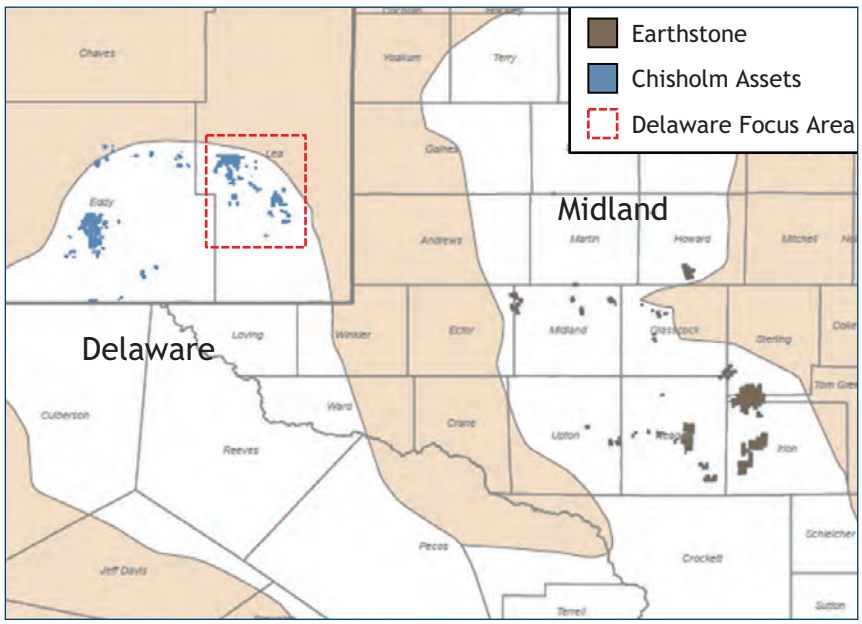
As in previous acquisitions, Earthstone is using a mix of cash and equity to acquire Chisholm's high-margin producing assets that generate free cash flow, adding "substantial size and scale while maintaining our balance sheet strength."

The aggregate purchase price of the Chisholm acquisition is approximately $604 million consisting of $340 million in cash at closing, $70 million of deferred cash due over the 12 months after closing and about 19.4 million shares of Earthstone's Class A common stock valued at $194 million based on its closing share price on Dec. 15.

Warburg Pincus, a current beneficial owner of about 15.1% of Earthstone's total Class A and Class B common stock, is expected to indirectly receive roughly 13.2 million shares of Class A common stock through its majority ownership of Chisholm. Adjusted for the equity consideration expected to be issued, Warburg Pincus's beneficial ownership of Earthstone's total Class A and Class B common stock will be increased to approximately 24.7%, according to the company release.

Earthstone plans to fund the cash portion of consideration with cash on hand and borrowings under its senior secured revolving credit facility. The company said it also obtained commitments from a group of existing lenders to increase the borrowing base and elected commitments under its credit facility to $825 million from $650 million upon closing.

Chisholm's Permian Asset Overview



Source: Earthstone Energy Inc.

Based in The Woodlands, Texas, Earthstone Energy is a small-cap, Permian-focused producer with about 101,300 net acres in the Midland Basin, according to its most recently published investor presentation.

Over the past six years, Earthstone has utilized M&A of small operators in pursuit of its consolidation strategy, including the acquisitions of **Independence Resource Management LLC** and **Tracker Resource Development III LLC**, both of which closed in 2021 and added to Earthstone's Midland Basin position. More recently, the company closed in early November a bolt-on acquisition in the Midland Basin worth approximately $73.2 million in cash and stock.

Also, earlier this year, Earthstone closed an acquisition in the Eagle Ford Shale where the company also operates on a smaller scale.

"When this acquisition is combined with the previous four acquisitions completed in 2021," Anderson continued of the Chisholm acquisition, "we will have increased our Permian Basin net acreage footprint by approximately 400%, almost tripled our daily production rate and meaningfully increased free cash flow generation capacity."

In total, Earthstone expects the Chisholm acquisition to increase its Permian Basin acreage footprint by over 35% to roughly 138,000 net acres. Net production is expected to also grow by roughly 39% as well as adjusted EBITDAX by 49%.

Pro forma, Earthstone forecasts 2022 preliminary production of 44,000 to 48,000 boe/d (53% oil, 75% liquids) and $550 million to $580 million of adjusted EBITDAX.

"Additionally, the significant size of this transaction increases our scale materially and positions us to build on our corporate and field level operating efficiencies and drive additional cost savings," Anderson said.

Wells Fargo Securities LLC is exclusive financial adviser to Earthstone. **Jefferies LLC** is serving as exclusive financial adviser to Chisholm. Legal advisers included **Haynes and Boone LLP** and **Jones & Keller P.C.** for Earthstone and **Kirkland & Ellis LLP** for Chisholm.

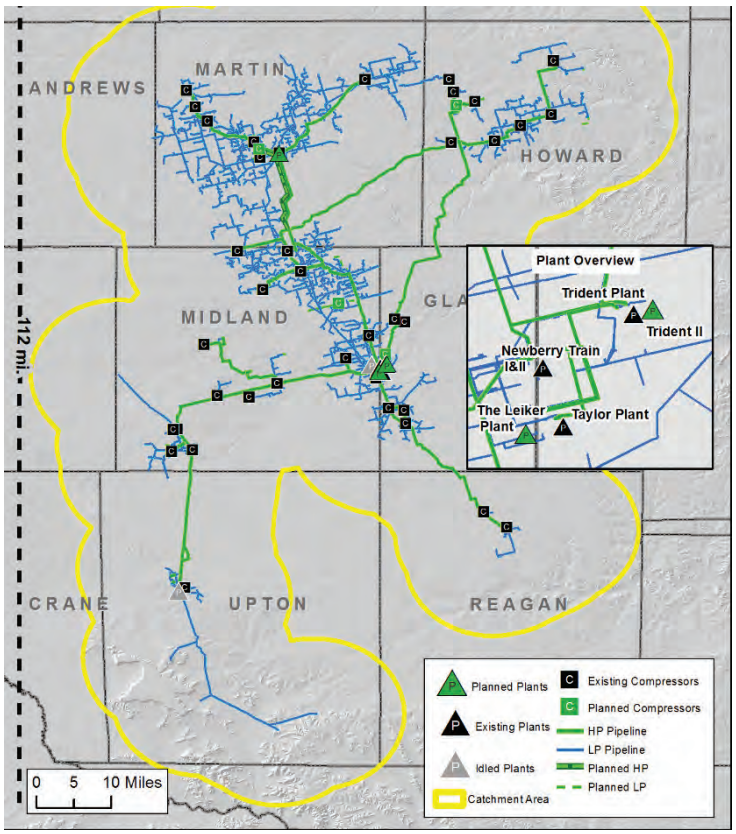
—Emily Patsy

Enterprise Grabs Navitas Midstream In $3.25 Billion 'Surprise' Deal

ENTERPRISE Products Partners LP agreed on Jan. 10 to acquire **Navitas Midstream Partners LLC** in a debt-free transaction for $3.25 billion in cash consideration, marking Enterprise's "surprise" entrance into the Midland Basin.

