Oil and Gas Investor

NOVEMBER 2021

Private operators pick up the pace in the Permian Basin.

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$500 MILLION	$560 MILLION	$535 MILLION	UNDISCLOSED	UNDISCLOSED
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UNDISCLOSED	UNDISCLOSED	$270 MILLION	$350 MILLION	UNDISCLOSED
NORTH AMERICAN TRANSPORTATION AND SERVICE PLATFORM CORPORATE CARVE OUT Financial Advisor	INTREPID HAS ACQUIRED CERTAIN ASSETS OF gyrodata Financial Advisor	elkpetroleum ADVISOR TO THE AD HOC CROSSOVER LENDER Financial Advisor	VIPER Energy Partners FOLLOW-ON OFFERING Co-Manager	PETROFLOW ENERGY ASSET DIVESTITURE Financial Advisor
UNDISCLOSED	UNDISCLOSED	UNDISCLOSED	$28 MILLION	UNDISCLOSED
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ENERGY GROUP KEY STATISTICS

$54+ Billion
Aggregate Transaction Volume since 2009

$320 Million
Average Transaction Size

169
Transactions Closed since 2009

ENERGY GROUP AGGREGATE TRANSACTION VOLUME

As an active participant in the energy industry with a principal mentality for over 50 years, we understand that capital and ideas are indispensable to a thriving oil and gas industry. Our advisory assignments demonstrate how an independent investment bank, backed by extensive industry knowledge and innovative ideas, can help build stronger, more prosperous energy companies.

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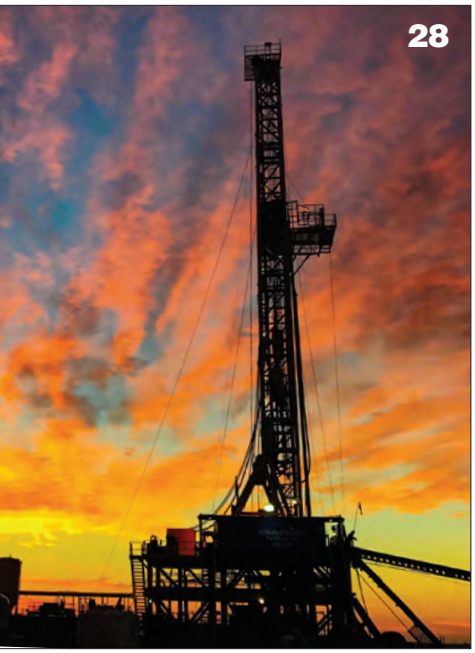

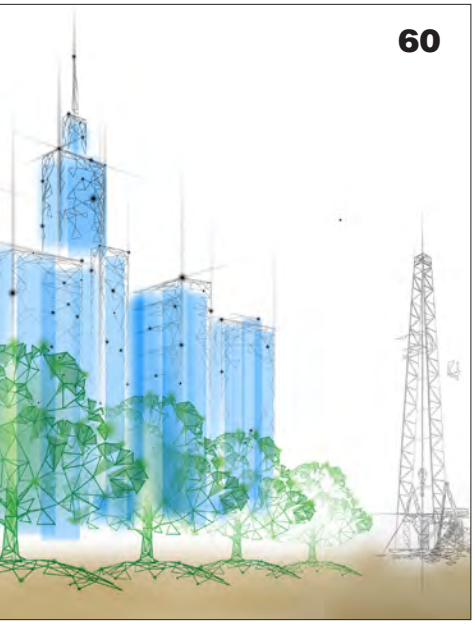

Oil and Gas Investor

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COLUMNS

DEPARTMENTS

ABOUT THE COVER: The sun sets behind two rigs at Henry Resources' Benners lease about 10 miles west of Midland, Texas, in the Permian Basin. Photo courtesy Henry Resources.

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LATEST CONTENT

Private Permian Basin Operators Take Center Stage As Oil Price Soars
By Faiza Rizvi, Senior Associate Editor
With oil prices nearing pre-pandemic levels, private players in the Permian Basin are ramping up drilling.

Is Oil And Gas Headed For Divorce?
By Velda Addison, Senior Editor
An energy investment bank executive delves into the divergent paths of oil and gas during Hart Energy's Energy Transition Capital Conference.

Oil, Gas Experts Share Insight On Tackling Supply Chain Issues
By Velda Addison, Senior Editor
Data drives decisions, but speaking the same language is essential to improving supply chain efficiency in oil and gas, say experts from EQT, Laredo Petroleum and more.

US Shale Producer Apache Reaches Flaring Goal Ahead Of Schedule
By Hart Energy Staff
Future wells will not be brought online by Apache without adequate gas takeaway capacity going forward, says John J. Christmann IV, APA's CEO and president.

Black Mountain Founder Rhett Bennett Launches Energy SPAC
By Emily Patsy, Senior Managing Editor
Black Mountain Acquisition Corp. expects to capitalize on the successful track record of its founder, Rhett Bennett, to identify and acquire a business in the energy industry in North America.

'Green' Investors Should Pick US Oil And Gas
By Joseph Markman, Senior Editor
The world will need more energy, and the responsible North American energy industry can provide it while lowering emissions, Quantum Energy Partners' CEO S. Wil VanLoh says.

ONLINE EXCLUSIVES

Deloitte Greenhouse Helps Oil Sector Develop Strategies For Low-Carbon Future
By Mary Holcomb, Associate Editor
Deloitte's Houston-based Greenhouse is an immersive environment helping oil and gas businesses devise low-carbon solutions to meet the evolving needs of the energy transition.

CCS Roundtable: Innovations Lead To A Greener Future
By Madison Ratcliff, Associate Editor
Service providers weigh in on how technologies affect the present and future carbon capture and storage operations.

Executive Q&A: Why Sustainability Is An Important Piece Of The ESG Puzzle
By Faiza Rizvi, Senior Associate Editor
Allyson Anderson Book, vice president of energy transition with Baker Hughes, spoke with Hart Energy about aligning company strategies with sustainable production as ESG considerations become increasingly core to oil and gas businesses.

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.

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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.

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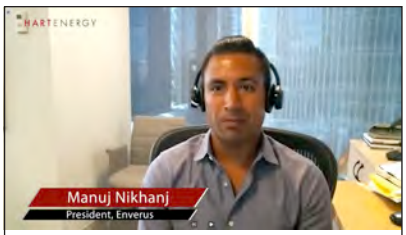
PATH FORWARD: Why PE Is Uncertain About Energy Transition Investments

Energy transition initiatives are attracting interest from private equity investors but several roadblocks remain, says Ravi Purohit, partner with Latham & Watkins.

hartenergy.com/exclusives/path-forward-why-pe-uncertain-about-energy-transition-investments-196411



Enverus President Talks Rise Of ESG Investing In Oil And Gas

Manuj Nikhanj, president of Enverus, discusses in this exclusive video interview why energy businesses and policymakers are doubling down on ESG investments.

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THANK YOU, STEVE TOON

BY LESLIE HAINES

By now, many of you have learned of the untimely passing of editor-in-chief Steve Toon on Oct. 22 of a heart attack while working from home. We all feel we've been robbed of one of the good guys. It is a sad duty to have to write this tribute to him, in the space reserved for his monthly editorials. The entire Hart Energy family and staff of *Oil and Gas Investor*, past and present, are shocked and heartbroken at the news of his passing. He was a great colleague and good friend.

He was "a consummate professional, and his leadership and insight will be missed," said Rich Eichler, CEO of Hart Energy. "He leaves big shoes to fill."

Steve was one of the hardest working editors I've known, smart and creative. He joined Hart Energy in 2007 after more than 20 years of journalism experience and assumed the editor-in-chief role in 2016 after being our resident A&D expert who had built up a large network of industry sources—and friends.

He was passionate about upholding high standards for himself and the staff and was well organized. A dedicated journalist who graduated from Baylor University, he was constantly trying to improve the magazine's editorial content and tried new design approaches to make sure the pages were compelling. He conceived of and designed the A&D section of the magazine, as one example of his thoughtful concern for making the content better. He also wasn't above putting in long hours, sometimes even on a holiday weekend, when the situation called for it. He loved doing the research and the interviews.

Many of you met Steve personally because he was also active in all the various Hart Energy DUG conferences and the annual A&D conference in Dallas. He helped plan the agendas and hosted many of these events, and he was a frequent panel moderator as well. He was such an amiable, outgoing person that he became a good networker, and as such, was well-known and well respected by our readers and event attendees. He has won several in-house Hart Energy writing awards in recognition of his skills.

He was serving on the board of the Houston Producers' Forum at the time of his passing.

Hart Energy and the Toon family are grateful for all the expressions of sorrow and messages of praise for Steve that have come flooding in, many from industry contacts who had worked with Steve recently on crafting good articles or planning events.

"He was a man of substance and integrity," said Dennis Petito, CEO, Montrose Energy Capital Advisors.

"I knew Steve well, and we shared many dinners and conversations together in the past," said Ted Williams, COO of EnCore Permian. "He is such a wonderful person, and I'm saddened to hear about his sudden passing."

Anyone who knew Steve knew he was a devoted family man who spoke often of his three children. He was also an active volunteer at his church and for several years with his local Boy Scouts of America troop, where he helped his son to become an Eagle Scout most recently. He was a proud father. Steve was a busy man, but he never made you feel he was too busy for you.

He loved to travel and organized many family trips throughout the U.S. He was an avid photographer as well, never without his camera, which served him in good stead when, after college and before starting his career, he backpacked in China and throughout South America; he published a book about his adventures in the latter, which will be a fascinating keepsake for the family.

A future fund is being set up to help with Steve's son and twin daughters' education and will be announced at a later date.

REALITY AND THE DAMAGE DONE

DARREN BARBEE,
SENIOR EDITOR

Musings from the field—meaning phone calls from the office, not the actual oil field of course.

First, the recent A&D Strategies and Opportunities Conference in Dallas was a salute to E&P capital discipline, particularly for oil makers. It should be noted that each congratulatory declaration seemed wrapped in a certain subtext: *Step away from the drill, and keep your hands up*.

How fleeting will E&P restraint be? Which of the large public companies will go rogue as wells in every basin return to viability, meaning able to generate 100% returns, A&D professionals mused. Trying to untangle such riddles is about as easy as defusing a bomb using only Ikea-style instructions. Finding the red wire is not so easy in black and white.

Simultaneously, external pressures are also surfacing. Service providers are ratcheting up prices, which will impact their E&P customers' bottom lines. The Dallas Fed recently reported that its index for E&P LOEs increased from -5.9 to 23.4 in the second quarter.

After hearing seemingly infinite choruses of "Scale will do it!" sung to the tune of Handel's "Messiah," possibly the time is coming for E&Ps to sing along.

But then there's the market, which remains a game of nerves. Like submarine commanders, E&P management no doubt wants to turn the screws to flank speed. But they're navigating the mined waters of investors who want to be paid and protected from another, inevitable sinking event.

Thus the contradictions of a strong commodity tape are revealed. The dilemma comes amidst a backdrop not of a slight uptick in commodity prices, but tall leaps in a single bound. The most remarkable examples have been natural gas spot prices in Asia and Europe that have spiked to the equivalent of $320/boe, according to Columbia University's School of International and Public Affairs.

And it could ultimately prove to be small potatoes as winter comes for an ill-prepared world. Already, China, India, the U.K., France and other large, developed countries are scrambling for fuels.

For natural gas, this may well be a pivotal moment in its role as the so-called bridge fuel of the future, according to Anne-Sophie Corbeau, a global research scholar at Columbia's International and Public Affairs.

Volatility in prices has some "arguing in favor of accelerating the transition away from fossil fuels" and those who still see fossil fuels are needed.

Recall that for years, the most militant environmentalists have waged campaigns—keep it in the ground and divestment—that seem hilariously shortsighted. For every natural gas company unable to produce a Mcf of natural gas, there's a truck of coal waiting to take its place. That's not good for the environment.

With a religious zeal, the condemnation of oil and gas and the lifting of renewables has the perhaps now obvious drawback of being unable to supply energy to everyone, particularly in less developed nations.

"Citizens in developed countries are unlikely to give up on the comfort of having electricity or gas readily available, while there are still significant number of citizens facing energy poverty," Corbeau said.

No doubt fossil fuel haters will rail against the imaginary windfall profits that natural gas companies are reaping. But as Haynes and Boone recently observed, many producers have locked-in hedges that were the breath of life in 2020 but are now limiters to cashing in on swelling second-half 2021 prices.

Wildly inflated or volatile prices, "a sustained crises that batters consumers may have critical repercussions for the fuel longer term."

What's clear is that oil and natural transactions will continue, especially as some participants are shut out of buying because of the stigma that Europe in particular has attached to oil and gas.

As Daniel Zwirn, CEO of Arena Investors LP, said during a web discussion hosted by the Financial Times, people are beginning to see the "clash between goals and reality."

In Germany and Belgium, some industries have been forced to cease or reduce operations because of high commodity prices, while China and India also face a power crunch that may force the closure of factories.

"As folks in Europe are realizing right now, it gets cold outside without oil and gas," Zwirn observed. "It's going to be present in the market, along with coal, for the next 30 years because there's no other way for it to be. So, you are going to continue to see transactions in those spaces that do make economic sense, particularly all the more so because they may be out of bounds for certain participants."

A FOREWARNING FROM EUROPE

JACK BELCHER, CORNERSTONE GOVERNMENT AFFAIRS

A global energy crisis looms as commodity prices spike around the world, and governments and other institutions scramble to try to minimize the damage. It is an ironic circumstance because many of these governments are largely responsible for the crisis as a result of making bad public policy decisions and being geopolitically outmaneuvered.

Currently, the crisis is most severe in Europe, where natural gas prices have risen 500% from a year ago. Yes, demand has increased as the continent emerges from the pandemic, but the root of the problem is Europe's gas supply, which is increasingly dependent on Russia. The main source of Russian gas to Europe has been through an older pipeline that travels through Ukraine. Another source is the TurkStream line that takes Russian gas under the Black Sea to Turkey and brings it into Europe through Bulgaria. The controversial Nord Stream 2 line, which will supply Russian gas to Germany via the Baltic Sea, has been completed but is not yet certified by the EU and Germany. Russia has refused to put additional volumes of gas through the Ukraine transport system because Vladimir Putin says it is old, in need of repair and additional volumes might cause "something to burst."

Putin is, of course, using that excuse to push Europe to expedite the opening of Nord Stream, lessening the need to transport Russian gas through Ukraine, while still increasing Europe's reliance on Russian gas. This is a foreign policy blunder for Europe and the U.S., as Europe will now be more dependent on Russian gas, and Russia is already using its gas as a weapon.

What is especially disturbing about Europe's energy price crisis is that it is taking place during the fall, normally a season where demand is low and temperatures are modest. It is frightening to think about what prices could do in the winter. Expensive gas means expensive power, as the highest priced energy in the European system sets the contract price.

Inadequate infrastructure is further compounding the direness of the situation. While there are many LNG terminals in Europe, there is simply not enough to supply a market that is currently undersupplied. Under Europe's deregulated power market there is little incentive for gas storage, and policymakers and the public have recently discovered that there is no spare capacity. Europe's own gas production, from the North Sea and the Netherlands, has been declining. While Europe does have gas potential, such as shale gas in the Paris Basin as well as gas potential in the Mediterranean, policymakers have refused to allow its development. Nuclear power has been eliminated in parts of Europe, as has coal. Eastern Europe, which still has significant coal-fired capacity, supplies electricity to the west during periods of high demand and/or when there is low renewable energy output.

Tragically, the price situation is bankrupting businesses in Europe, especially manufacturers that are now at a profound disadvantage to competitors with lower priced energy. The European Commission is attempting to adjust regulatory policies to allow EU member nations to subsidize businesses that can't afford their energy bills. Other proposed solutions vary from a windfall profit tax on investor-owned utilities to freezing prices to making changes to the EU's Emissions Trading System.

A political backlash for these prices can be expected in upcoming elections. Businesses and workers alike that are disillusioned with recent European Commission activities, such as the European Green Deal, think that the EU is moving too far, too fast. Populist movements are returning, and yellow vests can again be seen in the streets of Paris. Could there be a return to Brexit-type movements and a rise in power on the right? How will this all impact the COP26 Climate Conference that is commencing in early November in Glasgow?

On this side of the pond, the U.S. is embarking on or pursuing numerous policy initiatives that could also facilitate an energy crisis. A budget reconciliation package is currently stalled in Congress that would make significant changes to our tax code that could undermine the competitiveness of the oil and gas industry and disincentivize E&P at a time the U.S. needs more supply. Additionally, efforts are underway to cut off oil and gas leasing on federal lands and waters and make it more difficult anyway. At the same time, investors remain wary of investing in the sector, due to anti-fossil sentiment among investors and the federal government.

What is troubling about the situation in the U.S. is that we have the resources to meet our own needs and to help supply Europe and the rest of the world through exports. However, current public policy discourse has apparently chosen to ignore that fact and disregard the significance of doing so. Instead, the federal response to rising oil prices has been to make domestic production more burdensome while asking OPEC to increase its production. Let's hope we don't find ourselves in the same situation as Europe.

EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2021				
Executive Oil Conference	**Nov. 3-4**	**Midland, TX**	**Midland County Horseshoe Arena**	**executiveoilconference.com**
Carbon Management Forum	**Nov. 3**	**Midland, TX**	**Midland County Horseshoe Arena**	**executiveoilconference.com**
WEA Wildcatter of the Year	Nov. 6	Denver	Hyatt Regency at Colorado Conv. Ctr.	westernenergyalliance.org
Louisiana Energy Golf Open	Nov. 8	Lafayette, La.	Oakbourne Country Club	loga.la
North American Gas Forum	Nov. 8-10	Washington, D.C.	Hilton Washington DC, National Mall	energy-dialogues.com/nagf/
COGA Annual Meeting	Nov. 10	Denver	Hilton Denver City Center	coga.org/annualmeeting
Rice Energy Finance Summit	Nov. 12	Houston	Rice University	business.rice.edu/rice-energy-finance-summit
OK Petroleum Alliance Fall Conference	Nov. 17-18	Oklahoma City	Skirvin Hilton	thepetroleumalliance.com
Energy ESG Conference	**Nov. 29**	**Houston**	**Westin Memorial City**	**energyESGConference.com**
25 Influential Women in Energy Reception	**Nov. 29**	**Houston**	**Westin Memorial City**	**hartenergyconferences.com**
World Petroleum Congress	Dec. 5-9	Houston	George R. Brown Conv. Ctr.	23wpchouston.com
DUG East/Marcellus-Utica Midstream	**Dec. 7-8**	**Pittsburgh**	**David L. Lawrence Conv. Ctr.**	**dugeast.com**
2022				
IPAA Private Capital Conference	Jan. 20	Houston	JW Marriott Galleria	ipaa.org
NAPE Summit	Feb. 9-11	Houston	George R. Brown Conv. Ctr.	napeexpo.com
DUG Midcontinent	**March 1-3**	**Oklahoma City**	**Oklahoma City Conv. Ctr.**	**dugmidcontinent.com**
CERAWeek by IHS Markit	March 7-11	Houston	TBD	ceraweek.com
Mineral & Royalty Conference	April 18-19	Houston	Post Oak Hotel	mineralconference.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**
IPAA Annual Meeting	July 20-22	Colorado Springs, CO	The Broadmoor	ipaa.org
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-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

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For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com/events.

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2021 upstream A&D activity to nearly surpass peak shale boom

When Doug Reynolds, managing director of Piper Sandler, gave a speech to the Society of Petroleum Engineers in March, he labeled it "The Golden Age of A&D" with a question mark.

At the time, the upstream oil and gas industry was seeing a lot of deal activity in the works but not a ton announced. Regardless, Reynolds had an inkling that 2021 was going to be the year for A&D's return.

"Today, six months on roughly, I think we can remove the question mark and put an exclamation point on it," Reynolds told attendees of *Oil and Gas Investor*'s A&D Strategies and Opportunities Conference on Sept. 29.

The upstream oil and gas industry in the U.S. has seen more A&D activity this year than the past two years combined, according to Reynolds, who described 2020 as an "unnerving" year with relatively few asset deals and 2019 as "equally disappointing." As of his presentation, he estimated about $42 billion in A&D has been transacted in 2021.

"We have seen a significant reshaping of the landscape in our business," he continued. "Public companies have been fundamentally changed with deals that have occurred this year and frankly, I think we're going to see quite a bit more coming in the next 12 months."

In particular, Reynolds noted that 2021 will be the best year in A&D in terms of asset deal activity since 2014, a record-breaking year for dealmaking largely due to the shale land rush in the U.S.

"If you were thinking about selling, quite frankly now is the time," he said. "There's an active buyer universe and stuff is moving. You may or may not like where prices are, that's up to you, but I can tell you that things are transacting."

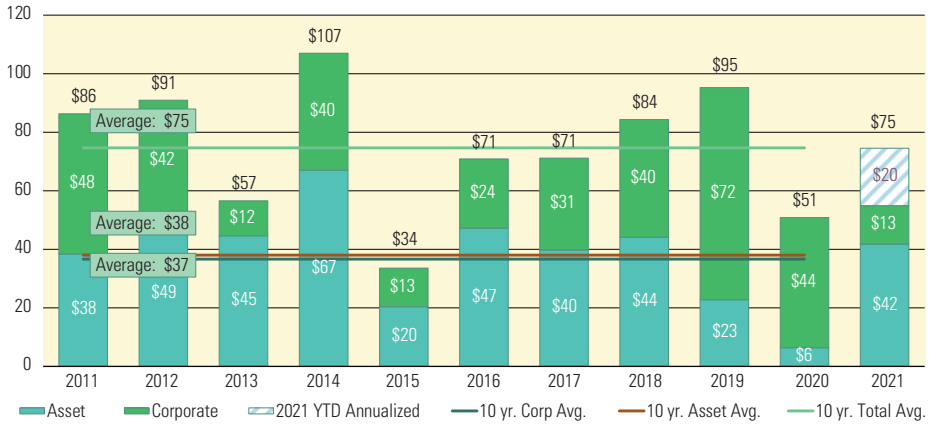
In the public domain, Reynolds estimates about $5 billion in upstream oil and gas assets are currently on the market right now, which he notes could be closer to $10 billion.

"I think we will have a very strong finish to the year, and we could be over $50 billion of asset-level activity in 2021," he said.

"While we might not make the record year of '14," he added, "we're going to have the best year since then."

As for M&A, Reynolds noted deals on the corporate side tend to happen during downturns. During those times, big companies feel under pressure from their banks and for their capital structure, he said, using Noble Energy Inc.'s sale to Chevron Corp. in 2020 as an example.

U.S. Upstream Transactions—10 Year Lookback ($B)

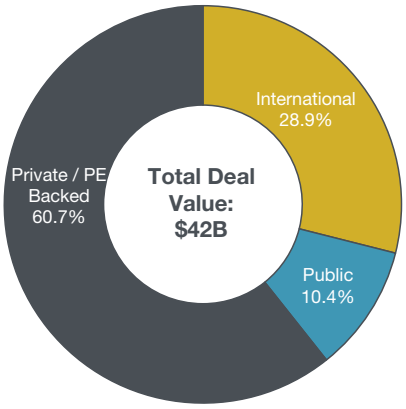


Source: Enverus; Excludes transactions < $20 MM

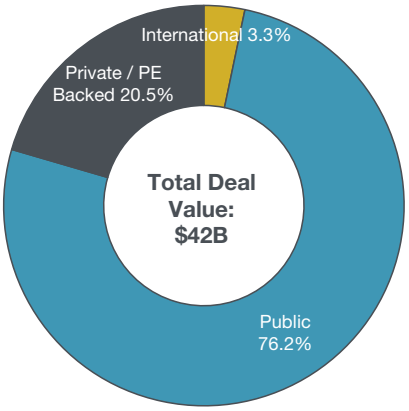
Note: 2021 corporate transactions include COG / XEC, BCEI / XOG, and CHK / VEI; Averages exclude 2021.

A&D Transaction Trends

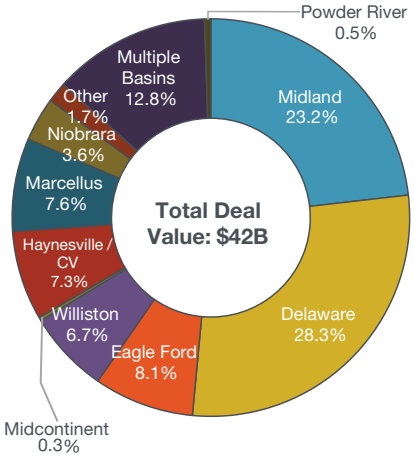
Asset Sellers—Percentage Of Transaction Value



Asset Buyers—Percentage Of Transaction Value



Asset Transactions By Basin



Source: Enverus; Excludes transactions < $20 MM

"It felt like falling into the bigger embrace of Chevron in that example was the thing to do," he explained.

Going forward, Reynolds does expect M&A transactions to remain relatively modest.

"I don't see a ton on the horizon between now and calendar year-end," he said. "I do see a number on the horizon as we go into 2022."

As for what is driving the resurgence in A&D activity this year, Reynolds highlighted several of what he called "sub-trends" beginning with new basin entrants.

According to Reynolds, new basin entrant acquirers represented over $20 billion of the total $42 billion in A&D activity so far in 2021. Examples Reynolds gave include Validus Energy's $880 million acquisition of Ovintiv Inc.'s Eagle Ford Shale asset and Vitol Group buying Hunt Oil's Midland Basin position in a transaction estimated to be worth $1.4 billion.

"As we think about who is buying in a conservative market, we always tend to think the guy who is going to buy my property is the guy operating next door—that's not always the case," he said. "And I think for large, significant platforms like this, we still have many new entrants coming into the market."

Another sub-trend, A&D activity has occurred in every basin this year, which is indicative of a healthy market, according to Reynolds. The Midcontinent could be considered an exception; however, he did note a couple million dollars of activity in the region.

The third sub-trend Reynolds mentioned was the growing trend of international sellers, such as Royal Dutch Shell Plc and Equinor ASA, getting out of the U.S. shale business, which he sees continuing. In total, international sellers have made up 28.9% of total A&D deal value in 2021.

"I would be very surprised if international majors and international owners don't sell more assets this year notwithstanding the energy crisis going on in Europe," he said.

Additionally, Reynolds noted that in 2021 both private and private equity-backed companies are leading sellers of assets year to date. Private and private equity-backed companies have been active also on the buyside.

"Generally speaking, we've seen a number of private bids at just about every process we've run," he said. "We've sold companies and assets to private entities. That bid has been very solid most of the year. I suspect that will continue."

Still, Reynolds said the private and private equity-backed space has also been responsible for roughly $20 billion in sales this year—a huge win to private equity that he believes will enable them to reload with new funding.

The last sub-trend Reynolds highlighted during his presentation is the resurgence in public companies buying, which totals over $30 billion in transactions.

"By and large, public companies have been buying and that has significantly reshaped them," he said.

—Emily Patsy

Outlook points to growing energy demand, rising emissions

About 30 years from now, the world is projected to consume more than double the amount of renewable energy than it does today, but that won't be enough to stop emissions from rising.

At least not with the policies and technology currently in place, according to the U.S. Energy Information Administration (EIA).

In a recent report, the EIA projected the world's population is projected to increase by 2 billion people by 2050, driven by non-OECD countries, pushing up global energy use by nearly 50%.

Oil production is expected to rise to meet the growing global demand, keeping petroleum and other liquids as the world's dominant energy source. Liquids are closely followed by renewables, which is projected to limit natural gas' share of the energy consumption mix though it rises by nearly one-third, according to the EIA.

Projected oil and gas production growth is mainly to support increasing energy consumption in Asia under current trends, Stephen Nalley, acting administrator for the EIA, said during a recent webinar in which the findings of its latest International Energy Outlook were presented.

"A driver of this growth is that we believe that the developing economies, of non-OECD Asia in particular, will import more liquid fuels because those economies lack sufficient production capacity to meet growing demand," Nalley said, during the Center for Strategic and International Studies webinar. "When we adjust our model for faster global economic growth or for higher oil price trajectory, we actually see unprecedented levels of petroleum and other liquid feedstock production into the future."

The outlook is released annually to help inform energy policy discussions by providing analysis and projections based on existing policies and technologies. For the U.S., the outlook is based on policies in place as of September 2020. The EIA cautioned that the outlook does not predict what is likely to happen but instead gives modeled projections based on assumptions reflected from current energy trends, laws and regulations, technological changes and economics.

Its release came amid continued focus by energy companies and world leaders on reducing emissions to slow global warming. Much focus has been on eliminating leaks, flaring and venting as well as improving operational efficiency to more responsibly produce oil and gas.

Some companies have turned to technologies like carbon capture, utilization and storage. Many have set targets to reach net-zero emissions by 2050. Chevron Corp. was among the latest to join peers that include Equinor, Eni, Shell and Repsol, among others, with similar goals.

Some companies have also stepped up plans to produce more renewable energy.

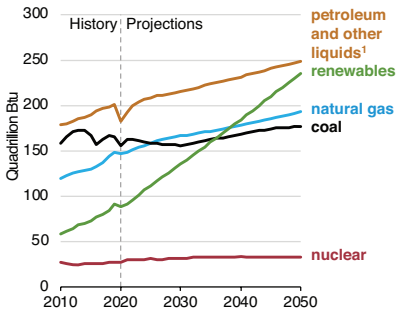
The EIA projects renewable energy use will grow to nearly the same level as liquids fuel by 2050, accounting for 27% of 2050 global energy consumption.

"As renewables, particularly solar and wind, become cost competitive, the reference case projects that nearly all post-2020 electricity generation growth in the OECD regions will come from these sources and displace an increasing share of existing nonrenewable, mostly fossil fuel-based sources," said Angelina LaRose, the EIA's assistant administrator for energy analysis, noting governmental policy support encourages renewables generation growth.

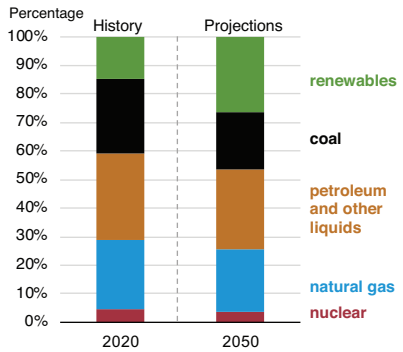
Non-OECD regions could also see growth.

However, fossil fuels will be needed to help maintain reliability

Primary Energy Consumption By Energy Source, World



Share Of Primary Energy Consumption By Source, World



Source: U.S. Energy Information Administration, International Energy Outlook 2021 (IEO2021) Reference case

of the electric grid and growing demand in non-OECD Asia, she added.

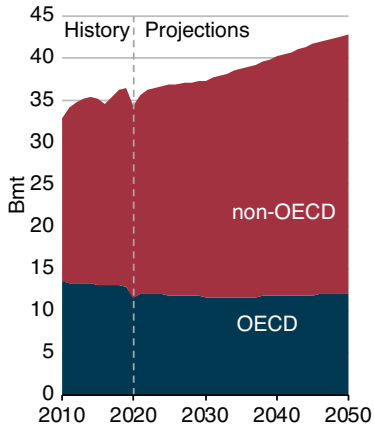
The EIA projects global emissions to rise through 2050, despite renewables growth, more energy efficiency and regional policies.

"Mandated efficiency, fuel and technology regulations are generally more stringent in the OECD countries," LaRose said. "Energy-related CO_2 emissions grow much more rapidly in the non-OECD, largely as a result of increases in energy demand associated with population and economic growth. Non-OECD countries' energy-related CO_2 emissions increase by 35% in 2050 over 2020. This is compared to the 5% emissions growth in the OECD."

