Oil and Gas Investor

FEBRUARY 2021

The oilfield-services sector retools strategies as field activity retracks.

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OFS IN TRANSITION / PE'S TECH PIVOT / NATGAS RISING / OUTLOOK ROUNDTABLE

FEBRUARY 2021/VOLUME 41/NUMBER 2

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Oil and Gas Investor

FEBRUARY 2021/VOLUME 41/NUMBER 2

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ABOUT THE COVER: Oilfield services companies face a stiff headwind for profitability as producers gear down capex to reflect a lower demand scenario and investors' expectations for cash returns. *Photo courtesy of Canary LLC.*

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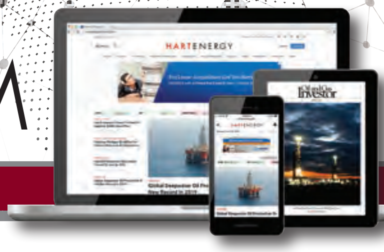

LATEST CONTENT

Apache, Total Hit Oil Pay Offshore Suriname
By Velda Addison, Group Senior Editor
The latest oil find by Total and partner Apache follows discoveries at Maka Central, Sapakara West and Kwaskwasi.

France's Total Leaves API Citing Climate, Political Differences
By Emily Patsy, Group Managing Editor
Total's departure will mark the first major energy company to quit API, which is the largest U.S. oil and gas lobby and the primary trade group for the industry.

Norway's Equinor Selected for Largest-ever US Offshore Wind Award
By Emily Patsy, Group Managing Editor
The contract awarded to Equinor to provide generation capacity to New York with renewable power is set to position the Empire State as an offshore wind industry hub.

Top 12 Recent Gulf of Mexico Discoveries
By Larry Prado, Activity Editor
January 2021: Mississippi Canyon Block 503 discovery: 2,930 bbl of oil, 8.64 MMcf of gas per day.

Wind Power Overtakes Coal in Texas Electricity Generation
By Justin Jacobs, Financial Times
Renewables capacity is surging in Texas, which is largely considered the heartland of fossil fuels in the U.S.

ONLINE EXCLUSIVES

Eyeing Exploration, Analysts Spotlight Wells to Watch
By Velda Addison, Group Senior Editor
Though oil and gas companies' plans are still developing, the Americas are expected to dominate high-impact exploration activity.

Fossil Fuels' Place in a Low-Carbon Future
By Joseph Markman, Senior Editor
Companies have made moves toward net-zero operations, but the oil and gas industry still struggles to be liked, executives say.

Pioneer's Sheffield: Focus Remains on Permian Basin Flaring
By Velda Addison, Group Senior Editor
With new pipelines online or under construction, Permian Basin operators, regulators and other industry players keep flaring reduction on the agenda.

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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By Jessica Morales, Director of Video Content

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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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What's Trending

1. Equinor Considers Selling Bakken Shale Assets
2. Oil and Gas Investor Spotlight: Barnett Shale, PDP King
3. Chesapeake Energy Bankruptcy Plan Giving Lenders Control Approved by US Judge
4. Apache, Total Hit Oil Pay Offshore Suriname
5. US Shale Producers Lock in Future Sales as Oil Prices Hit One-year High

CONFERENCES

VIRTUAL EXECUTIVE OIL CONFERENCE

After the virtual **Executive Oil Conference** in late January, Hart Energy continues its award-winning programs with a mix of virtual and live events throughout 2021. Safety remains our top priority; read what we're doing to ensure security at **HartEnergyConferences.com**.

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DON'T GET TOO COMFORTABLE AT $50 OIL

STEVE TOON,
EDITOR-IN-CHIEF

For all the reasons to say a hard goodbye to 2020 and a hopeful hello to 2021, the dramatic saga of WTI racing to the bottom and below and back to a respectable $50 again is on the short list of hoorays. It's just enough to make a whole host of operators breathe a collective sigh of relief and revisit those early year capex projections.

Only don't get too comfortable at $50 oil just yet.

The global oil industry can thank OPEC—and Saudi Arabia specifically—for this latest uplift in the oil markets. The effect of earlier OPEC production cuts along with the promise of an imminent vaccine for the COVID-19 supply destruction problem sent prices off the $40 floor and closer to $50 by year-end. Then just when OPEC-plus-Russia decided to begin loosening production constraints by 500,000 bbl/d, potentially softening prices, the Saudis surprisingly announced they would voluntarily and without conditions pull an additional 1 MMbbl off the market for February and March.

Who doesn't love that? Hello $50, finally again. Pull those rigs out of the mothballs.

But hold the capex increases. A word of warning: Depending on OPEC and Russia for your profit margins is a risky business. They don't have your best interests at heart.

Former Parsley Energy CEO Matt Gallagher said it best in the company's fourth-quarter 2019 conference call a year ago in February: "Allocating growth capital into a global market with artificially constrained supply is a trap our industry is falling into time and time again."

A trap. That was merely two weeks before OPEC and Russia got cantankerous last March and subsequently flooded the market, sending prices crashing. That "artificially constrained supply" is once again the problem. It may always be the problem.

Helima Croft is head of global commodity strategy and MENA research for RBC Capital Markets. In a note following Saudi's surprise announcement, she said Saudi prince Abdulaziz pulled "a big boss move" with the announcement of a gift to the oil market while the world is facing demand uncertainty due to expanding COVID-19 shutdowns. This even while Russia was allowed to increase supply. However, she added, "We suspect that there may be other intended recipients and that today's action may be designed to serve broader strategic priorities."

Which means Saudi can add supply as quickly as it pulled it when it fits their strategic priorities. What happens after March? "This rally has got legs," said Rystad's head of oil markets Bjornar Tonhaugen, "but the real question is when will it run out of steam?"

Despite the upward trend of WTI in recent weeks, American producers seem to be holding their enthusiasm to bank on the bigger number. In a survey conducted by the Dallas Federal Reserve of oil and gas companies in December, almost three-quarters responded they were using a price between $40/bbl and $46/bbl for capital planning this year, with $45 at the median. That's a conservative number to plan around, but lower would be better. Just to be safe.

"Most companies are starting to budget and tailor their programs around lower prices than what they did a few years ago," Capital One analyst Phillips Johnston said an interview last fall. "The industry has been subsidized by OPEC cuts for a while now, and these companies are starting to get the message and are retooling their investments for lower mid cycle prices."

Driving down the cost structure to weather price shocks is critical to long-term survival—along with aggressive debt reduction. Johnston views $45 as that sweet spot, as any sustained price below that diminishes the investment needed to keep global production level, he said.

In December, BloombergNEF reported U.S. oil producers in 2020 reduced breakeven costs by $11.50 per barrel compared to the previous year. "BloombergNEF estimates producers lowered their average breakevens by almost 20%—from $56.50 per barrel in 2019 to $45 today," the firm said. "In the most productive oil regions (the core of the Permian and Eagle Ford plays), breakevens declined from an average of $44 per barrel to $36.50."

Raymond James analyst Marshall Adkins, in August when WTI stood at $39, predicted $50 oil by year-end, and it came true. He also predicted $80-plus by year-end 2021, largely predicated on post-COVID-19 world demand and OPEC constraint. That would be nice, but that prediction could unravel for both reasons stated. The price could just as easily see $35 again. If COVID-19 continues to squash demand. If Iran's barrels come back on the market. If OPEC and Russia decide to open the spigots just a tad more.

$50 is nice for now, but as the Saudi prince-in-charge noted, it is a gift. And that gift can be withdrawn any time it's in Saudi Arabia's strategic interest. Plan accordingly.

HARD, CLASSIC ROCK

DARREN BARBEE,
SENIOR EDITOR

The Golden Age of shale M&A was a kind of swinger's party for oil and gas prospectors.

Private equity firms, (thousands of) lawyers and public companies traded money for shale. Afterward, any actual parties happened elsewhere, out of earshot of those public companies.

Now, shale seems to have entered a slightly less lustrous Bronze Age. Brought on by the cabin fever of coronavirus lockdowns and the languishing market caps of public E&P companies, the Bronze Age is marked by Zoom calls, dwindling cash and no parties whatsoever.

But behold! Like the ancients scanning the sky for portents, large bodies are colliding in the observable M&A-verse. Recent mergers include Devon Energy Corp. and WPX Energy Inc.; Diamondback Energy Inc. and QEP Resources Inc.; and Pioneer Natural Resources Inc. and Parsley Energy Inc.

What should be made of these massive combinations? Scale, friends. Scale.

Scale is often cited among the celestial mechanics that inevitably causes mergers. And it may be that those companies and their investors are comforted by feeling stronger, safer and bigger. Markets are, after all, about feelings.

Or not.

Before its deal for QEP, Diamondback CEO Travis Stice said on the company's November earnings call that "We do not need to increase our scale to further reduce our cost structure," citing the company's production, healthy balance sheet and inventory.