Backed by **Warburg Pincus LLC**, Navitas provides natural gas gathering, treating and processing services in the core of the Midland Basin of the Permian. Enterprise's agreement to acquire the privately held company comes as a surprise, according to analysts with **Tudor, Pickering, Holt & Co**. (TPH), given Enterprise's recent capital discussions and messaged preference for downstream.

Navitas Midland Basin System Overview



Source: Enterprise Products Partners LP

"While the relatively inexpensive portfolio cost should help mitigate initial market concern, implied DCF yield comes at only a slight premium to standalone EPD metrics and increasing exposure to the wellhead without a clear readthrough to NGL logistics is tough to reconcile with messaged strategy," the TPH analysts wrote in a research note.

"Notably, there is little discussion of incremental downstream volumes to EPD's pipeline, fractionation and export business as a result of the deal which will be a key market question to justify expanding wellhead exposure," the TPH analysts added.

Navitas Midstream's assets in the Midland Basin include approximately 1,750 miles of pipelines and over 1 Bcf/d of cryogenic natural gas processing capacity with the completion of the Leiker plant, which is expected in first-quarter 2022.

Other than downstream pipelines, Enterprise co-CEO A. J. "Jim" Teague said the company does not have a natural gas or NGL presence in the Midland Basin.

"The Navitas management team has developed a premier system in the heart of the Midland Basin. ... This acquisition will give us an entry point into the basin," Teague commented in the release.

Based in The Woodlands, Texas, Navitas was formed in 2014 by an experienced management team in conjunction with Warburg Pincus. Founders R. Bruce Northcutt, Bryan Neskora and Jim Wade previously built Copano Energy LLC into a $5 billion enterprise before its sale to **Kinder Morgan** in 2013.

"We are excited to contribute our unique Midland Basin system to Enterprise, one of the premier midstream operators," commented Northcutt, who serves as CEO of Navitas, in a separate company release.

"We have succeeded in our goal of creating a unique company that provides critical infrastructure to meet the needs of our Midland Basin producers," he continued. "We would like to thank our customers for trusting Navitas to develop a system that would meet the needs of their rapid volume growth, and we know they will be in good hands with a company the scale of Enterprise."

The Navitas system is anchored by long-term contracts and acreage dedications with a diverse group of over 40 independent and publicly owned producers. The system is also supported by fee-based contracts that provide additional revenues based on commodity prices.

"We believe this acquisition will be immediately accretive to distributable cash flow per unit," commented Randy Fowler, co-CEO and CFO of Enterprise's general partner, in the company release.

Navitas Midstream provides visibility to future growth with up to 10,000 drilling locations, or over 15 years of drilling inventory based on current rig counts, on the dedicated acreage, according to the release. Based on the current outlook for commodity prices in 2023, which would be Enterprise's first full year of ownership, Fowler said the company forecasts distributable cash flow accretion will be in the range of 18 cents to 22 cents per unit as a result of the Navitas acquisition.

"This investment will provide Enterprise with an attractive return on capital and support additional capital returns to our limited partners through distribution growth and buybacks of common units," Fowler added.

The transaction—the largest acquisition of a private gas gathering and processing business, according to Warburg managing director John Rowan—is expected to be completed in first-quarter 2022. Enterprise plans to fund the acquisition using cash on hand and borrowings under the partnership's existing commercial paper and bank credit facilities.

Jefferies LLC was financial adviser to Navitas in connection with the transaction, and **Kirkland & Ellis** served as the company's legal adviser.

—Emily Patsy

Targa Resources Strikes $925 Million Deal With Stonepeak

TARGA RESOURCES CORP. is buying back the interests in its development company joint ventures (DevCo JVs) from investment firm **Stonepeak Partners LP** for approximately $925 million, the Houston-based midstream company said in a Jan. 10 release.

The assets from the DevCo JVs—originally formed in 2018—include a 20% interest in Grand Prix NGL Pipeline, a 25% interest in Gulf Coast Express Pipeline and a 100% interest in Train 6 fractionator in Mont Belvieu, Texas. The transaction, which was scheduled to close on Jan. 14, had previously been discussed during the company's third-quarter earnings call last November.

"With all assets set to be consolidated as of Friday, we anticipate a near-term sale of GCX [Gulf Coast Express Pipeline] could be in the works as previously rumored sales price of ~$750 million would reduce the net outflow to $175 million resulting in a TPHe sub-2.0x transaction multiple on the remaining Grand Prix and Frac 6 interests," analysts with **Tudor, Pickering, Holt & Co.** (TPH) wrote in a Jan. 11 research note.

Targa had agreed in February 2018 to form the DevCo JVs with Stonepeak Infrastructure Partners to support the development of the three key fee-based downstream assets. The partnership was expected to significantly reduce Targa's equity funding needs for 2018 and 2019, according to a company release from that time.

As part of the initial DevCo JV agreement, Stonepeak committed an aggregate of approximately $960 million of capital, including an initial contribution of approximately $190 million that will be distributed to Targa to reimburse the company for capital spent to date. Targa committed to fund approximately $150 million related to its share of the DevCo JVs' future capital costs.

In total, the DevCo JVs were estimated to be worth roughly $1.1 billion. Targa had also retained the option as part of the agreement to acquire all or part of Stonepeak's interests for a four-year period beginning on the earlier of the date that all three projects have commenced commercial operations.

Targa had approximately $3.2 billion of available liquidity at year-end 2021 and intends to fund the DevCo acquisition using available liquidity, the company said. Pro forma for the acquisition, Targa will own a 75% interest in its Grand Prix NGL Pipeline, 100% of its Fractionation Train 6 in Mont Belvieu, Texas, and a 25% equity interest in the Gulf Coast Express Pipeline.

With the elimination of the DevCo structure and broader capital simplification, TPH estimates that Targa's existing valuation guidance of about 5.5 times EBITDA translates to about $170 million of additional earnings though the firm said it models slightly above that for Targa for fiscal-year 2022 given ramping NGL throughput.

—Emily Patsy

HAYNESVILLE

■ **Aethon Energy Management LLC** is exploring a sale of its Haynesville Shale acreage in North Louisiana that could be valued at around $6 billion, including debt, people familiar with the matter said.

Bankers hired by Aethon reached out in the final weeks of 2021 to a small number of potential buyers to gauge initial interest in its Haynesville assets in North Louisiana, the sources said, ahead of a formal sale process later this year. Aethon's assets in the East Texas portion of the Haynesville Shale formation are not part of the process, the sources added. The sources, who spoke on condition of anonymity to discuss confidential information, cautioned there was no guarantee that Aethon would complete a sale.

A spokesperson for Aethon declined to comment.

A number of privately owned Haynesville gas producers went up for sale in 2021, as owners capitalized on a rebound in natural gas prices, which hit a 12-year high in October, to offload long-held investments.

The acquirers were publicly listed companies seeking to reduce costs through economies of scale and bolster operations close to the Gulf of Mexico coast, which has emerged as a key gateway for U.S. exports of LNG.