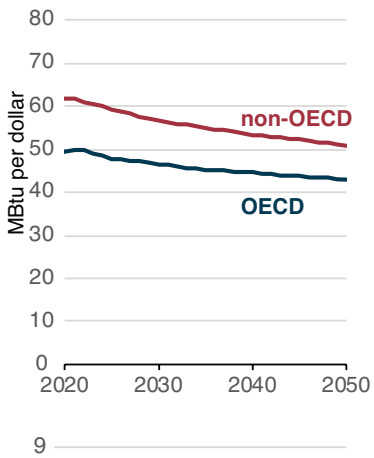
Carbon intensity, defined by LaRose as the carbon emitted per unit of energy consumed, is projected to decrease in OECD and non-OECD regions through 2050.

"Larger declines occur in non-OECD Asia because of an increasing share of renewable energy as well as have technological efficiency improvements. However, the average carbon intensity across non-OECD countries remains higher than those in the OECD through 2050, mainly because of a higher retention of fossil fuels

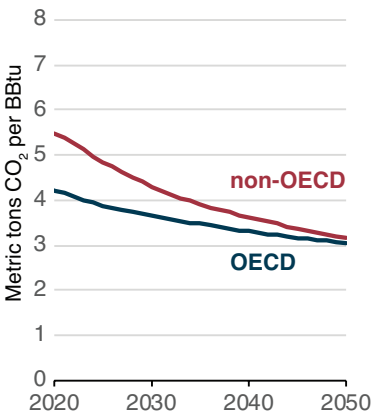
Energy-Related CO_2 Emissions



Energy Intensity



Carbon Intensity



Source: U.S. Energy Information Administration, International Energy Outlook 2021 (IEO2021) Reference case

in the non-OECD," LaRose said. "So, for example, on average, the share of electricity derived from coal across the non-OECD countries is more than twice that than what is in the OECD over the projection period."

Aaron Bergman, macroeconomics and emissions team lead for the EIA, pointed out that the renewables penetration in the electric sector tremendously reduces carbon intensity of electricity generation. The outlook projects that 90% of increases in electricity generation over 2020 to 2050 will come from renewable sources.

However, "the opportunities for decarbonization in the transportation sector and the industrial sector are not nearly as prominent," Bergman said, "and those are also very large drivers of emissions."

Erin Boedecker, energy consumption and efficiency modeling team lead for the EIA, brought air and freight travel into the conversation. "They do have limited options for switching to alternative fuels away from fossil fuels," she noted.

The EIA's reference case shows OPEC and non-OPEC oil production rising through 2050, with OPEC production growing nearly three times the rate of non-OPEC production.

"Although OPEC member countries in Africa and South America contribute to this production, the Middle East drives increases in projected OPEC production, increasing production by more than 50% from 2020 to 2050 in this region," according to the outlook.

The EIA said more exploration, drilling and technology advances are needed to meet increasing demand.

—Velda Addison

Souki: Gas industry can brace for blame for poor energy policies

Global energy policy can be boiled down to hopes for a warm winter, Tellurian Corp. executive chairman Charif Souki said during a webcast Sept. 28. And that approach, which ignores the need for infrastructure, will inevitably result in blame directed at the energy industry.

"I see nothing but catastrophe," Souki said during a discussion hosted by Washington-based Center for Strategic & International Studies. "It's kind of disconcerting and you know what is going to happen: We are going to be called pandemic profiteers or something like this, and I'm horrified at that thought."

Souki, who led the U.S. shift from LNG importer to exporter when he ran Cheniere Energy Inc.,

Charif Souki

spoke as the price of natural gas rose above $6 per million British thermal units (MMBtu) briefly on Sept. 28. The benchmark Henry Hub price ended trading for the day at $5.84/MMBtu, a seven-year high. In Europe, the closing price was $26.89/MMBtu and in Asia, the benchmark was $29.35/MMBtu.

"I would like for the price of gas to be more predictable, a lot less volatile and that the planning happens on a normal basis in order to avoid this huge volatility," he said. "In one year, we went from $2.50 gas prices globally to $25 globally. It's just terribly destabilizing."

The recent gas price spike was "all predictable," Souki said. "This should not be a surprise for anybody. Fundamentally, if you invest in supply, you are going to be in a good position, and if you don't invest in supply, then you run the risk that if demand doesn't do what you expected it to do … you have a problem.

"We have been lulled by a period of low prices everywhere, not just for natural gas but for energy in general," he continued. "We became complacent. We looked at the data with optimism, thinking that things were not going to change. And they did change, and they did change predictably."

In Souki's view, the natural gas world is divided into two parts—the U.S. and every other country. The U.S. has enormous amounts of energy, but suffers infrastructure constraints. Build that infrastructure and this country can continue to enjoy plenty of energy at reasonable prices, he said.

The rest of the world, however, is not as lucky. Outside of the U.S., the world relies on natural gas from only two other major producing countries: Qatar and Russia. Qatar has announced plans to ramp up its production of LNG by 40% by 2026, but Souki is skeptical of its ability to accomplish that goal.

And that raises some key questions in terms of how the U.S. sees itself in the world, Souki said.

"The central question with what is happening now is, what are we going to do about our critical position?" he said. "Are we going to keep it for ourselves, or are we going to share it with the rest of the world?"

The question is one of infrastructure, he said, noting that high gas prices do not exist solely beyond this country's borders.

"California and New England are also suffering from high prices, but that's because they don't want to build the infrastructure," Souki said. "That's the decision that we have to make today. Are we part of the world economy, or do we want to be isolated?

The infrastructure issue is atop Washington's agenda this week because two major infrastructure bills are facing crunch time in Congress. Souki said he favors the $1 trillion infrastructure bill that has already passed the Senate, but made it clear he considers it to be a starting point.

"If we think this is the end of the infrastructure investment that we need in this country, we are delusional," he said. "First, we are going to need to choose our energy source."

Simply stating a desire for electrification isn't enough because it's necessary for policymakers to decide how to generate that electricity. And the consequences for getting it wrong are high.

"It's amazing because diametrically opposed political systems in California and in Texas [have] the same issue—dysfunctional grids," Souki said. "You can't say that one side is more apt to deal with the issue than the other side; they're both making a total mess of their infrastructure."

He said he has backed a carbon tax as part of the solution for the past 10 years. A tax will help to manage demand and restore equilibrium. The only way to combat climate change as an existential threat, Souki said, is to increase the cost of carbon in the energy mix.

"If you don't want to acknowledge this, then you're never going to be successful," he said. "Going around saying that non-hydrocarbon energy sources are cheaper is just wrong. It's not true."

Souki also shared his opinion of President Joe Biden's goal of achieving carbon-free electricity by 2035.

"That's not an energy policy, that's a prayer," he said. "We're not going to get that. It's unrealistic. You can aspire to whatever you want. At some point, reality is going to hit you in the face."

—Joseph Markman

Analysts warn of dead DUC headwinds ahead for U.S. shale

As industry watchers eye the U.S. oil and gas sector's shrinking DUC count and natural declines, wondering what the future holds for drilling in shale plays, analysts say operators must spend more in 2022 to keep production from falling.

If oilfield inflation continues and hits well costs, they may have to shell out even more.

"If a public E&P is exposed to say 7% inflation and say 14% loss from end of DUC subsidy, a more than 20% rise in capex would deliver a comparable completion level as 2021," Bernstein analysts said in a note this week. "We think signaling such a rise in capex with relatively little benefit (or a 30% rise in capex to achieve say a 5% production growth) would be met poorly with investors."

Other issues to consider include the impacts of fewer E&P and service company staff available to carry out work, incentives for E&P management teams to limit spending and potential inflation up to 10%, Bernstein analysts said. The industry has already seen some inflationary pressure in areas such as diesel, steel and other materials plus labor.

Bernstein's analysis was delivered as developers of shale oil and gas assets focus on completing drilled wells, which have driven U.S. production growth recently. However, the DUC inventory has dropped to about 5,000 from about 8,000, analysts say.

The shrinking DUC inventory could limit oil production growth in the coming months, the U.S. Energy Information

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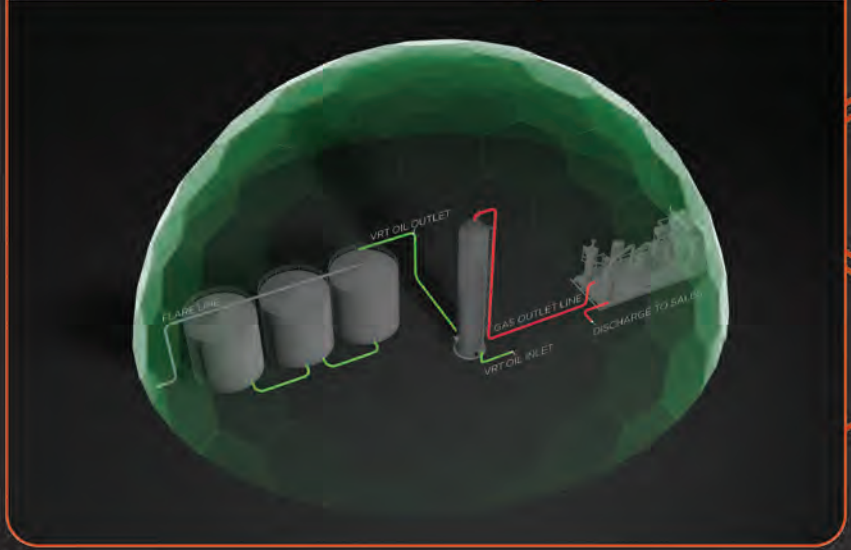

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Administration (EIA) said in September. At that time, DUCs in the Bakken, Eagle Ford and Niobrara regions had sunk to their lowest levels since December 2013, while DUCs in the Permian and Anadarko basins had dropped to levels not seen since June 2018.

Data dating back to August 2020 show completed wells have outnumbered wells drilled every month for major oil- and gas-producing basins tracked by the EIA.

Completing DUCs has allowed producers to maintain production without spending more and adding rigs, but they might have to find the happy medium to appease investors: balancing priorities of capital discipline, shareholder returns and efficiencies against drilling more new wells to grow supply at higher oil prices to increase profit.

Given the "dead DUC double-digit headwind," Bernstein analysts said they estimate the industry would have to spend about 14% more capex in 2022 without the DUC subsidy to complete about 7,000 wells during the next 12 months. The analysts estimate wells cost about $7 million, which includes about $5 million for completion work and $2 million for drilling.

There were some caveats. Higher oil prices and hedges were among the concerns.

Oil prices have rebounded from historic lows, with WTI near $78/bbl on Oct. 6. Rising prices could enable producers to spend more on drilling while increasing shareholder payouts. Bernstein has said that shale players could reinvest about 50% to 60% of cash flow, at $73 WTI, and remain in the "safe zone."

Which companies opt to raise spending in 2022 and by how much remains to be seen. The earnings season in November could shed some light on potential indicators.

Growing cash flow remains among the top priorities for E&Ps.

"Clearly high prices generate significant additional cash flow," analysts said. "E&Ps are generating sufficient cash flow to grow spending."

Add to this the ability for public E&Ps to lock in strong hedges, the analysts noted.

However, "again, just because they generate a lot of cash flow doesn't require that they spend it."

—Velda Addison

Navigating the oil and gas industry's energy transition

As the energy industry sets its goals to transition to cleaner energy, experts have explained exactly how to manage those ambitious goals and how to deal with uncertainty during the transition period. At the recent Rice University Baker Institute's 2021 Annual Energy Summit, four panelists discussed the ways government policy will shape ESG initiatives and how to deal with the uncertainties in the energy industry moving forward.

Dong Kwun Kim, deputy director of the loan programs office (LPO) at the U.S. Department of Energy, opened the panel by sharing the department's four objectives:

1. Supporting carbon-free electricity by 2035;
2. Supporting net-zero carbon emissions by 2050;

3. Benefitting disadvantaged communities; and
4. Stimulating job growth in the American economy.

To accomplish these goals, the LPO is financially backing companies that have goals aligned with their own, setting aside money specifically for environmentally sustainable technologies and projects and for investment in startup companies in overlooked communities.

Kim said, "When you consider that we are pursuing these large megaprojects, large projects that are at times first-of-a-kind engineering endeavors, projects that include nascent companies, startup companies—overall, in spite of all the challenges that we have with new and innovative technologies—new startups, companies that are trying to retool ... we have a 3.3% loss rate, accurate recoveries of $36 billion dollars guaranteed and issued."

Accompanying panelist Mark Finley, fellow in energy and global oil at the Center of Energy Studies at the Baker Institute, spoke on how to meet the global energy demand with sustainable alternatives. Roughly 40% of the world's supply of energy goes to generating electricity, and 90% of the world's transportation fuel is met with oil. While individual companies have declared personal ESG goals, Finley believes the real work will begin when consistent government policy matches the environmental checkpoints the companies set.

"To me, the central challenge, as we think about a transition to a lower carbon energy future, is how do we collectively, between policy makers, companies and users of energy, thread the needle?" he said. "How do we make sure that there's sufficient affordable energy to keep powering the world's economy today and improving quality of life around the world, while at the same time meeting this transition? And I think it's the reality of our world that elected leaders won't stay elected for very long if they fail to meet the first part of that challenge, continuing to supply affordable, reliable energy today."

In a study conducted by Columbia University, it found that the only way oil demand fell at the necessary rates was through "aggressive government policy" and "a very large and durable COVID impact," Finley said.

However, while COVID-19 had a positive impact on oil demand reduction, it had devastating impacts on public health and economic growth.

"If the recent history of COVID has taught us anything, it's that we were able to reduce global CO_2 emissions last year because of COVID, but that's not the way to do it," Finley added. "Collapsing the world economy and losing millions of jobs is not likely to be a popular way to reduce CO_2 emissions going forward. Without a concerted effort to reduce oil demand in the emerging economies, oil demand and energy demand, more broadly, is likely to continue rising."

Christopher Smith, senior vice president of policy, government and public affairs with Cheniere Energy, contributed to this conversation by expanding on how companies can plan when allocating capital and investments, keeping in mind what investors are seeking. Smith explained that

adaptation was a trait that would serve these companies well, using his own as an example.

"Cheniere's first terminal was an LNG import terminal by design before it was turned into an export terminal," he said. "We were growing very quickly, but we're growing in an environment in which the very business drivers are changing very rapidly."

Mitch Fane, Americas energy and resources leader and U.S. oil and gas leader with EY, followed up this sentiment and concluded the panel by addressing how to work with clients in a fast-evolving environment and dealing with the uncertainties that come from that. While there's no one-size-fits-all solution for helping clients, a good starting point is identifying the company's ESG scores and basing their goals around that instead of what everyone else in the industry is doing.

—Madison Ratcliff

Biden's net-zero plan won't push oil and gas away

At the current pace, weaning the U.S. power sector entirely from fossil fuels by 2035 appears to be an unattainable feat.

Technological limitations, policy design, market structures and even the political and constitutional foundations in the U.S. could hamper the progress of Biden's net-zero targets, according to a new report by international research consultancy firm Wood Mackenzie.

"Achieving this will take tremendous effort. All sectors of the energy industry will have to be transformed," noted David Brown, head of markets and transitions at Wood Mackenzie.

However, even if net-zero is achieved in a best-case scenario, Brown said fossil fuels will still be a part of the U.S. energy system.

"Even in a net-zero economy, not all hydrocarbons will be removed from the U.S. energy system," he said. "They will be needed to back up renewables in the power market, for example."

Additionally, WoodMac researchers noted that in order to reach net-zero emissions, the U.S. would need to quadruple its carbon capture and storage capacity.

"In our net-zero scenario, U.S. needs to reach 1 billion tonnes per annum (tpa) of storage by 2050, up from 25 million tpa today," Brown said.

He added that priority areas for investment to put the U.S. on a net-zero pathway include a carbon abatement-cost fund to support carbon removal capacity such as carbon capture, utilization and storage, direct air capture and low-carbon hydrogen.

For Biden, achieving net-zero emissions in the power sector by 2035 will be no easy task for a number of reasons.

For starters, current proposals for climate-related spending in the U.S. fall far short of the $10 trillion WoodMac believes will be needed between now and 2050 to achieve the Biden administration's emission goals.

"Based on our understanding of technologies, market policies, the challenges of quickly building transmission lines and the electrification of energy, we believe that 66% clean generation by 2035 is more feasible," said Brian McIntosh, Wood Mackenzie's director of North America power service.

Additionally, to reach Biden's net-zero goal, the analysts said wind and solar power—which currently account for about 10% of grid power supply—would have to become the largest generation sources by 2035.

While noting that proposed policies and financial incentives will make renewable technologies relatively inexpensive, McIntosh said solutions that maintain reliability and resilience are both "expensive and full of unknowns."

"A multiday storage solution is needed in a net-zero world, but we think we can expect no more than 10- to 15-hour durations from battery storage by 2035," he said. "The remaining gas-fired power plants will need to be fitted with carbon capture and storage, but the technology's ability to deal with large-scale carbon emissions in the power sector needs to be proven."

Speeding up electric vehicle (EV) adoption will also be vital to achieving net-zero, WoodMac's report noted.

Last month, President Biden signed an executive order setting a goal that 50% of all new passenger cars and light trucks sold in the U.S. by 2030 need to be zero emissions—a move backed by the country's biggest automakers.

"Our net-zero scenario for the U.S. transport sector suggests annual EV sales through the end of the decade would need to be around 50% higher than in our base case, which shows a zero-emissions market share of only 27% in 2030," noted WoodMac's head of road transport, Ram Chandrasekaran.

However, a surge in EV sales could pose a challenge for power markets, the report said, noting that EV buyers would, on average, see a 20% to 30% increase in their household power consumption.

—Faiza Rizvi

Report: A quarter of oil execs plan transition away from fossil fuels

Amid intensifying pressure to fight climate change in the ESG-dominated business environment, a recent report by Deloitte shows that only 23% of oil and gas executives globally are planning or starting their transition away from fossil fuels.

The study noted, however, that of the 77% that will remain focused on oil and gas business, nearly half are mapping out strategies for low-carbon operations in the near term by 2030s. Of these, 30% of oil and gas executives said they would stay focused on oil and gas as a core business at least through 2040.

"The CEOs that we spoke to in the study are not ignoring energy transition, but it's important to understand that a net-zero world does not mean zero hydrocarbons," Amy Chronis, vice chairman and U.S. oil, gas and chemicals leader with Deloitte, told Hart Energy.

The report noted that the companies staying in hydrocarbons as their long-term strategy see concentrated value in an anticipated smaller, but more competitive market.

"Staying in oil and gas would require decarbonization, which is both a possibility and opportunity while continuing to meet the world's growing energy demand," Chronis continued. "Forty-seven percent of our surveyed executives stated the pathway to becoming a low-carbon producer aligns most with their long-term vision."

In its study titled "Oil and gas business in a low carbon world," Deloitte surveyed 100 C-suite executives across global oil and gas companies, including

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integrated, U.S. pure-play, multinational E&Ps and national oil companies to determine their energy transition strategies. The report said the energy transition, overall, will play out over time, driven by fundamentals, technology maturity and stakeholder pressures.

With corporate pledges for net-zero on the rise, Chronis noted that Deloitte's report has identified several pathways to energy transition with "varying shades of green," which means oil and gas companies are adopting different approaches to low-carbon production.

While some are setting their sights on green energy, most oil and gas producers will continue to focus on fossil fuel production, but with many of the latter doing so on a decarbonized basis, the report said. Stricter regulations coupled with capital market ESG strategic investment strategies are driving action, which Deloitte divided into four major categories:

- *Net-zero pioneers* are moving away from fossil fuels with net-zero targets and a bold vision to divest their hydrocarbon business model built over decades—especially at an oil price of $75/bbl, which could create and unlock significant value through capex redeployment, valuation uplift and divestment proceeds.
- *Green followers* are planning to "go green" and could realize significant financial gains by monetizing their traditionally higher reserves-to-production ratio in the near term and using this revenue to venture into the green business at a reduced risk in the medium term. These companies seek to right-size oil reserves and pace into new energy solutions as more green technologies reach commercial maturity around the mid-2020s.
- *Low-carbon producers* could create new value by streamlining their portfolio, decarbonizing their business and optimizing their operations.
- *Hydrocarbon stalwarts* see long-term value of staying in the oil and gas business with the capability to remain the last-standing suppliers and gaining value through increased market share. By 2050, some oil and gas producers expect to remain focused on regions and assets with the lowest costs and extract the remaining value of reserves.

While there is increasing pressure to act sooner on climate change goals, "companies waiting to make a green plunge are carefully researching where best to redeploy capital while those deciding to stay in the hydrocarbons business are studying how best to grow market share in a shrinking market," the report said.

"Irrespective of which pathway they choose, companies must serve a widening array of stakeholders: their shareholders, customers, governments and communities, all becoming more environmentally conscious. Additionally, progress on four capabilities—operations design, supply chain ecosystem, the digital mindset, and organizational set-up, including workforce planning for tomorrow—could differentiate the rate of value creation across and within the four pathways to a low-carbon world."

—Faiza Rizvi

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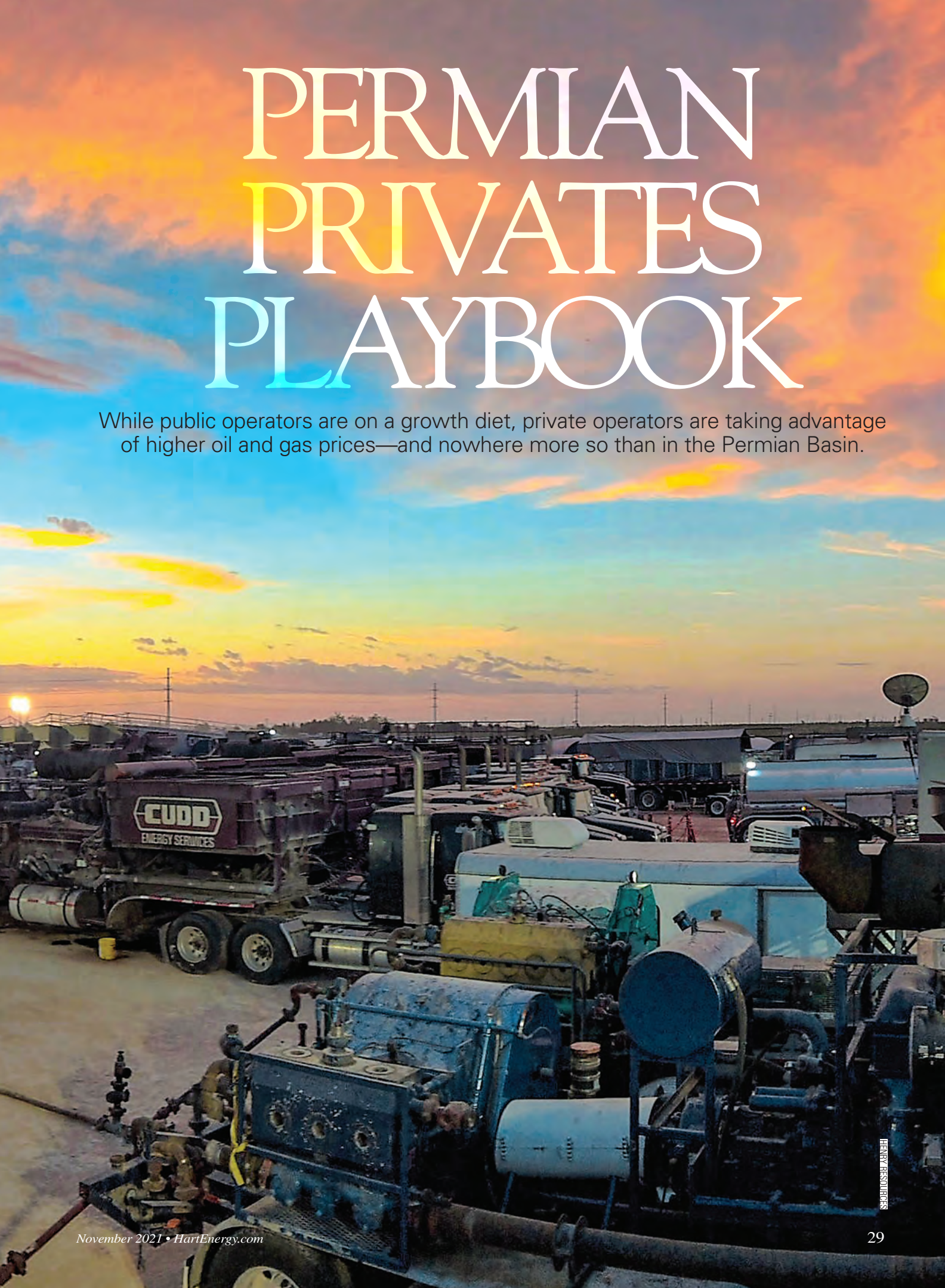
PERMIAN PRIVATES PLAYBOOK

While public operators are on a growth diet, private operators are taking advantage of higher oil and gas prices—and nowhere more so than in the Permian Basin.



HENRY RESOURCES

ARTICLE BY
ANNA KACHKOVA

"I think what differentiates us is what we're choosing to do with the excess cash flow," UpCurve Energy president Zach Fenton said.

The U.S. oil and gas industry is benefiting from higher oil and gas prices this year—a welcome development for producers following the pandemic-related downturn in 2020.

In the prolific Permian Basin, publicly listed operators remain under pressure to prioritize returns to shareholders and maintain discipline, but private companies do not necessarily have the same constraints.

In a recent report, Morningstar Equity Research noted that the U.S.' privately operated rig count increased by 80% since the pandemic nadir, compared with only 50% for the publicly operated rig count. This is largely playing out in the Permian, which accounted for almost all U.S. shale production growth in the second quarter of 2021 and remains attractive to operators.

Morningstar estimates that the marginal U.S. shale well breaks even at a WTI price of about $55/bbl and that most are profitable at even lower prices.

"For the Permian, a single figure would be misleading as the distribution of well economics is complex and varies across county, target reservoirs and factors in numerous variables related to the completion design," said David Meats, Morningstar's director of equity research of energy and utilities. "Safe to say most Permian wells are economic at $55, and the majority are profitable at much lower prices than that ($30 to $40 would be typical, albeit with plenty of exceptions for the reasons described)."

Thus, based on oil prices alone, it is not surprising that private players—without the same kind of pressures that publicly listed operators face from shareholders—would be tempted to ramp up activity.

"At current prices, and accounting for the above comments on breakevens, it is perfectly rational as well as NPV [net present value]-maximizing to accelerate drilling. That's actually true for public firms, too," said Meats. "But return-maximizing behavior is not the same as NPV-maximizing."

Morningstar has warned that if the ramp-up in private activity continues unchecked it could risk tipping oil markets back into oversupply. Indeed, it noted that the total U.S. rig count currently exceeds the equilibrium level, which it estimates to be around 400.

Plenty of private operators continue to show a degree of caution, however, as even without shareholders, they have other constraints to consider. A variety of strategies is emerging among these companies as they try to grow, in some cases in the hopes of selling off their operations, and to gain a competitive advantage over their rivals.

Facing page, Rig H&P 489 is drilling on UpCurve Energy's Tea Time West 1H well in Reeves County, Texas.

Leveraging expertise

The pursuit of a competitive edge in the Permian looks different depending on the operator and its particular strengths. In the case of Houston-based UpCurve Energy, the company is trying to leverage its past expertise and apply it under a new and evolving set of circumstances.

UpCurve was founded in 2015 by a core team of former employees of ConocoPhillips Co., with an equity commitment of $120 million from Post Oak Energy Capital. The company used the expertise it had gained at ConocoPhillips and applied it to running a private firm. Most recently, such expertise is being applied to ESG performance, UpCurve president Zach Fenton said.

"A lot of us came out of ConocoPhillips and larger companies where safety and environmental responsibility have always been a priority, so we do think it's fundamentally part of our company," Fenton said. He added that he sees the ESG realm as more of an opportunity than a challenge in the negative sense.

"I think it also provides a way for us, hopefully, to differentiate ourselves as a company going forward," he continued. "The bar has been set higher for us—both public and private companies—to raise capital and bring on new talent, etc. By continuing to stay ahead on the ESG front, it helps our company specifically too."

Another way UpCurve wants to leverage its expertise is by taking its learnings from its operations in Texas' Reeves County and potentially applying them to new areas beyond what has been its core area of focus thus far. The company's current operations are all located in Reeves County's southern Delaware Basin, but Fenton said it was seeking to grow across the Delaware and Midland basins. And while it is mostly focused on the Wolfcamp A, B and C plays, UpCurve is open to considering other targets.

"There have been some promising Bone Spring results nearby recently that we'll continue to watch," Fenton said. "We don't have the bandwidth to look across six different basins, but what we do think is interesting is if we can leverage what we've learned and done in our development program in Reeves County to other parts of the Permian Basin. Those are the types of opportunities that we will look at."

Fenton believes that public companies, just like private players, are also taking advantage of higher crude prices but in different ways.

"I think what differentiates us is what we're choosing to do with the excess cash flow," he said of the higher oil price environment. "Publicly listed companies are passing this directly back to their shareholders via dividends and share repurchases, whereas for UpCurve, what currently makes the most sense is to redeploy those proceeds into its development program," he said.

"However, we aren't chasing growth at all costs. That without a doubt has changed, whether you're public or private," Fenton added. "I think ultimately we'll get to the level where we can look like a public company in that we can grow our production at a low single-digit rate, reinvesting 50% to 75% of our free cash flow and distributing the remainder to our investors."

UPCURVE ENERGY

Even if crude prices go up further, UpCurve may not add to its sole running rig, which is the only one it plans to operate through 2022. However, Fenton said the company has the flexibility from both a land and capital standpoint to ramp down activity if commodity prices drop significantly.

UpCurve says it is focused on utilizing technology and innovative engineering practices to develop its Permian assets. Fenton believes that there is still more room for efficiency gains to emerge even though they may not necessarily be the types of step changes seen previously. He cited the recent emergence of simul-frac development, which has only started picking up steam in the past year but can potentially save a few hundred thousand dollars per well.

"I do think there's going to be a lot more incremental improvement that in aggregate is going to add up to a meaningful amount," Fenton said.

Pursuing steady progress

Many small, private Permian players have spent their lifetimes evolving and pursuing continuous improvement as the basin's unconventional potential has become better understood and as technological advances have helped to unlock more reserves. The COVID-19 pandemic forced many companies to rethink their strategies, but those that survived last year's downturn can reassess how best to proceed once more.

Among them is EnCore Permian, a successor to PetroLima, which over time has shifted from solely focusing on leasehold and mineral acquisition to also having a growing upstream business.

The company is backed by Minneapolis-based private equity firm Castlelake.

"We're not specifically a portfolio team, but we are a JV [joint venture] with Castlelake," EnCore CEO J.D. Smith said. The company started out backed by a $200 million commitment in 2017 and has since grown to more than $320 million.

On the mineral and leasehold side, EnCore has "gone through every iteration" in terms of how to do business, according to Smith. The company has pursued deals both in JVs

A haboob, a type of intense dust storm, is happening at one of Sabalo Energy's drilling locations in northern Howard County, Texas.

SABALO ENERGY

and alone and has shifted from a broad approach to more focused deals in line with operators narrowing their own focus to core areas.

"On the operation side, really, that was more of a growth story," Smith said. "We were [a] young team; we're probably the smallest E&P group out there. And so out of our capital commitment, only so much was dedicated toward that."

The company took a gradual approach to growing its business in the E&P space, building up increasingly bigger units that it could later sell, moving from nonoperating interests to taking on operatorship. It is now marketing its Colt 45 position in the Delaware Basin in Texas' Reeves and Culberson counties, consisting of about 7,700 net acres with a 100% working interest.

"We got done drilling up most of our commitments or nearly all of our commitments up until 2023," said Smith of the Colt 45 asset. "We are going through a marketing process right now with Barclays, and we're just seeing if we can take some money off the table."

Smith highlighted the company's focus on continuous improvement when discussing EnCore's broader strategy.

"We just grow, and that's been our story—a really methodical plodding along, trying to become an operator, then a better operator and gain efficiency," he said.

Smith believes that technology has considerable scope to advance even further and bring new efficiency gains on top of those reached thus far. He highlighted sand logistics as one area where he sees an "unbelievable amount" of room to grow.