Stice further said that the company's supply chain was fine and that "These facts should prove to investors that we have the scale necessary to compete in this industry."

Such justifications, he said, were "specious and self-serving."

But in the third and fourth quarters, Devon, Diamondback, Pioneer and others agreed to part (at little or no premium) with $15.6 billion of their stock for their respective dance partners.

As accretive deals go, these didn't intuitively jump out as wallet fatteners. The annual synergies and savings ranged from $80 million to $575 million. Unless oil prices go back up, of course.

Moody's Investors Service said in a Dec. 8 report that stock-for-stock, low premium deals were creating more durable companies that favored "the strongest."

Others have opined that consolidated companies will exert more control over production growth as the oil and gas markets continue their recovery. To be fair, though, no one was planning to floor it with oil rigs any time soon.

As Moody's noted, capital spending in 2021 is expected to continue at a level similar to last year's misery brought declines of 40% to 50% in capex. For the run-of-the-mill E&P, capital access isn't likely to improve. The risk of defaults among low-yield E&Ps remains high. The goal now, Moody's said last summer, is to find a path across the current desert and stumble into 2022 with an oasis of recovered oil prices.

So, could merging into even larger companies be somewhat akin to the bet once placed on the undeveloped resources that are, at current prices, roughly worthless?

No, Morgan Stanley said in a Dec. 11 report. The firm upgraded E&Ps to "attractive" and argued that a "regime change" was in the air. Analyst Devin McDermott cited oil company consolidation, rationalization of overhead and revamped management compensation among proofs that the industry has truly embraced free-cash-flow generation and put garbage production growth behind it.

"Over the past two quarters, E&Ps have broadly embraced capital allocation frameworks that constrain mid-cycle investment rates to 70% to 80% of cash flow and, in most cases, limit production growth to 5%," McDermott wrote.

Well costs, he said, are now 20% below fourth-quarter 2019 prices—though it's unclear if that's due to a magic potion of efficiency or because service companies are hemorrhaging.

In 2021, McDermott predicted, the E&P sector will put 10 years of failure behind it and offer a yield of 11% free cash flow at $50 WTI.

Still to be resolved, however, are the icky problems of oil and gas declines. As Randy King, managing partner at Anderson King Energy, said in January, most of the significant profits in the upstream realm were made by entrepreneurs who bought low, did a little proving up of acreage and then sold at a higher price. This was largely during the Golden Age.

The sweet spot today is for long lived, conventional oil and top tier oil shales, predominantly the Permian Basin, he said.

"Having reviewed thousands of shale decline curves, I still don't see any real science in choosing b-factors and terminal declines," King said.

Whatever. Decline curves are in the future. Devon stock is up by 55%, Pioneer by 57% and Diamondback 47% since their announced mergers.

Enjoy this, the Bronze Age of M&A.

EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2021				
Executive Oil Conference	**Jan 27**		**Virtual**	**executiveoilconference.com**
Enverus EVOLVE Conference	Feb. 16-18		Virtual	enverus.com/evolve-2021
Houston Oil and Gas Forum	Feb. 17-18	Houston	Petroleum Club of Houston	usenergystreamforums.com/events/3rd-houston-oil-gas-forum-2021
CERAWeek by IHS Markit	Mar. 1-5		Virtual	ceraweek.com
25 Influential Women In Energy	**March 25**		**Virtual**	**hartenergyconferences.com/women-in-energy**
Williston Basin Petroleum Conference	May 11-13	Bismarck, N.D.	Bismarck Event Center	ndoil.org
DUG Haynesville	**May 26-27**	**Shreveport, La.**	**Shreveport Conv. Center**	**dughaynesville.com**
Energy Capital Conference	**June 1-2**	**Houston**	**Omni Hotel Houston**	**energycapitalconference.com**
DUG Permian/Eagle Ford/ Midstream Texas	**July**	**Fort Worth, TX**	**Fort Worth Conv. Center**	**dugpermian.com**
DUG Bakken and Rockies	**August**		**Virtual**	**dug-rockies.com**
Offshore Technology Conference	Aug. 16-19	Houston	NRG Park	2021.otcnet.org
NAPE Summit	Aug. 18-20	Houston	George R. Brown Convention Center	napeexpo.com/summit
DUG Midcontinent	**Sept. 22-23**	**Oklahoma City**	**Oklahoma City Convention Center**	**dugmidcontinent.com**
A&D Strategies and Opportunities	**Sept. 27-28**	**Dallas**	**Fairmont Hotel**	**adstrategiesconference.com**
Executive Oil Conference	**Nov. 2-3**	**Midland**	**Midland County Horseshoe Arena**	**executiveoilconference.com**
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Thursday, odd mos	Fort Worth	Fort Worth Petroleum Club	adamenergyfortworth.org
ADAM-Greater East Texas	First Wednesday, even mos	Tyler, Texas	Willow Brook Country Club	getadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bimonthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.com
ADAM-Permian	Bimonthly	Midland, Texas	Midland Petroleum Club	adampermian.org
ADAM-Tulsa Energy Network	Bimonthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.com
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bimonthly	Houston	Houston Petroleum Club	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	sblackhefg@gmail.com
Houston Producers' Forum	Third Tuesday	Houston	Houston Petroleum Club	houstonproducersforum.org
IPAA-Tipro Speaker Series	Second Wednesday	Houston	Houston Petroleum Club	tipro.org

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Barclays forecast: slight uptick to come in global E&P spending

Following an unprecedented year of oil price volatility, production cuts and demand shattered by a global pandemic that continues to wreak havoc, E&P spending worldwide is expected to inch up by 1% to nearly $296 billion in 2021, according to a Barclays survey released in January.

That's up from a 29% drop in spending seen in 2020 when every region tracked saw double-digit spending declines, led by North America where E&Ps cut spending by 44%.

Calling 2021 a "transition year" for the oil and gas industry, Barclays analysts forecast international markets will drive spending growth with Russia and Latin America at the helm.

In the U.S., spending is on course to drop 6% this year as companies exercise capital discipline and consolidate, reinvesting less into the business from cash flows, according to the survey.

"Overall, we view 2021 as a transition year for the industry, exhibited by conservative spending plans amid great macro uncertainty," Barclays analysts said in the survey. "Although most budgets are using a $40 to $50/bbl oil price, the timing of a global oil demand recovery is a significant variable for the pace of spending in 2H 2021."

The outlook was based on a survey, conducted from Nov. 11 to Dec. 16, of more than 200 oil and gas companies' 2021 spending intentions along with announced guidance and forecasting models.

Barclays E&P spending survey was released Jan. 5, the same day the OPEC and non-OPEC ministerial meeting ended with another lifeline being tossed to the market for stability. Saudi Arabia volunteered oil output cuts of 1 MMbbl/d in February and March above its current quota as coronavirus ushered in another round of lockdowns in the U.K. and other parts of the world. Barclays survey shows Middle East spending could fall by 4% this year, compared to 14% last year.

As part of the OPEC+ deal, Russia—where the survey showed spending could rise 16% to more than $33 billion this year following a 17% decline—is among the countries allowed to pump more. Steering growth are Rosneft and Gazprom, which Barclays said it believes "should be a positive read-through for Schlumberger in particular."

Latin America is another international region that could see a double-digit spending increase, potentially jumping by 19%. "But it comes with caveats," Barclays said.

Analysts disregarded Pemex's 2021 budget increase of 20%, pointing to a "closed market" with the current administration shutting out international producers and suppliers. They also questioned Petrobras' expected 19% hike, saying spend typically goes to FPSOs or engineering and construction rather than E&P.

The survey delivered a mixed bag for anticipated spending in North America.

Spending is projected to decline by 4% this year, far less than the 44% drop seen in 2020. However, Barclays analysts cautioned that only about a third of the U.S. E&Ps have unveiled capital guidance—more news is expected in February—and privates are underrepresented in the survey. Analysts said they relied on an online survey to gauge spending by privates.

Recovering from a brutal year, U.S. land spending is expected to fall by 6%, the survey showed. That's an improvement from a 46% drop in 2020.

Investors' push for continued capital discipline coupled with market consolidation are factoring into spending patterns. At less than 60% of cash flow, reinvestment ratios are projected to be the lowest seen in the past 20 years or longer, Barclays said.

In North America, majors are expected to cut spending more than others—down 6% compared to 5% for large-cap E&Ps and 4% for small- and midcap E&Ps, according to Barclays.