■ **Milestone Environmental Services LLC** recently acquired an energy waste disposal facility in Center, Texas, along with additional permits, marking the Houston-based company's entrance into the East Texas Haynesville Shale. Financial details weren't disclosed.

"We believe we have an obligation to help our customers make good on their commitments to lower their emissions and produce vital energy for the world in a more sustainable way," Gabriel Rio, president and CEO of Milestone, said in a company release on Jan. 4.

Milestone was an operator in East Texas for several years prior to the acquisition. However, the company said its acquisition of the Center facility repositions Milestone in the core of the Haynesville and makes Milestone a leading operator of environmental infrastructure in the basin.

"We believe the Haynesville will be a growing market given the increased global demand for natural gas as the world transitions its energy usage to lower-carbon sources," Rio added in the release.

The acquisition includes the purchase of an active slurry injection facility that is a cornerstone of the environmental infrastructure in place to manage energy waste generated by E&P operators drilling for natural gas in the Haynesville Shale in Texas and Louisiana. The facility, which includes two inception wells, is located in Shelby County, 3 miles north of Center, Texas, on Hwy 96.

MARCELLUS

■ Spain's **Repsol** has bought shale oil and gas assets from U.S. firm **Rockdale Marcellus** for $222 million, a company spokesperson said.

Repsol will pay $220 million in cash and assume an additional $2 million in debt, he said. The assets were sold by Rockdale Marcellus as part of a Chapter 11 process.

The assets are located near an area in Pennsylvania where Repsol already operates a shale field.

Rockdale Marcellus was formed with the acquisition of **Royal Dutch Shell Plc**'s operated Marcellus properties in Tioga, Lycoming and Bradford counties in Pennsylvania in 2017. The company filed for bankruptcy in September 2021.

■ **Rising Phoenix Royalties** on Jan. 6 revealed a transaction described by the Dallas-based company as "another natural gas royalty acquisition" in the Marcellus Shale.

Built on four generations of oil and gas industry expertise, Rising Phoenix is a privately held independent mineral and royalty interest acquisition company focusing on the Haynesville Shale, Barnett Shale, Eagle Ford Shale and Anadarko Basin.

The Marcellus Basin mineral acquisition spans 98 net royalty acres in Pennsylvania's Washington County. **Range Resources Corp.** is the wellsite operator, according to the company release.

Rising Phoenix did not disclose the terms of the transaction or the seller, but CEO and founder Jace Graham noted that their clients chose to divest out of their oil and gas royalties "due to its volatile nature, increasing regulations and possible future unfavorable capital gains tax legislation."

"It made sense for their estate planning to sell and reinvest the proceeds into a more financially stable asset," he added in the release.

MIDCONTINENT

■ **BCE-Mach**, a partnership led by industry icon Tom Ward, is closing out the year with a pair of acquisitions that expands its footprint in the Midcontinent, which already stretches across a formidable 678,000 net acres as of Sept. 30.

The transactions mark BCE-Mach's tenth and eleventh acquisitions since Ward's **Mach Resources LLC** teamed up with Houston-based private equity firm **Bayou City Energy Management LLC** to pursue a strategy of consolidation within the Midcontinent through the prudent acquisition of oil and gas assets.

The two recent acquisitions were executed through purchase and sale agreements totaling $66.5 million, the first of which represents BCE-Mach's fourth acquisition in the STACK play and includes additional working interest across 61 wells it operates in Kingfisher County, Okla.

"Our strategy since forming BCE-Mach in 2018 hasn't changed," Ward, who serves as CEO of BCE-Mach, commented in a company release on Dec. 9. "Despite changing commodity prices and investor interest in our industry," he continued, "we have consistently been able to deploy capital and acquire assets at approximately 2.5 times cash flow."

GOM

■ **W&T Offshore Inc.** on Jan. 10 agreed to a $47 million cash acquisition of producing properties in the Gulf of Mexico Shelf as the region's A&D environment improves, according to CEO Tracy W. Krohn.

"Acquisitions are a core component of how we create value at W&T, and this transaction is another great example of an acquisition that adds value for our stockholders," said Krohn, who also serves as chairman of the W&T Offshore board, in the company release.

The Houston-based company entered a definitive purchase and sale agreement to purchase the oil-weighted operated producing properties from privately-held **ANKOR E&P Holdings Corp.** and **KOA Energy LP**. The pair of companies had previously retained **Detring Energy Advisors** and **Oil & Gas Asset Clearinghouse LLC** to market

for sale the assets located in the central region of the Gulf of Mexico Shelf.

The transaction will increase W&T's federal shallow-water acreage in the Gulf of Mexico by approximately 57,500 gross (46,000 net) acres and add over 50 gross producing wells in three shallow-water fields: the Ship Shoal 230, South Marsh Island 27/Vermilion 191 and South Marsh Island 73 fields.

DELAWARE BASIN

■ **UpCurve Energy Partners II LLC** completed an initial acquisition in the Delaware Basin after announcing a new equity commitment from **Post Oak Energy Capital LP** on Jan. 5. Financial terms were not disclosed.

UpCurve is focused on utilizing technology and innovative engineering practices to develop the company's acreage position in the core of the southern Delaware Basin. "We are excited to once again partner with the Post Oak team," UpCurve president Zach Fenton commented in a Jan. 5 company release.

UpCurve currently operates a leasehold position of 12,000 net acres in Reeves County, Texas, producing 12,000 boe/d, according to the company release.

Prior to the new equity commitment, UpCurve held a roughly 10,000 net-acre position in Reeves County producing about 10,000 boe/d. The company, however, has since tacked on another 2,000 net acres to its Reeves County position with 2,000 boe/d of production as part of UpCurve II's initial acquisition.

MIDLAND BASIN

■ **FireBird Energy LLC** completed an acquisition of operated assets on Dec. 30 located in the Midland Basin from **Chevron U.S.A. Inc.** and **Chevron Midcontinent LP**, marking privately held FireBird's second major acquisition since its inception.

Based in Fort Worth, Texas, FireBird is an upstream oil and gas company focused on the acquisition and responsible development of assets in the Midland Basin of the Permian. The company, which, according to its website, made a significant acquisition of producing properties in the western Midland Basin at the time of its founding in 2019, is backed by **RedBird Capital Partners** and **Ontario Teachers' Pension Plan**.

Pro forma for the Chevron transaction on Dec. 30, FireBird will have about 72,000 gross acres in the western Midland Basin and about 11,500 boe/d of production.

"This transaction will be our second major acquisition as we continue to advance our consolidation strategy and enhance our western Midland Basin footprint with additional scale," FireBird CEO Travis F. Thompson said in a company release.

Terms of the Chevron transaction weren't disclosed.

APPALACHIA

■ **Exxon Mobil Corp.** on Jan. 11 launched the sale of shale gas properties stretching across 27,000 acres in the Appalachian Basin of Ohio, the company confirmed, part of an ongoing divestiture of U.S. assets.

The top U.S. oil producer is marketing 61 wells that last year produced around 81 MMcf/d of natural gas, according to a marketing document viewed by Reuters. The sale includes another 274 wells operated by other companies.

A sale could value the assets at around $200 million based on current natural gas prices and existing production from the wells, a person familiar with the matter said.