"I think we're going to keep going more efficiently and see more cost opportunities," he said, adding that EUR opportunities seem to be further away. "But cost opportunities are going to be the driver," he added.

Even as it is marketing Colt 45, EnCore is open to new acquisitions. Smith said drilling 12 to 15 wells feels about right for 2022, while around two dozen wells would be a full load.

"We need to make sure that quarter to quarter or every two quarters, we're looking at our next project," he said. "And we can very methodically go at those."

Facing page, Ensign Rig 766 drills the two-well Mr. Hobbs/ Shenandoah pad for Bayswater Exploration & Production in the Permian Basin in Howard County, Texas.

BAYSWATER EXPLORATION & PRODUCTION

Smith agrees that private operators may be better placed to take advantage of stronger oil prices even as publicly listed players continue to hold back.

"For the private guys like ourselves, it looks like it's easier to take advantage when we run our static, flat numbers from this price, $5 gas, $70 oil," he said. "But we've got a good bit of backwardation in the forward strip. I think when we get close to contango or right at contango with those futures prices, it's going to be a good catalyst."

This could translate into more consolidation still or operators feeling more comfortable about pursuing new projects.

"But where we're at right now is definitely such a great improvement," Smith added. "It seems like that's the best news we have as operators, as we're still staring down COVID and still staring down OPEC increases."

Henry Resources' sweet spot

The Permian has seen some high-profile A&D play out over the past year. The trend is not limited to large public operators alone, and there has been plenty of A&D activity among the smaller, private players as well.

One of the private operators active in the A&D space is family-owned Henry Resources. The company has reinvented itself several times over its 52 years in operation, most recently pivoting toward horizontal drilling and offloading its vertical operations and other noncore assets.

"Most of our vertical assets we've divested, and then, over the last three months, we've divested several nonop properties—about $20 million worth," Henry Resources co-manager and president David Bledsoe said.

Meanwhile, the company is "very active" on the acquisition front, he continued, picking up about 8,000 acres of operated acreage in Texas' Upton County in the past year.

"Acquisitions are always going to be an important part of our business, and for the most part, it's going to be drilling opportunities," Bledsoe said. He described these acquisitions as an example of what Henry does best, "which is bolt-on and add-on around current active areas." This is where Henry has found its niche—one on which it is likely to remain focused for at least a few years.

This is often acreage that other, larger operators may have drilling commitments on but do not want to prioritize and likely consider it to be Tier 2 acreage.

"It's not going to be at the top of any of the big boys' portfolios, but if they need to get it drilled or if some of these private equity-backed companies need to wind down, we have an edge there where we can move rigs in fast, we can get it drilled fast and we have plenty of capital available," Bledsoe said.

The company prefers to drill out of cash flow and is "very debt-averse," he added. Partnering up with others has also helped make more capital available for drilling. Pickering Energy Partners and Grey Rock Energy Partners are examples of current partners Henry is working with, as well as Chevron Corp.

"We really don't like to own 100% of anything—our sweet spot is between 30% and 60% working interest—and that allows you to diversify, drill in more areas and level-load your risk," Bledsoe explained.

Additionally, he noted that while some partners, including Pickering and Grey Rock, have private equity money, Henry is not a portfolio company of any private equity firm and prefers to stay in control of its own decision-making.

"That is an important distinction in our partnership model," he said.

Henry currently has two rigs running in Upton County and will briefly bring a third online later this year but only to wrap up some drilling obligations. Bledsoe does not expect that third rig to run for longer than about a month. Beyond this, the company plans to drop back down to two rigs and then to one rig for one to two years from around May 2022 unless any new acquisitions come with more urgent drilling commitments.

"For the last five to six years, we've been a one to two rig company," Bledsoe said, though the company laid down its sole rig during the first wave of the COVID-19 pandemic and picked it back up toward the end of 2020. Adding the second rig made sense, he explained, because of "reasonable" oilfield service costs and firm crude prices.

"It does make sense for us to go ahead and capitalize on some good economics, but it's not really outside our normal window of operation," he said.

As well as using hedges, Henry has roughly half of its value in non-oil and gas investments, including real estate and banks. Having these investments sheltered from commodity price volatility has "absolutely" paid off, according to Bledsoe. The company was able to avoid laying off staff or even cutting salaries during the last oil price crash thanks to this.

"That's a very important part of who we are," said Bledsoe.

Seeking reentry

The experience of Sabalo Energy LLC, a portfolio company of EnCap Investments LP, illustrates how some private operators have already taken advantage of stronger oil prices to grow their operations before making an exit.

"We wanted to build a company that would be immediately accretive to a buyer from a cash flow perspective," Sabalo Energy president Barry Clark said. He noted, though, that the company "never went crazy" with drilling rigs and frac crews but maintained what it considered to be a sensible pace from a cash flow perspective.

Corpus Christi-based Sabalo was founded in 2014 and shifted its focus from the Eagle Ford to the Permian with two acquisitions in Texas' Howard County in 2015 and 2016. The company then drilled about 80 horizontal

"We wanted to build a company that would be immediately accretive to a buyer from a cash flow perspective," said Sabalo Energy president Barry Clark.

"Acquisitions are always going to be an important part of our business, and for the most part, it's going to be drilling opportunities," said Henry Resources co-manager and president David Bledsoe.

"We feel like so long as oil prices are in the $40 to $45 range, then we can create value," said Bayswater president and CEO Steve Struna.

wells in the Wolfcamp A and Lower Spraberry plays over the subsequent five years, all the while expanding its position with "strategic and generally contiguous" acquisitions.

Sabalo drilled a number of wells on its own but also partnered with a financial institution and drilled 30 wells with it under a drilling partnership, or drillco, structure. Additionally, it had what Clark describes as a "significant" amount of nonoperated acreage that it participated in alongside operators such as Surge Energy Inc., SM Energy Co. and Ovintiv Inc.

Laredo Petroleum LLC recently bought Sabalo's Howard County assets, as well as interests belonging to a nonoperating partner, for about $715 million in total in June 2021. The transaction left Sabalo without any current operations, but Clark said the company was now actively seeking new opportunities, most likely also in the Permian.

"Sabalo is primarily focused on the Permian Basin, but we have looked at a couple Eagle Ford deals," he said. "We won't stray too far from either of those basins."

The company's plans are backed by a new equity commitment from EnCap worth $300 million initially.

Clark sees this as a good time to be shopping around for new assets, noting that publicly listed operators in particular are offloading noncore operations.

"Now that prices are higher, there are multiple companies out marketing acreage to divest of noncore assets or assets that don't compete for capital within their portfolio," he said. "We think this will present a target-rich environment for us to capture a new asset."

In terms of what Sabalo will now look for, Clark said there are no specific expectations in terms of what the proved developed producing (PDP) reserves at an asset would look like for the company to consider it attractive.

"We don't care if an asset has a large or small component of PDP; it just needs to have a long enough runway for us to be able to come in and drill a significant number of development wells so that we can grow the asset," he said. He added that ideally a target asset would be in an area the company is comfortable with and would have attractive economics without depending on high breakeven prices.

"We have to be comfortable that the well results are going to be what we need them to be, and we don't want to be out on the fringe," Clark said.

Additionally, he expressed confidence that new Midland Basin targets would emerge beyond the Wolfcamp and Lower Spraberry formations.

"We are already starting to see operators target the Dean, Middle Spraberry and the Jo Mill with good results," he said. "Those intervals are probably not productive or economic over the entire basin, but in localized areas they can generate excellent returns."

Indeed, Clark noted that it is not just the small private players that are targeting these plays, citing Exxon Mobil Corp.'s XTO Energy Inc. shale division as an example of a major company starting to look at the Dean and Jo Mill. He also mentioned efforts being made by SM Energy and Ovintiv to drill these plays.

"We were in some wells with Ovintiv, and they were drilling Dean wells with great results," he added.

Henry Resources picked up about 8,000 acres of operated acreage in Texas' Upton County in the past year.

HENRY RESOURCES

BAYSWATER EXPLORATION & PRODUCTION

Python Pressure Pumping frac fleet completes the two-well 44 Magnum/ Formula One pad for Bayswater Exploration & Production in the Permian's Midland Basin in Howard County, Texas, in May.

Positioning for exit

Sabalo's sale to Laredo and other deals in the same area come as welcome news for neighboring operators in Howard County that are also positioning for an eventual exit. Among these is Colorado-based Bayswater Exploration & Production, whose business model is designed to return capital through asset sales.

The company raised its first natural resources fund in 2010 and is currently deploying capital in Funds III and IV, the latter of which recently closed at $462 million.

"I think the recent Howard County deals appear to have included a substantial amount of value for undeveloped acreage," Bayswater president and CEO Steve Struna said. "And that would be our decision point. Exiting now versus continuing to invest capital—which one creates more value for our investors? But we're absolutely looking forward to an eventual exit. It's just right now it feels like converting that acreage into production creates the most value."

Bayswater's Permian assets consist of about 30,000 operated Midland Basin acres in Howard County, plus roughly 11,000 net royalty acres in the Delaware Basin. It is selectively growing its mineral business and actively seeking to add to its operated position.

The company views the Delaware Basin mineral business and the Midland operations as "very complementary to one another," Bayswater Permian asset manager John Dyer said.

"We made a decision to operate in the Midland Basin because it looked more like our D-J operations," Dyer said, referring to Colorado's Denver-Julesburg Basin. By contrast, the company found the Delaware Basin to be more costly and complex to drill and chose to gain exposure to the technological advances there by buying mineral rights across acreage being developed by a variety of other operators.

Bayswater has had one rig running continuously since 2019 and will be picking up a second in the fourth quarter of this year.

"We feel like so long as oil prices are in the $40 to $45 range, then we can create value," said Struna. Conversely, he does not feel like Bayswater would add even more rigs if oil prices were to keep rising further.

"If oil prices really scooted up, we wouldn't go to four or five rigs," he said. "I think a two-rig steady program is the sweet spot for our capital availability, our human resources and our acreage base."

The company is also working through its inventory of DUC wells that it deferred during the worst of the 2020 downturn. It picked up completion crews late last year and has been running them ever since. Indeed, Dyer noted that Bayswater is currently running a simul-frac operation on a 10-well pad.

"It's a significant operation for us, as a small company," he said. "We think it's very efficient. We're moving very quickly with frac right now, and we're very hopeful that it adds a lot to our bottom line as far as cost reduction and efficiencies go."

One issue to address as the company moves forward is the question of well spacing after running into well interference from offset fracs.

"That has been a real issue for not just Midland Basin players but greater Permian Basin players and really resource basin players in general: what the appropriate well spacing is. So we're watching that very carefully," said Dyer. For now, Bayswater has opted to decrease its planned well density to 16 wells per mile.

"We made a decision to operate in the Midland Basin because it looked more like our D-J operations," said Bayswater Permian asset manager John Dyer.

"I'd say that our development pace is on par with the disciplined public companies, when you account for the exceptional reservoir quality and well performance that our locations deliver," said Ameredev president and CEO Parker Reese.

ESG performance is another issue the company is increasingly prioritizing.

"Our investor base is very ESG sensitive," said Struna. "But at the same time, that collection of investors I believe recognizes the importance of low-cost fossil fuels. And therefore, they remain inclined to invest in oil and gas with the view that if it's developed here in the U.S., it's developed in a very environmentally and socially responsible manner."

Bayswater touts the low greenhouse-gas footprint of its D-J Basin operations in particular and says it tries to export its best practices from Colorado to its Texas operations and vice versa. The company will publish its first ESG and sustainability report in November.

Looking long term

There is considerable uncertainty over the future of the oil and gas industry, but this has not stopped various operators in the Permian from building a business designed for the long term. Among the companies looking to the long term is Austin-based Ameredev, which is betting on the quality of its assets to give it a competitive edge.

"We've got excellent geology, a large contiguous footprint, infrastructure that offers reliable market access and a team that can execute on the plan. So it's one [business] that we'd be happy to own for the long term," Ameredev president and CEO Parker Reese said.

This is the second incarnation of the company after Ameredev I was sold off in 2017. Ameredev II was formed in the same year with a $400 million equity commitment from EnCap Investments and management. The company is currently producing 20,000 bbl/d from assets that span both the Texas and New Mexico portions of the Permian. It expects to double this to 40,000 bbl/d in 2022, based on its current level of development activity and bolstered by infrastructure investments that help with takeaway capacity and market access. On the infrastructure side, these include the operations of Ameredev's Washington Crossing Field Services subsidiary and a partnership with Piñon Midstream, which recently brought a gas treatment facility online.

Ameredev is operating three rigs, and Reese does not anticipate the company increasing activity even in the event of a materially higher oil price environment. He noted, however, that Ameredev has "plenty of flexibility" to slow down if oil prices drop again.

"I'd say that our development pace is on par with the disciplined public companies, when you account for the exceptional reservoir quality and well performance that our locations deliver," Reese said. "We've got some very unique geology where we are and, in combination with a good completion design, we feel like that gives us some of the top quartile or top decile undeveloped locations in the basin. On a basin-wide capital allocation basis, we feel like we're moving at a moderate pace."

Reese said that while capital availability had decreased for much of the industry, this was not such a problem for the best-performing operators, including among private companies.

"We like to say that capital is always going to find the best ideas," he said. "The businesses with strong operating performance and outstanding assets continue to be well funded."

Reese identified ESG performance in particular as the main driver in the current environment, where investment and operating discipline are rewarded.

"We think it creates an opportunity for a company like Ameredev to shine," he said. "Both our infrastructure and our company have been designed from the ground up to meet the current and anticipated regulatory environment."

Examples of what the company has been doing on the ESG front include reducing its flaring intensity to less than 0.5% and recycling essentially all of the water it uses for completions.

Ameredev is targeting the Third Bone Spring, Wolfcamp X and Wolfcamp A formations, almost entirely with 10,000-ft laterals. Over recent years, the industry has pursued technological advances in various areas, including lateral length and multiwell pads, but Reese believes there are future gains to be made in other areas too.

"We're seeing very significant runtime and cost savings from our investments and our focus on field automation and remote operations right now," he said. "As we focus on producing more volumes more reliably, that will be important."

The issue of well interference is something Reese described as being well documented.

"For Ameredev, we've arrived at a development plan that puts 12 wells per section in the Third Bone Spring, Wolfcamp X and Wolfcamp A all together," he said. "This plan has a lower well density than what some of the offset operators have tried around us, but we do utilize a greater fluid and proppant intensity. We feel like that maximizes the economics of the well development."

Some restraint

The comments from these various operators suggest that some restraint can still be expected, especially when their small size limits how much they can do. However, the trend has still been one of rising activity so far this year, even if that means a company bringing only one rig back online in some cases.

Morningstar's Meats agreed that one cause of the rise in private drilling was an attempt to attract buyers and make an opportunistic exit. But he believes that public operators will struggle to justify expensive M&A at this stage, so he does not expect a spree.

What is also clear is that if oil prices dip again, private players are ready to throttle back activity. If Morningstar's assessment of oversupply risks is correct, the window of opportunity to boost cash flow and A&D on higher crude prices may be limited. □

Facing page, Bayswater Exploration & Production's facility on the Mr. Hobbs/ Shenandoah pad in the Midland Basin in Howard County, Texas.

BAYSWATER EXPLORATION & PRODUCTION

E&Ps STAYING RELEVANT

The M&A that has occurred over the past year reveals three main strategies U.S. independent E&Ps are pursuing to remain viable, according to Wood Mackenzie analyst David Clark.

INTERVIEW BY
LESLIE HAINES

Historically, oil and gas companies face many challenges—it's considered part of the gig. However, in recent years, those challenges started to evolve and, subsequently, so have U.S. independent E&Ps.

David Clark, vice president of upstream research at Wood Mackenzie, recently shared his take on the new pressures facing oil and gas and what that means for the future U.S. E&P landscape.

In light of many pressures (ESG, anti-carbon, energy transition, shale maturity, etc.), what does the future independent E&P look like in 10 years?

The 2030 E&P landscape will likely be dominated by fewer, larger companies.

There isn't a one-size-fits-all template for the U.S. independent of the future, but there are likely some shared characteristics that will enable survivors to navigate the risks and stakeholder pressures of the next decade. Strategies to 2030 are being shaped by the economics of a maturing industry, the energy transition and investor pressure to show capital discipline, maintain resilience and deliver cash back to shareholders through the commodity price cycle.

"The different strategies we are seeing diverge largely around the importance of portfolio diversity," said David Clark, vice president of upstream research at Wood Mackenzie.

I'd say the key characteristics are sufficient scale; a balance sheet and portfolio that are resilient through the price cycle (and therefore able to deliver cash to shareholders through the cycle); a good governance framework; and a clear and viable energy transition strategy.

The different strategies we are seeing diverge largely around the importance of portfolio diversity. Some think it is critical to dealing with risk, (while) others see it as diluting their investment proposition.

The U.S. M&A that has occurred over the last 12 months give us a sense of the templates for different strategies the independents are pursuing to remain viable and investable out to 2030. For sake of simplicity, I think they fall into three groups.

First, you've got the mini-majors, who value diversity and optionality, but who seek economies of scale in the Lower 48 portion of their business (such as) ConocoPhillips-Concho.

Then you've got Lower 48 companies who know they need to get bigger, think diversity across basins and/or commodities is important for risk management but don't want to stray from their core unconventional competency such as Devon-WPX (and) Cimarex-Cabot.

Finally, you've got the pure-play scale builders, who think investors will still value very focused investment stories, but who understand they need scale and inventory depth to remain viable: Pioneer-Parsley/DoublePoint, Diamondback-QEP/Guidon and the interesting bankruptcy emerging combination of Bonanza Creek-HighPoint-Extraction Oil & Gas-Crestone Peak (Resources) in the D-J (Denver-Julesburg) Basin/Niobrara.

Given the increasing competitive advantages of scale, there is a sense now that you either get bigger or you exit. That may be a bit extreme, but for many that is probably true.

Within a basin, you likely get increasing economies of scale to at least 1,000 boe/d (which is one reason why you see the majors with vol-

umes targets that ramp to that level before they flatten). For companies that are pursuing a basin pure-play model (Pioneer, Diamondback), we have seen an urgency to acquire their way to sufficient scale, since the market will no longer tolerate aggressive organic growth.

For clear and viable energy transition strategy: Ten years from now, surviving companies will need to be well down the road to decarbonizing their own operations. They will have come close to eliminating flaring and venting (other than for safety/emergencies) and methane leakage, and then moved beyond that low hanging fruit to electrification of the oil field. CCUS (carbon capture, utilization and sequestration) will be on the horizon as an increasingly economically viable decarbonization technology over the next decade (2031 to 2040). The fewer, larger companies that remain find it easier to collaborate on regional CCUS and other decarbonization projects that benefit multiple operators and other adjacent industries.

How should public and private independent E&Ps change? How will they change?

Publicly traded companies have been changing strategy and behavior, some of them dramatically so, over the last year and a half. The combination of investor/market pressure and the pandemic downturn moved the sector from a state of semi-denial to acceptance, with regards to both investor expectations and the growing risks related to the energy transition. The public independents will need to sustain their new-found capital discipline and shareholder-friendly return of capital as oil prices rise to firm up their credibility, but they are off to a good start. In terms of the energy transition they have been fairly aggressive in playing catch-up to the rest of the industry this year. Many have laid out Scope 1 and 2 net-zero targets (though many are heavily relying on carbon offsets, which still have major credibility issues), established fairly meaningful medium-term mileposts and moved their energy transition plans to the front of the investor slide deck. But investors and lenders are under pressure and moving fast on this front, too, and to maintain access to capital, the independents will need to be even more ambitious and execute well on the targets they have set.

Privates arguably feel less direct pressure to change, though the better way to phrase it may be that they have a different set of pressures. While they aren't worried about equity market investors or as concerned about their public reputation, they do have to worry about access to capital and the cost of capital. Lenders' standards are rising, and the cost of capital will rise over time as well as climate-related risks build.

They also need to consider the demands of their customers (for example, into LNG export where buyers may reject cargoes based on emissions intensity of the gas) and risks from regulations and policy changes. So, privates may not be as aggressive on their energy transition plans as the publicly traded companies, but they will need to keep pace with important stakeholder expectations.

What is the threat and the opportunity?

There are many threats—access to capital, rising cost of capital, the cost of addressing the energy transition, the cost of not addressing the energy transition, the inevitable peak and then decline in demand for oil and gas.

In terms of long-term demand, a world on a decarbonization path—whether it is the Paris-aligned 1.5 (degrees Celsius) or 2 C paths, or the more realistic "base case" path that is aspirational but falling short of Paris-aligned targets—does not need hundreds (or in the case of the worldwide total, thousands) of oil and gas companies chasing volumes.

The opportunities depend on the company—for many smaller operators, the opportunity will be to identify the appropriate time to exit. For the largest companies, the opportunity will be to forge a viable path through consolidation and possibly through investments in an emerging carbon-as-a-business. For those in the middle, the opportunity may be to extract maximum value out of a portfolio of advantaged assets, remaining to the left of the supply curve as demand for oil starts its decline.

Are we heading for a time of only two to three companies per basin, a la Pioneer Natural Resources Co. or ConocoPhillips Co.?

Consolidation would be happening in the sector regardless of the energy transition, given the maturity of the key basins and the immense pressure from investors to restrain growth investment and deliver free cash flow to shareholders through the cycle. But the energy transition puts the pressure for consolidation into overdrive.

We are maybe halfway there on Permian consolidation. Right now, a dozen companies hold 80% to 85% of the value in the basin. That dozen will likely consolidate a lot of that remaining 20%. And combinations among those dozen companies (which include the U.S. majors) will probably bring the number of important players down further. By 2030, there may be just a half-dozen key players in the Permian. Other mature basins may have fewer. Scott Sheffield has talked about having just five U.S. E&Ps with sufficient scale to be investable by 2030. It may be more than that but probably not more than 10.

Consolidation creates a healthier sector for navigating the energy transition. Companies with scale typically have greater resilience through business and price cycles and therefore greater support from capital markets. Fewer and bigger companies will rationalize development and production, lower capital requirements and enable better capital stewardship. It will be easier to collaborate on energy transition issues—regional consortia for CCUS, oilfield electrification, policy engagement with government—with a handful of key players. ☐

"Consolidation creates a healthier sector for navigating the energy transition."

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FAMILY FUNDED

As traditional public and private sources of capital step back, family offices are stepping in to fund selective deals. The question is, what attracts them and can they fill the gap?

ARTICLE BY GREGORY DL MORRIS

"Anecdotally, yes, it seems like investment in oil and gas from family offices has increased on a percentage basis," said Marc J. Sharpe, chairman and founder of the Family Office Association. "While it's difficult to say if the trend is accelerating, it certainly feels like an institutional pullback in oil and gas investing, both debt and equity, is creating opportunity for family offices to fill the vacuum in funding."

However, the specific motivations have more to do with internal governance and investment mandates, Sharpe noted.

"Younger generations often want to offset petroleum investments or diversify away from the sector, but deep family expertise in oil and gas, as well as a predictable and reliable return profile, maintain the asset classes overall appeal. To bridge some of these generational divides, there is an increasing interest in technology companies that seek to improve efficiency and reduce the carbon footprint."

Family offices take a risk-mindful approach, Sharpe said. "Given that less institutional capital is flowing in, and less capital in general is available, better structures with tighter covenants are possible. Such structures might not have been possible a few years ago when the availability of capital for growth and expansion was more readily available. Equity upside with debt characteristics is ideal for many family offices and given the direction of the market I expect to see more of those opportunities present themselves."

The watchwords these days for investment are risk-adjusted returns and sustainable, tactical investments. At the same time, there has been a great deal of criticism of unconventional producers for their track records on total return. Still, private capital remains attracted to oil and gas.

"Regardless of the popular marketing terms, at the end of the day you're dealing with income-producing, real assets. When managed well you can call them 'risk-adjusted,' 'sustainable,' 'tactical' or something else," said Sharpe.

"Analysis begins with understanding the underlying asset and its potential value. The physical and financial engineering around that asset is always a function of the asset itself. No one I know believes oil and gas is going away in the next 10 years, so there will be a need to continue funding high-quality projects for some time to come."

"No one I know believes oil and gas is going away in the next 10 years, so there will be a need to continue funding high-quality projects for some time to come," said Marc Sharpe, chairman and founder, Family Office Association.

As ever with investing, the only matter more important than getting in is getting out. Exit strategies and timelines have changed significantly for large private equity investments in upstream. An operating company typically would be in the portfolio about five to seven years before being sold to a public or strategic buyer. Now many assets and operators are simply being shuffled around between or sometimes within big private equity portfolios.

In contrast to that, "family offices tend to be defensively oriented," Sharpe said. "Wealth preservation is often a priority. In terms of oil and gas, the investment needs to stand on its own. If profitable and cash-producing, any exit scenario can be treated as pure upside. Multigenerational family offices understand the value of the asset itself and look for ways to minimize downside risk. I think we will see longer hold times by family offices and more self-liquidating vehicles that will be held until end of life."

Land and cattle

There is no typical family office, but CedarTop Capital reflects one that could be considered characteristic: It is a single family that had a large land holding with cattle on the surface and liquid hydrocarbons under. The ranch was sold several years ago as a going concern, with the family retaining some mineral rights. While with the family, the ranch's oil and gas production included several dozen operators, so the family had a wide experience in the sector.

"The family office I now manage does not stray too far from what the family knows: ranching and agriculture, oil and gas and real estate," said Matt Lemme, chief investment officer, CedarTop Capital. "There definitely seems to be an uptick of interest in the oil and gas sector from family offices in general, and the folks that have historically been in energy

"There definitely seems to be an uptick of interest in the oil and gas sector from family offices in general, and the folks that have historically been in energy have stayed active," said Matt Lemme, chief investment officer, CedarTop Capital.

Bryan Sheffield, managing partner of Formentera Partners LP, said, "Family offices like to see deep value, which translates to the current environment in oil and gas."

have stayed active. I am also seeing a lot more deals come across my desk these days."

While family offices are usually eager to put their capital to work, Lemme said that in oil and gas at the moment, "a lot of us see a chance to participate in the industry in a bigger way as banks, public capital sources and even some private equity shun the industry, making capital formation more inefficient and returns higher." To some that may sound opportunistic, even mercenary, but Lemme suggested it is more like tough love.

"We have seen a bunch of deals where acreage is getting picked off or small assets are getting carved out at attractive valuations. They are often off the fairway, or on the [Central Basin] Platform [in the Permian]. Drilling economics in general are obviously very good at these prices, but the deals we've invested in still work at sub-$40 oil.

"We are mostly agnostic about regions except for a few. For example, we will avoid California because there is a good chance your downside is a donut. That is one of the no-nos in this family office: Avoid situations with a non-negligible risk of permanent loss."

The first half of the year was very quiet, Lemme noted, then activity increased notably starting in June.

"We mostly work on direct deals. There is a lot of networking involved because it's not as easy as placing money in a blind pool or a fund, but we think that is how you get the best returns and maintain as much control as possible when you are not operating. One novel form I have seen a couple of times this year is the series LLC. It is one entity with sub entities, each with their own assets, so an operator can buy one set of assets in one sub entity and then set up another one and raise money for it separately as it identifies other assets."

Market has turned 180 degrees

Family offices do like contrarian investments, said Bryan Sheffield, managing partner of Formentera Partners LP. "They don't need to go with the money flow because they each have their own investment criteria. Also, family offices like to see deep value, which translates to the current environment in oil and gas. I wouldn't say family offices are accelerating, they are being very selective. Also, most family offices like one-off deals versus an open-ended fund. This makes it trickier. There will need to be more patience on deal execution."

That patience is especially important given that there is a lack of capital in the segment. "Family offices cannot fill the void" on their own, Sheffield said. "There is simply too much pressure between sellers versus buyers. That means price will have to change. Overall, the return opportunity is a bigger driver of interest versus seeking exposure to the commodity."

Deal activity has picked up significantly compared to last year across the spectrum of deals and transaction types, Sheffield observed. "One of the main drivers has been the recovery of oil and gas prices that has bridged the gap between capital providers as well as buyers and sellers. The types of transactions really range from equity-type capital to more structured capital. This activity should continue to be robust as there are significant asset sales on the market that need to be funded, and that is not expected to change in the near future."

All that said, Sheffield acknowledged that historical returns have been poor in oil and gas. "The main issue is the historical model of growth has been very challenged during the volatility of commodity prices and a prolonged period of low prices," he said.

"Given the lack of capital, there is a real opportunity for the first time in a long period where you can buy de-risked oil and gas assets and generate risk-adjusted returns," said Sheffield. "The reason this was not available historically is that there was too much capital that resulted in people paying for growth which had a high degree of execution risk. The market has turned 180 degrees to where there is limited to no value on growth and discounted value on existing production which is significantly lower risk."

Tactically, Sheffield suggested that, at present, sellers are wise to run a marketed process as opposed to one-off transactions. "The market is distorted," he said, "and sellers always have huge expectations. To find true valuation, a seller needs to hire a bank to run a process. It's the exact opposite in that we use to do at [my former operating company, where] all deal flow was done by relationships."

Deal type—operated, nonoperated or minerals—will determine whether investors are seeking their own deals or looking at deal flow that is shown to them, Sheffield said. "Typically, unless a family office has an existing operations team, they are not seeking operating deals directly; however, minerals or nonoperated may allow for that. There are all types of opportunities available and so investors can be selective depending on their risk tolerance."

Exit planned but assets held

Family offices are seeking "high-quality private deals where the risk/return profile is dislocated," said Steven Ganss, managing partner of ReignRock Capital Partners. That is both a push and a pull.

"When you factor in real expected returns and where valuations are and have been recently, investing in the energy sector still looks attractive, even more so when you factor in the prospect for increasing inflation numbers. I would say more and more family offices are seeing a return to traditional or conventional production opportunities as a better hedge to inflation than even real estate."

Among the varied approaches favored by family offices, Ganss said he had heard some discussion on private debt, "but with inflation on the horizon, the real risk in that is increasing.

"And those deals, unlike traditional bank debt and even some mezzanine debt, are fixed coupon. Given likely changes to the capital-gains laws, I think people that have wanted

SHUTTERSTOCK/STMOOL

to sell assets have or are completing those now and hoping any tax law changes are not retroactive. Most people I talk to are less likely to sell with higher anticipated cap gains, which is to be expected."

Risk-adjusted return remains important, mostly. "I'm not sure how much weight it carries, however," Ganss cautioned. "If you have an angle that reduces any type of environmental impact or risk, then people want to discuss. For example, the project we just funded last December is a tertiary recovery project, meaning we are taking old assets with a high degree of understanding about the subsurface structure and remaining oil in place and finding a creative way to re-energize the reservoir."

The ESG angle in that deal was in keeping an active asset that would normally be plugged.

"Additionally, we can produce through most of the existing well bores," Ganss said, "which means our drilling footprint will be very light, and all of the gases produced will be re-injected so there is no atmospheric release. When you combine that profile with risk-adjusted returns in the mid-30% range over a long cycle, 20 years worth of income, you have something people want to look at."

Even though exit strategies are more flexible for family offices than they are for large private equity funds, those are still important scenarios.

"One of the interesting things about our recent deal is that we run the typical five- to seven-year hold with an exit planned, but at the same time, all of our deals must stand on their own and, at a minimum, deliver cash-on-cash returns of greater than 20% over the long term. Thus, our strategy here is to hold this asset for 20 years or more and simply return cash to investors (30% IRR/11x ROI) with the option to sell if conditions warrant."

Drinking out of a fire hose

"With rising commodity prices, we are seeing an increase in interest of family offices in oil and gas," said Robert Martinez, president and CEO, Titan Rock Exploration & Production LLC. He noted that capital is "deal by deal and plug equity. Not like the usual capital 'commitments' by big PE [private equity] houses. The family office involvement is very tactical, very specific. It is not just backing a team in a basin, but it is filling a vacuum that has been left by other forms of capital."

The family offices expanding into upstream hydrocarbons are often experienced in oil and gas themselves, Martinez added. "Many of them have their own operating platforms, and by that I mean either, literally, production on their land or already in their portfolios, or in terms of in-house expertise, an engineer or landman."