Of the majors and IOCs, the survey showed Exxon Mobil

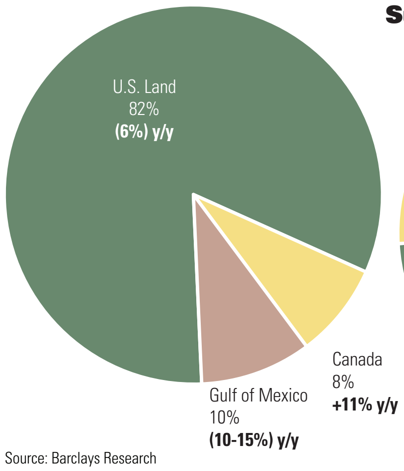
Barclays Global E&P Spending Survey ($MM)

	2019A	2020E	2021E	2019-2020 (%)	2020-2021 (%)
IOCs	46,999	30,419	28,455	(35%)	(6%)
U.S. Large E&Ps	37,141	17,253	16,412	(54%)	(5%)
U.S. Smid E&Ps	19,611	10,450	10,070	(47%)	(4%)
Canada E&Ps	8,191	4,382	4,844	(47%)	11%
Private E&Ps	27,299	15,503	15,038	(43%)	(3%)
North America Spending:	**139,241**	**78,007**	**74,819**	**(44%)**	**(4%)**
Middle East	40,904	35,172	33,716	(14%)	(4%)
Latin America	25,559	20,752	24,597	(19%)	19%
Russia/FSU	34,495	28,790	33,376	(17%)	16%
India, Asia and Australia	70,047	55,961	55,745	(20%)	(0%)
Europe	28,850	25,596	23,153	(11%)	(10%)
Africa	17,544	11,869	10,481	(32%)	(12%)
Majors/IOCs (International)	48,214	33,381	35,644	(31%)	7%
NAM Independents (International)	2,835	2,172	2,645	(23%)	22%
Other E&Ps (International)	2,478	1,342	1,401	(46%)	4%
International Spending Total:	**270,925**	**215,034**	**220,759**	**(21%)**	**3%**
Worldwide E&P Spending:	**410,166**	**293,041**	**295,58**	**(29%)**	**1%**

Source: Barclays Research, company reports

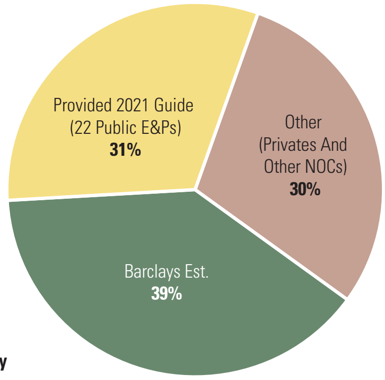
Note: Barclays uses companies that spend primarily in their home regions as a proxy for the regional breakout provided.

North America Spending By Region



Source: Barclays Research

Percentage Of US Production Represented By Surveyed Companies



Corp. spending was expected to fall the most in North America at 29% with Chevron Corp. spend down 8% and ConocoPhillips Co. and Murphy Oil Co. flat.

Stressing a commitment to cost reduction and prioritized spending on "advantaged assets with the highest potential future value," Exxon Mobil said in November it would cut its overall spending to between $16 billion and $19 billion. Part of its strategy included removing from its portfolio "less strategic assets," including some dry gas assets in Appalachian and Rocky Mountains, Arkansas, Louisiana, Oklahoma, Texas and western Canada.

"Assuming global oil demand rebounds in 2H 2021, we believe the U.S. onshore market will ultimately recover to stabilize at about 70% of 2019 levels by 2023," Barclays said.

Canada appears to be the only positive in terms of spending growth in 2021 for North America.

Canadian E&Ps are expected to increase spending by 11% this year, though Barclays said it makes up only 6% of North American spend.

"The switch to growth is driven by more stable prices and curtailments lifted, resulting in Canadian E&Ps to allocate incremental capex to shorter-cycle developments," Barclays said.

Canadian Natural Resources Ltd. leads the pack in spending growth with an anticipated 131% rise compared to last year's 66% decline.

"The company has been nimble in the past to changing market conditions and can quickly adjust our targeted capital expenditure levels or reallocate capital to our highest returning assets," Canadian Natural's President Tim McKay said in December. "Our 2021 plan will be no different, targeting capital of approximately $3.2 billion, delivering targeted production of approximately 1,225,000 boe/d, with disciplined growth of approximately 62,000 boe/d from forecasted 2020 levels."

However, a ramp-up in spending offshore doesn't appear likely based on the survey, which forecasts spend falling for the seventh straight year.

"Optimism for a deepwater recovery at the beginning of [2020] came to a screeching halt and the floating rig count fell from 131 rigs in March to 103 today," Barclays said. "We expect a trough of 75 rigs to be reached by year-end 2021 as continued macro and oil price uncertainty weighs heavily on the sector."

The survey shows offshore spending could drop by about 4% this year based on day rate trends, FID activity, rig contracting levels and service cost projects. That, however, is better than the 15% spending drop in 2020.

—Velda Addison

API Chief: Biden admin faces 'big decisions' on energy dynamics

API President Mike Sommers expressed his willingness to work with the incoming Biden administration during his annual State of the American Energy address on Jan. 13, listing areas, like methane regulation, where he believes there can be common ground.

At the same time, areas such as access to federal lands and waters could be contentious.

"We know that there are going to be issue areas where we're going to disagree," he said during a Q&A session following his presentation. "We're going to work with the Biden administration when we can, but we're going to oppose them when we must."

Sommers touched on the role of oil and gas in combatting climate change and acknowledged that the industry had work to do to address issues of diversity, equity and inclusion.

"One of the things we know, based on an API study, is that 50% of our workforce for the future is going to be supplied by women and minorities," he said. "And we need to make sure those women and minorities within our industry have a path to grow within the oil and gas industry, and that means providing mentors, that means providing leadership so they can continue to grow and continue to succeed within the oil and gas industry writ large."

Sommers appeared to be bracing API's members for change in Washington following four years of a fossil fuel-friendly Trump administration.

"Our new president and Congress have some big decisions to make on energy—energy abundance or foreign dependence, American jobs or outsourced jobs, economic revival or small-town decline, progress or retreat," Sommers said.

In particular, Sommers cited regulatory efforts that would have achieved far less of what the industry has been able to accomplish on its own. He noted the 2010 Waxman-Markey bill, which would have reduced CO_2 emissions in 2019 by 10% from 2007. The bill was named after its authors, former representatives Henry Waxman of California and Edward Markey of Massachusetts.

The proposal did not make it into law but the industry, which rode innovations in hydraulic fracturing and horizontal drilling to vastly increase production of natural gas, achieved a drop in CO_2 emissions of almost 15%. The industry's efforts on methane emissions have already resulted in a 70% reduction in the largest-producing U.S. regions.

"When demand and production go significantly up while emissions go significantly down, we're clearly on the right track," Sommers said. "We haven't been waiting on guidance or on orders from others; we have done this all on our own initiative, with our own money, with our own engineering and technology. We've exceeded goals that even the most heavy-handed regulators wanted to impose on us."

President-elect Joe Biden's description of oil and gas during the campaign as a "subsidized" industry did not sit well with Sommers. He noted that manufacturers in general are encouraged by tax law because those investments serve a competitive economy by creating new jobs, goods and services. In the case of energy, investments help deliver environmental progress.

"This talk of subsidies is a false and tiresome claim we have heard before," Sommers said. "In 2021, as always, we're going to defend the principle that energy producers should be treated like any other manufacturer. We can't forget that it's low-cost, reliable and secure energy that makes our industries competitive in the global marketplace."

With the White House and both houses of Congress in Democratic control, policy tensions are likely, but while Sommers stressed that API would not "get caught up in every political battle of the moment," the organization would continue to have members' backs.

"We are all familiar with the caricatures of the oil and gas industry," he said. "But I can assure you that whatever the issue, whatever the controversy, we're going to stay on mission with positions based in reason, fact and reality."

—Joseph Markman

Dallas Fed survey: U.S. energy execs to spend more capital

About half of U.S. energy company executives polled by the Federal Reserve Bank of Dallas expect their firms to increase capital spending in 2021, and another quarter of respondents see those expenditures remaining flat next year, according to a survey released on Dec. 30.

The coronavirus health crisis wiped out as much as a third of global fuel demand and sent U.S. benchmark crude prices crashing in April, even ending one trading session in negative territory. Oil and gas companies slashed budgets and curtailed production.

Oil prices are down 20% for the year but have recovered from the historic lows, strengthening spending plans for the bulk of the 146 energy firms surveyed. Of the executives polled from Dec. 9 to Dec. 17, two-thirds headed up exploration and production companies; the others were in oilfield services.

About 25% of the respondents said they expected their firms to increase capital spending slightly and 14% said they planned significant increases next year. One-fifth predicted spending would decrease.

Stricter oil and gas regulations expected from President-elect Joe Biden's administration could tighten U.S. supply and boost crude prices, some executives told the Dallas Fed.

"We are optimistic that we will have a weaning of excess oil supply, and more importantly, suppliers of oil and gas and that will lead to a slightly higher sustainable price," said one executive, who remained anonymous.

After a recent spate of mergers and acquisitions, most executives agreed exploration and production firms would keep consolidating or disappear entirely.

Chuck Yates, former managing director with Kayne Anderson

About half said the number of publicly listed independent E&P firms would fall as low as 37 by the end of 2022, from 60 now. A quarter of the executives said only 25 to 36 would remain. The rest of those surveyed predicted an even smaller number of the companies would survive.