The company in 2020 took about a $20 billion write-down on properties, primarily purchased with subsidiary **XTO Energy** a decade earlier. It removed gas assets in Appalachia, the Rocky Mountains, Oklahoma, Texas and elsewhere from its development plan after the write-down.

The Ohio properties produced around 250 MMcf/d of gas in 2017 and are among assets that Exxon Mobil put on the market as it focuses development in Guyana, offshore Brazil and Texas's Permian Basin.

SERVICE & SUPPLY

■ **Regiment LLC**, a pressure pumping company based in Midland, Texas, has announced the recent close of two acquisitions. In late September, Regiment acquired a fleet of pumps and high specification frac stack equipment from a private pressure pumper. In a separate transaction in November, Regiment acquired additional pressure pumping equipment from a leading Permian Basin operator.

Together, the two acquisitions increased Regiment's total asset base to over 75,000 HHP and expanded the company's service offering to include pump rental and frac stack services, the company said on Dec. 23.

Regiment is a portfolio company of **Energy Founders Fund LP** and operates both in the Eagle Ford and the Permian Basin.

■ **Liberty Lift** acquired **Corral Oil Field Services LLC** (COFS) in Andrews, Texas, on Jan 10. COFS is a family-owned and -operated artificial lift company specializing in the service, repair and sale of pumping units and related artificial lift equipment in the Permian Basin.

"Corral is a first-in-class organization, with an exceptional reputation for high service quality and hard work and a customer-first mindset, just like Liberty," Bobby Evans, CEO of Liberty Lift, said. "They will be an integral piece of our continued plans for growth in the Permian. We're excited to welcome Lorenzo, Carlos and the entire Corral organization to the Liberty Lift team."

MIDSTREAM

■ **BP Plc** agreed on Dec. 20 to acquire **BP Midstream Partners LP**, the British oil major's pipeline operator in the U.S., in a buyout transaction worth more than $700 million.

"In line with BP's strategy introduced last year of becoming an integrated energy company, this transaction will deepen BP's interests in, and simplifies the ownership and governance structure of, midstream assets that support integration and optimization of its fuels value chain in the U.S.," BP said in a company release.

According to the release, BP will acquire all outstanding common units of BP Midstream Partners not already owned directly or indirectly by BP, representing roughly 47.8 million common units, in an all-stock transaction. In exchange, BP Midstream unitholders will receive 0.575 of an American depositary share of BP, translating to a total price of about $723 million for the deal, according to Reuters calculations.

BofA Securities is financial adviser, and **Baker Botts LLP** is acting as legal adviser to BP. **Vinson & Elkins LLP** is serving as BP Midstream Partners' legal adviser. **Tudor, Pickering, Holt & Co.** is financial adviser, and **Gibson, Dunn & Crutcher LLP** is acting as legal adviser to the conflicts committee of the BP Midstream Partners board.

PERMITS

Operators continue to focus on the Midland Basin portion of the Permian Basin with 248 permits for Martin (113), Howard (60), Upton (38) and Midland (37) counties alone. Of Pioneer Natural Resources Co.'s 35 new permits, 18 were issued for Martin County. Also in Martin County, Endeavour Energy had 24 permits, Diamondback Energy Inc. had 19 permits and XTO Energy Inc. had 18 new permits.

In the Delaware Basin part of the Permian, there were 107 permits issued in Lea County and 98 in Eddy County. The most permits in Lea County were issued to Devon Energy Corp. (18), EOG Resources Inc. (22) and Delaware Basin-focused Titus Oil & Gas (18). In Eddy County, Devon had 37 permits, XTO had 18 and Mewbourne Oil Co. had 11.

In the Eagle Ford Shale in Texas, there were 20 permits for Karnes County, 18 for Atascosa County and 10 in McMullen County.

Oklahoma issued 93 new permits. In the STACK portion of the Sooner state, there were 11 Kingfisher County permits, 10 Canadian County permits and nine Blaine County permits.

North Dakota issued 24 new permits for McKenzie County (Oasis Petroleum, seven), (Petro-Hunt, six), (Grayson Mill Operating, four). In Williams County, N.D., Continental Resources Inc. received six permits, and Hess Corp. and Blackbeard Operating each received five permits.

Permits By Operator*

Devon Energy Corp.	60
Endeavor Energy Resources	44
Pioneer Natural Resources Co.	35
XTO Energy Inc.	35
EOG Resources Inc.	32
Diamondback E&P	32
Pennhills Resources	27**
Mewbourne Oil Co.	26
Ovintiv Inc.	22
Lewis Petro Properties Inc.	21

*Data source: Datalink
**Shallow Onondaga gas wells in Cattaraugus County, N.Y.

Permits By State* **

Texas	736
New Mexico	208
Oklahoma	93
North Dakota	50
Pennsylvania	49
Northern Gulf Of Mexico	39
Louisiana	38
New York***	33
Colorado	27
West Virginia	24

*Data source: Datalink
**Data from Wyoming Oil & Gas Conservation Commission not available.
***Shallow vertical Onondaga gas wells in Cattaraugus County, N.Y., by Pennhills Resources (27 permits) and Dallas Energy LLC (six permits).

Permits By Basin*

Midland Basin	330
Delaware Basin	272
Eagle Ford	121
SCOOP/STACK	67
Appalachian	60
Williston	50
Gulf Of Mexico	39
Louisiana	38
D-J Basin	26

*Data source: Datalink

Data from Rextag ENERGY DATALINK

RIG COUNT

The U.S. rig count is up 4% in December and 74% in the last year. The largest week-over-week changes occurred in the Permian Basin, which added four rigs and the Anadarko Basin that added three.

The last time the U.S. rig count was higher than 700 was March of 2020 before the COVID-19 shutdown. During the first three quarters of 2021, roughly 80 rigs have been added per quarter, with the first quarter showing the strongest increase at 112 rigs. The second quarter was the weakest, adding just 51 rigs.

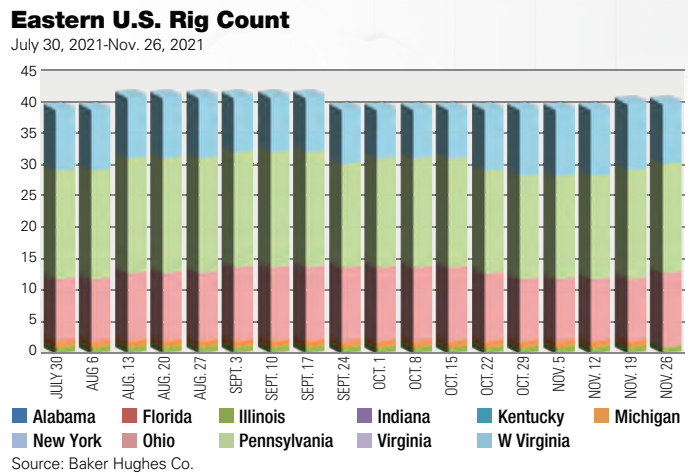
Compared to March 2020, the number of operators drilling wells in the U.S. has increased by 55 as of Dec. 15, indicating greater industry participation but at lower activity levels on average.