One of the advantages of family office investment is the flexibility. Martinez said that the deals with which he has been involved recently have run the gamut from equity plugs for specific operations to limited partnerships in a debt structure to upside-only investments and drilling partnerships, or drillcos.

"The deal structure is often dictated by the nature of the A&D market at the time," Martinez said. "Looking back over 2021, we went from no deals at all for quite a while to drinking out of a fire hose. The opportunity set has gotten better quarter by quarter this year. The uptick in deal flow started at the end of the first quarter and accelerated through the second quarter. When we hit $70 oil and $5 gas, everyone pushes to high-grade their holdings."

Martinez stated plainly that "deal structure matters is key. We approach valuation very carefully, particularly with the alignment of investors and operating management."

He explained that it is not unknown for deal structure and alignment to take precedence. Even when a prospective transaction involves prime acres and good rock, if the terms, the structure and the alignment are not of equally high caliber, there may be no deal. Conversely, prospects a bit off the fairway may be an easy choice if valuations are compelling, the deal structure is advantageous and the operating team is aligned with investors.

"All risks are evaluated, and full-cycle economics are weighed in," said Martinez. "The essential question is, 'When will I get my money back?' For the past 15 years, the industry has been a development machine. In the last few years, investors have been starting to ask, 'How does all of this drilling make sense?' The answer, clearly, is that some of it never did."

Higher prices have helped in the past few months, but Martinez stressed that "the days of drilling a few wells and selling off the position are over. Today and for the foreseeable future you will have to live with your decisions."

The beauty of the family office, Martinez said, is the ability to move quickly, be flexible and opportunistic. "You get into the room with the decision makers. The exit strategy can be to sell in six months or 16 years, what makes the most practicable and economic sense. For a long time, prices could cover a lot of mistakes. In the past year or two, the industry has been able to cull the herd. Now with rising prices, the feeling among operators and investors is: Game on, let's go!" □

Family offices are seeking "high-quality private deals where the risk/return profile is dislocated," said Steven Ganss, managing partner of ReignRock Capital Partners.

"The family office involvement is very tactical, very specific. It is not just backing a team in a basin, but it is filling a vacuum that has been left by other forms of capital," said Robert Martinez, president and CEO, Titan Rock Exploration & Production LLC.

TALOS' CARBON CAPTURE VENTURE

Offshore producer Talos Energy Inc. was awarded Texas' first site for a large-scale carbon capture and storage project along the Gulf Coast.

ARTICLE BY
BRIAN WALZEL

The energy transition and, perhaps even to a larger degree, the heightened focus on ESG initiatives, are pushing traditional oil and gas operators to reconsider the way they do business and the ways in which they operate. Carbon management is quickly emerging as a method to achieve net-zero goals—if a company has announced such aspirations—or enhance ESG performance, and in many cases, both.

Offshore Gulf of Mexico (GoM) producer Talos Energy Inc. announced two major partnerships this summer, as well as a winning bid for a carbon sequestration project site that positions the company as one of the early-innings leaders in carbon management.

In June, Talos announced a joint venture (JV) with London-based Storegga to source, evaluate and develop carbon capture and storage (CCS) projects along the U.S. Gulf Coast and GoM, which includes state and federal waters offshore Texas, Louisiana, Mississippi and Alabama.

Just two months later, Talos reported that it, along with partner Carbonvert, was the winning bid for a Texas General Land Office

"CCS is a business to which we can rapidly transfer our skill set to develop a material low-carbon business," said Talos Energy Inc. president and CEO Tim Duncan.

Talos Energy Inc. will apply its knowledge as a shallow-water Gulf of Mexico operator in its two carbon capture and storage ventures with Storegga and Carbonvert.

(GLO) carbon storage project for a site located near Beaumont and Port Arthur, Texas.

The JV project with Storegga spanning the Gulf Coast targets the region's 30-plus gigatons of potential carbon storage, while the specific GLO project with Carbonvert has the potential to sequester up to 275 million metric tons of CO_2 over the life of that project alone.

Talos president and CEO Tim Duncan said the idea to initiate carbon management projects first arose in 2018 when the company began to more closely evaluate its emissions and how to lower those emissions, but the idea in investing in CCS really picked up momentum in the past year.

"CCS is a business to which we can rapidly transfer our skill set to develop a material low-carbon business," Duncan said. "We started talking to banks and our friends in the investing community about some of these initiatives. We were introduced to Carbonvert, which had an experienced team in renewables and CCS with other companies, particularly the majors, and we started talking about the GLO bid process. Working on that bid convinced us to take a more regional approach and really lean in on the idea."

GLO project details

The project site for Talos and Carbonvert's CCS project with the GLO comprises a total land area of more than 40,000 gross acres offshore Texas state waters in the GoM. According to Talos, the project site is 100% covered by the company's existing seismic database and is located in proximity to a large concentration of industrial CO_2 sources along the Texas and Louisiana Gulf Coast.

"We have a lot of seismic and deep understanding of the geology, as well as experience with the regulatory environment, logistics and all of the things you need to fulfill an offshore operation," Duncan said. "And we believe that was what the state of Texas found in our bid. They had an area with the right geology that will allow us to create the right storage site, meaning we can put carbon away, monitor it and store it for a long period of time."

According to Talos, the process has now entered into an exclusive phase where Talos and Carbonvert are actively negotiating a lease agreement with the GLO based on the terms of the Talos bid and the terms included in the original request for proposal from the GLO. The final terms of the agreement are subject to the approval of the Texas School Land Board.

Duncan explained that the deal with GLO is a more localized approach to carbon management as compared to the JV with Storegga, which he said was more regional and covers most of the Gulf Coast.

"In the GLO bid, we selected acreage with great geology while limiting potential liability for us and the state, meaning there is the least

"Talos is working to be a first mover in the CCS space and intends to accelerate the process," said Bob Abendschein, executive vice president and head of operations, Talos Energy Inc.

TALOS ENERGY INC.

amount of older wells, plugged wells, in that populated area," he said. "So, it was the most efficient use of space. This would do the most good from a carbon storage, tracking and monitoring [aspect] over the next 30 to 40 years. We want to continue this approach regionally.

Both Duncan and Bob Abendschein, executive vice president and head of operations at Talos Energy, explained that the onset of the project's operations are still at least a few years away.

"Talos is working to be a first mover in the CCS space and intends to accelerate the process," Abendschein said. "Back in April is when the GLO came out with the request for proposal, and the bid award was then presented in August 2021. So, we'll be working in parallel to wrap up the lease while we start to plan the next phase of the project."

He added, "With engineering and geological work, coupled with the permitting required for permanent sequestration, there are numerous elements that all need to come together, but we're definitely aiming to reach a final investment decision on the project as soon as we can."

Localized CCS

According to Talos, the JV with Storegga will originate and mature CCS ventures with emitters, infrastructure providers, service companies and financing partners, among others. The company reported that under the terms of the agreement, as individual CCS projects are matured in the future, each will be ring-fenced with separate operating agreements, financing structures and the possibility of additional working interest partners.

The agreement requires no upfront capital, and Talos and Storegga will share costs in a 50:50 split in the initial phase. And although Talos has been designated as the operating partner in the JV, Duncan said the deals with both Storegga and Carbonvert effectively turn them into a service provider.

"You have to be able to talk to the industrial partners and make sure you understand that now they are the customers, and we're the service provider," he said. "So it changes the nature of the relationship that we have as an offshore oil and gas operator for us to turn into a service provider. We talk to the customer, which is the industrial partner focused on lowering emissions, work with a midstream partner and create the full value chain, and execute the carbon storage and monitoring of the product."

Duncan added that this type of project is similar to others Storegga is involved with in the U.K.

"They have had the experience of talking to everyone involved in the value chain, including industrial sources and capture to transportation, to storage and monitoring, and they've partnered with Shell, Harbour and now Exxon Mobil [Corp.]," Duncan said. "We get the benefit of all the learnings of those projects."

TALOS ENERGY INC.

Talos Energy Inc. has partnered with Carbonvert for a carbon capture and storage project with storage deposits located along the U.S. Gulf Coast.

Improving credits

Established in 2008, the 45Q tax credit provides tax credits to companies capturing, storing and sequestering CO_2. And while the credit increase in 2018 was welcomed by the carbon management community, most in the industry agrees that an increase in the credit may be needed in order to see real movement of the CCS needle.

"Right now, you're looking at roughly a $50 credit by the time injection commences," Abendschein said. "Across the spectrum of emitters, if they are what we call Tier One, those credits can be sufficient on their own to incentivize participation in CCS. Separately, an element of our strategy is to aggregate more than just one tenant per project, which should drive costs per unit down."

He added that because of Talos' operational skillset in shallow water and being a traditional low-cost operator, the company's expertise can help bring costs down as well.

Abendschein continued, "When you move to the next tier of emitters, additional support of carbon reduction initiatives, including increasing the tax credits—maybe it's $85, maybe it's $100—would help drive CCS participation across a wider range of industries. Along the value chain there is technology, there is engineering capability, there is midstream interest, Talos will have the critically important storage and with broader emitter participation then these types of projects can work for everyone." □

RETURN OF THE UPSIDE

The post-pandemic A&D landscape was a feeding frenzy marked by a resurgence in cash, confidence and caution as a surprising number of entrants entered the fray.

ARTICLE BY
DARREN BARBEE

As hundreds of A&D professionals gathered in Dallas for Oil and Gas Investor*'s A&D Strategies and Opportunities Conference, we snuck three of the leading practitioners of dealmaking far, far offstage for a private conversation. On hand were Chris Atherton, CEO and president of EnergyNet; B.J. Brandenberger, partner at TenOaks Energy Advisors; and Matt Loewenstein, director at Detring Energy Advisors, to discuss the twists, turns, megadeals and surprises in 2021 and how the market is taking shape for the year ahead.*

What's your assessment of the A&D market today? How have things changed?

ATHERTON: We're seeing sellers bring a lot more quality assets to market. I think in the past six months or so, the bid-ask spread has narrowed significantly, and the deals are getting done. The publicly traded E&P companies are definitely buying again, which is a positive sign. The private equity portfolio companies have been able to sell and make an exit when that market was really closed for them for the past couple years, so I think you're seeing a lot more processes come to market and kind of private equity [portfolio companies] and maybe accept company stock as a portion of the consideration for the sale.

My take is I still think that there's probably more consolidation to happen, and maybe not a lot of it, but I wouldn't be surprised to see two or three more kinds of mega deals between the next 12 to 18 months. The sub-$200 million, sub-$250 million market seems to be very active right now. There's deal flow. I think that the market remains very active.

I think [for] the large, the majors and the super independents, a $1 billion deal doesn't do much good for them. They need to do a $5 billion deal or a $10 billion deal. With some of these processes out there, I would imagine there'll be consolidation among the private equity groups … and then I think the sub-$250 million market will remain pretty hot and active going into 2022.

BRANDENBERGER: It's a feeding frenzy out there right now. The market is flooded with assets. The commodity price uptick has spurred activity. For sellers, the deal-on-deal competition is fierce because buyers have so many deals in their pipeline to evaluate. The quality of assets in the market has also improved considerably.

We have several new buyers in the space that have capital. I think that's one thing I've been surprised by is the number of new entrants who are well-funded. I feel like the closing rate on transactions has been higher overall this year, albeit lately we've seen the heavy backwardation of the strip cause sellers to reconsider and hold on to their assets if they think commodity prices will continue to climb.

I'd echo a lot of what Chris is saying, the market for assets less than $250 million is alive and well. Larger deals are prevalent, but there are only so many groups with access to that type of capital.

Who are your buyers?

BRANDENBERGER: We've seen a little bit of everything in the middle market space. We've seen institutionally backed teams that have longer time horizons on their capital. It's not three-to-five-year capital but more seven-to-10 year-plus type capital coming in there with lower return thresholds.

We are also seeing family offices in a more meaningful way. We've sold to multiple family offices who either had an existing team in place or who were backing a team that they're familiar with. You of course have several old and new private equity-backed groups out there who are being very acquisitive. Those are probably the three buyer types we've seen the most in our space.

LOEWENSTEIN: I think if you look at the three groups here, we've been extremely active in the middle market space. I'd say that never really went away in the middle market in 2020 as you'd expect with the quantity price of volatility that was a larger bid ask spread. We definitely see narrowing today, but in the middle market the capital has been there. Transactions were closing in 2020, and I think 2021 is going to be a breakout year for deals in our size range. When you look at the question comparing the larger market to sub-$250,000 market when you

look at the $500 million, $1 billion A&D deals, we obviously haven't seen as many of them. To B.J. and Chris' point, there are fewer buyers, but also if they want to pay for upside that they have to use stock. In our space we're seeing the cash market, and it's generally guys that are able to describe value to the upside is pricing.

BRANDENBERGER: Matt brings up a good point there. We've seen more involvement from the private equity sponsor in the data room, which is interesting. Historically the management teams would do their evaluation, and then get board approval, etc. Today we see the private equity sponsors in the data room working the assets early in the process too, which we are supportive of because it eliminates a layer of potential uncertainty.

Why are they doing that?

BRANDENBERGER: Several PE (private equity) shops have their own technical folks in house when historically that wasn't the case. They're doing some of their own technical evaluations to see if it matches up with the management team to make sure they're on the same page early in the process. This PE involvement may allow the portfolio company to be more aggressive out of the gates, and it lends itself to instant buyer credibility knowing that the sponsor has assessed and signed off on the technical evaluation upon submitting an offer.

ATHERTON: Yeah. I would agree with that. We're seeing that as well. It's comforting. I think part of the issue can be, and B.J. alluded there, these guys used to have three deals they're evaluating, and now they have 20 or 15 that they're screening. I think if the private equity team or the sponsor, whoever the sponsor is, we just try to make sure they're aware that their management team is looking at the deal, and about to make a bid, or making a bid I'm sure there are instances where, well I think to the PE shops, in the data room, and then in the weeds throughout the process it's good that they're doing that. They look at the portco's (portfolio company's), the management teams' evaluation, they look at their own evaluation, and it makes it easier to submit an offer and feel comfortable and aggressive and ready to close and sign the check.

How much value are you seeing ascribed to upside?

BRANDENBERGER: Upside value varies by asset type. It's a function of a buyer's discounted cash flow analysis. For conventional assets, upside value may come in the form of a lower discount rate on your PDP (proved developed producing). For unconventional assets, it's about the returns on your future horizontal locations and drilling program, but it's still a function of the discounted cash flow model. You can back into a dollar per acre after your discounted cash flow analysis is complete, but it's highly subjective. It's very seller-dependent, buyer-dependent and asset-dependent.

"We're cautiously optimistic to bullish that both A&D and commodity prices will continue this trend," said B.J. Brandenberger, partner at TenOaks Energy Advisors.

ATHERTON: On the deals that are getting done, and that's more of them, there's a large PDP component of that deal, and the buyer and seller are able to pretty much come to terms on that portion. And then if there is some upside, I think the sellers are pleasantly surprised that they're getting consideration for that, as well. The deals that are tough to sell are the ones that are, I would say, have only 10% to 25% PDP component, and then there's all their big wedge of value is all upside or drilling and just getting buyer and seller to come to the same evaluation on that asset can be tough.

But I definitely think that more and more it's not $50,000 an acre or something like that, but they are giving value to upside whereas maybe a year or two ago they really weren't at all. They would say, 'We're not going to describe any value to upside, and we're just going to give you a PDP number, and we'll see if we win.' I think that's changed.

LOEWENSTEIN: I'd echo B.J.'s point that it is obviously DCF (discounted cash flow)-driven. I'd add that it's also asset class-dependent. We're seeing operated working interest deals where buyers are more so able to underwrite undeveloped that they see returning good returns at today's pricing that they plan to develop near term for minerals, royalties we do see buyers describing real undeveloped value to longer-term inventory, but certainly mostly to line the site, your ducks and permit wedges. Then I'd rank in a nonoperative working interest toward the back of the pack where the market has been slower to return to really underwriting inventory, but over the past month or so I think in that market just given I feel like the Permian or even the SCOOP/STACK at $6 gas wells being drilled today are returning north of a 100%. Buyers will pay for that. Again, I think that the asset class does make a big difference in discount rates and really how far out into the future buyers are willing to underwrite the upside.

"I think in the past six months or so, the bid-ask spread has narrowed significantly, and the deals are getting done," said Chris Atherton, CEO and president of EnergyNet.

As natural gas prices have recovered this year, are you seeing value ascribed in places such as the Permian due to associated gas production?

BRANDENBERGER: When prices go up overnight, everything else just doesn't go up along with it right away. There is typically a lag, because you need to see some consistency in commodity prices before valuations start to rise all together. Buyers still use some form of strip pricing for their evaluations. As prices rise and stay consistent, both your PDP and upside should become more valuable, assuming you can keep costs down.

LOEWENSTEIN: I think at the end of the day acreage evaluations, I think even back in 2016 to '18 when we were seeing $60,000 per acre in the Permian. It was always discount cash flow based and continues to be, but I think buyers are underwriting much more conservatively today. I expect that they will continue to do so. We're not going to see transactions where buyers are paying PV20 for four benches of development that a fairly aggressive development pays. I think you're going to see again much more conservative pacing, as well as total inventory underwritten.

There's been a lot of deal flow in the Permian Basin but obviously we're not at the same elevated price metrics as in years past. Raymond James data showed Northern Oil and Gas actually paid the highest price per acre while ConocoPhillips deal to acquire Shell's Permian assets was about $15,000 per acre. How much will acreage valuations rebound?

ATHERTON: Acreage prices have seemed to be for a while there that every deal we kind of benchmarked on an acreage value and what the buyer was paying for, I feel like a lot of the acreage is owned, a lot of the good rock is owned, so deals are trading hands. But I feel like the E&P companies are kind of in development mode for the good acreage that they already have. We've done a couple transactions primarily in the Delaware Basin where we were seeing about $15,000 an acre. We had one that was kind of an anomaly that was $25,000 an acre. These were sub-$100 million type deals, but I think it's more online of sight on development. And there are some companies that Matt mentioned earlier, they're just not going to be able to (develop) that acreage.

It could be good rock, but they will sell it because the public companies are intentionally trying to be capital disciplined, and not growth for growth's sake. That acreage will trade hands. It really depends on how fast the new owner believes they can develop it, I believe.

What are you seeing in terms of conventional assets on the market? Is that still of interest to buyers or are they more committed to shale?

ATHERTON: We still sell a lot of packages that are conventional or they are mature shale. Part of this is just kind of the nature of the beast, and the type of sellers that we're selling for these become noncore assets over time in their portfolio, but there's a whole food chain of buyers that really feel they can do a lot of good blocking and tackling, and lowering opex and increasing production, and refracks, reworks. Things like that. In the sub-$250 million space those are a lot of the asset packages that trade, simply because for the big companies, it's not moving the needle for them anymore.

LOEWENSTEIN: I would say Texas conventional oil is one of the hottest commodities. We'll see 100 CAs (confidentiality agreements) and 20 bids on Texas conventional oil packages.

BRANDENBERGER: It's been a popular asset for mostly private buyers for a long time. Conventional assets are enjoyable to the market really because the buyer turnouts are typically fantastic, and there are usually multiple layers to the upside story. I feel like that buyer universe has been resilient, and there are even more groups chasing it now than ever before because PDP is in vogue. That market is alive and well and could be for the foreseeable future. To Chris' point, the operational upside and low-cost, lower-risk upside opportunities in today's market are pretty attractive.

Turning to gas assets, we've seen a number of deals in the Haynesville Shale, as well as the Marcellus and to a lesser extent the Barnett. What kind of activity are you seeing in the gassy places?

BRANDENBERGER: I think you're going to see more transaction activity in gas-weighted plays if gas prices hang in there. The appetite for gas-weighted assets has improved

dramatically. You could see some continued consolidation in these plays.

We know a couple of Barnett packages that are in the works there. Mature shale gas plays like the Barnett typically get attention from buyers who are focused on buying PDP versus those who are focused on development. Haynesville and Marcellus deals could shake loose as well, but potential sellers are also seeing the long-awaited opportunity to drill at these higher prices.

LOEWENSTEIN: I think looking at the Barnett in particular over the past several years, there's been few rigs, and to B.J.'s point, it's a PDP-weighted market. You didn't see a lot of assets shake loose only because there's really no incentive for a lot of the sellers in today's market to transact.

I think today we're likely to see more transactions in the Barnett because opportunities like refracking have just become more competitive for capital. Then echoing B.J.'s point on the Haynesville and Marcellus, we continue to see rigs in those basins throughout 2018, '19, '20, but today you're every day seeing a rig added, particularly for the privates, so we do see that activity increasing. There's certainly a lot of capital that wants to get gas there.

ATHERTON: The Haynesville is really exciting right now. I know Rockcliff is drilling some great wells, and Comstock and others. I think we'll continue to see consolidation there. I think there are a lot of really big companies that want to make stuff happen.

BRANDENBERGER: I was just saying that operators of gas properties have been waiting for this day for a long time. It's a question of, 'Do I sell? Do I drill? Do I grow via acquisitions?' It will be interesting to watch it unfold.

ATHERTON: I'd add, you're also seeing more mineral buyers rotate to these basins. I think going back to 2018 and when the royalties' market was really picking up steam and starting to see a more liquid market there. All the attention was on the oil basins. Today if you look at mineral buyers, they're very active in the Haynesville (and) in Appalachia in particular.

Are you still seeing creative financing with smaller-scale deals? Or is it really more of a cash market?

LOEWENSTEIN: On the front end is how you package the assets. I think an example would be a Chevron Delaware Basin package that we're marketing currently where Chevron has high NRIs (net revenue interests) on their leasehold, and we work with a team to split out an override and a working interest package given the differentiated cost to capital of the override buyers.

It's packaging, to really work on the front end more so than we see structured or creatively financed deals in the market. You'll occasionally see commodity prices kickers, but in terms of VPPs (volumetric production payments) and other structured finance type deals, we don't see that in our market.

ATHERTON: I would add that most of the deals that are cash deals, what we found is that some of the contingency deals or we're structuring things works well, or the instances we've had those discussions and try to build around it and make a deal work, and because those discussions kind of flushed out maybe a better evaluation, or better meeting of the minds between buyer and seller, and then it ultimately comes back to a cash deal. So we have to go down the road of doing contingencies and then structuring the deal in different ways that makes it work for the buyer. It makes it work for the seller, and then because of those discussions kind of flushed everything out, it turns back into a cash deal because they're bid asset is narrowed.

BRANDENBERGER: A couple of times this year we've seen the seller willing to take a minority ownership in the acquiring company going forward. This allows them to roll some equity forward and continue to live to fight another day and hopefully capture more of the development and/or commodity price upside. That's about the extent of the creativity outside your occasional commodity price driven structures that Matt mentioned.

Do you see 2022 as being as robust as it's been this year?

LOEWENSTEIN: Yeah. I think so. I think there's certainly pent-up demand on both the sellers and the buyers' side of the table. I think as we … as these, the current strips season, as we continue to see kind of $70 oil flow through to the LOS (lease operating statement), it's always a little bit of a lag, but we can see some of the cash flows, the current pricing I think there will continue to be a robust A&D market.

ATHERTON: I think if I could ask for anything it would be stability. I've been doing this for almost 20 years and gone through three major crashes: 2008, 2014, 2020. Those are all kind of big optimistic, the public is trying to be as disciplined as they can, and no growth to moderate growth, if that will hold. It feels to me like there are under investments going on, and that will probably cause more capital to eventually come back to the energy space, but if you can get some stability, I think that will bring investors back.

BRANDENBERGER: We're cautiously optimistic to bullish that both A&D and commodity prices will continue this trend. We are not seeing any signs of slowing down. I think as long as we can maintain and see some consistency at these higher commodity price levels, you will continue to see transaction activity. I'm the last one who likes to predict commodity prices, but we are encouraged by the momentum. □

THE GUARDIANS OF ORPHANED WELLS

Industry executives, environmental leaders and elected officials are among those working to plug millions of wells left abandoned throughout the country.

ARTICLE BY MICHELLE THOMPSON

When Curtis Shuck saw his first orphaned well in northern Montana about two years ago, the sight of the dilapidated fixture shocked him.

"I was absolutely horrified by the condition at the surface and could not believe that from an oil and gas industry perspective that it was in any way acceptable or that it could have any positive reflection on the industry," Shuck said. "I felt strongly that—now that I had seen the condition—that I could not unsee it and that it was incumbent upon me to take some action."

On his drive home to Bozeman that night, the idea for the Well Done Foundation was born.

The company, which Shuck today leads as chief executive, has been a frontrunner in the plugging of orphaned wells, a practice that's becoming increasingly popular as the industry works to lessen its environmental impact.

It's an issue that's even on the radar of President Joe Biden, who earlier this year pledged to spend $16 billion capping noncompliant wells that have been inactive for at least a year.

By the EPA's estimates, there are more than 3.2 million deserted onshore wells nationwide, including 2.1 million that are unplugged. It matters because the holes spew several million metric tons of CO_2 per year, the agency said.

Although fossil fuel operators are legally required to properly shut out production wells, they often lack the funds to do so and abandon the unprofitable fixtures.

The initial shock Shuck felt toward abandoned oil wells in 2019 has since been transformed into a determination to plug the holes and restore surface areas. In doing so, he's permanently eliminating their carbon and methane emissions.

"Many of the orphan wells that we deal with have been leaking methane for years or even decades," Shuck said. "Left undone, these orphan wells will only continue to vent and release methane gas, some of them at really alarming rates."

"There is certainly a lot of attention on the orphan well issue and how to get funding and deploy it meaningfully," said Curtis Shuck, chief executive, Well Done Foundation.

Trending topic

New research is highlighting the environmental and economic benefits of shuttering out-of-service oil and gas wells.

Plugging abandoned wells reduces air pollution while eliminating greenhouse-gas (GHG) emissions at a price in line with other options, a Columbia University's 2020 Center on Global Energy Policy and Resources for the Future report found. Conversely, the costs of ignored orphaned wells include heightened air pollution and environmental risks, the study said.

From the Well Done Foundation's perspective, the greatest benefit comes from the immediate elimination of methane gas, one well at a time.

"(Our) mission is really methane-focused, and so identifying and plugging orphan oil and gas wells with high concentrations and flows of methane gas is our thing," Shuck said.

"Methane as a greenhouse gas is 80 times more harmful than CO_2, so besides just being the right thing to do, our work delivers an immediate benefit to the environment. It's as simple as 'gas on, gas off.'"

Methane has significantly more warming power than CO_2 during the first two decades after reaching the atmosphere, according to the Environmental Defense Fund.

Of course, it's not the only company taking the initiative, particularly as the industry works to align with ESG standards.

"There is certainly a lot of attention on the orphan well issue and how to get funding and deploy it meaningfully," Shuck said. "Currently, with the price of oil being up, there is a lot of emphasis on production and new wells, which makes resources such as workforce and equipment harder to find.

"However, that pendulum will shift again, and there will be capacity that can be used for more plugging."

An unorthodox adoption

Shuck's vision stretches beyond the plains of Montana and toward the rest of North America.

Although the Well Done Foundation began its work in Montana's soil-rich Golden Triangle region—home to some of the nation's most productive acres—its ultimate goal is to see each of the 3.2 million wells in Canada and the U.S. permanently shut.

The company expanded its pollution-fighting efforts in April with the formation of two

strategic partnerships throughout Louisiana, East Texas, Pennsylvania, New York, Ohio and West Virginia.

By joining forces with the Pennsylvania-based Appalachian Legacy Project LLC and Louisiana-based OFC Solutions LLC, the non-profit was able to significantly scale up its operations.

Its growth streak continued in July through an expansion of an existing initiative with Alpine CapH4 LLC that aims to identify and remediate about 30 wells found to be the sources of significant methane emissions.

It aimed to have the wells closed within the next year and a half.

As the Well Done Foundation bolsters its efforts, it hopes other states follow suit.

"The orphan well issue boils down to simply doing the right thing, one well at a time," Shuck said. "It has nothing to do with politics or what your view is on climate change or global warming. Leaving things better than the way you find them should always be a priority, regardless of how the situation came to be in the beginning.

"The Well Done Foundation is all about taking meaningful action that hopefully inspires others to support our efforts or do something meaningful themselves."

WELL DONE FOUNDATION

According to the EPA, there are more than 3.2 million orphaned wells nationwide, including 2.1 million that are unplugged.

"It was important for us to find a solution that provided a positive and sustained environmental impact, not only for today's aging infrastructure, but for future generations as well," said Tony Sanchez III, founder, OneNexus Environmental.

Strategic approach

The Well Done Foundation's well-plugging strategies are far from indiscriminate. Rather, the company takes a purposeful approach to its work by identifying high-emitting wells through a meticulous measurement and monitoring system.

Once it identifies wells most in need of plugging, it launches a fundraising campaign to finance plugging and restoration efforts.

"The Well Done program is designed to focus on the 'super emitters' first and foremost, and these can be found in almost every state that is facing orphan oil and gas well problems," Shuck said. "There are of course some states that have higher concentrations or well density, such as Pennsylvania, which is why we are currently so focused on that area."

The company depends on public and private donations—as well as the sale of carbon offsets—to fund its education, plugging and restoration efforts.

"The Well Done Foundation is very fortunate to have some awesome funding partners to help us in this effort," Shuck said. "As a nonprofit, we are able to use all of those dollars to support the plugging of more wells."

It plans to ultimately establish a carbon finance vehicle through the American Carbon Registry, which it said would help the company's continued growth plans.

Political push

Elected officials at every level are helping lead the charge against the abandoned methane-omitting wells.

In April, New Mexico Congresswoman Teresa Leger Fernández introduced the Orphaned Wells Cleanup and Jobs Act of 2021, which would authorize nearly $8 billion in grant funding to cap and remediate orphaned wells on public, private and tribal lands.

The legislation would also bolster regulatory safeguards on public lands to prevent future orphaned wells and require operators to pay an annual fee for idled wells sitting on public land. It requires oil and gas operators to set aside enough money for the ultimate capping of wells as well to prevent more orphaned wells from emerging.

The legislation was endorsed by a number of leaders, including The Wilderness Society's New Mexico director, Michael Casaus.

"For decades, orphaned oil and gas wells have left communities responsible to pay for a mess they didn't create and deal with the hazards of chemicals leaking into the air and drinking water," Casaus said in a statement. "Rep. Leger Fernández's bill would immediately work to clean up the nation's orphan well crisis while creating thousands of good paying jobs that help transition our public lands away from fossil fuels toward a cleaner, sustainable economy."

WELL DONE FOUNDATION

About 280,000 metric tons of methane are released each year from the nation's millions of unplugged wells.

Economic benefits

Outside efforts to close orphaned wells could yield sizable benefits for the nation's economy, according to the Columbia University study. A federal program to plug 500,000 wells could create upward of 120,000 jobs while reducing pollution, its authors found.

The research was particularly notable at the time of its release, when the U.S. faced a historic economic downturn in the face of the COVID-19 pandemic.

Although the industry has largely rebounded from last year's crash, the nation continues to grapple with high unemployment numbers, and researchers say a federally funded well-plugging effort could bridge that gap.

"Plugging abandoned oil and gas wells could create tens of thousands of new jobs while cutting greenhouse-gas emissions," report co-author Jason Bordoff said in a statement.

Conversely, properly retiring out-of-service wells can be a costly endeavor for E&P companies.

It costs between $30,000 and $40,000 to cap a traditional well, according to Carbontracker.org, but closing a modern fracking well can cost $300,000.

It can be a pricey parting gift for companies looking to retire assets—but it doesn't have to be.

Forward-thinking planning

A recently formed financial assurance company said its solution can help relieve the financial burden, both in the near and long term, of the ever-growing asset retirement liability in the oil and gas industry.

Through his company OneNexus Environmental, industry executive Tony Sanchez III said he and his team have developed a viable solution for asset retirement obligations (AROs) that is scalable, cost effective and low risk.