—Laila Kearney, Reuters

Want alpha returns? In the oil patch, beta always dominates

Following 15 years of massive investment and a multitude of wells proving out the shale concept, the U.S. oil and gas industry has decidedly confirmed that it is unable to consistently generate alpha returns for investors, so said Chuck Yates, former managing director with Kayne Anderson. The reason? In this case beta—the volatility resulting from the price of oil—always and eventually swamps the alpha.

"In energy, as a collective, we have way over sold our ability to consistently generate alpha," he said, and "we have way underestimated the impact that the beta can actually have on us."

Yates shared his observations and analysis as part of Hart Energy's virtual DUG East conference in December.

As a high-level example, he noted that while Chevron Corp. outperformed ExxonMobil by 120 basis points, "If you miss the oil price drop of 50%, you lost two-thirds of your money, so beta dominates alpha.

"In terms of looking at energy as a spot to go find alpha, to go find someplace that you can make outsized returns above and beyond what others are doing, it's just really tough. We've just proved as an industry it's really tough to do."

The difficulty in generating alpha vs. other peers or sectors lies in the sector's homogeneity—there are no secrets in the oil patch. New geological discoveries and improvements in technologies are quickly assimilated by other operators. Knowledge from service companies and consultants are shared by all operating companies. And capital, until recently, freely flowed for new ideas.

"So it's really hard to generate alpha in that scenario. There aren't many examples we can point to where people are repeatedly generating alpha."

Contrast the difficulty in gaining an edge to the volatility in oil and gas commodities. Yates said while at Kayne they regularly ran analysis of how often strip pricing was accurate—and the result was always less than 50%, and sometimes as low as 18%.

"Most times a coin flip would have been a better indicator of the future price of oil than the strip. That's tough to do that as an investor. If you're going to invest in energy, you need to spend a lot more time on the beta, the oil price, because that is going to so dominate the alpha."

Ultimately, the oil and gas sector is a low-margin business, he said, similar to a grocery store, working at the margin of commodity prices that track lifting costs. That realization by investors and producers alike is fundamentally changing what makes the energy sector investable.

"There's really not a lot of reason to drill another well in the United States these days," he said, as OPEC is poised to backfill the supply gap post COVID-19. "I think we're going to produce a lot, pay down debt a lot, but not do much in the way of drilling."

And nickels and pennies are going to matter. "People are going to cut costs. The folks that don't are going to have tough time and potentially go out of business. Literally a nickel a barrel can be the difference today between having to declare bankruptcy or not. So, yes, we're going to have a challenging time, but at the same time, those that are able to execute like Walmart are going to be the ones that make it."

In this environment, consolidation and automation are necessary for survival, he said, and many more jobs will be lost. "The focus of the industry is going to be producing out as efficiently as possible, and people are costs. We just have too many people in the industry."

But the flip side of this contraction is that it's a prime time to be an entrepreneur in the industry, he said.

"Any time there are challenges in an industry like this, there are also great opportunities. Maybe you use your own capital to piece together little projects, maybe you are the person that's on the forefront of learning how this [new] technology works."

The age of the driller is over, he said, and the companies that outperform going forward will be valued on different metrics. Instead of watching finding and development costs, now the focus will be measured by lease operating expenses, clean balance sheets and distributing capital back to shareholders.

"Going forward, energy is going to be a low-margin business. It's a lot of execution."

—Steve Toon

M&A at historic low despite year-end merger frenzy

After an anemic start, E&Ps raced to announce corporate combinations in the second half of 2020, providing a well-needed boost to the year's deal value, according to an Enverus report published Jan. 6.

However, the late year wave of industry consolidation wasn't enough to save a dismal year of A&D activity, which Enverus said is likely to continue into the New Year thanks to the uncertainty created by the ongoing COVID-19 pandemic. While big corporate combinations lifted M&A value to $52 billion, deal flow for 2020, as measured by the firm as announced deals, fell to historic lows.

"There was very little appetite on either the public or private company side for buying upstream assets in 2020 as preserving cash to pay down debt or return to equity owners was prioritized," Enverus M&A analyst Andrew Dittmar said in the report. "In particular, companies were unwilling to invest substantially in buying undeveloped land, a staple of past upstream deal markets."

For 2020, Enverus counted only 140 announced deals with a reported value. According to the firm, the 2020 count is the lowest annual total since at least 2006 and roughly just one-third of average deal activity over the past 10 years.

"What asset deals did get announced were largely focused on acquiring existing production and cash flow, sometimes through bankruptcy sales," Dittmar added.

By comparison, Enverus tracked $96 billion of U.S. oil and gas M&A in 2019 and $85.6 billion in deals in 2018. However, the 2019 number might be skewed by Occidental Petroleum Corp.'s $57 billion acquisition of Anadarko Petroleum, which was the largest deal of the decade and the fourth largest oil and gas deal ever.

As with 2019, corporate M&A dominated transactions overall, constituting nearly 88% of all 2020 deals, with few asset deals for producing properties. Royalty deals were also down markedly to $1.2 billion compared with $3.2 billion a year ago, according to Enverus data.

The outlook for 2021 deal activity will depend largely on the trajectory of the COVID-19 pandemic, global economic activity and their associated impacts on commodity prices, according to the Enverus report.

Enverus noted a substantial backlog of noncore asset divestments for companies to pursue,

Top Five U.S. Upstream Deals Of 2020

Announce date	Buyers	Sellers	Value ($MM)	Deal type	Basin
10/19/20	ConocoPhillips	Concho Resources	$13,337	Corporate	Permian
7/20/20	Chevron	Noble Energy	$13,000	Corporate	Permian, D-J, others
10/20/20	Pioneer Natural Resources	Parsley Energy	$7,621	Corporate	Permian
9/28/20	Devon Energy	WPX Energy	$5,631	Corporate	Permian, Williston
12/21/20	Diamondback Energy	QEP Resources	$2,155	Corporate	Permian

Source: Enverus

particularly for those that participated in 2020's corporate merger wave and now have expanded portfolios. The firm listed likely buyers would include some public companies but with a healthy contingent of private equity capital looking to take advantage of opportunities created by the downturn. Other potential buyers include energy-focused SPACs.

"Wall Street appears supportive of E&P deals, but with very specific expectations on deal structure and the quality of the merger target," Dittmar said in the report. "The limiting factor for consolidation in 2021 will be the number of attractive merger partners left at the end of a very active year."

Upstream M&A accelerated dramatically in the second half of 2020, particularly in the fourth quarter with three multi-billion-dollar mergers centered on the oil-rich Permian Basin.

"As anticipated, additional merger activity during Q4 centered on E&Ps with high quality lands and reasonable debt loads, and the Permian Basin is the most target-rich region under those criteria," Dittmar said.

At $27 billion of deals, Enverus said fourth-quarter 2020 was the third most active quarter by value since oil prices lost their footing in late 2014. The Permian Basin, in particular, captured 83% of deal value in the fourth quarter though, for the year, Permian transactions accounted for 46% of transaction spending.

The biggest deal of the fourth quarter and of 2020 was ConocoPhillips Co.'s $13.3 billion acquisition of Concho Resources Inc. The Oct. 19 merger was quickly followed by news that Pioneer Natural Resources Co. intended to acquire Parsley Energy Inc. for $7.6 billion. Lastly, Diamondback Energy Inc. closed out the year with the acquisition of publicly traded QEP Resources Inc. and private equity-sponsored Guidon Operating for a combined $3 billion.

"The fact that three of the leading Permian independents—Concho, Pioneer and Diamondback—each participated in a deal implies a recognition by the industry that scale is vital for companies to remain relevant going forward," Dittmar added.

For example, ConocoPhillips' acquisition of Concho, one of the largest independent producers in the Permian Basin, is set to vault the Permian from a potential weak point in Conoco's portfolio to a cornerstone of its global strategy, the Enverus report said.

Further, the merger of Parsley gives Pioneer combined control of nearly 1 million acres across the Midland and Delaware sub-basins and Diamondback's dual mergers will build out its position in the heart of the Midland Basin.

Consistent with earlier deals in second-half 2020, such as Chevron Corp.'s Noble Energy acquisition and Devon Energy Corp.'s merger with WPX Energy, all the big fourth-quarter public company corporate deals were all-equity, low-premium combinations.

Corporate consolidation is likely to continue in 2021 as some of the industry's small and midsize companies are desperately in need of scale, according to the Enverus report.

The Enverus report noted companies that went through a Chapter 11 restructuring in 2020 could emerge as potential merger partners but overall the list of possible participants in consolidation have largely been winnowed down in the past year.

—Emily Patsy

Bloomberg experts predict 2021 oil, gas prices action

Bloomberg commodities experts do not foresee a large increase in crude oil prices this year. They now predict that the range of oil prices seen in 2020 may define the price range for several years to come.