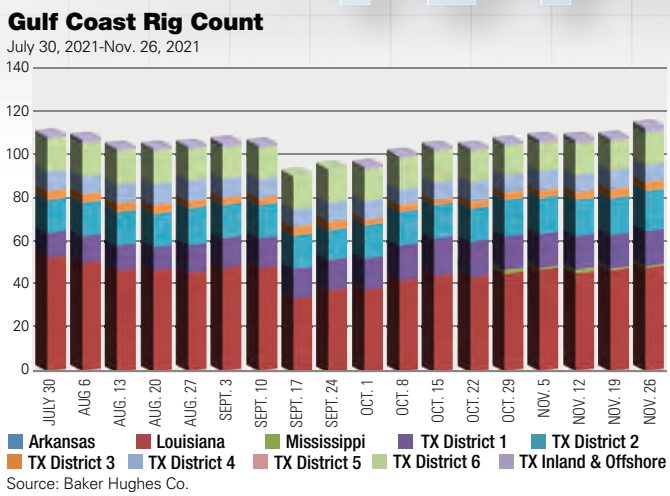
Even though the rig count has been rising for a record 18 months in a row, analysts noted that oil production was still expected to ease in 2021 as energy firms continue to focus more on returning money to investors rather than boosting output.

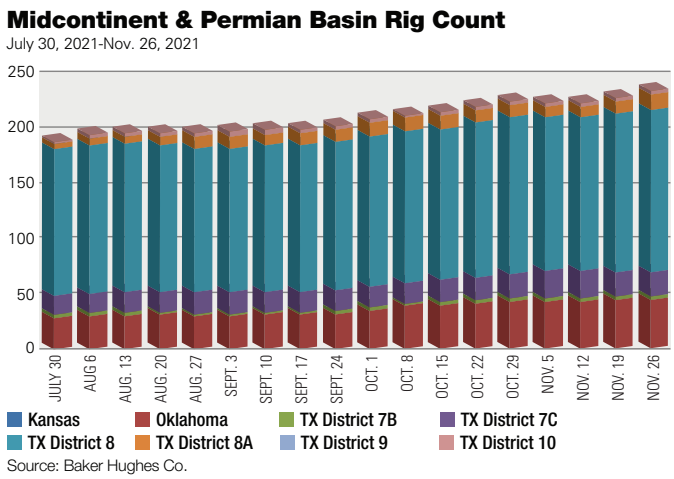
But with oil prices up about 46% this year, some energy firms said they plan to increase spending in 2021 and 2022 after cutting drilling and completion expenditures in 2019 and 2020.

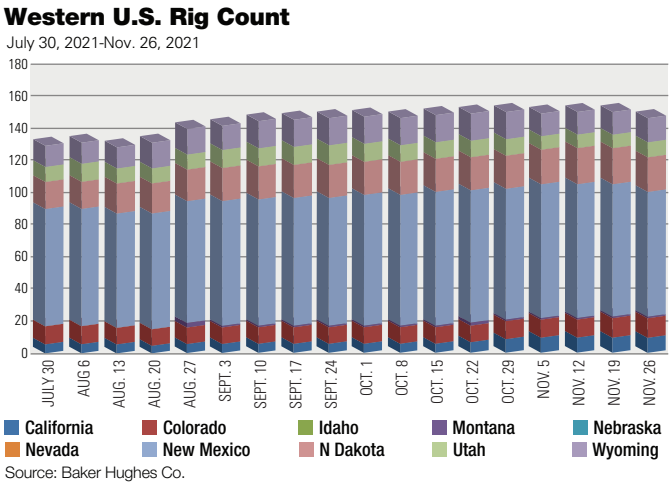
That spending increase, however, remains small, and much of the money was put toward completing wells that were DUCs.

But analysts have warned that the number of DUCs available was declining fast. There were only 4,855 DUCs left in the seven biggest U.S. shale basins in November, the lowest since June 2014, according to government data.









FOCUS ON
Ardmore and Arkoma Basins

Ardmore Basin Production* **

Formation	MMboe
Woodford	108.56
Caney	5.48
Penn Sand	3.59
Viola	3.35
Deese	2.19
Sycamore	1.87
Arbuckle	1.74
Simpson	0.8
Hunton	0.65
Tussy	0.64

*Data source: Datalink

** Includes Bryan, Carter, Johnston, Love and Marshall counties.

Arkoma Basin Production* **

Producing Formation	MMboe
Woodford	204.69
Mississippian	67.39
Hunton	4.86
Mayes	3.41
Atoka	1.03
Cromwell	0.97
Viola	0.96
Hartshorne	0.91
Caney	0.72
Booch	0.56

*Data source: Datalink

* Includes Hughes, McIntosh, Pittsburg, Coal, Atoka, Muskogee and Okfuskee counties.

The Ardmore Basin, located in south-central Oklahoma, is roughly bounded between the Criner Hills and the Arbuckle Mountains. Exploration and production in the basin has been ongoing from more than 100 years, beginning with the discovery of Healdton Field in 1913.

The primary source rock in the basin is Pennsylvanian and Ordovician sandstones. The Woodford Shale that runs through the majority of the basin acts as the major seal. Faulting has also formed anticlinal and syncline traps that hold much of the region's petroleum.

Woodford Shale characteristics in the Ardmore Basin are similar to those found in the Arkoma Basin. The Ardmore Woodford interval is almost twice as thick as the Arkoma Basin.

The Arkoma is a peripheral foreland basin in eastern Oklahoma and west-central Arkansas and is one of the most prolific petroleum-producing basins in North America.

The Arkoma Basin contains many producing reservoirs with about 25 known gas-producing zones. Based off a 2010 assessment done by the USGS, more than 26 Tcf of gas can be found in two shale gas formations. The Devonian-Mississippian Woodford Shale and its lateral equivalent, the Chattanooga Shale, contain roughly 12.3 Tcf, and the Mississippian Fayetteville Shale with its laterally equivalent Caney Shale contains roughly 14.3 Tcf.

Ardmore Basin Top Operators*

Operator	MMboe
XTO Energy Inc.	118.16
Citation Oil & Gas Corp.	8.64
Continental Resources Inc.	5.18
BCE-Mach III	4.31
Mack Energy Co.	4.06
BNK Petroleum	2.64
Spring Operating Co.	2.52
Finley Resources, Inc.	2.36
Walker Keith F Oil & Gas Co.	2.33
Charter Oak Production Co.	2.09
Kodiak Oil & Gas Corp.	1.22

*Data source: Datalink

Arkoma Basin Top Operators*

Operator	MMboe
Trinity Operating	123.79
Merit Energy Co.	52.91
Foundation Energy Mgmt.	44.96
XTO Energy Inc.	41.77
Blackbeard Operating	22.14
Silver Creek Oil & Gas	10.15
Mustang Fuel Corp.	9.36
Pablo Energy II	9.09
Kaiser-Francis Oil Co.	8.81
BRG Petroleum Corp.	6.21

*Data source: Datalink

Data from Rextag ENERGY DATALINK

INTERNATIONAL HIGHLIGHTS

After Cyprus awarded hydrocarbon exploration and drilling rights in its offshore Block 5 to Exxon Mobil Corp. and Qatar Petroleum, Turkey threatened to block any unauthorized search for gas and oil in its economic exclusive zone in the Mediterranean.