"It was important for us to find a solution that provided a positive and sustained environmental impact, not only for today's aging infrastructure, but for future generations as well," Sanchez said. "We started to investigate AROs and plugging and abandonment and realized it was a much bigger industry problem than I originally had thought."

His team soon discovered that it could cost more than $1 trillion to decommission onshore oil and gas properties nationwide when infrastructure and surface remediation costs were factored in. It also recognized that as the industry transitioned to a more sustainable operating model, there would be greater demand for well plugging and the safe decommissioning of facilities.

And so, OneNexus Environmental set out to use technology and statistical analytics to address the challenge of AROs up front.

"The root cause of the problem can be found in the lack of planning for the future," Sanchez said. "A simple analogy is that if you want to retire at 65, you don't start saving for your retirement at 63 because by then it would be too costly, which is why you begin planning long in advance and saving a bit each year so that that financial risk and timing is mitigated."

OneNexus likens itself to a permanent life insurance policy for wells: It makes planning for the future affordable by helping companies set aside funds for future expenses related to retiring assets.

The company also allows E&P producers to transfer the title to wells that are inactive and with no future utility to OneNexus, and in doing so assumes the responsibility and obligation for properly plugging wells, fully decommissioning the asset and doing the surface reclamation work.

As the E&P company has prepaid the services, OneNexus ensures assets are properly retired, while absolving E&Ps of any future financial or environmental responsibility.

By offering title transfer at the time of the operator's choosing, an asset can be removed from the company's balance sheet once it's no longer economically viable.

"The orphan well issue boils down to simply doing the right thing, one well at a time."

—Curtis Shuck,
Well Done Foundation

According to Carbontracker.org, it costs between $30,000 and $40,000 to cap a traditional well while closing a modern fracking well can cost $300,000.

WELL DONE FOUNDATION

"Operators can focus on producing the oil and gas, while we focus on the decommissioning of the assets at the appropriate time," Sanchez said. "As we aggregate these assets to retire, we will be focused on capturing economies of scale, improving efficiencies in process and operations while developing better technologies and compounds [cement and resins] to plug wells safely and effectively."

The ARO-focused financial assurance company recognizes that planning for asset retirement goes beyond economic savviness—it also entails environmental foresight, a tenet of ESG and sustainability strategies.

"Inactive wells pose physical and environmental threats to land, water and human safety," Sanchez said.

"They can leak gas into the air or fluids into waterways or aquifers with combustible fluids and could be sources of pressure that can cause harm to human life. Inactive wells are also associated with surface equipment that often contain leftover hydrocarbons that can cause leaks or fires, posing potential risk to human life."

WELL DONE FOUNDATION

An orphaned well sits in a field in Toole County, Mont.

Growing momentum

The nation's millions of unplugged wells release about 280,000 metric tons of methane each year—enough to contaminate aquifers, soil and water. Given that methane is 34 times more potent than CO_2, the environmental and health repercussions of abandoned wells can be immense.

That's why Sanchez felt it important to create a cost-effective plugging solution that could help address the backlog of inactive wells, as well as marginally producing wells that ought to be retired. Without it, he said, the next generation would be stuck cleaning up the mess their predecessors left behind.

Since launching in June, OneNexus has seen a steadily increasing demand for its service. It's due, in part, to the Revive Economic Growth and Reclaim Orphaned Wells Act in President Biden's infrastructure plan. The act highlights the need for funding to plug orphaned wells and dedicates nearly $5 billion to plug abandoned wells that individual states were previously tasked with addressing.

The momentum is increasing within the regulatory space, Sanchez said, and has opened across-the-board discussions on how to best address the issue.

"Our goal is to offer companies a solution to neatly address their AROs prior to regulation that is forcing the issue," he said. "We believe the best way to address the ARO/decommissioning issue is for the energy industry to be proactive, rather than through government funding, which usually comes with strings attached, such as proposals for increased bonding requirements that don't benefit operators or structurally solve the problem."

By the numbers

On top of the millions of unplugged retired wells throughout the U.S., there are upward of 40,000 new wells being drilled each year. Given the unpredictable nature of the industry, it means the number of abandoned wells could grow substantially at any given time.

And although some companies are working to cap abandoned wells, statistics indicate those efforts are barely scratching the surface.

Pennsylvania plugged just 59 of its more than 8,000 orphaned wells between 2016 and 2020, according to state regulatory authorities. During the same period, Texas plugged more than 6,800 wells, but its orphan well count was reduced by just 77 from 2018 as more wells continue to be abandoned.

"Wells are continuing to fall into orphan well status, and we are not making any meaningful headway in reducing the backlog," Sanchez said.

The solution, he said, is to introduce legislation that would require all new wells to hold a third-party financial assurance solution that would guarantee the funding of future AROs.

If the orphaned wells aren't capped by operators, states become liable for properly plugging them and restoring the surface area. Orphan well programs are often funded by bonds, permitting fees or a conservation tax, Sanchez said.

The trouble, he added, is that there's not enough money through those taxpayer funds to finance the currently existing orphan well programs.

"Several estimates show that the funds available at the state level to plug orphaned wells amount to less than 5% of the estimated costs, so just plugging the existing backlog of orphaned wells is going to cost the taxpayer billions of dollars," he said. "That's why this problem needs to be addressed at its root cause so that we can avoid it from coming back in the future." □

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THE ROLES OF FRACKING AND EOR

How hydraulic fracturing and the case for driving carbon capture utilization and sequestration forward on the basis of EOR can help achieve a feasible energy transition.

ARTICLE BY
STEPHEN
ARBOGAST

Editor's note: *This is the final article in a four-part series* Oil and Gas Investor *is featuring with Kenan-Flagler Energy Center at the University of North Carolina at Chapel Hill.*

In May 2021, the Biden administration began showcasing its climate agenda. The agenda's centerpiece, a "clean electricity standard" (CES), calls for elimination of all greenhouse-gas (GHG) emissions from the U.S. power sector by 2035. Some, especially the utilities charged with carrying this out, would call this plan far-reaching, even radical. But it proved too timid for a coalition of environmental groups, who sent the administration a letter protesting the plan's half measures. As reported in Politico, the letter advocated as follows:

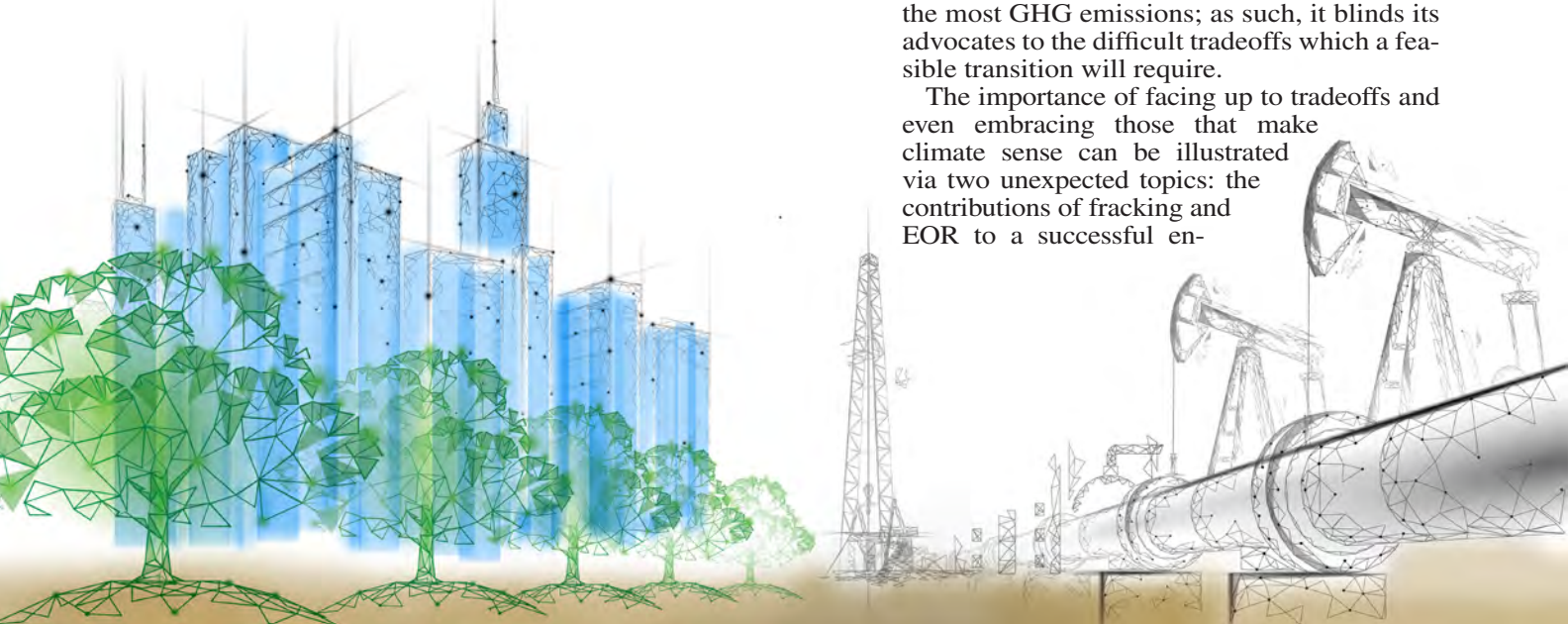
"More than 600 groups sent a letter to Congress … warning that a CES would promote 'false climate solutions' such as natural gas, nuclear and biomass power plants, as well as efforts to keep polluting plants open by capturing their carbon. The dissenters instead called for a stricter renewable electricity standard limited to wind, solar and geothermal power, not only to accelerate the deadline for a zero-emissions grid from 2035 to 2030 but to avoid perpetuating the deep racial, social and ecological injustices of our current fossil-fueled energy system …

"The dissenting groups—including Friends of the Earth, the Center for Biological Diversity, 350.org, the NAACP and Food and Water Watch—say that no plan would be better than a flawed plan that values political viability over scientific necessity and could help prop up natural gas."

It is of course possible that this effort is largely one of political tactics. Strong protests out on the extremes can make even a radical plan seem moderate by comparison. However, for the sake of gaining some clarity about achieving an energy transition that might be feasible, let us take this environmental position at its word. What does this protest letter say about green plans for transition, and what are they missing?

Clearly the letter rests on a belief that is turning out to be one of the biggest obstacles of climate progress—namely, that wind, solar and battery storage can bring about anything close to zero emissions. This proposition, infeasible in the U.S. power sector, is inapplicable to vast sectors such as aviation, heavy transportation and heavy industry, and largely irrelevant to the global economies producing the most GHG emissions; as such, it blinds its advocates to the difficult tradeoffs which a feasible transition will require.

The importance of facing up to tradeoffs and even embracing those that make climate sense can be illustrated via two unexpected topics: the contributions of fracking and EOR to a successful en-



ergy transition. The transition faces submerged reefs which likely will delay and undermine its progress. It turns out that fracking and EOR are two solutions, that could help avoid these reefs as the transition unfolds.

How can it be that perpetuating two forms of fossil fuel development will further climate progress? The answers have to do with three important dimensions of a feasible transition:

- Getting "from here to there" without major distracting disruptions;
- Decarbonizing the Eastern Hemisphere growth economies; and
- Helping carbon capture technologies be proven at scale, enabling their broad deployment.

The first two pertain to fracking while the third will develop on the back of EOR. Let's discuss how these dimensions may play out within scenarios where fracking and EOR are either enabled or suppressed.

Getting from 'here to there'

Many statesmen have commented that "events" presented their biggest obstacles. This is another way of saying that the best-formulated plans often go out the window when major crises unfold.

The energy transition is especially vulnerable to event disruption. This is true because the transition will take a long time to carry out. Despite calls for emergency action by 2030 or 2035, most considered plans use 2040 and beyond as the horizon for reaching net-zero emissions. Also consider that many plans concern only components of the broader U.S. economy and not those sectors with the most intense carbon footprints. A feasible transition in the developing world will take even longer.

The transition's Achilles' heel is that this long timeframe requires stable, even tranquil conditions for implementation. Crises that threaten life in the "here and now" hold considerable potential for interrupting transition focus. Texas got a dose of this in February 2021, when frigid temperatures resulted in power outages for days across the state. Wind and solar power dropped dramatically, and natural gas was called upon to pick up the slack. Regulators across the country took note. Many are unlikely to support driving natural gas from their power generation stacks anytime soon.

The list of events that could disrupt the transition is long, but these three would be near the top:

- Electric power price inflation;
- Geopolitical disruptions resulting in peak oil prices; and
- Grid power outages, which highlight renewables intermittency risks.

Fracking's recent contributions to containing these risks have been huge. Allowed to continue without regulatory suppression, these contributions can facilitate the sustained focus on low-carbon solutions that's needed to progress the transition.

It goes largely unrecognized that fracking allowed renewables to enter power generation without driving up electricity prices in a way that would have invited blowback.

Henry Hub Average Annual Closing Prices For Natural Gas, 2007-2019

$/MMBtu	2007	2010	2013	2016	2019
	6.97	4.37	3.73	2.52	2.56

Fracking for natural gas began in earnest around 2009 to 2010 in Texas and Louisiana. It received a second leg with the development of the prolific Marcellus Shale and a third leg as producers developed unconventional oil plays such as the Permian Basin. These plays yielded immense amounts of associated gas. As a result, natural gas prices began a decade-long decline, which ultimately totaled a 63% price cut. It was during this same period when wind and solar were introduced into power grids at scale. Much has been written about how their costs declined over the period as technology and supply chains improved. This literature largely ignores how declining natural gas prices masked the higher costs of early stage renewables projects and canceled out the unrecognized costs of intermittency, grid integration and the forced retirement of plants with existing economic life.

Today, natural gas prices have risen to more than $5 per million Btu. This shows the other side of this equation. With fracking suppressed by first the COVID-19 shock and then the acute anti-fossil fuel hostility rippling through Wall Street and Washington, U.S. gas production is down.

Drilling has been slow to respond, and gas inventories are well below normal levels. Depleted gas inventories and soaring prices are even more conspicuous in Europe and Asia. Price inflation, partly driven by higher energy prices, is elbowing its way toward the top of national political agendas. It would serve being able to sustain the transition focus if the U.S. fracking industry could resume development, produce more oil and gas in the "here and now" and enable the vast set of issues surrounding long duration storage, nuclear, hydrogen and carbon capture to progress without "look what a mess you've made" political blowback.

Geopolitical events that produced an oil shock would be a second disruption. Examples include events such as the 1973 Arab-Israeli war and the later Iraqi invasion of Kuwait. Such events force their way to the top of the national agenda by igniting oil price spikes and threatening key American allies. Despite decades of working on energy security, Japan and most of Europe remain dependent on Middle East oil.

Until recently, the U.S. was similarly exposed. Fracking changed that. From a situation where U.S. production totaled only 5 MMbbl/d and was judged in irreversible decline, fracking took oil output to a record 13 MMbbl/d in 2019. That made the U.S. the globe's largest oil producer. Because much of the fracked oil is light crude, the U.S. also benefited from an oil arbi-

"The challenge of decarbonizing the Eastern Hemisphere is rooted in two conditions. First, much carbon-intensive heavy industry has migrated from the developed world to this region. Secondly, the region lacks indigenous natural gas supplies."

trage—exporting millions of barrels a day of quality oil while importing lower-grade heavy crude suitable for processing in complex Gulf Coast refineries.

The result was a dramatic drop in U.S. exposure to Middle East oil disruptions. This was demonstrated when Iranian missiles damaged important Saudi oil infrastructure. U.S. oil and stock prices barely reacted. It was more fundamentally at work when the Trump administration imposed severe sanctions on Iranian oil exports. These subsequently dropped below 1 MMbbl/d with barely any response in oil prices.

These results resemble what used to happen when the U.S. served as the market's reserve supplier prior to 1970. In a sense, fracking is even better suited for this role. Fracking can surge production in a relatively short amount of time. There is no exploration required or no complex offshore platforms to fabricate. The industry needs to mobilize rigs and drill. It can do so in multiple basins including the Permian, Eagle Ford, Bakken and Utica shales. Unconstrained, U.S. fracking can insulate the U.S. economy from supply shocks, price shocks and even from the need to intervene in the Middle East to protect its allies.

Major electric grid supply disruptions constitute the third potential transition disruption. The third article in this series showed what such events look like when it presented the chart of power generation by source during the February 2021 Texas freeze. That event lasted more than 10 days. Wind and solar power declined to negligible contributions. Such battery storage as existed was quickly depleted with little chance to recharge. Though it too was ultimately impacted, natural gas generation not only picked up the slack but serviced much of the load demand surge that frigid weather induced.

The Texas event and outages in California point to several disruption risks. The most obvious one is that renewable power cannot be counted on in the face of prolonged weather events. The less obvious but equally concerning issues are the ability of evolving generation stacks to "load follow" and the amount of reserve capacity maintained in the system. Both California and Texas have been driving fossil fuel plants from their system and accepting the consequences in the form of reduced reserve capacity. In both states, natural gas plants constitute the bulk of the in-state system's reserve power and its ability to respond quickly to shifts in load demand.

Getting "from here to there" in the transition requires avoiding repeated grid failures like those in California and Texas. Residential customers and businesses expect that electricity be available when they want it. Moreover, they will not quietly accept price surges like those that overwhelmed many in the wake of the Texas freeze.

Market design and other issues were involved here, but what is fundamental across all markets is the need for adequate power reserves that can respond to demand and handle severe shocks. This will require plentiful natural gas power generation for the foreseeable future, and those plants will need to be backed by abundant natural gas supplies flowing through adequate logistical infrastructure.

This means the grid needs to be backed by fracking that assures plentiful supplies at reasonable prices. Tight supplies and volatile prices plus inadequate reserve power and growing intermittent generation is a recipe for disruptive events, political blowback and a halting transition.

Decarbonizing the Eastern Hemisphere

A chart, published by the Union of Concerned Scientists, illustrated the CO_2 emissions by country in 2019. There are a couple of things that were highlighted: U.S. emissions combined with those of major European countries plus Canada and Japan comprise only 26% of the total. That is less than China alone. Add India, Brazil and the rest of the developing world to China's total, and it's clear that the vast majority of the CO_2 emissions issue resides in the developing world economies.

A CO_2 emissions international monetary fund chart from late 2019 (pre-COVID) showed actual 2018 GDP growth figures for the developed and developing economies as well as late year projections for 2019 and 2020. Both actual and forecast data show the developing world growing at twice the pace of the developed economies.

The charts dramatize two points: the carbon intensity of developing nations and their higher economic growth rates. Together these points underscore where the decarbonization challenge resides. It lies in the developing world and especially in the high-growth economies of Asia.

The challenge of decarbonizing the Eastern Hemisphere is rooted in two conditions. First, much carbon-intensive heavy industry has mi-

grated from the developed world to this region. Secondly, the region lacks indigenous natural gas supplies. This means that Asia's surest means for rapidly decarbonizing, substituting natural gas for coal-fired generation, is hard to accomplish there. It also means that industrial demand for natural gas competes for supplies with power generation.

Solving Asia's decarbonization puzzle will require hybrid contributions. China's aggressive adoption of renewables, electric vehicles and nuclear power illustrates this formula. However, there is little doubt that ample supplies of LNG are an essential part of this effort. All the grid resiliency and load following arguments apply in these markets; indeed, they are more consequential for locations where demand grows rapidly and industrial uses figure prominently.

The Asia decarbonization challenge powerfully illustrates how the feasible transition requires sustained focus and a tranquil international environment. All of these economies are very dependent on imported energy. China currently imports over 10 MMbbl/d of oil along with large quantities of LNG. India, Japan, Korea and the others are in comparable shape. Any oil and gas supply shock will resonate profoundly in these markets. What was said above about fracking's role in preventing such shocks applies with even greater force to Eastern Hemisphere economies.

If we assume for now a tranquil supply environment, fracking can then make a second contribution to the Eastern Hemisphere transition. That contribution involves the U.S. having become the globe's marginal supplier of LNG. Much of Asia's LNG imports come from the Middle East, especially Qatar. Other supply points include Australia and Papua-New Guinea. However, the prices charged by these suppliers are increasingly influenced, if not set by, exports coming out of the U.S. Gulf Coast. Since 2015, the U.S. has built a considerable LNG export capability, with more capacity on the way. These supplies go in all directions, to Europe, South America and Asia through a widened Panama Canal. U.S. exporters thus "swing" their supply destination to capture the best 'netback' price realizations. In the process, they increasingly act as both the market's marginal supplier and its global price setter.

This surging export capacity came into being because fracking produced such a surplus of natural gas. As documented above, U.S. natural gas prices fell dramatically during the 2010 to 2019 decade. Producers realized that better margins were available from shipping the gas abroad; export projects soon followed, especially when the Trump administration began to fast track regulatory reviews. Soon, global LNG prices began to retreat. LNG contracts, which formerly were both long term and linked to oil prices, began to shorten and to price off U.S. spot gas prices. Asian customers saw their import costs, which often had reached $15 per million Btu, fall by 50% or more.

The beneficial decarbonization effects of U.S. LNG exports are now in danger of plateauing. U.S. gas production reached over 96 billion cubic feet per day (Bcf/d) in 2019. Production then fell below 90 Bcf/d in 2020 and has yet to return to 2019 levels. Moreover, the steady decline in conventional U.S. gas production combined with the rapid declines characteristic of fracked wells means that aggressive U.S. fracking activity will be required to rebuild production and underpin continued LNG export growth.

This all adds up to a choice for the U.S. It can acknowledge the contributions fracking is making to preserve a stable international supply environment and fostering growing, affordable LNG supplies into Asia. Or it can suppress fracking to "avoid fossil fuel dependence" and watch China, India and others build even more coal power plants.

Carbon capture and EOR

Limiting the number of Eastern Hemisphere coal plants, as worthwhile as that is, will only contribute to a feasible transition there. Many other inputs will be needed. These will include carbon capture utilization and sequestration (CCUS). CCUS will need to be that "second pathway," i.e. the way in which hard to replace existing assets with big carbon footprints will be able to stay in operation and still participate in the transition.

CCUS is at present an "infant industry." Annual global CO_2 emissions currently run around 35,000 million tons (MMton), while true CCUS captures only 8 to 10 MMton/year (this ignores 20 to 30 MMton/year of CO_2 separation from natural gas, which involves taking CO_2 out of the ground and then returning it). On the other hand, there is a broad consensus among those studying decarbonization that massive CCUS will be needed to achieve a 2 degrees Celsius future. The average CCUS contribution among 12 studies on the subject sees a need for CCUS to capture 7,900 MMton/year by 2040. Nowhere will this need be greater than in the Eastern Hemisphere, where stationary CO_2 sources in industries such as steel and cement are concentrated.

How can CCUS progress from an infant industry to a world-scale transition contributor? There is a process involved here. Most CCUS know-how is concentrated in the oil and gas industry. For years, these companies have separated CO_2 from the natural gas they produce. They also understand how to ship CO_2 and store it safely in underground reservoirs and saline formations. Until now, these companies have been ambivalent about committing capital to CCUS deployed for decarbonization. That recently has changed. Persistent activism has refocused industry attention on moving from research to project development. This was a vital first step.

The second step involves demonstrating better capture technologies at scale. Existing capture technologies are expensive. The best proven technology for use in power plants is aqueous amines. It is capital intensive and power parasitic, meaning it requires consider-

able energy to work. For example, the thermal efficiency of a 550-megawatt coal plant drops from 40.7% to 32.5% when amines capture is installed. Another way to think of this is that each ton of CO_2 captured this way costs about $70 per ton.

Better technologies are in the works, but these will require firms willing to bear first-of-a-kind project risk. This is where EOR comes into play. EOR using CO_2 offers CCUS pioneers the opportunity to deploy new capture technologies in circumstances offering reasonable return prospects. Consider these economics. Today you can capture CO_2 via amines technology, incur a $70 per ton cost and then incur added costs of $10 to $20 per ton for shipping, sequestering and long-term monitoring/reporting. For this, the 45Q tax provision will compensate up to $50 per ton, assuming you have tax capacity to use it. These economics don't work and as a result, fewer projects have proceeded on this basis.

Now consider the economics of CO_2 EOR. At present, Permian Basin EOR operators are paying ~$25 per ton for CO_2. They inject slightly above half a ton to extract a barrel of oil. With prices in the $60 to $70 range, that leaves ample margin to support other operating costs and returns on capital. Indeed, these Permian operators are looking for more CO_2 supplies at such levels.

What about the economics for new potential suppliers? With $25 per ton of sales revenue and a $35 per ton 45Q tax credit, they are closer to breakeven with amines capture and logistics costs. With better capture technology and/or a higher CO_2 value, these suppliers could be looking at decent margins. Integrated economics, i.e., margins for an EOR producer who also captures the CO_2 from elsewhere in its system, can be even better.

The point here is that EOR-tied projects are likely to be the proving ground for America's emerging CCUS technologies. CO_2 EOR revenue plus $35 per ton 45Q tax credit will beat $50 per ton credits at offsetting the costs of capture plus logistics and sequestration underground.

The third stage in this process is large-scale deployment. This will involve adoption of a leading capture technology, the construction of CO_2 trunk lines and the development of both EOR and sequestration sites. The U.S. is uniquely endowed to lead in these areas. It has the technology developers, the logistical know-how, the EOR opportunities and most of all, the underground storage to develop CCUS at scale. As the U.S. provides and deploys better capture technologies, it can then transfer these capacities for applications elsewhere, especially in the Eastern Hemisphere.

EOR projects are thus essential to this process of CCUS technology adoption. Interestingly, CO_2 EOR on its own tends to be emissions beneficial. There are two ways to look at this. Environmental groups will draw a ring around the EOR process. They will ask, within that ring, how much CO_2 is captured versus re-released?

Within this framework, it takes 7,000 to 15,000 cf of captured and injected CO_2 to produce one additional petroleum barrel. The breakeven CO_2 injection level is 10,000 cf, i.e., using more than 10,000 cf of captured CO_2 to produce an additional petroleum barrel is carbon negative. Below a 10,000-cf injection rate, CO_2 EOR is thus slightly carbon positive.

A shorthand way of framing this equation would be that 1 bbl of petroleum releases 0.43 tons of CO_2 when combusted. Typical EOR CO_2 will inject at least 0.5 tons of CO_2 to produce that barrel. Thus CO_2 EOR tends to be carbon negative on its own.

The more rigorous approach assumes that petroleum demand is exogenous and a given in the short run. On this basis, assume that EOR employs 0.5 tons of captured CO_2 to produce one additional barrel. However, that plus production backs another barrel into the ground elsewhere, most likely in Saudi Arabia. The Saudi barrel, if produced, was fully carbon positive. Thus, on a net basis, CO_2 EOR benefits the global atmosphere by avoiding production of an incremental barrel that is produced with no capture.

Considering both the past and likely future contributions of fracking and EOR, we conclude with this: it is shortsighted and counterproductive to advocate that any activity involving continued production of oil and gas will impede the energy transition. The feasible transition will take decades. It will require tranquil international conditions to avoid crises that elbow their way to the top of national agendas. Oil and gas supply and price shocks are the opposite of what the feasible transitions needs to progress.

Finally, the feasible transition will require practical steps to decarbonize the emission-heavy Asian economies. This will require both a growing and affordable international LNG business and the development of CCUS as a viable option for otherwise hard to decarbonize sectors.

Robust fracking activities and EOR projects are vital to developing and sustaining these conditions. A failure to recognize and accommodate these essential facts will result in unintended consequences that will only disrupt and delay the feasible transition. □

ESG FACT AND FOLLIES

As the hydrocarbon industries face intensifying pressure from stakeholders to emit less, nine oil and gas leaders share their viewpoints on how the industry should deal with expectations versus reality and why that might cut across the grain.

ARTICLE BY
STEVE TOON

The pressure to mitigate climate change pervades discussions about energy today, particularly within the oil and gas realm. Hydrocarbon-producing companies are tasked with either lowering or offsetting carbon emissions within their capabilities. Yet while most agree that lowering emissions is a worthwhile strategy, not all agree with third-party objectives steering the outcomes.

Two panels at recent major industry events tackled these questions on ESG as it relates to capital investments and the industry's path to Scope 1, 2 and 3 emissions targets.

At NAPE in Houston, panelists included: Kaitlyn Allen, president and CEO, Global Affairs Associates LLC; Ale Veltmann, founder and CEO, ESG Lynk; Craig Webster, sustainability advisor and director of ESG and sustainability, Tudor, Pickering, Holt & Co.; Brooke Baum, sustainability advisor, Devon Energy Corp.; and Michael Rubio, general manager, ESG engagement and sustainability, Chevron Corp.

At the Colorado Oil & Gas Association Energy Summit in Denver, panelists included Kristi Pollard, principal, P2 LLC; Alanna Fishman, managing director, strategic communications, FTI Consulting; James Reddinger, former CEO, Stabilis Solutions; and Chris Wright, CEO, Liberty Oilfield Services.

Including ESG considerations into portfolio decision-making "does not necessarily mean you exclude oil and gas. The majority of responsible investing nowadays is in ESG integration."

—Kaitlyn Allen,
Global Affairs Associates

Investors: In or out?

The debate today pivots around whether to include or exclude fossil fuels by investors. Global Affairs' Allen, who works with many companies across sectors on their ESG strategies, wanted to differentiate between "exclusionary screening" and "ESG integration," which are virtually opposite investment strategies, she emphasized.

Exclusionary screening is when banks or investors decide to eliminate a particular sector or industry from their portfolios, she noted. "But that is not ESG investing," Allen said. Instead, ESG investing is when an investor actively includes ESG considerations into portfolio decision-making, and "that does not necessarily mean you exclude oil and gas," she continued. "The majority of responsible investing nowadays is in ESG integration."

That's good news for oil and gas companies attempting to align themselves with ESG-focused investors, but the devil is in the details—no uniform standards exist for reporting. Veltmann, founder and CEO of ESG Lynk, likened the environment to the Wild West.

"There are different frameworks and standards" for ESG reporting, she said. "It's impossible to have comparability if you have different standards." And any reporting is voluntary. Therefore, when it comes to the materiality of investment decisions, beauty is in the eye of the beholder. "It's really the definition of what materiality is, and different groups define it differently."

In an effort to create some uniformity in ESG definitions, the Sustainability and Accounting Standards Board, a nonprofit organization, has defined industry-specific standards for 77 sectors, including upstream, midstream, downstream and renewables. These definitions, said Veltmann, will put a little bit of structure to ESG to facilitate the analysis for the investors. You have to have a way to normalize it for every company."

FTI's Fishman said six years ago ESG conversations centered on why the industry was entertaining conversations around activism and environmentalism. Now, she said, the predominant question is, "How do we get our feet in the door? What do we need to do to build an ESG program?

"Sustainability has gone from being nice to have to being a must-have. There really is no opt-out clause anymore, particularly for this industry."

Fishman works with companies across all industry verticals and oil and gas companies of different sizes, both public and private. "There is no one size fits all strategy," she said.

"What Chevron might do is very different from what a private equity-backed oil and gas company is going to do." But does that mean a smaller company needs to wait or be more cautious about what they do? "That's a resounding 'no,'" she said. Having a sustainability strategy adds value, "so why wouldn't a private or small company do it like the larger public companies?"

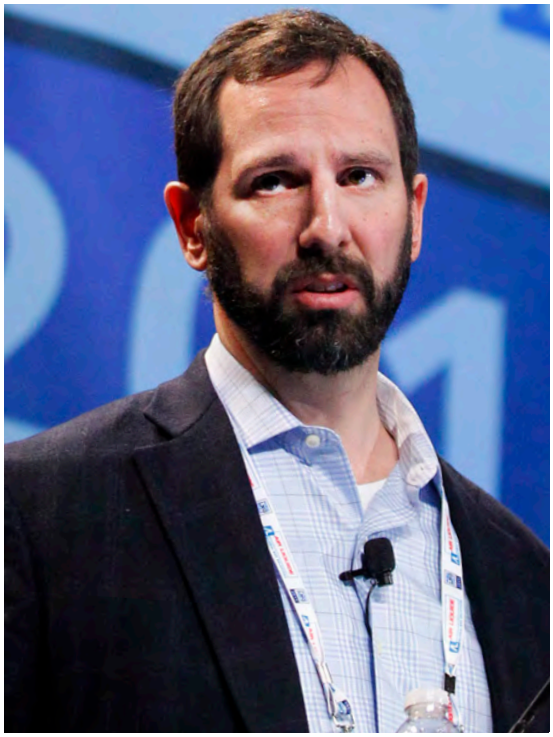
And right now is an opportune time for the industry to set the standard on best ESG practices and what that looks like quantitatively.