And $50/bbl appears to be a key threshold—If WTI continues to trade around that level, sturdy resistance should keep a lid on prices in 2021, said a recent report. Demand challenges and production oversupply seen in the last few years seem to be the more probable course again this year, the firm said.

"Unless the S&P 500 can add to its roughly 12% gain in 2021, we see little hope for higher crude oil."

Natural gas risks point more toward $2/Mcf, not $3-plus, they said, citing a possibly warmer than normal winter and economic impacts from the pandemic, not to mention higher gas inventories than usual.

Gold and copper are set to outperform crude oil in 2021. The analysts tracked the performance of the dollar and other markers against the Bloomberg Commodity Index (BCOM), a highly liquid and diversified benchmark that includes oil and gas, agricultural commodities and base and precious metals.

In a recent report, the experts said the broad commodity market in 2021 is "well situated to follow the upward path paved by gold in 2020, in our view."

A weaker dollar, and much stronger gold, indicate that most commodities, including those in agriculture and metals, should advance this year.

For crude oil, Bloomberg said, "We see little upside in WTI crude oil above $50 a barrel, yet more of the same since the peak in 2008 may revisit $30 support."

A recent survey of 300 oil and gas executives by the Federal Reserve Bank of Dallas indicated that almost half those surveyed expect oil to range from $50 to $55/bbl in 2021.

Bloomberg has a different view. "Time decay, advancing technologies, demographics and decarbonization are aligned against WTI crude oil sustaining above $50/bbl, in our view," said the report.

Rising oil prices would incentivize cash-strapped OPEC members and U.S. shale producers to increase activity, it said, while demand elasticity should be decreasing.

Metals may be best advantaged to appreciate further, the report said. They could be a bull market leader as decarbonization efforts increase demand for certain metals, such as those used in batteries and electric vehicles.

U.S. grain exports should recover and do well also. Corn at $4 a bushel appears to be shifting upward to $5. Faltering equities after a standout performance in 2020 are a primary risk, the report said.

"World equities were last this high just before 2014's Brent crude collapse from a bit over $100/bbl to the low around $27 in 2016."

—Leslie Haines

Oil shortage due if exploration remains stagnant: Rystad

Despite lower future demand due to the COVID-19 pandemic and the accelerating energy transition, the world is on track to run out of "sufficient oil supplies" to meet its needs through 2050, a recent report by Rystad Energy revealed.

The solution, according to Palzor Shenga, senior upstream analyst with the research firm, is for a significant acceleration in exploration efforts made by upstream oil and gas companies.

"The scope of exploration will have to expand significantly," Shenga wrote in the report. "Unless we see a momentous transition in the global energy mix sooner than currently expected, or a much faster development pace than the current norm, upstream players may have to more than double their conventional exploration efforts in order to meet global oil demand through 2050."

To meet the global cumulative demand over the next 30 years, Rystad Energy calculates undeveloped and undiscovered resources totaling 313 Bbbl oil need to be added to currently producing assets. As a result, exploration programs will have to discover a worthy-to-develop resource of 139 Bbbl liquids by 2050, "an impossible task if this decade's low exploration activity levels persist," the firm said in the report.

The target is high, according to Rystad, because not all existing discovered volumes are profitable to develop.

"In theory, the total undeveloped supply would amount to 248 Bbbl oil between 2021 and 2050," the Rystad report said. "However, when we dive deeper into these discoveries and look at their discovery decade and current status, we find that about 74 Bbbl are highly unlikely to materialize and need to be replaced by new discoveries."

Looking at the global conventional exploration potential, Rystad identified two main sources for the new volumes: further appraisal of existing fields and resources, and new discoveries.

The first source includes projects in their early production stage, projects under development and unrisked volumes in discovered assets.

"We expect that some future exploration activity will lead to reservoir delineation and enhancement of resource estimates, while technological improvements and other secondary recovery techniques will also increase recoverable volumes," the Rystad report said.

Projects in the above-mentioned categories are currently forecast to contribute around 378 Bbbl of liquids supply between 2021 and 2050. If future exploration follows industry norms, it will enhance recoverable resources by around 5%, or 18 Bbbl. This leaves a deficit of about 121 Bbbl to be unearthed through future exploration drilling in currently undiscovered areas–Rystad's second source of new supply.

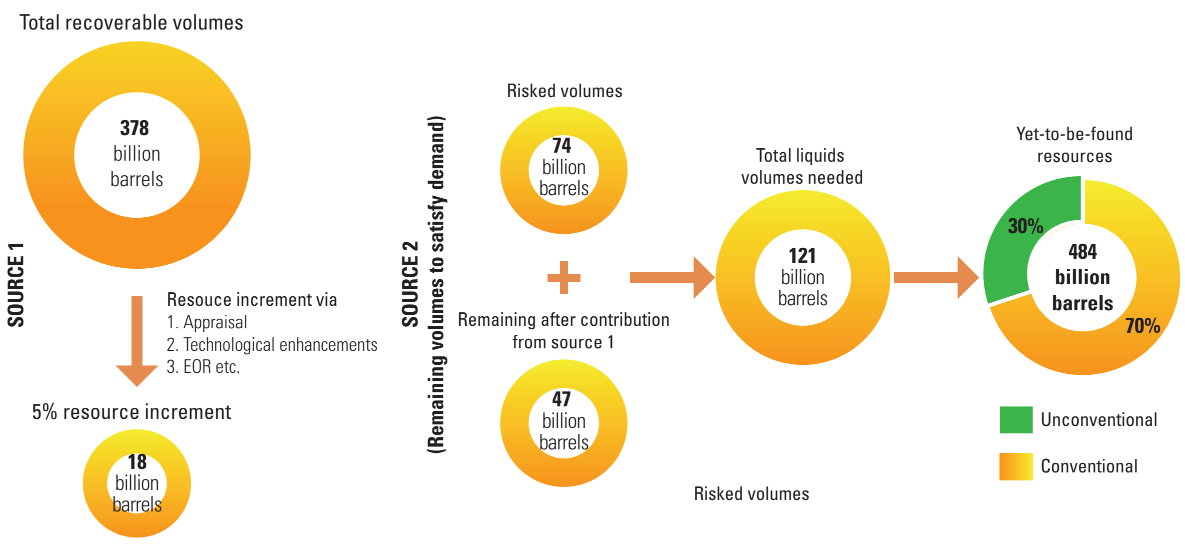
Analyzing the discovery rates of the current decade and the latest trends, Rystad Energy expects that global conventional discovered liquid volumes could settle at around 4 Bbbl per year, with an average discovery size of around 40 MMbbl. Translation: "Explorers would need to announce at least 100 new conventional discoveries each year to reach the magic volume number needed to meet demand," the Rystad report said.

However, the firm continued that, just like in the past, not all volumes discovered during this period will be developed and produced, and much of it may not be brought on stream to meet demand by 2050. Therefore, the firm said the total discovered volumes will have to be much higher than the required cumulative liquids supply.

To find an approximate volume number for new discoveries, Rystad Energy looked at variables such as the share of produced volumes from discoveries in the past three decades and the time taken from discovery to start-up.

About 617 Bbbl of liquids have been found since 1990, and

Total New Liquids Supply Required To Meet Demand Toward 2050



Source: Rystad Energy UCube, research and analysis about 25% of these discovered volumes had been produced through 2020. Analogically, explorers would have to unearth about 484 Bbbl of new resource through 2050 to put the required 121 Bbbl of liquids to production over the next 30 years.

Rystad believes unconventional exploration will also contribute to meet the required volumes.

However, the firm expects around 30% of the deficit volumes between 2021 and 2050 to come from global unconventional plays. Consequently, conventional exploration drilling would need to unearth around 330 Bbbl of oil through 2050 to meet global demand, the firm added.

Additionally, the global exploration success ratio has dropped sharply, from about 72% in 2010 to 17% in 2020, according to Rystad.

"As 'easier' hydrocarbons are already discovered, it will become increasingly difficult to find new resources in mature areas, and a more stringent exploration approach means that only the top-ranked prospects will be drilled," the Rystad report said. "We, therefore, expect to see an average success ratio of 15% to 20% through 2050."

The firm noted that a 20% ratio requires around 500 wells to be drilled each year, or 650 wells at a 15% chance of success.

Deepwater offshore areas are also expected by the firm to continue to dominate future new discovered volumes.

As for the cost of exploration, Rystad said more challenging drilling environments will push the average well cost to about $50 million, lifting the annual cost of exploration drilling to between $25 billion and $33 billion at the above success rates. However, at the past decade's pace and success rates with average annual discoveries of 4 Bbbl, it would take about 80 years to find the 330 Bbbl needed to cover the supply deficit for undiscovered resources.

Rystad forecasts the cost of drilling to range between $2 trillion and $2.6 trillion and added that, in addition to drilling, discovering these volumes will require spending on geological and geophysical studies, leasehold costs and signature bonuses to be paid for future lease rounds.