The Turkish Foreign Ministry said that a part of the license area in question violates Turkey's continental shelf rights in the eastern Mediterranean.

The disputed site is the largest gas find for EU member Cyprus. Turkey's claim further irritates strains between Turkey and Cyprus and rival countries Israel and Egypt, as all have a claim to the resources. The EU has urged Turkey to de-escalate tension in the region, while vowing to defend the interests of member states Greece and Cyprus if it didn't. Turkey claims it is protecting its rights as well as those of Turkish Cypriots who control the northern third of the divided island.

The island has been effectively divided since Turkey's military captured the northern third of it in 1974, following a coup attempt in which a military junta in Athens sought to unite Cyprus with Greece.

The Turkish minority's self-proclaimed state in Cyprus (Turkish Republic of Northern Cyprus) is the only organization that is recognized by Ankara, and the Turkish Republic of Northern Cyprus claims all of the energy resources discovered off its coast.

—Larry Prado

1 *Mexico*

Eni has announced an oilfield discovery within the Yoti West structure at Block 12, offshore Mexico. The field was discovered after drilling the first exploration well. According to preliminary estimates, the initial oil in place is 250 MMbbl. The #1 EXP Yoti West penetrated a sand reservoir in Upper Miocene with high permeability and oil-saturated thickness of about 25 m. An assessment plan for Yoti West Field will be based on additional drilling and testing results. The block has an area of 521 sq km. Partners in the project are operator Eni, 60%, and **Lukoil**, 40%.

2 *Trinidad*

Touchstone Exploration completed a test at exploration well #1-Royston in the Ortoire Block, onshore Trinidad. The purpose of one test was to evaluate an interval in the intermediate sheet of Herrera. The completion spanned a 92-ft gross interval (30 ft of net pay) below 10,434 ft where hydrocarbons were identified from wireline logs. The well was shut in and built to a pressure of 3,150 psi at the surface and flowed through 3.5 in. tubing on a variety of choke sizes between 16/64 in. and 40/64 in. at rates up to 550 bbl/d. The recovered oil has an average 33° API gravity, with an average 94% oil cut and some solution gas. The second production test was conducted in the lower portion of the Herrera overthrust sheet between 9,878 ft and 10,148 ft with a gross 270 ft of perforation (202 ft of net pay). A light oil reservoir was verified with flow rates of up to 430 bbl/d. Testing indicated 30° API oil with no gas. Calgary-based Touchstone has an 80% operating working interest in the well, and **Heritage Petroleum Co.** holds the remaining 20% working interest.

3 *Brazil*

Petrobras found hydrocarbons in the Santos Basin pre-salt in a pioneer well in the Aram Block. The #1-BRSA-1381-SPS (Curacao) was drilled in 1,905 ft of water. The oil-bearing interval was verified through wireline logging and fluid samples that will be analyzed in the laboratory to evaluate the potential of the next exploratory activities in the area. The Aram Block was acquired in 2020. Rio de Janeiro-based Petrobras is the block operator holding 80% interest with partner **China National Offshore Oil Corp.**, holding 20%.

4 *Norway*

Aker BP has received permits to drill two exploration wells in offshore Norway's Block 25.2. The #25/2-23 S and #25/2-23 A will be drilled from the Deepsea Nordkapp drilling facility in production license PL 873. The ventures will test the Grefesenkollen/Ost Frigg prospect. Area water depth is 108 m. Aker BP's headquarters are in Lysaker, Norway.

5 *Norway*

MOL, operator of production license PL 820 S in the Norwegian North Sea, completed two Balder Field appraisal wells, #25/8-21 S and #25/8-22 S, on the #25/8-19 S (Iving) oil and gas discovery. The Iving discovery was proven in 2019 in reservoir rocks from Paleocene (Heimdal), Early Jurassic (Statfjord Group) and Late Triassic (Skagerrak) and in basement rock. The #25/8-21 S encountered a 3-m gas column over an approximate 30-m oil column in Skagerrak. The well was drilled to 2,663 m, and the true vertical depth is 2,587 m. Oil was also found in a 6-m sandstone layer in the lower part of Skagerrak. A separate oil column of about 50 m was found in basement rock. The #25/8-22 S hit a 20-m gas column over a 29-m oil column in Skagerrak. Pressure data indicates communication in the

Skagerrak reservoir between all wells in the discovery. A 2-m oil column was encountered in sandstones in the lower part of the Statfjord Group, and this has been interpreted to be a separate accumulation in relation to #25/8-19 S (Iving). Water depth at the site is 127 m. MOL is based in Budapest.

6 *Abu Dhabi*

INPEX announced an oil discovery in onshore Abu Dhabi Block 4. The find holds multiple conventional oil, condensate and gas. According to the Tokyo-based company, this is the first oil discovery of mainly Murban grade from this concession area as well as from a new geological formation. The provisional oil, condensate and gas in place combined totals up to 1 Bboe. INPEX currently estimates 480 MMbbl of recoverable reserves. Onshore Block 4 is located in a coastal area in the central part of the Emirate and includes Abu Dhabi City. The block is in the vicinity of existing oil and gas production infrastructure and could begin early-stage development and production of crude oil and gas. INPEX is planning additional testing, including pressure tests and further exploration ventures in the block.

7 *Malaysia*

A gas discovery at wildcat #1-Nangka was reported by **PTT Exploration & Production** in Block SK417, offshore Malaysia. The well was drilled to a total depth of 3,758 m, and sweet gas was discovered in the Middle to Late Miocene Cycle VI clastic reservoirs. It is the second gas discovery in the area and is part of the established Baram Delta region. Earlier in 2021, the company announced a gas discovery at #1-Dokong in the same block, which hit an 80-m gas column. Additional flow and reservoir testing is planned. PTT holds 80% interest with partner **Petronas**(20%).

8 *Australia*

Norwest Energy provided updates for a Perth Basin oil and gas exploration well, #1 Lockyer Deep, a conventional gas discovery in EP368 in Western Australia. Based on petrophysical analysis, the well encountered a 34-m (true vertical depth) gross pay interval in Kingia between 3,888 m and 3,922 m. It was tested on an unreported choke size with a reservoir pressure of 6,514 psi. According to the company, a gas column of up to 800 m indicates the areal extent of the discovery is approximately 66 sq km, with an additional 22 sq km of low-risk upside in the downthrown fault block to the south of the North Erregulla culmination. While the sandstones are not regarded as conventional pay, the Perth-based company believes it may provide incremental recoverable gas resources through secondary charge of the overlying high-quality pay zone.