"We're quickly moving away from that opportunity, so jump on it," said Fishman. "ESG has been sitting in the private markets, but it's quickly making its way to the government. When it gets to the SEC [Securities and Exchange Commission] and the rulemakings in the future, you can say you didn't need to manage me to do this because we've already been doing it. We can prove we've been doing it."

Money shapes behavior

Climate activists targeting money have led to the finance community having their own set of ESG issues and criteria, said Tudor Pickering's Webster. "Part of it is this idea that if you focus on the money, you can change behavior. And that is what has happened."

He points to the explosion of oversubscribed "green" bonds that are somehow related to ESG as a "shiny, new thing" for the financial community to sell. "A lot of debt is being issued relating to ESG," he said, "but the question becomes, 'Is there any advantage to it?'"



"You need energy solutions that can actually perform the function they're meant to perform in a cost effective way. Finding solutions that are green, but also cost effective, sounds logical, but sometimes it's excluded from the discussion."

—Jim Reddinger,
Stabilis Solutions

Research shows an uptick in sustainability bonds versus the plain vanilla equivalent, he said. Companies are being rewarded with lower basis points when they agree to meet certain indicators that are climate or diversity related that investors agree to reward. The same thing is happening in the equity markets as well.

But, Webster asked, does that make you a better investment if you have these ESG characteristics? The answer is not linear, but the fact is the investment community is interested in ESG and are rewarding it.

P2's Pollard said investors are applying ESG factors across various industry sectors, not just oil and gas, and that shareholder value is viewed as more than just a dollar figure today but also as being aligned with ESG standards. "As we continue to see ESG metrics applied alongside traditional metrics, the energy industry must continue to innovate and think proactively about these strategies."

Lenders are seeing their own ESG pressures as well, said Webster. "There are things they will place restrictions on," he said. All the biggest banks have some level of not lending toward Arctic drilling or oil sands, for example, and J.P. Morgan is requiring companies in its portfolio to lower their carbon footprints

ENERGY POVERTY VS. CLIMATE CRISIS

While data capture and climate targets are critical to measuring and lowering carbon intensity, Liberty Oilfield Services' CEO, Chris Wright, warns against prioritizing feel-good over reality. Liberty's goal, he said, is not to check a box or to meet a goal that someone else says is important. "We're not about fashion. It's what we believe will drive the bettering of human lives."

Eliminating global energy poverty drives Wright's passion. Some 2 billion people in impoverished countries have little to no access to electricity, he noted. One-third of humanity cooks their daily meals burning wood, dung or other agricultural waste inside their homes, resulting in 2 million to 3 million deaths per year from indoor air pollution.

"Solving all of these requires basic energy for the lowest income folk on our planet."

But the Herculean effort to push hydrocarbons out of the energy mix puts that goal of bettering human lives in jeopardy.

"The energy dialogue getting divorced from reality has massive, massive costs," he said.

Wright does not oppose efforts to reduce greenhouse-gas emissions; in fact, the opposite is true. Liberty this summer released an in-depth sustainability report on the company's efforts to do so. The report also acknowledges human contribution to increasing levels of atmospheric CO_2. "Reducing greenhouse-gas emissions is a good thing," he said.

But Wright challenges the narrative that a climate "crisis" is at hand.

"There is no climate crisis. There has been no increase in extreme weather in the entire roughly hundred years of data sets that we have." Global deaths from extreme weather events have dropped 95% in the past century, he noted, based on a report from the Intergovernmental Panel on Climate Change.

Pursuing the narrative that a crisis is imminent unless fossil fuels are driven out of existence will have a catastrophic effect on human lives, he said. "The question is the costs and the trade-offs. We're starting a phase of just massive malinvestment."

He lamented the U.S.' recent decision to not support World Bank investments in fossil fuels for developing countries. "For the 2 billion people that don't have reliable access to electricity, it is now politically popular to slow and stand in the way of them getting that. This isn't just unfortunate; it is deeply wrong."

Unfortunately, investors are just not focused on that bigger picture right now, said Alanna Fishman, managing director, strategic communications, FTI Consulting.

"What gives us the right to have access to oil and gas while we tell third world countries we're not going to give you the same?

"But call a spade a spade: ESG is popular because it talks about the financial value and capital allocation for companies to get brand recognition and more market money. So it's a difficult shift to balance between the benefits of energy and the differences it makes internationally to what the BlackRocks and Vanguards are focused on, which is money."

When making ESG-targeted goals, Wright implores energy companies to evaluate the long-term impacts.

"When you're going to make giant, societal or companywide decisions, dig into the data and align feeling good with things that actually do good. If something feels good but is massively destructive, that's irresponsible. We need to align those two things."

The oil and gas industry holds the responsibility to broaden the dialogue and to bring the facts forward, he said.

"Our industry has let a small group of highly motivated politicians, media and activists design a narrative that's great for them and feels good, and we've just passively gone along with it. They say we're terrible, [and we say] we're less bad than you think. That's bullshit and a losing strategy.

"It is up to us to speak up. We have to be bold. We've got to get our heads out of the foxholes and just be honest. Don't be alarmist like the other side. If you're honest and credible and believe in what you're saying, people know that and they'll accept that. It's on our industry. No one else is going to stand up for us. Let's stand up."

Wright said he's "quite optimistic" on the future availability of energy, the future of people rising out of poverty, the future of continuing to clean the environment and to grow opportunities for those least fortunate in the world.

"What we want to do and we believe society should do is everything they can to increase the chances that people can pursue their dream and their wishes regardless of where they come from. But that takes a brutal honesty and willingness to call something out—even when it's wildly unpopular."

"It's impossible to have comparability if you have different standards. Beauty is in the eye of the beholder. It's really the definition of what materiality is and different groups define it differently."

—Ale Veltmann, ESG Lynk

by 2030. "These are real world things happening."

The "G" in ESG

Publishing an annual report on sustainability is no longer enough, said Fishman. That is "absolutely not what we're seeing anymore. If that's where your company is, then you're already 10 steps behind."

Investors are now looking to the governance side of ESG—boards of directors and executives leading an internal narrative prioritizing sustainability.

"Board members are being called front and center to address what their companies are doing in ESG." Executive compensation incentives, nominating corporate governance and audit committees adding a chief sustainability officer to the executive leadership team are now pertinent.

"They are the stewards of the future oil and gas space, so what are they doing to create a governance framework

"What we produce—the density of that energy—is very important to the world's future prosperity. We need to get better at telling that story. We need to get better at engaging with all stakeholders so that we can be part of the solution rather than being viewed as part of the problem for which people need to completely put us out of existence."

—Michael Rubio,
Chevron Corp.

to enable strategic decision-making in the day-to-day operations of the company? The first step is board buy-in and an awareness of what the company should be doing."

Equally as important is executive leadership: What happens at the top needs to be disseminated down, she said.

"We're finding that employees in the field have no idea what ESG is, or they don't know how their jobs tie into it. Leadership has to find a way to disseminate their values down to every last employee so everybody knows how they can contribute meaningfully to your ESG program."

The companies now shining in their ESG strategies are those that can talk to their investor groups and meaningfully say what their companies are doing, she said. But be careful not to overpromise, she warned, when putting target numbers into the marketplace.

"There is pressure for companies to report anything and everything," she said, "but the worst thing you can do is have an executive throw out a promise like that and not be able to back it up with what your plans are." If you have to walk it back because you've made no progress and people start asking questions, "you have to have a plan of how you're reducing your own emissions."

Likewise, companies have to "dig deep" to make sure any goals they are promising are not an intentional misleading of the public.

"ESG is just too fluffy right now. Anybody can claim something about you, and you have to be able to back it up. Just make sure that you have a process in place so if somebody asks you how you got to that number, you can show it. Prepare your executives to say the right things and don't make empty promises."

Practical—not idealistic—solutions

Stabilis' Reddinger generally agrees that cleaner, greener and being environmentally responsible is better than the status quo but believes that goal needs to be pursued with practical and realistic solutions. "The discussion on sustainability issues has really become one-sided," he said.

First, sustainability goals must be cost effective.

"You need energy solutions that can actually perform the function they're meant to perform in a cost-effective way." If the product produced is not affordable to the user or society over time, it is not a solution, he said. "So finding solutions that are green, but also cost effective, sounds logical, but sometimes it's excluded from the discussion."

"Sustainability has gone from being nice to have to being a must-have. There really is no opt-out clause anymore, particularly for this industry."

—Alanna Fishman,
FTI Consulting

"You've got investors in these companies that are voting in favor of not taking advantage of your expertise, your valuable asset base, and asking them to reduce what you do in your core business. Why would you do that? Actually executing on your core business is an option and an option that has value."

—Craig Webster,
Tudor, Pickering, Holt & Co.

Second, solutions must be reliable and predictable. As examples, he points to Texas' extended loss of power during the 2021 winter freeze, ongoing power reliability issues in California and New England's chronic shortage of gas for heating in the wintertime.

"We've got a big issue building in this country where we're very much pushing the 'E' and the environmental sustainability part of this, but we're forgetting the reliability and predictability part, which most people like when their heat or air conditioning comes on. They like when they can cook dinner when they want to. And so, while it sounds very simple, the message of environmental sustainability needs to be paired up with cost effectiveness and with predictability and reliability."

Reddinger said companies need to be open to ideas but also avoid plowing capital and resources into investments that, at the end of the day, aren't going to prove fruitful. "That doesn't help the company by any means. No one's going to remember in five years when you burned all your cash on a project that didn't work. They're going to remember that you have no more cash.

"It's your job to keep your company focused on what your mission is and how you're going to invest through that."

Devon's Baum said the ESG impetus hit an inflection point in 2020, and it is "most important" for oil and gas companies to improve environmental and climate-related performance to maintain the social license to operate. "This is a journey we're all on," she said, "and there's no finish line."

In June, Devon published a suite of environmental performance targets, the largest being a commitment to achieve net-zero greenhouse-gas (GHG) emissions for Scopes 1 and 2 by 2050. It also established interim goals of cutting GHG emissions in half and reducing methane by 65% by 2030 and to eliminate routine flaring.

"We don't believe this is just climate risk mitigation, but we do believe there's a lot of opportunity to be had for companies that are willing to spend the time, effort and capital to make real change."

And while she said the commitment for net-zero emissions demonstrates Devon's confidence to find ways to produce and deliver oil and gas more responsibly, "we believe our net-zero commitment demonstrates our confidence in the fact that oil and gas will remain for decades."

Helping investors "get up to speed" and understand that excluding oil and gas "is probably not going to do much for anybody," but

"As we continue to see ESG metrics applied alongside traditional metrics, the energy industry must continue to innovate and think proactively about these strategies."

—Kristi Pollard,
P2 LLC

integrating ESG considerations more deeply is good for everyone. "It's good for the environment, it's good for business and it's good for the economy."

The Scope 3 conundrum

While most oil and gas companies can understand how to tackle Scope 1 and 2 emissions strategies, Scope 3 GHG emissions are more ephemeral.

Chevron's Rubio said the big question hovering over the industry now is how to account for Scope 3 emissions, or the behavior by end users of hydrocarbon products.

"How do you measure those emissions, and ultimately, who is accountable for reducing those emissions" over the entire value chain? "Because we know that the world, we collectively, have to reduce those emissions over time in order to achieve the Paris Agreement. It can get very complicated, particularly when you talk about sustainability and metrics and targets."

In addition to various programs to abate Scopes 1 and 2 emissions, Chevron introduced its Portfolio Carbon Intensity metric that represents carbon intensity across the value chain. "We need to do better," he said. "We need to find a way to lower our carbon intensity. The demands from our customers and shareholders are different now, and we're not waiting for regulatory groups."

But Chevron is not apologizing for producing hydrocarbons, he said, as affordable, reliable and cleaner energy is at the heart of all prosperity today.

"The world needs it, period. And what we produce—the density of that energy—is very important to the world's future prosperity."

And while industry must move to producing that energy in a more sustainable way, it can't overlook the need to generate returns for shareholders.

"We have to sustain the cash flow. We have to sustain the dividend. We have to sustain the ability to deliver that return so that if you're a shareholder, you can rest assured that there's going to be a long-term value proposition.

"It's at the core of what we do. We need to get better at telling that story. We need to get better at engaging with all stakeholders so that we can be part of the solution rather than being viewed as part of the problem for which people need to completely put us out of existence."

Webster finds irony when energy company shareholders demand that they lower Scope 3 emissions.

"What you're really asking them to do is to produce less oil and gas. Think about this: You've got investors in these companies that are voting in favor of not taking advantage of your expertise, your valuable asset base and asking them to reduce what you do in your core business. Why would you do that? Actually executing on your core business is an option and an option that has value."

The answer is a perception of a broader, systematic risk rather than the value proposition of a specific company, he said, but illustrates the inconsistencies and growing pains that the ESG movement is undergoing.

"We don't believe this is just climate risk mitigation, but we do believe there's a lot of opportunity to be had for companies that are willing to spend the time, effort and capital to make real change."

—Brooke Baum,
Devon Energy Corp.

"It is something that should be raising eyebrows," he said. "What is the role of the investor, and what are we really trying to do? What are the potential outcomes and unintended consequences of some of these things that are happening?"

ESG is being pushed down from investors to the industry, Webster said, and the industry needs to ask them pointedly, "What are your expectations? What's a good number for emissions? Where do we need to fit in? Who do we need to be comparable to?

"We can talk about inconsistencies all day, but it is happening, and it's going to intensify. So try to understand how that's going to evolve with shareholders, lenders and other stakeholders and hold their feet to the fire on what they really want," he said.

One of those aforementioned unintended consequences, said Rubio, could be the privatization of oil and gas assets. Investors still covet the low-growth, high-returns, dividend-producing model, but reconciling that desire with sustainability directives can send mixed messages. Thus, selling down oil and gas assets offloads the carbon intensity in the portfolio—with environmental costs.

"They'll sell a heavy carbon asset to the highest bidder to get it off their books, and then they'll pat themselves on the back and say, 'We've lowered our carbon intensity Scope 1, 2 and 3.' But what

they've done is actually sold it to a private firm that's still going to produce it because the demand is ramping back up," said Rubio.

"We're taking emissions from a public, transparent arena and moving it to privatization. So in a perverse way, net-net, it has a negative impact on our effort to achieve the Paris Agreement."

Chevron's perspective is to remain transparent with its fossil fuel assets and work to lower the carbon intensity of the commodity that it's producing, he said. "We think that is what's going to be resilient not only in the short term but certainly in the long term as demand continues."

The carbon tax issue

Allen noted that Scope 3 reduction for companies offloading carbon-based assets is not necessarily a Scope 3 reduction for the world. And that's where mechanisms like a price on carbon become attractive to companies, some of the larger ones which are advocating for that on Capitol Hill.

"In theory, that would bring a level of efficiency and fairness to this," she said.

Rubio concurred that the most effective way to deal with emissions is a market-based mechanism such as a carbon price. Chevron was one of the lead negotiators in the cap and trade program in California, "one of the largest market mechanisms in the world today," he said, "that some would argue is working pretty well. Some might argue it's not."

"When you're going to make giant, societal or companywide decisions, dig into the data and align feeling good with things that actually do good. If something feels good but is massively destructive, that's irresponsible. We need to align those two things."

—Chris Wright,
Liberty Oilfield Services

But it is shaping the strategies of companies in that market to reduce emissions. The tax, he said, will drive research and change human behavior.

"Whatever demand looks like, the most effective way to get to Scope 3 emissions is a price on carbon because whether it's mine, whether it's yours, whether it's the plane I took or the car [you took], it's going to be covered. And that's the real challenge here."

True to the core

Neither Chevron nor Devon are abandoning their core businesses to achieve ESG excellence, the representatives said.

Rubio points to oil and gas companies allocating capital into solar, wind and nonhydrocarbon alternatives to reduce Scope 3 emissions, but "that's not Chevron," he said.

"If you're looking for a renewable company, you can take your capital and go invest in a renewable company. If you're looking for a company that's going to lower the carbon intensity of important commodities that are being used today and per the scenarios that have come out that are going to be used at least for the next several decades, we are your company, because we're also going to be producing that resource."

Chevron is, however, investing in carbon capture, hydrogen and renewable fuels, targeting systems in the overall energy system that can't be electrified today.

"You can't fly a plane today with solar panels, but we can produce biofuels and sustainable aviation fuels that lower carbon emissions. I think we need all strategies because the challenge we have from the ambition to the reality is significant."

For Devon, while reducing the carbon intensity of its operations is now a central tenant to its operating model, "we're not abandoning our core business commitment," said Baum. "We are focusing on assets that we own and operate where we believe we can most directly and meaningfully impact change over the near and medium term."

Pushing forward

Reddinger said society is "missing the mark" if the goal is to eliminate all fossil fuels at the expense of economies, human condition and quality of life.

"We need to figure out what we're trying to get to," he said. "You can't just have one target that lets people suffer the consequences; you're not helping people by doing that. We need to have goals and objectives that are actually measured quantitatively and evaluated objectively, so we know where we're going and can help companies get there."

"We don't have all the answers today," acknowledged Webster. "It's only going to be through engagement and sharing of good ideas that we're going to collectively come together to solve these challenges." □

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Shell Shakes Up Permian In $9.5 Billion Exit

ROYAL DUTCH SHELL Plc agreed to the sale of its Permian Basin position on Sept. 20 as the supermajor doubles down on its emission goals.

In a company release on Sept. 20, Shell announced it had reached an agreement for the sale of its Permian business to **ConocoPhillips Co.** for $9.5 billion in cash. The acquisition by ConocoPhillips follows its purchase of Permian pure-play **Concho Resources Inc.** in an all-stock deal that closed in January 2021.

Shell's exit from the Permian Basin has long been rumored, initially spurred by a landmark Dutch court ruling earlier this year ordering the company to speed up its plans to cut greenhouse-gas (GHG) emissions.

"After reviewing multiple strategies and portfolio options for our Permian assets, this transaction with ConocoPhillips emerged as a very compelling value proposition," Wael Sawan, the company's upstream director, commented in the release.

Shell's Permian business includes ownership in approximately 225,000 net acres located entirely in West Texas, with current production of around 175,000 boe/d. A further update to Shell's oil production outlook and portfolio will be provided with fourth-quarter earnings, according to the release.

"This decision once again reflects our focus on value over volumes as well as disciplined stewardship of capital," Sawan continued. "This transaction, made possible by the Permian team's outstanding operational performance, provides excellent value to our shareholders through accelerating cash delivery and additional distributions."

Shell said cash proceeds from the transaction will be used to fund $7 billion in additional shareholder distributions after closing, with the remainder used for further strengthening of the balance sheet. The distributions will be in addition to the shareholder distributions in the range of 20% to 30% of cash flow from operations.

CONOCOPHILLIPS CO.

ConocoPhillips also plans to increase its shareholder returns, driven by the boost to cash flow expected by the acquisition from Shell, according to CEO Ryan Lance.

"The transaction will be funded from available cash while still retaining a significant level of cash on the balance sheet for general purposes," Lance said in a separate release. "Our underlying business drivers will be stronger, and the expanded cash flows derived from this transaction mean shareholders will benefit from higher returns of capital consistent with our commitment to return of capital of at least 30% of cash from operations."

In the release, ConocoPhillips announced an increase in the company's quarterly ordinary dividend from 43 cents per share to 46 cents per share, representing a roughly 7% increase and a current dividend yield of 3%. ConocoPhillips' dividend is payable on Dec. 1 to stockholders of record at the close of business on Oct. 28.

ConocoPhillips also announced in conjunction with the Shell transaction it will improve its Scope 1 and 2 greenhouse-gas emission intensity reduction targets. The prior 2030 reduction target of 35% to 45% on a gross operated basis will be increased to 40% to 50%, versus a 2016 baseline, on both a net equity and gross operated basis.

"In addition to enhancing our base plan, this transaction also enhances our ability as an E&P company to have a valued role in energy transition by accelerating progress on our triple mandate," Lance added. "The objectives of the mandate are to responsibly produce energy to meet transition demand, generate compelling returns on and of capital and achieve our Paris-aligned targets and 2050 net-zero ambition."

The effective date of the transaction is July 1, with closing expected in fourth-quarter 2021.

A majority of Midland, Texas-based Permian employees and many Houston-based employees will be offered employment by ConocoPhillips with effect upon closing in accordance with the terms and conditions of the transaction, the Shell release said.

Tudor, Pickering, Holt & Co. acted as a financial adviser to Shell on the transaction.

—Emily Patsy

Cabot, Cimarex Emerge As Coterra Energy Following All-Stock Combination

CABOT OIL & GAS CORP. and **Cimarex Energy Co.** on Oct. 1 completed the all-stock "merger of equals" forming one of the largest U.S. shale companies under the name **Coterra Energy Inc**.

The combined business, to be headquartered in Houston, is estimated to have an enterprise value of roughly $17 billion and includes more than 700,000 net acres in the Marcellus, Permian and Anadarko regions.

"Today marks the beginning of our journey as one Coterra team," Thomas E. Jorden, CEO, president and director of Coterra, commented in the release on Oct. 1. "We couldn't be more excited to bring together our teams and form a new E&P company that is positioned to succeed in the next phase of the shale revolution and beyond."

Coterra's combined production base, as of second-quarter 2021, was approximately 605,000 boe/d, according to the Oct. 1 release.

"With tremendous flexibility between premier oil and natural gas assets and a focus on operating efficiently," Jorden continued, "driving substantial cash flows and generating capital returns through commodity cycles, Coterra is poised to deliver enhanced value to our shareholders."

In addition to Jorden, Scott C. Schroeder, formerly CFO of Cabot, joined Coterra upon closing of the merger as executive vice president and CFO, as previously announced.

Thomas E. Jorden

"We are proud to complete our transaction and launch Coterra, which will build upon the impressive legacies and many strengths of both Cabot and Cimarex," Dan O. Dinges, executive chairman of Coterra, commented in the release on Oct. 1.

Under the terms of the merger agreement originally announced in May, Cimarex shareholders received 4.0146 shares of Cabot common stock for each share of Cimarex common stock owned. The value of the all-stock merger was pegged by Enverus at roughly $9.25 billion.

At closing, Cimarex shareholders were expected to own approximately 50.5% of the combined company with Cabot shareholders owning the remaining 49.5%. The companies said on Sept. 29 more than 99% of Cabot common shareholders and more than 90% of Cimarex shareholders voted in favor of the merger.

In May, the companies projected a free cash flow outlook of the combined company of approximately $4.7 billion from 2022 to 2024 based on $55/bbl WTI oil prices and $2.75/MMBtu Nymex natural gas prices.

Plans are for Coterra to supplement an annual base dividend of $0.50 per share with a quarterly variable dividend to achieve a target capital return of at least 50% of quarterly free cash flow. The companies are also targeting annual G&A cost synergies of $100 million beginning within 18 months to two years following the closing.

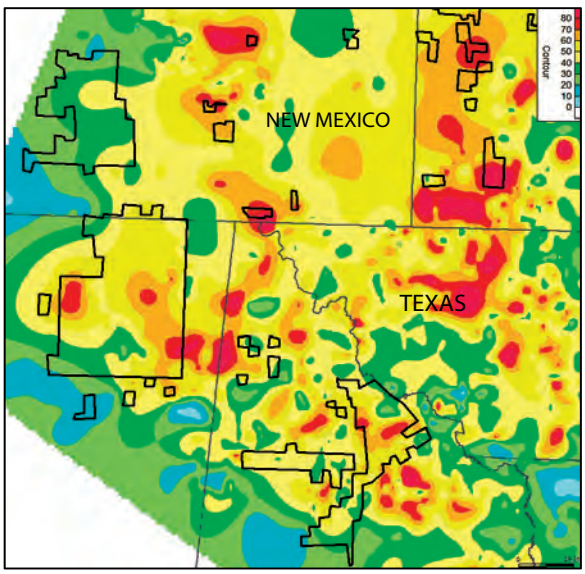
Coterra also expects to build on Cabot's and Cimarex's ongoing ESG efforts by, among other things, continuing to link executive compensation to ESG performance and maintaining strong board oversight of ESG risks and programs.

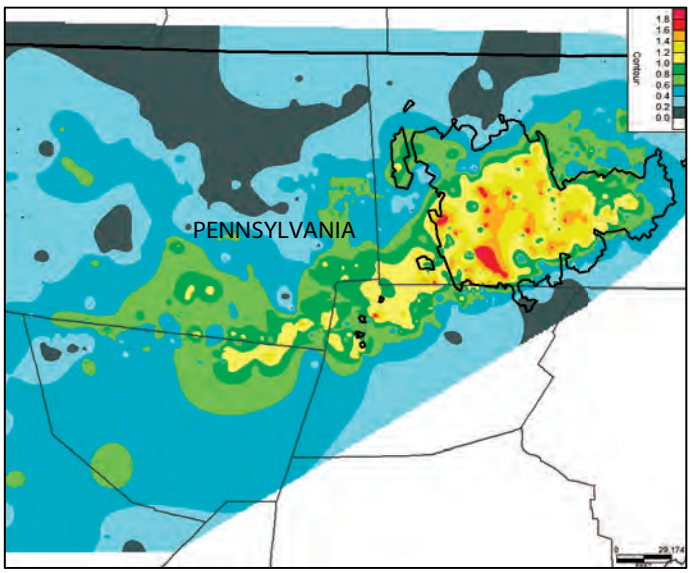
"Driven by a commitment to operating accountably, sustainably and safely, Coterra will be well positioned to increase returns to shareholders and deliver long-term value for all our stakeholders," added Dinges, who previously served as chairman, president and CEO of Cabot.

J.P. Morgan Securities LLC was financial adviser to Cabot for the transaction, and **Baker Botts LLP** served as its legal counsel. **Tudor, Pickering, Holt & Co.** was Cimarex's financial adviser, and **Wachtell, Lipton, Rosen & Katz** provided legal counsel.

—Emily Patsy

Cabot And Cimerax's Combined Assets





Source: Cabot Oil & Gas Corp.; Cimarex Energy Co.

Diversified Energy Takes Tapstone In $419 Million Midcontinent Expansion

DIVERSIFIED ENERGY CO. Plc recently announced a cash acquisition of Oklahoma City-based **Tapstone Energy LLC** for $419 million, representing Diversified's fourth deal in what the company said is its new central regional focus area.

Founded in late 2013 by industry veteran Tom Ward, Tapstone Energy focuses in the Anadarko Basin of the Midcontinent region. The independent oil and gas producer recently completed a successful restructuring process whereby a new capital sponsor, **Kennedy Lewis Investment Management**, selected Tapstone to be its key E&P platform.

According to a company release, Diversified agreed to acquire upstream assets, field infrastructure, equipment and facilities in Oklahoma from Tapstone and an affiliate of Kennedy Lewis Investment Management for $419 million in cash. Private equity group **Oaktree Capital Management LP** will pay $192 million for an initial 48.75% stake as part of the deal.

In the release, Diversified said its adjusted net share of the purchase price, at $174 million, represents a nearly 1.8x multiple on around $95 million of estimated adjusted EBITDA, not including potential synergies.

"With a net purchase price of less than two times net cash flow, this acquisition represents another highly accretive, fully balance sheet-financed acquisition that further demonstrates our status as a capable consolidator of producing assets within the central region," Diversified Energy CEO Rusty Hutson Jr. said in a company release on Oct. 7.

Headquartered in Birmingham, Ala., and listed on the London Stock Exchange, Diversified's business model focuses exclusively on buying PDP natural gas assets, which, until its May acquisition of assets located primarily in Louisiana, had all been focused in the Appalachian Basin.

Since its initial acquisition in May, Diversified has added positions in its central region footprint, including in the Cotton Valley, Haynesville and Barnett shale plays. In total, Diversified has spent close to $470 million from its prior central region acquisitions, which consisted of **Tanos Energy Holdings III LLC**, **Blackbeard Operating LLC** and **Indigo Minerals LLC**.

"Replicating our success in Appalachia, we have quickly established ourselves as a significant operator in the central region, which positions us for additional growth," Hutson said.

The Tapstone acquisition also represents the third co-investment since May with its financial partner, **Oaktree Capital Management**, which will make a nonoperated working interest investment in the Tapstone acquisition, according to the company release.

Net of Oaktree's co-investment, Diversified said through the Tapstone acquisition it will acquire about 660 net operated wells located in Oklahoma within the broader Midcontinent producing area. Production in August was roughly 12,000 boe/d (over 80% natural gas and NGL).

The Tapstone acquisition will add almost 33% of anticipated production to Diversified's central region focus area. The assets are also expected to increase adjusted EBITDA from the central region by 80% to $214 million.

"Our enlarged regional footprint strengthens our portfolio with additional high-quality assets and added scale to drive synergies," Hutson added. "We are pleased to once again partner with Oaktree to acquire assets at a compelling multiple and with material upside potential available through asset optimization."

Diversified intends to retain Tapstone personnel, which the company said is consistent with its growth strategy, to assist with Diversified's smarter asset management program, which focuses on optimizing asset performance and reducing costs that will ultimately add value through realization of operational synergies.

The purchase price of Tapstone is expected to be adjusted down to about $366 million to account for production between the Aug. 1 effective date and an anticipated December closing, the release said.

Pro forma of the Tapstone acquisition, Oaktree will have deployed an aggregate of roughly $370 million of its $1 billion commitment for Diversified to pursue larger acquisition opportunities that the companies agreed to in 2020.

Evercore is the exclusive financial adviser to Diversified in connection with the acquisition. **Jefferies** acted as sole financial adviser to the sellers.

—Emily Patsy

Earthstone Energy Strikes Again With Midland Basin Bolt-On Acquisition

EARTHSTONE ENERGY INC. continued its buying spree on Oct. 4 with a bolt-on acquisition in the Midland Basin worth approximately $73.2 million in cash and stock.

"This transaction will be our fourth acquisition this year as we continue to advance our consolidation strategy and enhance our Midland Basin footprint with additional scale," Robert J. Anderson, president and CEO of Earthstone, said in a release by The Woodlands, Texas-based company.

Earthstone Energy, a small-cap, Permian-focused producer, holds 29,100 net acres in the Midland Basin and another 14,500 net acres in the Eagle Ford Shale, according to the company's website.

During the past six years, the company has utilized M&A of small operators in pursuit of its consolidation strategy, including 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. The company also completed an acquisition in the Eagle Ford in June.

In its latest acquisition, Earthstone said it agreed to acquire privately held operated assets located in the Midland Basin from two sellers in exchange for $49.2 million in cash and approximately 2.6 million shares of Earthstone Class A common stock.

The stock consideration represents approximately 3% of the total outstanding Class A and Class B common stock on a pro forma basis and is valued at $24 million based on a closing share price of $9.20 on Sept. 30.

Earthstone said it will fund the cash portion of the consideration and fees and expenses with cash on hand and borrowings under its revolving credit facility. As of Aug. 31, and adjusting for the current borrowing base of $650 million, Earthstone had liquidity of approximately $365 million based on the $363.4 million of undrawn borrowing base capacity and $1.2 million in cash.

Robert J. Anderson

"The mix of consideration between cash and equity in accordance with our focus on maintaining a strong balance sheet positions us well to continue our consolidation efforts," Anderson said. "We are pleased to continue to add incremental scale in an accretive manner without sacrificing our balance sheet or free cash flow generation."

The acquisition will add roughly 4,400 boe/d (26% oil, 52% liquids) of production. The acquired asset base and operations also include projected next 12-month adjusted EBITDAX of approximately $42 million plus associated reserves of approximately 13.3 MMboe (11% oil, 31% NGL, 58% natural gas).