Historically, the ratio of drilling to other exploration costs is 52:48. Furthermore, appraisal drilling needs to be carried out to get the 5% incremental volumes mentioned previously, which the firm estimates this would require an additional $45 billion in spending.

"Altogether, we estimate that the cumulative exploration cost required to satisfy liquids supply from conventional sources could be between $3.8 trillion and $5 trillion through 2050," the Rystad report said. "However, as these figures are based on historic assumptions, costs could be pushed down significantly—potentially to around $3 trillion—thanks to fast-tracking of discovered resources and some giant discoveries."

—Mary Holcomb

OFS IN TRANSITION

Like the E&P sector that precedes it, U.S. oilfield services companies are facing a precipitous drop in capex for 2021. The hard reality? Adapt or die.

CANARY LLC

ARTICLE BY
BLAKE WRIGHT

Overleaf, companies like Canary Oilfield Services found it difficult to navigate the balance between crew and available work in 2020.

Much like The Beatles' Paul McCartney sang in 1970, U.S. oilfield services (OFS) companies have "seen this road before,'" but the climb from the bottom of the 2020 version of the historic oil patch trough feels extra daunting—a road paved with uncertainty. The service industry was collateral damage of the unprecedented combination of excess supply and crippled demand that waylaid its client base at a time money was fleeing the industry and a global pandemic was settling in.

As of December 2020, the U.S. land rig count stood at 308. That tally is up from the year's low point that dipped below 200 during the summer, but it remained just 40% of the total active land rigs from a year earlier.

The decrease in activity has, of course, led to less need for oilfield services. The plunge in services demand has forced many to take drastic cost cutting measures including spending freezes for R&D, product line suspensions and headcount reductions. The services business has been hit hard by layoffs, with estimates of job losses in the tens of thousands. The state of Texas alone lost around 60,000 OFS jobs between April and October 2020, according to estimates from the Petroleum Equipment & Services Association.

A steady flow of bankruptcies has rippled through the OFS pool since the beginning of 2020. According to a Haynes and Boone LLP report, there were around 60 new OFS bankruptcies through the first 10 months of 2020, compared to about 20 new filings in all of 2019. Some of the OFS companies that have sought bankruptcy protection in 2020 include McDermott International, Pioneer Energy Services, BJ Services, Calfrac Well Services and Hi-Crush, as well as offshore drillers Noble Corp., Diamond Offshore and Pacific Drilling.

"I'm surprised we haven't seen more [bankruptcies] frankly," said David Anderson, senior equity analyst for oilfield services with Barclays. "We do see a number of companies that have been right on the edge for some time now, and we're watching the debt maturities closely. We've changed our coverage. We've reduced our coverage, dropping a number of names just because some players have gotten so small that they are essentially irrelevant."

The current market stresses have created a proliferation of what some have termed "zombie" companies in the OFS sector. These are service providers that are highly cash impaired and loaded with debt. While many E&Ps in this condition have taken the bankruptcy plunge, some believe there are still holdouts on the services front that will eventually fall.

"We're probably midway through [the bankruptcy cycle]," according to James West, senior managing director, oilfield services, at Evercore ISI. "We've had a large number of bankruptcies, but there are more to come. Most management teams have engaged with lenders at this point. Maybe they haven't filed for Chapter 11 or Chapter 7, but that is kind of a formality at this point."

In the OFS sector, "We're going through a horrific downturn, but the other side of this is not going to be that great either," said James West, with senior managing director, oilfield services, at Evercore ISI.

Market improvements for 2021 are in the cards, but the bar for improvement is low, and many forecasts are tempered and contingent on oil price stability. Spears & Associates estimates the U.S. OFS market to be around $34 billion in 2021, down about 10% from 2020 estimates of $37 billion. That compares to spending of $99 billion in 2018 and $90 billion in 2019. About half of the estimated spend in U.S. land OFS is predicted to occur in the Permian and Eagle Ford basins.

"There will be less capital to go around, which means there will be less drilling activity and less fracking, so we think a new normal for the market would be around 450 rigs and maybe 150 to 175 frac spreads, which of course is well below the 800 to 1,000 rigs and 300-plus fracking units from the past peak," said West.

Adapt or die?

The constriction of the market is expected to force the hands of companies in all but the best financial shape. Bankruptcies will come, but there will also be firms that are pressured to take a good hard look at their existing services and prune those that no longer offer the best results to the bottom line. Product lines can be sold or simply discontinued. Services providers will need to take the necessary steps to set themselves up for the best outcome once the market shows sustainable signs of life.

"I think we are in an adapt-or-die situation, and people need to reset their expectations for what's possible," said Dan Eberhart, chief executive officer at service provider Canary LLC. "To me the headwinds are very fierce on access to capital and pricing leverage with our customers. Also, there's the coming storm of the climate change movement and the push to move to renewables on the horizon as well. The confluence of all that is a toxic mix of economic headwinds for the OFS sector."

Early indications from E&Ps signal that they will spend around 70% of cash flow in 2021. That level of investment is designed to keep activity and production flat. By comparison, pundits estimated producers spent around 89% of cash flow in 2020. With not much left to give on the pricing side, services companies will need to feed aggressively into operator efficiencies in order to keep production levels from dipping further.

"The dirty secret of all this was that this industry was headed down this path well before COVID-19 hit in March," said Anderson. "This really is a necessary purge that has been building over the last several years. Fifty-dollar oil doesn't work for most shale plays in the U.S., which is why so many small-cap E&Ps and private E&Ps have really struggled.

"Likewise, you are seeing service businesses contract because they shouldn't have been there in the first place. Compared to 2019 levels, the U.S. market will probably only recover to about 70% of the size it used to be in terms of upstream spending. We think that about 2 million barrels per day of production is permanently impaired.

TOM FOX

TOM FOX

"The challenge going forward for the oil companies is finding ways to squeeze out more efficiencies," Anderson said. "They will have to get much better to bring costs down and increase cash flow."

Tens of billions in asset write-downs have ravaged the operator side of the business. At the end of 2020, majors took turns wiping their ledgers clean of uneconomic assets—ExxonMobil Corp. ($20 billion), Royal Dutch Shell Plc ($22 billion), BP Plc ($17.5 billion), with more likely to come.

Services companies were by no means immune to the harsh reality of value adjustments. Schlumberger Inc. wrote down over $12 billion in late 2019, and additional restructuring costs are expected. Baker Hughes Co. took a $15 billion impairment charge in the spring of 2020, followed by a $2 billion write down by Halliburton Co. a few months later.

"Services companies, similar to E&P companies, have been reckless with capital expenditures, added way too much equipment to the market, and we're going through a horrific downturn, but the other side of this is not going to be that great either," said West. "As the E&P companies have learned, or have been told by their shareholders, they must live within cash flow and they must return some of that cash flow to the stakeholders."

With the pressures applied by an abysmal oil market, many of the bigger, international producers have taken the opportunity to up the ante in renewables by announcing plans for strategic investments in wind, solar, hydrogen and other nonhydrocarbon fuels that await on the other side of the energy transition.

BP said last fall it would push toward renewables, leaving some of its conventional oil and gas assets behind. Pledges by Shell, Repsol, Equinor and others are all aimed at boosting renewables production over the coming decades.

What about the services sector? Should traditional OFS companies look to adapt and embrace the energy transition with new product lines and offerings that cater to that work?

Richard Spears, vice president of oilfield research firm Spears & Associates, once served on the board and in the ownership group of a company that for years was the biggest pipeline engineering company in America, he said without directly identifying the company. "We had the Keystone XL pipeline, which ultimately didn't get built. In the process of having this world-class pipeline engineering company, we said, 'You know, we ought to expand into wind energy too.'"

The firm bought a large wind farm engineering company, "and it was like a bunch of French guys trying to speak Swahili," he said. "We were both speaking a common language, but we were not communicating. It was not good at all, and yet both companies were engineering companies. The metrics and the needs for both of those divisions were so different that it would have been better for them to be two totally separate organizations and not managed by a single ownership group."

The challenge of an OFS company with multiple product lines is that each one can behave differently with a slightly different customer base and a slightly different geographic foot-

A worker for Casing Specialties makes pipe connections on Unit Drilling rig 408 for QEP Resources in Andrews County, Texas. Facing page, a Liberty Oilfield Services hydraulic fracturing team monitors an Eagle Ford completion in progress.

TOM FOX

TOM FOX

Consolidation in the E&P sector can be a double-edged sword for OFS, as mergers might mean fewer wells drilled, but more stability when contracted.

David Anderson, senior equity analyst for oilfield services with Barclays, said oil and gas was headed toward consolidation long before COVID-19. In the case of OFS, "You are seeing service businesses contract because they shouldn't have been there in the first place," he said.

print. Trying to run that type of business in the oilfield is a full-time job for the management team. A good directional driller or a top-notch hydraulic fracturing service company would not necessarily make the best solar panel distributor, he said

"Stick to your knitting," added Spears. "Be the last guy standing.