9 *Australia*

A test by **Strike Energy** at #5-Walyering has confirmed the presence of a high-quality conventional gas accumulation at the suspended Walyering gas field in the Perth Basin in Western Australia. Mud logs, core samples, logging-while-drilling and wireline logging tools were used to evaluate the four conventional gas-charged sands throughout the Jurassic-aged Cattamarra Coal Measures. Four gas-charged reservoirs have been confirmed with a total gross thickness of 116 m and total net pay of 51 m. Individual horizons include A Sand (14 m of net pay), B Sand (10 m of net pay), C1 Sand (9 m of net pay) and C2 Sand (18 m of net pay). The reservoir pressure was 4,386 psi with permeability of 274 millidarcies. The planned depth of the venture was 3,400 m. West Perth-based Strike Energy is the operator and the holder of a 55% joint-venture interest in EP447, and **Talon Energy** holds a 45% joint-venture interest.

10 *Australia*

Mosman Oil and Gas completed an Amadeus Basin airborne gravity and gradiometry data acquisition over permit area EP-145 in Northern Territory, Australia. It is the first time data will be acquired for the whole permit and will provide information across the entire 818 sq km permit area. Current subsurface seismic data are limited in the Northwest Territory to the central part of the permit. The survey has the ability to image salt and subsalt geometry across a range of depths. The gradiometry technique has a higher level of resolution and sensitivity than standard gravity tools and will improve the interpretation of high density and gravity features. Mosman is based in Sydney.

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount ($MM)	Comments
EQT Corp.	NYSE: EQT	Pittsburgh	$1,000	Announced approval by board of directors of a share repurchase program under which the company is authorized to repurchase up to $1 billion of its outstanding common stock. The share repurchase authority is effective immediately and valid through Dec. 31, 2023. This program is equivalent to approximately 13% of EQT's current market cap. The shares may be repurchased from time to time in open market transactions through privately negotiated transactions or by other means in accordance with federal securities laws. The company intends to fund repurchases from available working capital and cash provided by operating activities. The timing, as well as the number and value of shares repurchased under the program, will be determined by the company at its discretion and will depend on a variety of factors, including the market price of the company's common stock, general market and economic conditions and applicable legal requirements.
Clearfork Midstream LLC	N/A	Fort Worth, Texas	$400	Secured an initial capital commitment from **EnCap Flatrock Midstream LLC**. Concurrently, also entered into a definitive agreement to purchase **Azure Midstream Energy LLC**, which has a natural gas gathering and treating platform spanning the core areas of the Haynesville Shale and includes more than 500 miles of pipeline and 1.2 Bcf/d of treating capacity across systems in North Louisiana and East Texas. Additional capital will be used to optimize the efficiency of Azure Midstream's systems in support of existing customers and to pursue additional acreage dedications, throughput volumes and regional infrastructure. **Latham & Watkins LLP** served as legal adviser to EnCap Flatrock, and **Vinson & Elkins LLP** served as legal adviser to Clearfork.
PrairieSky Royalty Ltd.	TSX: PSK	Calgary, Alberta	CA$230.1	Closed bought deal offering of common shares issuing about 17.2 million shares, including roughly 2.2 million issued pursuant to the exercise in full of the overallotment option granted to the underwriters, at a price of $13.40 per common share. Proceeds will be used to partially fund an acquisition of 1.9 million acres of royalty lands across Western Canada and complementary seismic assets. Syndicate of underwriters was led by **TD Securities Inc.** and **RBC Capital Markets** as joint book-runners and co-led by **CIBC Capital Markets** and **BMO Capital Markets**.
Calumet Specialty Products Partners LP	NASDAQ: CLMT	Indianapolis	$50	Announced that **Montana Renewables LLC** closed the of project financing from **Stonebriar Commercial Finance LLC** related to construction of the renewable hydrogen plant for Calumet's renewable diesel business in Great Falls, Mont.
Lapis Energy LP	N/A	Dallas	N/A	Announced an agreement for **Cresta Fund Management** to fund the company's origination, development and implementation of carbon capture and storage and clean hydrogen projects.
Merge Electric Fleet Solutions	N/A	Houston	N/A	Closed a Series A funding round led by strategic investor **Pickering Energy Partners** (PEP). Funding will be used to accelerate the team expansion of the fleet electrification services and finance company and broaden its electrification service offerings to additional fleet segments. **Latham & Watkins** advised PEP in the financing round.
Southwestern Energy Co.	NYSE: SWN	Spring, Texas	N/A	Announced the proposed underwritten block trade of roughly 64 million shares of its common stock by certain shareholders who received their shares as part of Southwestern Energy's acquisition of **Indigo Natural Resources LLC**. Shares will be offered from time to time for sale in one or more transactions on the New York Stock Exchange, in the over-the-counter market, through negotiated transactions or otherwise at market prices prevailing at the time of sale. Southwestern Energy will not sell any shares of its stock and will not receive any proceeds. **J.P. Morgan Securities LLC** is sole bookrunning manager.
UpCurve Energy Partners II LLC	N/A	Houston	N/A	Closed an equity commitment from **Post Oak Energy Capital LP**. The new equity commitment was used by UpCurve II to complete an initial acquisition in the Delaware Basin. Remaining equity commitment will be used to continue to pursue an "acquire and exploit" strategy focused on value creation via best-in-class execution.

DEBT

Kodiak Gas Services LLC	N/A	Montgomery, Texas	$1,875	Amended and upsized its existing credit facility with an additional $175 million in commitments. In 2021, Kodiak has now secured several additional lenders to participate in the credit facility with total commitments of $1.875 billion.