Additionally, Anderson noted in his statement that the bolt-on acquisition will tack on approximately 10,000 net acres (100% operated; 67% HBP) to Earthstone's position in Irion County, Texas.

"We expect to benefit from additional operating synergies when production operations are combined with other assets in the area," he continued. "As we have done in prior acquisitions, we look forward to applying our operating approach to these assets in order to reduce costs and maximize production and cash flows."

The bolt-on acquisition is expected to close by the middle of the fourth quarter with an effective date of July 1. Earthstone maintains its target of achieving sub-1.25x leverage by year-end 2021, the release noted.

—Emily Patsy

Citizen Energy Expands In Oklahoma With $153 Million Bolt-On

CITIZEN ENERGY LLC recently landed a gas-rich, bolt-on acquisition that **Enverus** analysts said will boost the company's production within its existing Anadarko Basin footprint by about 12%.

As part of the acquisition, Citizen entered into a definitive purchase and sale agreement with an undisclosed seller to acquire 28,000 net acres (94% HBP) for $153 million. According to a company release on Oct. 11, the acquired acreage located primarily in Oklahoma's Blaine, Canadian and Kingfisher counties lies largely within Citizen's existing footprint.

"The contiguous nature of the acquisition provides an ideal opportunity for infrastructure connectivity and development continuity," Citizen Energy said in the company release.

Based in Tulsa, Okla., Citizen Energy III is backed by **Warburg Pincus** and focuses on the development of "horizontal play concepts" in the Anadarko Basin, according to the company's website.

The privately funded company was founded in November 2017 and initially pursued emerging extensions of the STACK and MERGE plays. However, the company eventually returned to the core of the MERGE through the acquisition in 2019 of **Roan Resources**, a publicly traded oil and gas producer that had a position of 140,000 net acres.

Roan was founded in 2017 from the remnants of **Linn Energy Inc.** in partnership with Citizen Energy II, a predecessor of the current iteration of Citizen. The $1 billion take-private acquisition of Roan established Citizen Energy III as the largest private operator in Oklahoma.

Pro forma for the acquisition announced Oct. 11, Citizen will have net daily production of about 74,000 boe/d, interests in over 1,700 wells and more than 230,000 net acres across the Midcontinent region, according to the company release.

"Citizen expects the acquisition to be accretive to shareholder returns and crucial to building and maintaining its momentum as the largest private operator in Oklahoma," the company added.

Citizen will fund the purchase entirely out of existing liquidity within the company's reserve based lending facility, which was upsized to $850 million prior to the transaction.

The acquisition includes net production of 8,000 boe/d (58% gas, 25% NGL) from 97 operated wells and 400 nonoperated wells. The deal has a July 1 effective date and is expected to close in the fourth quarter of this year, according to the company.

Schaper Energy Consulting was technical adviser for Citizen Energy on the transaction. **Shearman & Sterling** served as legal counsel for the company.

—Emily Patsy

SilverBow Hits Center With Eagle Ford Deal

SILVERBOW RESOURCES INC. continued to add to its position in the Eagle Ford Shale on Oct. 11 with the acquisition of oil-weighted properties for $75 million.

The transaction, with two undisclosed sellers, represents SilverBow's third acquisition since the beginning of August and the largest to date for the company, according to SilverBow CEO Sean Woolverton.

"Today's announcement is a testament to the extensive work we have done evaluating opportunities and executing our in-basin consolidation plan," Woolverton commented in a company release on Oct. 11.

The total purchase price for the acquisition consists of $45 million in cash and approximately $30 million in equity. The transaction follows an all-stock acquisition SilverBow closed on Oct. 4 that the company said both bolstered its gas position and added new oil positions in the Eagle Ford.

"The use of equity has allowed us to access a larger opportunity set for strategic growth while aligning our interests with surrounding peer companies and other key stakeholders for accretive, long-term value creation," Woolverton said of SilverBow's latest acquisition.

SilverBow also closed an acquisition in August of nonop working interest in its operated La Mesa property in Webb County, Texas, in a cash-and-stock transaction worth $24 million.

SilverBow Resources is an independent E&P company based in Houston that is actively engaged in the exploration, development and production of both oil and gas in the Eagle Ford Shale and Austin Chalk in South Texas.

In its latest acquisition, SilverBow will add 17,000 total net acres in the oil window of the Eagle Ford shale play in La Salle, McMullen, DeWitt and Lavaca counties, Texas. Net production in May was approximately 2,500 boe/d (71% liquids / 46% oil) from 111 PDP wells.

The acquired oil production represents a 30% increase to SilverBow's current full-year 2021 oil production guidance, according to the company release.

"This acquisition meaningfully increases SilverBow's oil production and furthers our Eagle Ford and Austin Chalk consolidation efforts while maintaining a balanced oil and gas portfolio," Woolverton added.

SilverBow is also acquiring over 100 net drilling locations, which Woolverton described as "high rate of return locations." In total, SilverBow estimates the acquisition adds approximately three years of inventory at the current's current drilling pace of one rig.

"As we have shown over time, we expect to continue driving our peer-leading capital efficiency and cost structure as these assets are combined with our existing portfolio," Woolverton said.

Including the pro forma contribution of the company's recent acquisitions, he noted SilverBow is targeting a leverage ratio of 1.25x at year-end 2021.

SilverBow intends to fund the cash component and fees and expenses of its latest acquisition with cash on hand and borrowings under its revolving credit facility. Woolverton said SilverBow plans to share additional details as part of the company's third-quarter 2021 reporting in November.

—Emily Patsy

Comstock Resources Sells Bakken Shale Assets For $154 Million In Cash

COMSTOCK RESOURCES INC. announced the sale of its Bakken assets on Oct. 7 to **Northern Oil and Gas Inc.**, and the company intends to reinvest the proceeds into the Haynesville Shale.

Northern agreed to acquire the Bakken assets from Comstock Resources for $154 million in cash. The transaction, which Northern expects to fund with cash on hand, operating free cash flow and borrowings under its revolving credit facility, is set to close in November.

Comstock's Bakken assets, described by Northern as a bolt-on acquisition, comprise nonoperated interests across over 400 producing wellbores located primarily in North Dakota's Williams, McKenzie, Mountrail and Dunn counties. The assets are operated by multiple operators in the Williston Basin and include 65.9 net producing wells. October production on the assets is projected to be greater than 4,500 boe/d (2-stream, about 65% oil).

Northern holds existing ownership positions in 84% of the wellbores to be acquired, according to a release by the company.

"We remain consistent with our strategy," Northern CEO Nick O'Grady commented in a company release. "The focus continues on being the natural consolidator of working interests and executing with financial discipline, concentrating on cost of entry, return on capital employed and cash flow net to our shareholders."

Based in Minnetonka, Minn., Northern aims to be the go-to resource for operators that want to offload nonoperated working interests in leasehold. Originally focused in the Williston Basin, the company has begun to branch out with acquisitions over the past year in the Marcellus Shale and Permian Basin.

"This is our third major transaction this year in as many basins," Northern COO Adam Dirlam added in the release. "Our team's ability to actively pivot has provided for consistent optionality to pursue value enhancing opportunities in the most prolific basins across the U.S."

Northern on Oct. 5 said it expects a significant increase to its borrowing base from both the acquired and existing assets and will begin the process to expand its elected commitment during its regularly scheduled fall borrowing base redetermination, which it expects to complete in November.

Additionally, given the strong, low-risk cash flows from the acquired properties, Northern said its management plans to submit a request to the board of directors for a 33.3% increase to the common stock dividend for the fourth quarter.

"With the planned dividend increase, we will have doubled our shareholder return program in less than five months since inception," O'Grady said in the release.

Comstock expects to recognize a pre-tax loss of $130 million to $140 million on the divestiture. The company plans to use the sale proceeds in its Haynesville development program, including the acceleration of completing 13 (9.4 net) DUC wells, which were originally budgeted to be completed in 2022.

Comstock said it may also use a portion of the proceeds to acquire additional leasehold and to fund additional drilling activity in 2022.

The transaction is expected to close in the fourth quarter and will have an effective date of Oct. 1. **EnergyNet** is acting as exclusive adviser to Comstock on the sale. **Kirkland & Ellis LLP** is Northern's legal adviser.

—Emily Patsy

Penn Virginia Rebrands As Ranger Oil Following Close Of Lonestar Acquisition

PENN VIRGINIA CORP. closed its all-stock acquisition of **Lonestar Resources US Inc.** and said on Oct. 6 it will rename the combined company **Ranger Oil Corp**.

With a corporate lineage dating back to the late 1800s, Penn Virginia was formed as an Appalachian coal company. It later evolved into a natural gas producer and then oil with assets in various shale basins.

The rebrand to Ranger Oil, according to a release, reflects the company's focus on "safe and efficient oil and natural gas operations in Texas," where it eventually narrowed its focus solely to the Eagle Ford bolstered with the recent acquisitions of Lonestar and **Rocky Creek Resources**, both of which closed within the past year.

"In a very short time, we have significantly increased the scope and scale of the company, amplifying its free cash flow generation and return potential," Darrin Henke, president and CEO of the company, commented in the release on Oct. 6.

The combined asset bases of Penn Virginia, Rocky Creek Resources and Lonestar created a consolidated asset that produces almost 40,000 boe/d with over 140,000 net acres strategically positioned in the core of the Eagle Ford play in South Texas.

"We now own high-quality inventory approximating 750 locations, approaching two decades of inventory at our current drilling pace," Henke added.

The company currently anticipates that going forward it will maintain the two-rig program it was operating prior to the closing of the $370 million Lonestar merger. Based on this pace of development, capex for the fourth quarter is anticipated to be approximately $65 million to $75 million, which the company said it expects will continue its track record of generating significant free cash flow.

"We've announced seven consecutive quarters of free cash flow through June 30 of this year and project Ranger to produce over $200 million of free cash flow in 2022 at current strip pricing," Henke said.

In addition to its expansion through acquisitions, Henke also highlighted the significant changes to the Penn Virginia management team that he said drove step change in recent asset, operational and financial performance over the last several quarters. The result, Henke noted, was made apparent as Penn Virginia achieved the highest EBITDA margin per boe of any public U.S. independent oil and gas company from the beginning of 2020 through the first half of 2021.

Henke joined Penn Virginia as CEO in August 2020, which happened to be during mid-negotiations for the company's acquisition of Rocky Creek Resources with **Juniper Capital Advisors LP**, Rocky Creek's financial backer.

As part of the deal, Juniper Capital took a nearly 60% majority ownership position in Penn Virginia. In exchange, Penn Virginia's balance sheet was relieved of about $130 million in debt, almost tripling the producer's liquidity under its credit facility and more than doubling its market capitalization.

"In addition to our strategic and operational achievements," Henke continued, "we transformed our balance sheet over the past year by bringing in substantial equity capital from an experienced oil and gas equity group, issuing senior unsecured notes to extend maturities, and amending and expanding our credit facility borrowing base while reducing the balance borrowed on the facility.

"This resulted in our company having an estimated 1.5x pro-forma LTM leverage," he added.

In a statement commenting on Penn Virginia's rebranding, Edward Geiser, chairman of the board of the company and managing partner of Juniper Capital, said, "Juniper Capital congratulates the Ranger Oil team for its recent accomplishments and remains a committed long term equity partner of the company."

"The recent operational, financial and strategic achievements continue to validate and bolster our investment thesis in partnering with the company," Geiser continued, "and we look forward to the ongoing performance that Ranger Oil and its management team have planned as they execute their strategy in the core of one of the most prolific oil basins in North America."

Penn Virginia intends to officially rebrand as Ranger Oil Corp., effective Oct. 18, and expects the rebranding to be fully complete prior to year-end 2021, which according to Rusty Kelley, senior vice president and CFO, will mark the beginning of another phase of "significant fundamental value creation" for the company.

Going forward, Kelley said the company will maintain focus on maximizing operational and capital efficiency, generating superior returns and building on its consistent track record of free cash flow generation, which it has sustained every quarter since fourth-quarter 2019.

"We plan to continue our disciplined approach to potential consolidation opportunities while maintaining a pristine balance sheet with substantial liquidity, including our commitment to achieving a 1.0x leverage ratio in the first half of 2022," he said.

As Ranger, the company also intends to drive further operational efficiencies including longer laterals, increased wells per pads, enhanced completion techniques and shared facilities.

Lastly, Kelley said the company plans to further establish itself as a leader in ESG-related results.

"We have already been recognized as having among the lowest emissions for operators in the Eagle Ford, and we plan to target additional enhancements as we integrate the Lonestar assets," he said. "In addition, the company will continue fostering its diverse and inclusive environment and increase our community engagement efforts."

In conjunction with the closing of the Lonestar merger, the company is assuming the swapped hedge volumes held by Lonestar and resetting the majority of these swaps to reflect current market pricing. This reset is not anticipated to materially impact the company's leverage metrics; however, it is anticipated to increase its future adjusted EBITDAX and free cash flow, the release said.

Additionally, Darin G. Holderness resigned from the company's board of directors in connection with the Lonestar closing. Richard Burnett, former chairman of the board of directors for Lonestar, has been appointed to the company's board to fill the vacancy. Burnett will also serve as chairman of the audit committee.

Effective Oct. 18, Ranger Oil will begin trading under the NASDAQ ticker symbol, "ROCC."

—Emily Patsy

Callon Petroleum To Sell Noncore Eagle Ford Acreage For $100 Million

CALLON PETROLEUM CO. followed by the closing of a deal to acquire **Primexx Energy Partners**' Permian Basin assets by announcing it would execute a $100 million sale of Eagle Ford Shale assets.

The divestiture of the Eagle Ford properties to an undisclosed buyer includes approximately 22,000 net acres in northern La Salle and Frio counties, Texas. Net daily production from the properties, which Houston-based Callon said were noncore, was approximately 1,900 boe/d (66% oil) on average in the third quarter.

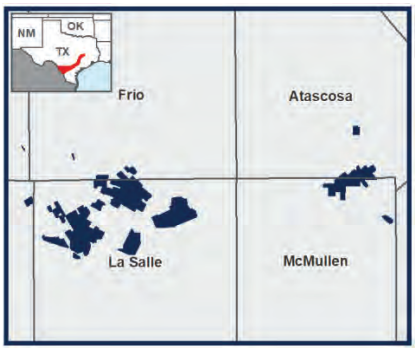
Callon first entered the Eagle Ford Shale in 2019 through its all-stock acquisition of Carrizo Oil & Gas. The company holds about 73,000 net acres producing 27,000 boe/d in the Eagle Ford, according to a recent company presentation.

In an Oct. 5 release, Callon noted the Eagle Ford asset sale increases total cash proceeds from the company's 2021 divestiture program to over $140 million to date, within the guidance range for the year of $125 million to $225 million.

Separately, Callon also announced on Oct. 5 the closing of the acquisition of Primexx. The company paid roughly $788 million in cash and stock for the Primexx leasehold interests and related oil, gas and infrastructure assets in a transaction previously announced in early August.

"We are excited to get to work integrating this high-quality asset base into our Permian Basin operations, overlaying our life of field development philosophy on the acquired multizone resource base," Joe Gatto, president and CEO of Callon Petroleum, commented in the company release.

Callon's Divested Eagle Ford Assets



Source: Callon Petroleum Co.

The acquisition of Primexx, a private oil and gas operator with 35,000 net contiguous acres in Reeves County, Texas, increases Callon's Delaware Basin footprint to over 110,000 net acres. Callon also has an acreage position in the Midland Basin of the Permian.

Gatto added that he expects a seamless transition given Callon's deep subsurface expertise in the Delaware Basin and operational preparation.

During the fourth quarter, Callon intends to operate six drilling rigs and an average of 1.5 completions crews as the current Primexx development program is transitioned to larger scale development with increased project sizes targeting multiple landing zones. In addition to expanding the DUC inventory on the acquired Delaware assets, the company expects to place approximately 18 gross (15 net) wells on production in the quarter, all in the Permian Basin.

"As we look ahead into the coming quarters," Gatto continued, "this latest acquisition provides a meaningful increase in free cash flow generation and is a catalyst for substantially improving the balance sheet."

The Eagle Ford sale, according to the company release, will eliminate approximately $50 million in capex related to continuous drilling obligations over the next two years, allowing for capital redeployment by Callon to higher return projects.

The Eagle Ford transaction is anticipated to close in November.

Daily production for the fourth quarter, including the impact of the pending divestiture, is expected to be 110,000 boe/d to 112,500 boe/d (63% oil) and operational capital in the range of $150 million to $160 million.

For the third quarter, production has been above previous expectations due to strong well performance in the Delaware and Midland basins, the company added in its release. As a result, Callon said it raised third-quarter production guidance to 98,500 boe/d to 99,500 boe/d (64% oil) from a previous range of 95,500 boe/d to 97,500 boe/d (64% oil). Operational capital for the quarter is currently estimated to be $120 million to $125 million.

—Emily Patsy

EAGLE FORD

■ **SilverBow Resources Inc.** closed on Oct. 4 its previously announced all-stock transaction to acquire oil and gas assets in the Eagle Ford Shale from an undisclosed seller.

The aggregate purchase price for the assets was $33 million. The transaction, which had a June 1 effective date, consisted of approximately 1.5 million shares of SilverBow's common stock.

The acquisition, which added 45,000 total net acres to SilverBow's position in the Eagle Ford, exemplified the execution of key company objectives, CEO Sean Woolverton said.

"Namely, we are growing production and EBITDA while living within cash flow, expanding inventory, driving a peer-leading cost structure and further de-levering our balance sheet," Woolverton commented in a company release on Oct. 4.

"We seek to build on this momentum as we close out the year," he added.

SilverBow holds about 155,000 net acres in the Eagle Ford, the company said.

The acquisition adds to SilverBow's gas position in McMullen and Live Oak counties while also adding oil positions in Atascosa, Lavaca and Fayette counties in South Texas. For April, net production was approximately 1,580 boe/d (39% liquids) and net oil production was 569 bbl/d.

■ **Crescent Pass Energy LLC** announced a series of acquisitions on Sept. 28 that marked the privately held E&P's entry into the Eagle Ford.

In a company release, Crescent Pass said it closed on the acquisition of producing assets in the northern area of the Eagle Ford play from Tulsa, Okla.-based **Armor Energy LLC**, as well as three bolt-on acquisitions in the Cotton Valley trend in East Texas.

"We are pleased to have closed on our first Eagle Ford acquisition and look forward to continuing to expand our footprint of high-quality producing assets, both along this trend and across the Lower 48," Crescent Pass CEO Tyler Fenley commented in the release.

Based in Houston, Crescent Pass focuses on the acquisition, integration and optimization of PDP-weighted assets throughout the U.S. The company currently manages a diversified asset base and is financially partnered with **Talara Capital Management**.

"Crescent Pass continues to make accretive acquisitions and improve the existing asset base," Andrew Heyman, partner at Talara Capital Management, commented in the release. "This team is at the cutting edge of applying the latest technologies related to revenue enhancements, cost reductions, and ESG matters."

The transactions on Sept. 28 increased Crescent Pass's corporate footprint to 974 operated wells and net production to approximately 6,400 boe/d, evenly weighted between oil and natural gas, according to the release. The assets are supported by more than 140,000 net HBP acres in various counties across Texas and Louisiana.

PERMIAN BASIN

■ **Viper Energy Partners LP** completed its previously announced acquisition of **Swallowtail Royalties** on Oct. 1 in a cash-and-stock transaction estimated to be worth nearly $500 million.

Based in Midland, Texas, Viper is a limited partnership formed by Permian operator **Diamondback Energy Inc.** to focus on owning and acquiring mineral and royalty interests in oil-weighted basins, primarily the Permian.

In August, Viper announced it had entered an agreement for the acquisition of certain mineral and royalty interests from Swallowtail Royalties LLC and Swallowtail Royalties II LLC, portfolio companies of **Blackstone Energy Partners**, in exchange for 15.25 million common units representing limited partnership interests in Viper and approximately $225 million in cash.

Blackstone Energy Partners was already a shareholder of Diamondback Energy prior to the transaction with its Viper subsidiary.

Viper said it added approximately 2,302 net royalty acres through the deal, primarily in the northern Midland Basin. About 65% of the acreage is operated by Diamondback.

Akin Gump Strauss Hauer & Feld LLP served as legal adviser to Viper for the Swallowtail transaction. **Kirkland & Ellis LLP** was legal adviser to Swallowtail.

■ **Warburg Pincus** and the **Ontario Teachers' Pension Plan** are exploring a sale of Chisholm Energy, an oil and gas exploration and production company focused on the Permian Basin, people familiar with the matter said on Sept. 27.

The two owners are working with an investment bank to run the sale process for Chisholm Energy, according to the sources, who noted the company is expected to attract a valuation approaching $1 billion.

There is no guarantee Chisholm will be sold and one or both owners could retain their holding, cautioned the sources, who spoke on condition of anonymity to discuss private information.

With U.S. crude prices up more than 50% since the start of the year, mergers and acquisitions in the oil sector have flourished. Buyout firms seeking to use the positive market backdrop to offload past investments are helping to fuel the dealmaking boom.

Chisholm Energy was formed in 2016 and has built a portfolio of acreage in the New Mexico portion of the Delaware Basin, according to its website. As part of its backing, Warburg extended the firm a $500 million line of equity to fund acquisitions to the Fort Worth, Texas-based company.

Warburg Pincus and Ontario Teachers declined to comment. Chisholm Energy did not respond to a request for comment.

DENVER-JULESBURG BASIN

■ **Whiting Petroleum Corp.** completed its previously announced exit from the Denver-Julesburg (D-J) Basin on Sept. 27 that included the redetermination of its borrowing base under its revolving credit facility.

The exit, initially announced in July, included the sale of Whiting's D-J Basin position for total cash consideration of $187 million. A private entity agreed to acquire the assets, which span 67,278 net acres in Colorado's Weld County, with daily production of approximately 7,100 boe/d (51% oil).

Concurrent with the sale, Whiting also announced an acquisition of Williston Basin assets that the company said "adjoins and complements" its existing Bakken operations in Sanish Field of North Dakota. The $271 million cash transaction with an undisclosed private company was completed on Sept. 27 as well.

"These two transactions result in a significantly deeper drilling inventory in our key Sanish operating area, while divesting of properties in Colorado that were not going to compete internally for capital," Lynn A. Peterson, president and CEO of Whiting, commented in a July 21 release.

PERMITS

Texas again led the number of newly issued permits for the U.S. with a total of 616, with most of the new permits granted for the Permian Basin. In the Midland Basin portion of the play, there were 71 for Midland County, 42 in Martin County, 32 in Andrews County and 27 in Howard County.

In the Delaware Basin part of the play, there were 57 permits, for Reeves County and 42 in Loving County. The county with the most permits issued was also in the Delaware Basin in New Mexico's Lea County (90). In Eddy County, N.M., there are 39 new permits.

California reported that there were 94 newly issued permits with the bulk granted for Kern County (Chevron Corp. with 30 and 20 for Berry Petroleum Co.). Pennsylvania issued 92 permits for Marcellus Shale-dominant counties. The total count of new permits for the Keystone State more than doubled in September. There were 45 new permits issued in August.

GMT Exploration Co. received 19 permits for Elbert County, Colo., which lies in the southern part of the Denver-Julesberg Basin. According to IHS Markit, the company has planned a Niobrara drilling program with at least 10 extended-lateral tests in Caledonia Field.

New Permits By Operator

Chevron USA Inc.	46
COG Operating LLC	42
GMT Exploration Co. LLC	40
BTA Oil Producers LLC	32
XTO Energy Inc.	28
Endeavor Energy Resources LP	27
Pioneer Natural Resources Co.	27
EOG Resources Inc.	25
BPX Operating Co.	22
Mewbourne Oil Co. Inc.	21

Source: Datalink

New Permits By State

Texas	616
New Mexico	133
California	95
Pennsylvania	92
Oklahoma	88
Colorado	62
Louisiana	44
Kentucky	31
West Virginia	29
Ohio	13
Northern Gulf Of Mexico	12

Source: Datalink

Data from Rextag ENERGY DATALINK

RIG COUNT

The U.S. rig count, according to Enverus Rig Analytics, is up 5% in August and up 118% in the last year.

The most notable recent increases occurred in the Gulf Coast (plus four to 76), the Permian Basin (plus three to 239) and Appalachia (plus three to 45). In August, the largest increases were in the Gulf Coast and Permian, where five rigs were added in each. In September, the U.S. count hit a 2021 high of 626. Oklahoma has added three rigs over the past month. Louisiana has added four since the beginning of September.

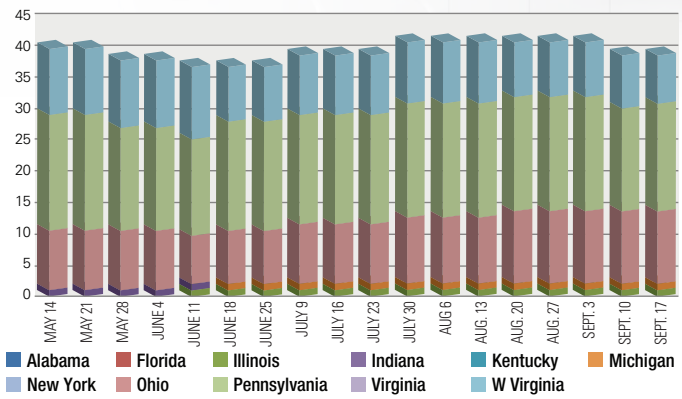
Fourteen offshore Gulf of Mexico rigs shut during Hurricane Ida and have since been returned to service. Personnel were evacuated from 89 production platforms and one rig, according to the Bureau of Safety and Environmental Enforcement.

Eleven dynamically positioned rigs were moved off location out of the storm's projected path as a precaution.

Overall, the oil and gas rig count has increased for 13 months in a row as rising oil prices have prompted drillers to return to the well pad.

Eastern U.S. Rig Count

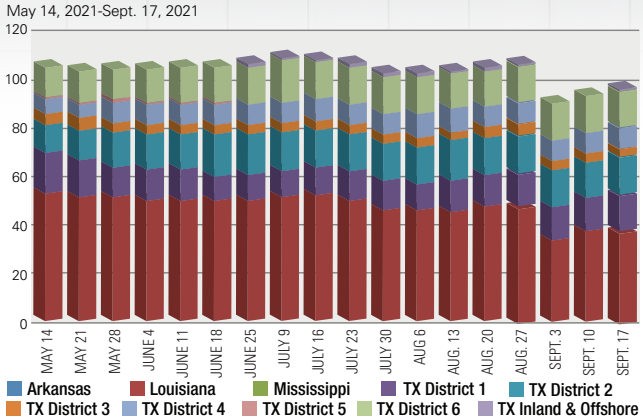
May 14, 2021-Sept. 17, 2021



Source: Baker Hughes Co.

Gulf Coast Rig Count

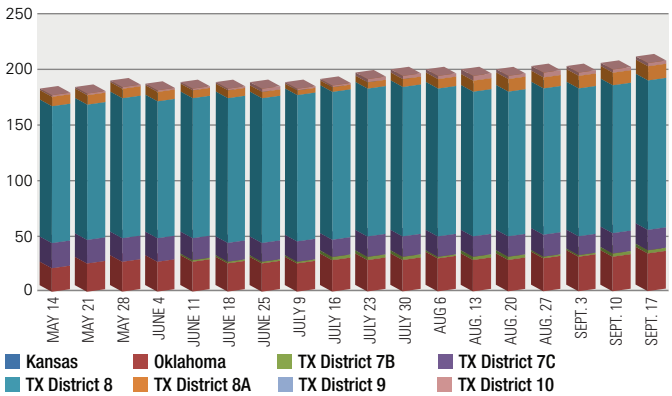
May 14, 2021-Sept. 17, 2021



Source: Baker Hughes Co.

Midcontinent & Permian Basin Rig Count

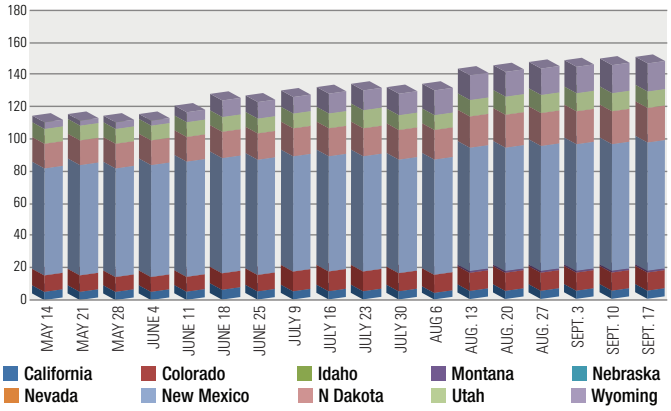
May 14, 2021-Sept. 17, 2021



Source: Baker Hughes Co.

Western U.S. Rig Count

May 14, 2021-Sept. 17, 2021



Source: Baker Hughes Co.

FOCUS ON
Midland Basin

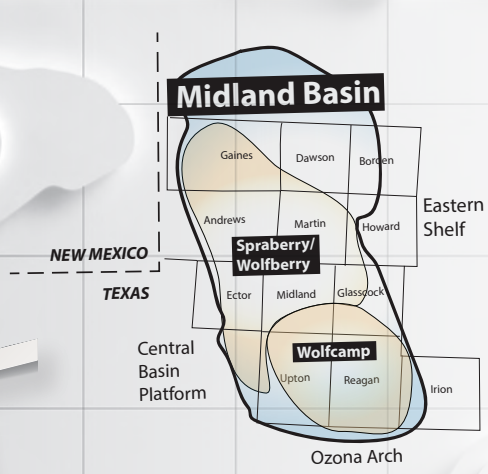
An August 2021 report by the Energy Information Administration said that the Midland Basin accounted for 15% of all U.S. oil production in 2020. In July 2021, according to Enverus, the Midland Basin had 44% of all rigs operating in the Permian Basin and 22% of all rigs operating in the U.S.

The Midland Basin is in the eastern Permian Basin and underlies an area approximately 250 miles wide and 300 miles long, and it includes the West Texas counties of Gaines, Dawson, Martin, Midland, Glasscock, Upton and Reagan, and portions of Borden, Andrews, Howard, Ector and Glasscock and Irion counties.

Plays in the basin have stacked potential with multiple benches. The primary and most productive benches for the Wolfcamp play are Upper (A), Middle (B) and Lower (C, D), and other producing formations include the Spraberry, Dean, San Andres, Atoka and Strawn.

According to the U.S. Geological Survey estimates, the undiscovered continuous hydrocarbon resources of Wolfcamp in the Midland Basin exceed 19 Bbbl of oil, 15 Tcf of gas and 1.5 Bbbl of NGL, which makes it one of the largest hydrocarbon plays in the U.S.

Spraberry and Dean sandstones have produced oil throughout the Midland Basin since the 1940s. The Spraberry Trend has productive areas across 18 counties and contains more than 10 Bbbl of oil.