"I look at these calls for oil service companies to beware—'You are a dinosaur, and you should participate in the greening of the globe's energy portfolio'—and I think to do that requires them to either not be a good oilfield service company anymore or wholly abandon their oilfield service roots and just be something completely different. I don't think they can be both."

Too many players, not enough game

Calls for consolidation in the OFS sector have echoed through the alleys near Wall Street and down the halls of investment banks for years. The terrible trinity of a global supply glut, weak demand and an uncontrolled pandemic has placed unprecedented stress on the current bust cycle. Price erosion has made it difficult at best to maintain profit margins as operators continue to squeeze the most out of the hardware that is working for as little as it can.

"There are still entirely too many small companies out there competing for work at pricing levels that barely make any sense assuming a debt-free balance sheet," said Canary's Eberhart. "One of the things that I struggle with is the capex requirements to do what we do is 8% of revenue, 12% of revenue, something like this. It is impossible to do that in a 5% business. You've got to cover your cost of capital and make your return and feed your capex. The math just doesn't work, and the math hasn't really worked since 2015."

Mergers in the OFS sector have historically been tough to justify. Putting two rig fleets together, for example, doesn't change the total number of rigs available to the market. It simply changes the ownership of one set of those assets. The competitor is gone, but the iron remains. The same number of units will require the same number of workers, so there is little, if any, cost savings to be had at the field level.

The greatest savings in deals like this would come from G&A costs, bringing together each businesses' office associates and middle managers and shedding some of those jobs. Even if the deals make good sense from an additive standpoint, be it complementary product lines or attractive geographical footprints, in today's oil patch, there isn't a lot of cash, or access to cash, to make deals happen.

"The only M&A that is getting done these days is where two competitors look at each other and decide to combine without swapping any dollars," said Spears. "It's just shares being folded together, so nobody is writing a check to buy the other's shares. In a case like that you take two competitors and make them one.

"Even when you do that, you're not doing anything to the capacity of the industry. For example, the Liberty/Schlumberger merger that is in the process of happening—it doesn't do anything about eliminating capacity in the industry. Two sets of salesmen now become one, but there are still 40 other competitors out there seeking and bidding on the very same work. You would need 10 of these combinations before any sort of meaningful consolidation of the industry to have happened. Is there reason to do it? Yeah, there is."

Demand for services has fallen roughly 75%, but there are still basically the same number of service companies out there all looking for work. The process of bankruptcy does not kill most companies; it simply transfers the ownership from its current group to the bank. Historically, according to Spears, not many service companies leave the industry during a downturn.

"Are there too many? Yeah," he said, "there are too many companies chasing work. There are too many of everything, and that's not going to be any better for the next year. That said, if you look at the levels of activity out in the field from now through next year, it actually rises a little bit. Frack activity rises. Drilling activity rises, on a quarter-by-quarter basis. Until you get rid of the number of competitors or you fill up the utilization of the existing competitors, you will still be working for really low prices. And how does anybody make any money like that?"

The U.S. rig count peaked at around 4,700 land rigs in 1982. By 1986, there were only 600 working. There were thousands of rigs—long-lived assets—weighing over the market. Today's overcapacity exists mainly in pressure pumping, where hundreds of units are idle. However, these units are not long-lived and are generally considered to have a five- to seven-year asset life.

"I think the big analogy everybody should be looking at is 1986," said Barclay's Anderson. "This is not 2008 or 2014. This is 1986 again. The industry went through a transformative period for about 10 years after the 1986 crash. Over that time, a massive amount of overcapacity weighed on the market, and it took a long time to work down, which is why it took so long for this industry to fix itself.

"The difference, back then, was the overcapacity was primarily land rigs with long asset lives. This time around, the overcapacity is mostly in pressure pumping, which has comparatively short asset lives, so that gives me some hope. We'll still have to go through the same painful process, but I don't think it takes as long."

For meaningful consolidation to occur you will need willing consolidators—companies, investors (and likely both) that will step in and aggressively match and marry companies looking for or in need of partners.

"We are sitting on a healthy cash balance, and we are actively pursuing M&A with ongoing opportunities and fielding new opportunities every day," said Derek Nixon, president and chief executive at Varel Energy Solutions.

"The space is very exciting for us right now because we're in that unique situation of fresh investment. This year has been tough, but it also has allowed us to focus on the things we want to be great at and the things we do very well. In turn, that allows us opportunity to bolt-on additional product lines that fit inside what we want to do in the downhole well construction space.

Nixon said he expects the OFS sector to "live within a consolidation phase" for some time, revealing opportunities for companies to build synergies and ultimately create more value for customers and shareholders.

"Varel will be extremely active in building stronger capabilities, but new deals must positively contribute with cash flow and upside value. Diversifying the portfolio makes a lot of sense right now, but it has to be the right deal. We will not pursue new opportunities that don't align with our core mission to become the leading value creator."

Derek Nixon, president and CEO at Varel Energy Solutions, remains optimistic about OFS despite the sector's challenges. "I firmly believe that whoever adjusts fast enough and continues those adjustments will come out of this better. Positivity is out there," he said.

Riding the digital wave

One way that pundits see OFS making meaningful strides toward the future of the oilfield is with the adoption of digital processes. These adaptions promise to simplify workflows and lower the cost of production while increasing recovery rates and making improvements to the company's ESG scorecard.

Digital will be a key element driving the efficiency gains operators will desperately need to drive increasing production with fewer dollars.

In a 2020 report, Barclays said using digital for small improvements in each phase of the well lead to efficiencies and could create as much $150 billion in value to producers. A digital services market is starting to take shape with a mix of tech companies, OFS and startups; over the next five years, the report said that digital could lower the cost of production by more than $3 per barrel, and expectations were for the digital services market to grow to more than $30 billion annually from less than $5 billion in 2020.

"There are some interesting technologies emerging that can dramatically improve efficiencies, which is where digital comes into play," said Anderson. "Oil companies will need to start adopting digital quickly to really move forward and meet their targets, otherwise they won't be able to compete. In oilfield services, we believe providing digital services in software, measurements or edge computing will be critical to outperformance, whether it's applied in drilling, completion or production.

However, Anderson also sees a host of companies tied to more commoditized services, the so-called "dumb iron" that is highly capital intensive.

"That's a train wreck, particularly if you're a company with a sizeable debt load. We'll see a shakeout over the next two to three years. The ones that remain will be the most efficient service companies with differentiated businesses and low debt. Those will be the survivors."

Crews lay oil, gas and water gathering lines in the Eagle Ford Shale.

TOM FOX

PRODUCTION WISE

Ambyint is a digital-heavy, next-gen oilfield technology company that specializes in well optimization. It utilizes digital and advanced analytics to assist operators in maximizing well rates of return. The company is driving plug-and-play analysis of its software to tell when a well is underperforming, identify what changes will optimize well performance and provide change automation improving efficiency.

"There is nothing more efficient from a capital deployment perspective than getting incremental hydrocarbons out of a well you have already drilled," said Ambyint CEO Blake McLean. "Where we sit in the value chain, at the wellhead, on the production side—that is an ideal place because, regardless of how many new wells are drilled or what the rig count or frac fleet utilization looks like, it will always be beneficial for operators to maximize the efficiency of wells they already have on production. Our ability to do that is proven in every major North American basin today. We like where we sit and are bullish over the next few years of constrained industry growth."

The company is in a unique position given the current state of the industry. Trying to get operators to apply a new bit of tech can be a challenge in the best of times; however, when efficiency mantras echo throughout operators' quarterly results calls with their investors, there may be no time like the present for a test drive.

"We've seen it break both ways," said McLean. "We've seen folks say they have to run a tighter business sorting out margin-leaking operational practices, and they are willing to spend some money on the front-end to do that. We've also seen folks recognize the need for greater efficiency but feel constrained in terms of capacity or hamstrung by broad cost-cutting policies."

One of the challenges this year is deals getting pushed to the right due to general market uncertainty—primarily deep budget cutting, volatility in commodities prices and organizational uncertainty, he said. "The good news is that toward the end of the year, we've seen this turbulence diminish as operators settle into a new normal. Wells that were shut-in are mostly back online. Deals that went dormant at the start of this downturn have also started to come alive again. Getting more from producing wells for less is clearly the new operating norm."

Ambyint had seen some price erosion initially, but it has developed more flexible pricing options allowing operators, for instance, to rent versus strictly hit a capex budget. Even as properties continue to change hands via bankruptcies or mergers and acquisitions well into 2021, the company finds comfort in the fact that good assets will produce and that efficient operations will continue to be a priority regardless of ownership.

"The equity holders may change, but good, core assets are going to continue to produce hydrocarbons for a number of years," said McLean. "Longer term, that's great for us. It doesn't really matter who owns them. We can add value. In the near term, when companies are working their way through bankruptcy or a change in ownership structure, investments and decisions may slow. But many operators get the fact that optimized, efficient wells bolster value and can benefit purchase decisions."