Company	Exchange/ Symbol	Headquarters	Amount ($MM)	Comments
Southwestern Energy Co.	NYSE: SWN	Spring, Texas	$1,150	Priced the public offering of 4.75% senior notes due 2032 sold to the public at a price of 100% of their face value. Proceeds will be used along with net proceeds associated with its proposed term loan credit agreement, borrowings under its revolving credit agreement and cash on hand to fund the cash portion of the acquisition of **GEP Haynesville LLC**, to fund its previously announced tender offers of certain series of its outstanding senior notes and to pay a portion of the outstanding balance of its revolving credit agreement. **J.P. Morgan Securities LLC**, **BofA Securities Inc.**, **Citigroup Global Markets Inc.**, **RBC Capital Markets LLC** and **Wells Fargo Securities LLC** are representatives of the underwriters and joint bookrunning managers.
Howard Energy Partners	N/A	San Antonio	$1,000	Announced extension of its $1 billion revolving credit facility. Proceeds will be used to help finance the previously announced build-out of a major renewable diesel logistics facility in Port Arthur, Texas, which is underpinned by a long-term agreement with **Diamond Green Diesel**, a 50:50 JV between **Valero Energy Corp.** and **Darling Ingredients Inc. RBC Capital Markets** was lead left arranger and administrative agent. **Sidley Austin LLP** acted as counsel. **Holland & Knight LLP** acted as counsel to the administrative agent.
Pembina Pipeline Corp.	TSX: PPL, NYSE: PBA	Calgary, Alberta	CA$1,000	Closed offering of senior unsecured medium-term notes conducted in two tranches consisting of $500 million principal amount of senior unsecured medium-term notes, series 17 having a fixed coupon of 3.53% per annum, paid semiannually and maturing on Dec. 10, 2031; and $500 million principal amount of senior unsecured medium-term notes, series 18 having a fixed coupon of 4.49% per annum, paid semiannually and maturing on Dec. 10, 2051. Proceeds will be used to repay indebtedness under its unsecured $2.5 billion revolving credit facility, as well as for general corporate purposes.
PrairieSky Royalty Ltd.	TSX: PSK	Calgary, Alberta	CA$725	Expanded unsecured revolving sustainability-linked loan to $725 million from $425 million concurrent with the closing of its acquisition from **Heritage Royalty** of over 1.9 million acres of royalty lands throughout Alberta, Saskatchewan and Manitoba, including over 1.7 million net acres of fee simple mineral title lands and extensive seismic assets. Maturity date of the SLL credit facility remains Feb. 28, 2025, and pricing and covenants are unchanged. The expanded SLL was used to partially fund the acquisition.
Ranger Oil Corp.	NASDAQ: ROCC	Houston	$725	Announced 20% increase to the borrowing base under its revolving credit facility to $725 million from $600 million. Elected commitment under the facility remains at $400 million.
Tamarack Valley Energy Ltd.	TSX: TVE	Calgary, Alberta	CA$600	Syndicate provided an extension of existing $600 million revolving credit facility to December 2023 and transitioned the facility to a sustainability linked lending facility. In conjunction with the acquisition of **Crestwynd Exploration Ltd.**, **National Bank Financial** as syndicate lead has provided commitments for a separate and additional $100 million credit facility.
Range Resources Corp.	NYSE: RRC	Fort Worth, Texas	$500	Priced at par an offering of senior notes due 2030, which will carry an interest rate of 4.75%. Proceeds will be used, together with cash on hand and borrowings under its bank credit facility, to redeem all of its outstanding 9.25% senior notes due 2026.
Howard Energy Partners	N/A	San Antonio	$400	Priced inaugural senior unsecured notes offering of 6.75% senior unsecured notes due 2027. Proceeds will be used to help finance the previously announced build-out of a major renewable diesel logistics facility in Port Arthur, Texas, which is underpinned by a long-term agreement with **Diamond Green Diesel**, a 50:50 JV between **Valero Energy Corp.** and **Darling Ingredients Inc. RBC Capital Markets** was lead left bookrunner. **Vinson & Elkins LLP** acted as counsel. **Baker Botts LLP** acted as underwriters counsel.
Ring Energy Inc.	NYSE American: REI	The Woodlands, Texas	$350	Announced borrowing base under its senior revolving credit facility was recently successfully reaffirmed at $350 million. Next regularly scheduled bank redetermination is to occur during May.
Surge Energy Inc.	TSX: SGY	Calgary, Alberta	CA$280	Closed a $130 million five-year term debt facility with an annual coupon of 8.85% and a new normal course $150 million first lien credit facility with a revised syndicate of five lenders. Concurrent with the closing of the term debt facility and first lien credit facility, the company has repaid its $42 million, non-revolving BDC term loan.

COMPANIES IN THIS ISSUE

This index refers to the pages of the story or news item in which the company is first mentioned. Advertisers are in boldface.

HARTENERGY

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Deadline for submissions is April 29, 2022.
Contact **meainfo@hartenergy.com** with any questions.

THE ENERGY TRANSFER AD

NISSA DARBONNE, EDITOR-AT-LARGE

Energy Transfer LP made a commercial—and ran it during a football game. A redditor, MyPublicFace, posted during the Sunday Night game Dec. 19, "This [bad word] commercial that ran during a U.S. football game today. Apparently, if we don't support oil and gas … the football, your football jersey and even your beer glass will turn TO DUST!!!"

(Note: The redditor might be a Bucs fan. At the time of the post, the Saints had just picked up a rare Tom Brady fumble; the game ended Saints, 9, Bucs, 0. Also, MyPublicFace seems unfriendly normally, having zero awarder karma and only 93 awardee karma.)

It gets more ridiculous. The post (and replies too, all concurring, of course) were at subreddit LateStageCapitalism (LSC). The LSC auto-bot posted, "Please remember that LSC is a SAFE SPACE for socialist discussion. LSC is run by communists."

And don't ask questions, it added: "Please take 101-style questions elsewhere."

Okay.

Energy Transfer ran the ad, published Nov. 24, at YouTube, again during the College Football Playoff National Championship game on Jan. 10. (Congrats to everyone who took the Under.)

Capitalist and longtime energy analyst Dan Pickering tweeted: "Energy Transfer ballin' hard with the 'what if we didn't have oil and gas' halftime commercial [in] the Bama/Georgia game. Will any skeptics be converted?"

Some followers suggested a pro-energy ad is wasted on a football game. SuitedUpWook wrote, "Not many football lovers want to end oil and gas."

Energy Transfer's YouTube post of the ad had more than 15,000 views by Jan. 12. It posted it with comments off.

At Twitter, it's had more than 42,000 views. There, comments were on. Most were disparaging of hydrocarbons, of course.

Then there's Bob Loves Hawaii: "Great commercial. Now show people starving because, without natural gas, there is famine. Oh and most will freeze to death in northern climes."

Bob's correct, but does he know that? It's often hard to tell on social media whether someone is smart, accidentally smart, cunningly daft or just daft.

Bob is (well, he says he is) a "semi-retired executive from the financial software industry. Now pursuing my three secular passions: Hawaii, trading and solar energy. Proud USMC Officer."

He's a U.S. Marine, so he likely knows exactly what he's doing. A look at his timeline also suggests he meant the tweet exactly as it was written.

The story: On Christmas Eve, Alex Epstein, author of "The Moral Case for Fossil Fuels," posted, "At recent day-ahead, electricity prices in Germany, it would cost $500 to charge your Tesla. (1 MWh = 10 Tesla charges.) Remember this when you are told that it's 'cheap' to cut fossil fuel production, shut down nuclear plants and rely on solar and wind."

A reply: "When it becomes cheaper to buy a … generator and run gasoline through it to recharge your EV than it is to charge it at a home or remote charging station, we will be long past a tipping point."

Then Bob chimed in: "Coming to California and the Northeast, very soon."

Coming soon to California, perhaps, is a solar tax led by the governor to which Elon Musk tweeted, "Bizarre anti-environment move by … California."

Meanwhile, in the Northeast, the latest is the New York governor's push to ban fossil fuels in new buildings; instead, new construction should use "electricity." SMH.

Energy Transfer's ad's point was "What if the products we rely on just disappeared? From the clothes you wear to the products in your hair, our modern lifestyle would look very different without petroleum products."

Tweeters, redditors and others quickly moved on. It seems that the content more upsetting about the championship game was another ad—or was the ad the half-time show?—that is simply a Katy Perry music video.

The new tune was born tired. But the setting appears to be a rocket-manufacturing plant adjacent to a gas-processing plant.

A comment at YouTube: "Um, OK so that happened."

Another: "This was dumb [bad word]."

Another: "[In] the Super Bowl, at least [the half-time show's] live no matter that the performers suck. At least they suck 'live.'"

Bringing us back to Pickering's tweet, where he asked if anyone had been converted by the Energy Transfer ad to appreciating oil and gas.

MacroIsMicro replied, "I was, especially after the odd Katy Perry video."






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