Top Midland Basin Producing Counties

County	MMbbl of oil	MMcf of gas	Boe production (MMbbl)
Midland	803.19	2,027.47	1,141.10
Martin	559.25	1,048.89	734.06
Upton	420.61	1,458.01	663.61
Glasscock	275.69	1,069.93	454.01
Howard	340.15	623.58	444.08
Reagan	247.49	1,163.11	441.35
Andrews	320.84	535.61	410.11
Ector	193.14	499.02	276.31
Gaines	207.29	184.97	238.12
Irion	87.99	711.19	206.51

Data source: Datalink

Top Cumulative Midland Basin-Wolfcamp Completions

Operator	MMbbl of Oil Equivalent*	Initial Prod. MMcf/d (Gas)	Initial Prod. bbl (Oil)	Texas County	Well	Comp. Date
Laredo Petroleum Inc.	22.6	3.93	1,607	Glass-cock	#2SC Lacy Creek 22-27	Aug. 2014
Sequitur Energy Resources LLC	21.9	3.29	1,650	Reagan	#31HA Turner AR Unit	July 2015
Laredo Petroleum Inc.	21.1	3.69	1,495	Glass-cock	#2NC LPI-Cox 21-Cox Bundy 16	Apr. 2014
Sequitur Energy Resources LLC	19.9	2.07	1,645	Irion	#41U SSH Unit H	Sept. 2014
Sequitur Energy Resources LLC	1.4.6	1.29	1,247	Irion	#04WB Linthicum B	June 2017
COG Operating LLC	13.4	1.15	1,142	Irion	#61U Scott Sugg 5051 East H	Oct. 2013
Pioneer Natural Resources Co.	13.1	2.51	883	Irion	#711HU Farmar AH Pooled Unit	Aug. 2017
Laredo Petroleum Inc.	12.9	2.28	915	Irion	#714HU 7C AG Pooled Unit	Apr. 2017
FDL Operating	12.8	1.14	1,099	Reagan	#08HK Turner AR Unit B	Dec. 2015
Laredo Petroleum Inc.	12.8	2.10	936	Irion	#4323GH University East	Dec. 2014

*Wolfcamp A-D
Data source: Datalink
Last production reported: April 2021

Top Midland Basin Operators

Operator	Boe (MMbbl)
Exxon Mobil Corp.	1,822.15
ConocoPhillips Co.	1,549.98
Pioneer Natural Resources Co.*	1,277.86
Apache Corp.	522.25
Occidental Petroleum Corp.	331.32
Laredo Petroleum LLC	194.12
Endeavor Energy Resources	191.76
Chevron Corp.	184.06
SM Energy Co.	162.41
CrownQuest Operating LLC	124.11

* Includes acquisition of Parsley Energy Inc.
Counties: Borden; Crockett; Dawson; Martin; Midland; Upton; Reagan; Glasscock, portions of Andrews; Gaines; Ector; Terry; Lynn; Howard and Irion
Data source: Datalink

Data from Rextag ENERGY DATALINK

INTERNATIONAL HIGHLIGHTS

A forecast by Det Norske Veritas (DNV), an independent forecaster of developments in global energy systems, said that even if all electricity was "green" from this day forward, the world will still fall short of achieving the 2050 net-zero emissions ambitions of the COP21 Paris Agreement.

Electrification is on course to double in size within a generation, and renewables are already the most competitive source of new power. However, DNV's forecast shows global emissions will be reduced only 9% by 2030, with the 1.5 C carbon budget agreed by global economies emptied by then.

Electrification plans in most countries include electric cars, buses and transit vehicles as well as new charging stations. Some of the more difficult transitions are also planned for manufacturing as well as electrifying heavy-duty trucking. Some experts believe that the sheer vehicle weight will make it physically impossible.

Experts at the University of California, Berkeley, calculate that by 2050, the U.S. will need almost 90% more electricity than it did in 2018 in a scenario where all new passenger vehicles sold by 2030 are electric.

Electrification will also require more production of rare earth elements for electronic devices and rare earth metals including neodymium, which China controls 90% of the metal's supply.

-Larry Prado

1 *Cuba*

Melbana Energy has spud exploration well #1-Alameda in Cuba's Block 9. The venture will test three separate targets with a combined prospective resource (best estimate) of 141 MMbbl oil. According to Melbana, this is the first well in a two-well drilling campaign, which is being funded 85% by **Sonangol** (via a farm-in) and 15% by Melbana. Block 9 is estimated to contain 14.8 Bbbl of oil-in-place with prospective resources of 676 MMbbl (best estimate). A second planned exploratory in Block 9, #1-Zapatoi, is in Cuba's oldest oil field, Motembo, which contains light oil. There are no previous wells that have drilled deep enough to test the Zapato structure. Melbana is based in Melbourne, Victoria, Australia.

2 *Guyana*

Exxon Mobil Corp. reported a discovery at #1-Pinktail in Stabroek Block, offshore Guyana. The well encountered 220 ft of net pay in high-quality, hydrocarbon bearing sandstone reservoirs. Additional completion details are not available. The #1-Pinktail is southeast of the Liza Phase 1 development project and a recent completion, #1-Yellowtail. The Irving, Texas-based company also announced appraisal results from the Turbot prospect. The #2-Turbot hit 43 ft of newly identified net pay in a high-quality, hydrocarbon bearing sandstone reservoir. The reservoir is separate from the 75 ft of oil-bearing sandstone reservoir pay encountered in the original #1-Turbot discovery. According to the company, this follows the additional pay in deeper reservoirs encountered at the previously announced Whiptail discovery. Exxon Mobil is the operator and holds 45% interest in Stabroek Block with partners **Hess Corp.**, with 30%, and **China National Offshore Oil Corp.**, with 25% interest.

3 *Guyana*

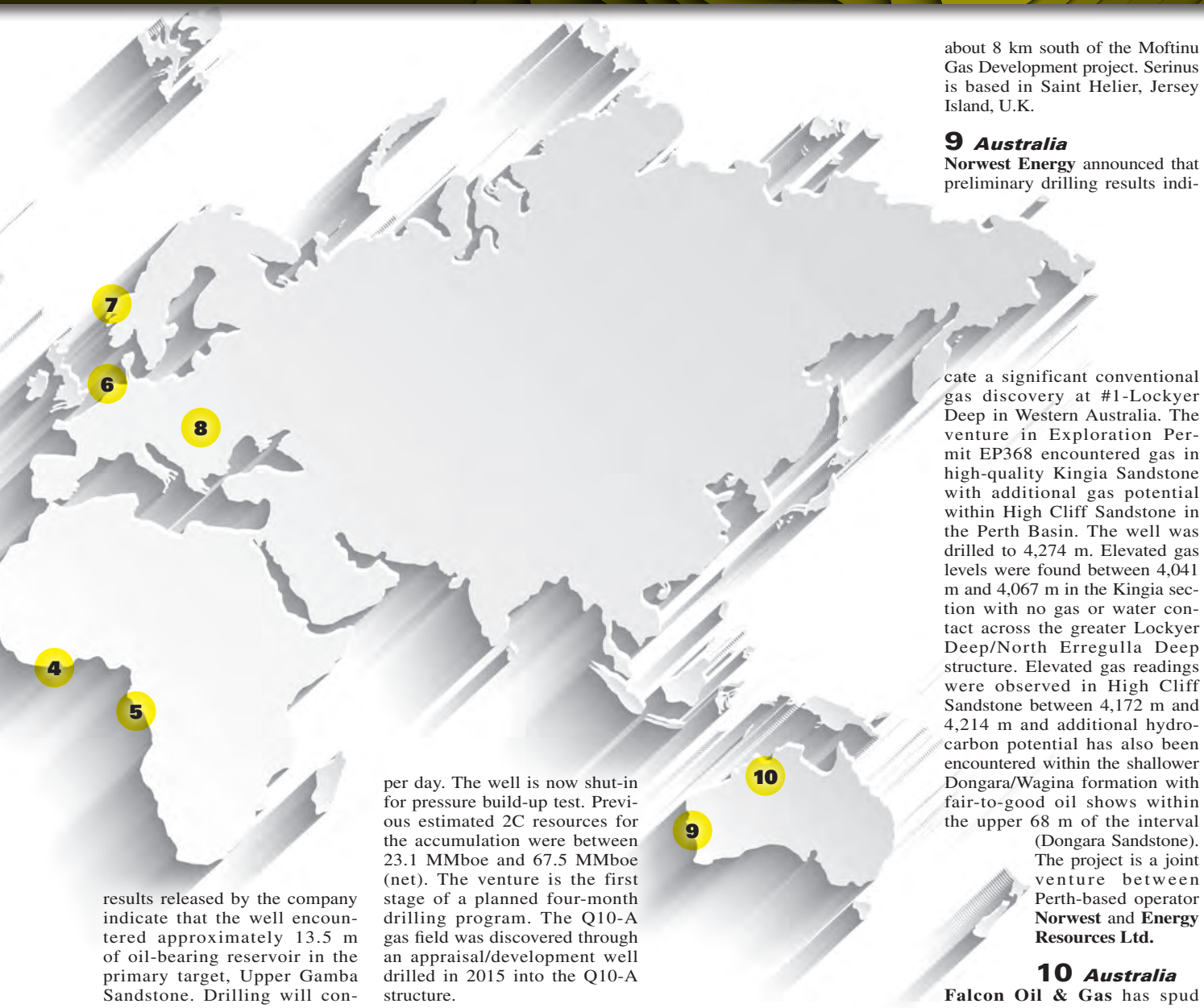
Exxon Mobil Corp. announced a discovery at #1-Whiptail in Stabroek Block, offshore Guyana. The well hit 246 ft of net pay in high-quality, oil bearing sandstone reservoirs. The Whiptail discovery is southeast of #1-Uaru and west of Yellowtail Field. Area water depth is 5,889 ft. Exxon Mobil is also underway at #2-Whiptail, which has encountered 167 ft of net pay in high-quality, oil bearing sandstone reservoirs. Drilling continues at both wells to test deeper targets, and results will be evaluated for future development. Exxon Mobil is planning to bring six projects online by 2027 with the potential for up to 10 projects to develop its current recoverable resource base.

4 *Ivory Coast*

Eni announced a major oil discovery in offshore Ivory Coast's Block CI-101 at the Rome-based company's Baleine prospect. The well, #1x-Baleine, found 40° API oil in two different stratigraphic levels (Santonian and Cenomanian/Albian age). An evaluation program will assess the upside potential of the overall structure that extends into Block CI-802, also operated by Eni. The well is in about 1,200 m of water and was drilled to 3,445 m. The lower Cenomanian/Albian level shows discrete-to-good reservoir characteristics and has been successfully production-tested. The potential of the discovery is preliminarily estimated at between 1.5 Bbbl and 2 Bbbl of oil in place and between 1.8 Tcf and 2.4 Tcf of associated gas. The #1x-Baleine is the first exploration well drilled by Eni in the Ivory Coast. Rome-based Eni owns a participating interest in four other blocks in the Ivorian deep water: CI-205, CI-501, CI-504 and CI-802.

5 *Gabon*

Panoro Energy announced a discovery at offshore Gabon's Hibiscus North exploration well, #1-DHBNM, in the Dussafu Marin Permit. Initial



results released by the company indicate that the well encountered approximately 13.5 m of oil-bearing reservoir in the primary target, Upper Gamba Sandstone. Drilling will continue through the secondary Dentale target to a total depth of approximately 3,500 m. Well logging and evaluation will begin when the lower target is reached. Panoro's headquarters are in London.

6 *Netherlands*

Initial drilling results were announced by London-based **Kistos** from an appraisal campaign in offshore Netherlands blocks Q07 and Q10 in the North Sea. The company was targeting Vlieland Sandstone Q07 and Q10 blocks. The well, #04 A Q10 A, encountered Vlieland at a depth of 1,562 m. The company drilled an 825-m horizontal section. It was tested flowing at a maximum stabilized rate of 3,200 bbl of 33° API oil per day. The well is now shut-in for pressure build-up test. Previous estimated 2C resources for the accumulation were between 23.1 MMboe and 67.5 MMboe (net). The venture is the first stage of a planned four-month drilling program. The Q10-A gas field was discovered through an appraisal/development well drilled in 2015 into the Q10-A structure.

7 *Norway*

DNO Norge spud exploration well #1-Gomez in offshore Norway's PL006C license. The planned depth of the well is approximately 3,300 m and is targeting Paleocene formations. The well is one of three exploration wells scheduled in 2021. The first well on the prospect, #1 Rover Nord, encountered a possible commercial discovery. Following #1-Gomez, the third exploration well, #1-Mugnetind, is expected to spud in the fourth quarter of this year. Pre-drill estimates range from 26 MMbbl to 80 MMbbl of oil equivalent. The well is close to existing infrastructure, including the Tor and Ekofisk complexes. Oslo-based DNO Norge holds a 65% operated interest in the license with the balance held by **Aker BP**.

8 *Romania*

Serinus Energy announced that exploration well #1-Sancrail has discovered gas. Continuous formation gas shows were recorded over 20 m of gross pay over four Pliocene sand intervals at 855-875 m. According to the company, the measured total gas over the interval ranged from 5.5% to 11.1% with an estimated average porosity of between 23% and 27%. The well was perforated in three zones before completion, but they have not been able to record gas flow from each selected zones. The well will be suspended pending further technical studies to better understand and evaluate the Sancrai structure. The test site is about 8 km south of the Moftinu Gas Development project. Serinus is based in Saint Helier, Jersey Island, U.K.

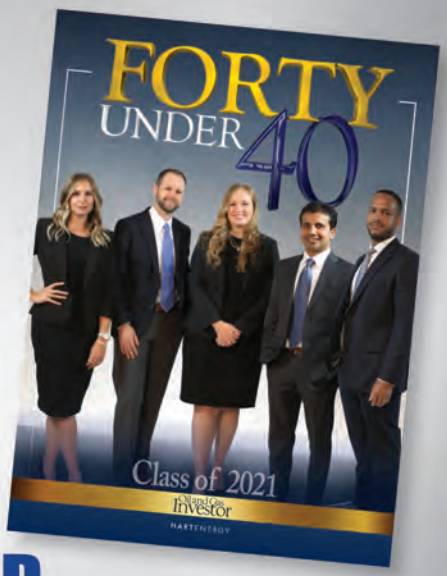
9 *Australia*

Norwest Energy announced that preliminary drilling results indicate a significant conventional gas discovery at #1-Lockyer Deep in Western Australia. The venture in Exploration Permit EP368 encountered gas in high-quality Kingia Sandstone with additional gas potential within High Cliff Sandstone in the Perth Basin. The well was drilled to 4,274 m. Elevated gas levels were found between 4,041 m and 4,067 m in the Kingia section with no gas or water contact across the greater Lockyer Deep/North Erregulla Deep structure. Elevated gas readings were observed in High Cliff Sandstone between 4,172 m and 4,214 m and additional hydrocarbon potential has also been encountered within the shallower Dongara/Wagina formation with fair-to-good oil shows within the upper 68 m of the interval (Dongara Sandstone). The project is a joint venture between Perth-based operator **Norwest** and **Energy Resources Ltd.**

10 *Australia*

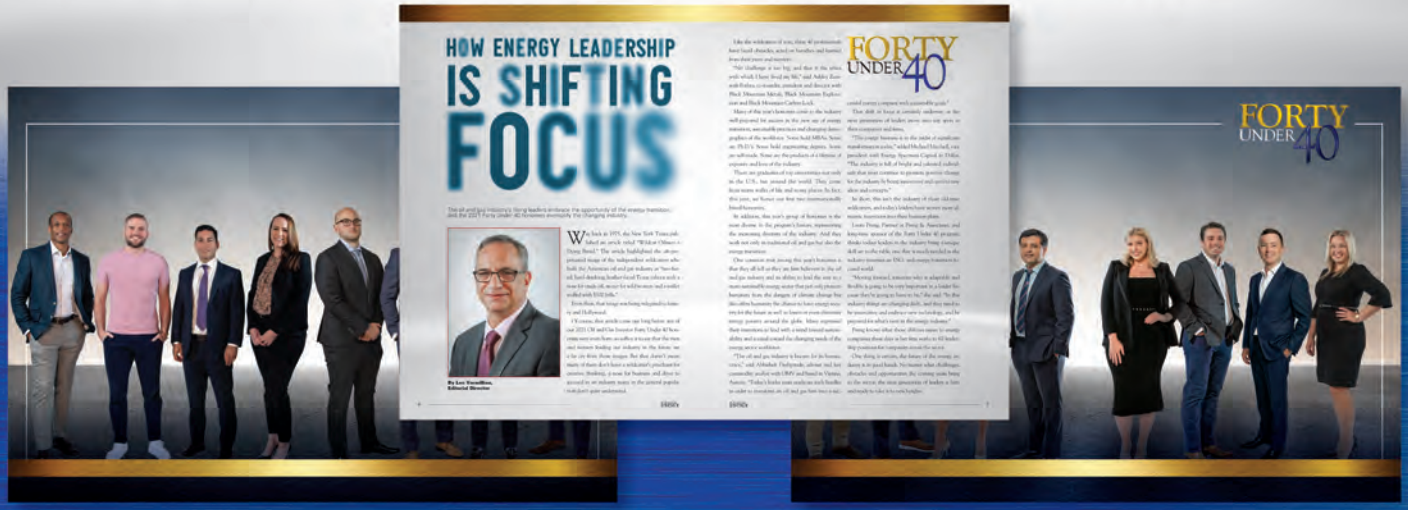
Falcon Oil & Gas has spud #1-Velkerri 76 S2 in the Beetaloo Sub-Basin, Northern Territory, Australia. The venture is targeting the Velkerri play along the southeastern flank of the Beetaloo Sub-Basin and is predicted to be in a liquids-rich gas window. Denver-based Falcon plans to acquire core and log data and conduct a fracture injection test data across the formation to assess hydrocarbon maturity, saturation and reservoir quality. The venture also seeks to get further information on the areal distribution of Velkerri and collect data for potential future horizontal drilling, completion, stimulation and production testing, including the ability to flow liquids-rich gas. Partner in the joint venture is **Origin Energy**.

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

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount ($MM)	Comments
EQT Corp.	NYSE: EQT	Pittsburgh	$518.6	Priced an underwritten public offering of about 25.9 million shares of its common stock by certain shareholders at a price to the public of $20 each. Such selling shareholders, who had received the shares as a part of the company's acquisition of **Alta Resources Development LLC**'s upstream and midstream subsidiaries, have granted the underwriters a 30-day option to purchase roughly up to an additional 3.9 million shares. EQT will not sell any shares of its common stock in the offering and will not receive any proceeds from the sale. **Barclays** and **J.P. Morgan** are joint bookrunning managers.
Sierra Energy Holdings LLC	N/A	Dallas	$500	Received equity commitments from **Providence Energy Ltd.** and funds managed by **Oaktree Capital Management LP** as part of the formation of the new mineral and royalty acquisitions company.
Sabalo Energy II LLC	N/A	Corpus Christi, Texas	$300	Closed an equity commitment from **EnCap Investments LP**. Proceeds will be used to build, operate and generate significant cash flow from a portfolio of upstream assets located in premier U.S. basins. **Vinson & Elkins LLP** was legal counsel to EnCap, and **Bracewell LLP** served as legal counsel to Sabalo.
Easton Energy LLC	N/A	Houston	$245	Received a preferred equity investment of up to $245 million from **Global Infrastructure Partners** through Global Infrastructure Partners Capital Solutions Fund II, part of GIP's credit platform. Proceeds will be used to fund the organic growth of Easton's asset base of transportation, storage and processing of NGL, refined products and petrochemicals along the U.S. Gulf Coast and other strategic growth opportunities, with a tailored delayed draw structure to support both existing and future growth projects. **Evercore** was financial adviser to Easton, and the company received legal counsel from **Willkie Farr & Gallagher**. **Latham & Watkins** provided legal counsel to GIP.
Hess Midstream LP	NYSE: HEM	Houston	$195	Priced an underwritten public offering of 7.5 million Class A shares representing limited partner interests by a subsidiary of **Hess Corp.** and an affiliate of **Global Infrastructure Partners** at a public offering price of $26 each. The offering was upsized from the previously announced 6 million shares. The selling shareholders also have granted a 30-day option to purchase up to roughly 1.1 million additional shares at the public offering price less underwriting discounts and commissions. Hess Midstream will not receive any proceeds from the sale of shares in the offering.
Freehold Royalties Ltd.	TSX: FRU	Calgary, Alberta	CA$173	Completed a bought deal equity financing, issuing about 19.1 million subscription receipts at a price of $9.05 per subscription receipt, including the full exercise of the overallotment option granted to the underwriters. The bought deal offering was completed through a syndicate of underwriters led by **RBC Capital Markets** and **TD Securities Inc**. Proceeds will be held in escrow pending the completion of the U.S. royalty transaction.
Topaz Energy Corp.	TSX: TPZ	Calgary, Alberta	CA$131.7	Entered an agreement with a syndicate of underwriters co-led by **Peters & Co. Ltd.** and **National Bank Financial Inc.**, pursuant to which the underwriters have agreed to purchase for resale to the public, on a bought-deal basis, 7.7 million common shares at $17.10 each. Underwriters will have an option to purchase up to an additional 15% of the common shares issued to cover over-allotments. Proceeds from the equity financing will be used to fund a portion of the acquisition of a newly created 5% gross overriding royalty interest on **Whitecap Resources Inc.**'s working interest in the Weyburn Unit.
Magnolia Oil & Gas Corp.	NYSE: MGY	Houston	$122.9	Priced an underwritten block trade of 7.5 million shares of Class A common stock by certain affiliates of **EnerVest Ltd**. In connection with the offering, Magnolia agreed to purchase from the selling stockholders 3 million shares of the company's Class B common stock at a price per share equal to the price per share at which the underwriter purchases shares of the company's Class A common stock in the offering. **J.P. Morgan Securities LLC** is the sole bookrunning manager.
EnerVenue Inc.	N/A	Fremont, Calif.	$100	Completed a Series A funding round led by **Schlumberger New Energy** and accompanied by **Saudi Aramco Energy Ventures**. Proceeds will be used by EnerVenue, the first company to bring metal-hydrogen batteries to the clean energy revolution, to build a gigafactory in the U.S., accelerate R&D efforts and expand its sales force as it scales its distribution capabilities with strategic partnerships similar to one recently announced with Schlumberger New Energy. **Barclays** was sole placement agent. **Rimon** served as legal adviser.

Company	Exchange/ Symbol	Headquarters	Amount ($MM)	Comments
InPlay Oil Corp.	TSX: IPO	Calgary, Alberta	CA$10	Entered a bought deal agreement with a syndicate of underwriters led by **Eight Capital** and **ATB Capital Markets,** pursuant to which the underwriters have agreed to purchase for resale to the public, on a bought deal basis, 8.3 million subscription receipts of InPlay at a price of $1.20 each. Underwriters will have an option to purchase up to an additional 15% of the subscription receipts issued to cover overallotments. Proceeds will be used to fund part of the cash portion of the company's acquisition of **Prairie Storm Resources Corp.**
DEBT				
Chevron Corp.	NYSE: CVX	San Ramon, Calif.	$2,000	Announced the pricing terms of its 23 separate offers to purchase for cash up to $2 billion aggregate principal amount of outstanding notes. **J.P. Morgan Securities LLC** and **Barclays Capital Inc.** are the lead dealer managers for the offers. **BNP Paribas Securities Corp.**, **Standard Chartered Bank** and **SG Americas Securities LLC** are co-dealer managers. **D.F. King & Co. Inc.** is the tender agent and the information agent.
Lightsource BP	N/A	London	$1,800	Secured a new credit and trade finance facility with funding provided by 10 top tier global financial institutions. Proceed will be used to fund a new global growth strategy of developing 25 GW of solar by 2025.
Cenovus Energy Inc.	TSX: CVE	Calgary, Alberta	$1,250	Completed a public offering in the U.S. of senior notes, consisting of $500 million of 2.65% senior unsecured notes due 2032 and $750 million of 3.75% senior unsecured notes due 2052. Proceeds will be used to partially finance the repurchase of certain of the company's outstanding senior notes pursuant to previously announced tender offers. **J.P. Morgan Securities LLC**, **BofA Securities Inc.** and **MUFG Securities Americas Inc.** were joint bookrunning managers. **BMO Capital Markets Corp.**, **Scotia Capital (USA) Inc.**, **Mizuho Securities USA LLC**, **CIBC World Markets Corp.**, **Goldman Sachs & Co. LLC**, **RBC Capital Markets LLC**, T**D Securities (USA) LLC**, **ATB Capital Markets Inc.**, **SMBC Nikko Securities America Inc.**, **Desjardins Securities Inc.** and **Wells Fargo Securities LLC** were additional advisers.
The Williams Cos. Inc.	NYSE: WMB	Tulsa, Okla.	$1,250	Priced a public offering of $600 million of 2.6% senior notes due 2031 at a price of 100.973% of par and $650 million of 3.5% senior notes due 2051 at a price of 99.833% of par. The new 2031 notes are an additional issuance of the $900 million aggregate principal amount of Williams' 2.6% senior notes due 2031 issued in March and will trade interchangeably with such notes. Proceeds will be used for general corporate purposes, which may include, together with cash on hand, repaying the $1.25 billion aggregate principal amount of our outstanding 3.6% senior notes due 2022. **Barclays Capital Inc.**, **SMBC Nikko Securities America Inc.**, **Truist Securities Inc.** and **Wells Fargo Securities LLC** are joint bookrunning managers.
Cheniere Energy Partners LP	NYSE American: CQP	Houston	$1,200	Priced an offering of senior notes due 2032, which will bear interest at a rate of 3.25% per annum and will mature January 2032. The 2032 notes were priced at par. Proceeds will be used, together with cash on hand, to refinance all of Cheniere Partners' outstanding senior notes due 2026 and a portion of **Sabine Pass Liquefaction LLC**'s senior notes due 2022 and to pay fees and expenses in connection with the refinancing.
Surge Energy US Holdings Co.	N/A	Houston	$860	Completed an amendment to the existing amended and restated revolving credit facility that increases the elected commitments by $100 million from $850 million and extends the maturity of the facility from April 2023 to October 2025. The facility's borrowing base was also increased to $1.2 billion from $850 million.
Flowserve Corp.	NYSE: FLS	Dallas	$800	Amended and restated its revolving credit facility and added a new $300 million term loan facility with **Bank of America NA** and certain other lenders. The senior credit facility includes a sustainability-linked option, which provides the opportunity to further lower the company's overall borrowing costs, based upon an agreement with **BofA Securities Inc.** as sustainability coordinator, regarding certain Flowserve ESG targets. The revolving credit facility is available for general corporate purposes, and the term loan facility's proceeds are intended to refinance upcoming debt maturities. BofA Securities was joint lead arranger and joint book-runner. **JPMorgan Chase Bank NA**, **Mizuho Bank Ltd.** and **BNP Paribas Securities Corp.** also served as joint lead arrangers and joint bookrunners.
New Fortress Energy Inc.	NASDAQ: NFE	New York	$725	Executed a term loan facility secured by eight company vessels with an initial borrowing of $430 million. The shipping facility has a three-year term, and loans issued under the facility will bear interest an annual rate equal to LIBOR plus 3%, subject to a 0% LIBOR floor.

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Helmerich & Payne Inc.	NYSE: HP	Tulsa, Okla.	$550	Completed a private offering of 2.9% senior notes due 2031. Proceeds will be used, plus cash on hand, to redeem and retire all of the company's outstanding 4.65% senior notes due 2025.
Weatherford International Plc	NASDAQ: WFRD	Houston	$500	Priced an offering of 6.5% senior secured first lien notes due 2028 at an issue price of 100%. Proceeds will be used with cash on hand to redeem all of its 2024 secured notes on Sept. 30 and pay-related fees and expenses.
Bonanza Creek Energy Inc.	NYSE: BCEI	Denver	$400	Priced a private placement to eligible purchases of new 5% senior notes due 2026. Proceeds will be used, together with cash on hand, to repay all borrowings outstanding under the **CPPIB Crestone Peak Resources America Inc.** credit facility, to repay borrowings under Bonanza Creek's credit facility and for general corporate purposes. The notes will be subject to a "special mandatory redemption" in the event that the transactions contemplated by the **Extraction Oil & Gas Inc.** merger agreement and the Crestone Peak merger agreement are not consummated.
Athabasca Oil Corp.	TSX: ATH	Calgary, Alberta	$350	Announced private placement offering of 350,000 units. Each unit will consist of $1,000 principal amount of senior secured second lien notes due 2026, which bear interest at 9.75% per annum, and one five-year warrant to purchase 227 common shares at an exercise price of $0.9441 per warrant share. Proceeds will be used along with cash on hand to redeem its $450 million aggregate principal amount of 9.875% senior secured second lien notes due 2022.
PDC Energy Inc.	NASDAQ: PDCE	Denver	$200	Gave notice to **U.S. Bank National Association** that it will redeem $200 million in aggregate principal amount of its 6.125% senior notes due 2024. The redemption price for the notes will be equal to 101.531% of the principal amount thereof plus accrued and unpaid interest.

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This index refers to the pages of the story or news item in which the company is first mentioned. Advertisers are in boldface.

NO SMALL SPILL

LESLIE HAINES, EXECUTIVE EDITOR-AT-LARGE

It's every CEO's nightmare: an oil spill offshore California. This one stems from a pipeline leak from Beta Field. Now, ugly tar balls are washing up on the famous beaches of Orange County. Public perception of the industry takes another bad hit. As spills go, it is a relatively small one, but for the concerns it raises, it is huge.

The concerns: public opinion, the role of small-cap companies versus Big Oil and the after-effects if the Bigs divest assets to smaller-cap E&Ps.

Once again, the anti-fossil fuel crowd has been handed a gift, another powerful yet unexpected arrow for their quiver. When an incident like this happens every year or two, it cancels all the good will, good works and PR the industry has delivered during the past few years. Education is vital, but it seems to be ineffective as far as changing general public opinion to the good.

This tragic accident, a ruptured offshore oil pipeline in federal waters, was apparently not the fault of owner Amplify Energy Corp., but now the micro-cap company, with a market cap of about $130 million, is under siege from every direction and will live with the damage for years. The lawyers seeking damages are eagerly lined up, representing enviros, the state of California and dismayed investors who saw Amplify's stock plunge.

This incident reinforces the public's negative perception about the industry, especially about pipelines, which are already suffering from increasing opposition for a variety of reasons. Perception is everything, but alas, perception is in many ways wrong and usually obscures most of the facts. It doesn't help matters that in the popular media, erroneous headlines blamed that old bugaboo, Big Oil.

Those of us knowledgeable about the business have a narrow definition of Big Oil; the media lumps all companies together. We in the investing world or the oil and gas industry get so wrapped up in our daily stuff that we forget most people have never heard of any oil company below the size of Chevron. What is a Devon Energy or an EOG, much less a company called Amplify?

A small company by industry standards, Amplify has about 200 employees. It owns operated and nonop interests in about 2,400 gross wells, spread widely through four plays besides offshore California's federal waters: Oklahoma, the Rockies, Eagle Ford and Haynesville/Bossier.

The company has a bit of a checkered past that it's been trying to rise above by paying down debt and increasing free cash flow. It was formed in 2014 through the merger of two MLPs that had exited bankruptcy, Memorial Production Partners LP and Midstates Petroleum Co.

We know that M&As and asset sales are a vital part of the industry's ability to constantly renew itself. That is the case with Beta Field. Memorial Production Partners acquired a 51% interest in Beta in 2012 from Rise Production Partners. (The field had been discovered years ago by Shell.) In 2015 Memorial acquired most of the rest.

Due to ESG pressures today, more large E&P companies will be unloading some or all of their lower-performing assets to smaller firms to improve their emissions profile and/or returns and to focus on higher-impact projects. This makes sense and is efficient. However, who are the buyers? What are their technical strengths and financial capabilities, to monitor, prevent, respond and mitigate when accidents such as this one happen?

Amplify reported $153 million of revenue in the second quarter but lost $54 million. Production was 25,000 boe/d. During the quarter, it had recompleted a well and was doing two sidetracks at Beta Field in a bid to improve the field's performance. The pipeline rupture was not its fault, but the stock price cratered, and litigation and controversy will now dog the company for months.

California enviros and politicians are calling for no more drilling, when in fact this incident is not caused by drilling, but then the public always confuses drilling with production and midstream operations.

But an accident is unforeseen. Amplify and other experts believe the pipeline was damaged by an anchor from a ship traveling through the area. The crowded sea lane is full of traffic, even more so than usual, as dozens of cargo ships are parked off Long Beach Harbor waiting to unload—a symbol of the global disruptions in the supply chain that we've heard so much about lately.

Small independents have always existed alongside the "household names" and always will. They grow by acquisition as much as by drilling. The small E&P company is a special breed, generally nimble, creative and tenacious. One can question the degree that a small-cap can use the latest high-tech artificial intelligence for preventive maintenance and real-time monitoring to identify leaks or other problems. Now, the proper response and the timely cleanup will hold the industry's attention.

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