An adversary takes the reins

As of January 20, the U.S. has a Democrat in the White House. A dizzying and tumultuous election season has resulted in former Sen. Joe Biden becoming the 46th president of the United States. Historically, a Democratic president has never been a good sign for the oilfield, but it also is hardly a death knell. The new administration isn't expected to be friendly to the oil and gas business, but pundits believe that he understands the role oil plays in the nation's security, labor markets and economy overall.

"I don't think he is going to declare an outright war on the oil and gas business; however, the EPA [Environmental Protection Agency] could be 'weaponized' somewhat and put methane back in as a pollutant in the Clean Air Act," said West. "They want to stop flaring and, frankly, the E&Ps would like to stop flaring too. There is just no export for the gas. I think the EPA might get a little tougher to deal with. More stringent. You've seen companies exiting Alaska. You've seen a rush to get permits on federal lands in case they decide to ban fracking on federal lands. They can't do a whole lot on state lands."

"There was a big report that was due out on fracking, and it never made it out," recalled Anderson. "I think there will be a rebuilt EPA. That's where the issues may come, but I think that is going to take a while."

In more recent years, unfriendly regimes have not done too much harm to the oil and gas business. In 1993, Democrat Bill Clinton took over the highest office in the land. In 2009, there was Barack Obama. Earlier this year, President Trump handed over a devastated industry to President Biden.

"The Obama event is probably the most similar to the one we're facing right now," said Spears. "At the very end of the George W. Bush eight-year period, the entire global economy had collapsed, and the oil industry was rocked back on its heels and was facing the worst down year it had ever faced to that point. Barack Obama, who is not friendly to the oil and gas business, came in [to office] yet the oil industry, over 2010 to 2011, got back up to the same level it had been when George W. Bush was in his heyday for the oil and gas industry, and it stayed there for four years."

While Biden is a known proponent of renewable resources, the drum still beats in the background that the world needs hydrocarbons and will need them in quantity until such a time that alternative fuels are ready to take over the brunt of energy demand.

"The world wants hydrocarbons," said Spears. "It wants them now, and it wants them in huge quantities. Every transition estimate you see, transitions to solar, wind, whatever, all of those supply numbers are 10 to 15 years in the future. The problem is, people need to boil their eggs and cook their biscuits today. So, the beast is incredibly hungry for hydrocarbons. The oil and gas industry in the U.S. is going to do fine in about two years. You just have to get through in the meantime."

Bracing for better days

The meantime will be a prolonged period of razor thin margins, an uncertain regulatory

Ambyint CEO Blake McLean said his company, which specializes in well optimization, sits at an ideal place of the value chain because "It will always be beneficial for operators to maximize the efficiency of wells they already have on production."

The Texas and U.S. flags fly above a Liberty Oilfield Services completion operation for Teal Natural Resources in Dewitt County, Texas.

climate and commodity price levels that challenge the economics of many projects across the Lower 48. These factors, coupled with the industry's impaired access to capital, mean it will be difficult over the coming years for service companies to grow, whether through adding product lines via acquisition or full-scale merger.

"I see it getting incrementally better, but man, it's a tough road out there," said Eberhart. "I worry about pricing leverage, access to capital. I feel like capex requirements have increased as returns have decreased since 2014. All of that together just makes me feel beleaguered. We've got to be nimble, and we need to reset expectations for what is possible. The profitability that you wanted or expected may not be there. We've got to have more consolidation, and [regarding] the leverage between the operators and the oilfield service companies, the pendulum has got to swing back a little bit to favor the service companies."

Some contractors are using this time to reorganize and restructure their businesses, which will leave them more efficient and better suited for the industry turnaround. Varel used this time to reposition its business and bring its legacy downhole products and drill bit businesses together. With sales down and manufacturing overheads going up, the company rededicated itself to going above and beyond for its customer base and giving operators one less thing to worry about.

"What has worked in the past isn't necessarily what is going to work moving forward," said Nixon. "We have to be a lot more creative in our approach to the market."

"We have to understand where we want to play and who we want to play with, so to speak," he explained. "You can't go out there and be everything to everybody anymore. I think it's important that we've taken some time to understand our core competencies, which is in the manufacturing space and on the customer service and delivery side of the space as well. Keying in on those is where our purpose and vision comes from."

As most contractors know, pricing can be very quick to go down when things go bad but slow to rise when the market improves. In order to preserve profit margins, service companies must at times look inward to their own

TOM FOX

supply chains and move to coax savings from that—with possibilities ranging from things as challenging as more efficient manufacturing to obvious measures such as field logistics.

"Everybody has good products these days," said Nixon. "It's a very competitive landscape. By delivering that superior experience, we find that customers are inclined to meet your price expectations."

Varel has shrunk from a people standpoint during 2020 but is still covering the same markets. Once the two business units were combined, the company found redundancies at the manager level.

"It's about figuring out how to do more with less," said Nixon. "When you try to get somewhere in a spaceship, let's say, you move in a straight line, but there are thousands of little adjustments every day that allow you to get there. It may look like a straight line, but a line is never that straight.

"We have to be aware that we are in a fluid situation, and we'll constantly adjust our plans based on what we're seeing. I firmly believe that whoever adjusts fast enough and continues those adjustments will come out of this better. Positivity is out there."

Those closest to the industry see things getting better by the second half of 2021 for North America, with international markets to follow. By the summer, pundits see most of the restructuring processes complete and companies rightsized to the point of restoring some profitability. The process has been and will continue to be painful, but with each passing day the levels of optimism rise that the light at the end of the tunnel isn't the front of an oncoming train.

"It is really just about the simple block-and-tackle things—keeping your costs low, trying to be as razor-sharp competitive as possible and being extremely choosy about capex spending," said Eberhart. "The small things [are critical]. I don't think this is a time for grand strategy or big strategic moves. I think the market dictates being more humble and more patient and more conservative right now." □

EARTHSTONE ON THE RISE

A model of disciplined tenacity, Midland Basin-focused Earthstone Energy patiently and diligently builds scale through good times and bad. And new CEO Robert J. Anderson makes no apologies for being a small-cap, growth-oriented oil and gas producer.

INTERVIEW BY
STEVE TOON

After his first year of college in the early 1980s studying pre-law, Robert J. Anderson decided he didn't like that life path, so he unenrolled. He jumped from small job to small job in his hometown Denver, eventually picking up a Yellow Pages and looking up drilling contractors. He had heard about the oil and gas industry and was curious. He dialed the rotary phone until he came to Noble Inc., which back then still ran onshore rigs.

"Can you be in Williston tomorrow?" the man on the other end asked.

Anderson began working as a rig floor "worm" during the bitter North Dakota winter where minus 40 is a real temperature. He worked on two deep wells commissioned by Chevron Corp. targeting Winnipegosis below the Bakken "long before the Bakken was discovered," he said. "We would drill through the Bakken, and it was an annoyance."

When he figured out being a rig hand wasn't his calling, he enrolled at the University of Wyoming where he earned a petroleum engineering degree. Anderson graduated in 1986, when no oil and gas jobs were to be had, so he continued onward getting an MBA from the University of Denver. That foundation set the stage to becoming CEO of The Woodlands, Texas, based-Earthstone Energy Inc., a title he assumed in April last year.

STEVE TOON

Earthstone CEO Robert Anderson believes small-cap producers will still find Wall Street favor when the time is right. "As long as the small guy is operating and putting up good metrics, I think the investor will come back to us," he said.

A Unit Corp. rig drills for Earthstone Energy in the Midland Basin. The company added to its Permian footprint with a cash-and-equity deal in January, with an appetite for more.

"That experience helps you when you sit in this seat, because I appreciate what the guys in the field are doing."

Earthstone is a small-cap, Permian focused producer with 34,000 net acres in the Midland Basin and an additional 14,500 net acres in the Eagle Ford Shale. Anderson was part of the management team at privately held Oak Valley Resources, formed with properties contributed from Encap Investments LP, which reversed merged into Earthstone in 2014 to gain access to the public markets. Anderson was elevated to president in 2018, and prior to that executive vice president of corporate development and engineering.

Before joining Oak Valley, Anderson was on the GeoResources team that exited to Halcón Resources in 2012 for $1 billion, the same team that later reformed as Oak Valley. GeoResources was also a reverse merger executed by Southern Bay Energy and which included Anderson.

Over the past six years Earthstone has utilized M&A of small operators to propel its scale building, including a 2017 acquisition of Bold Energy, another EnCap-backed company and which gave the capital provider a controlling interest in the stock. Earthstone in late 2018 abandoned a near-$1 billion acquisition of Sabalo Energy when WTI fell from $70 to $45 after signing the PSA.

In January, however, Earthstone closed the acquisition of Warburg Pincus-backed Independence Resource Management LLC (IRM), a fellow Permian producer, for $182 million in cash and equity. Earthstone picked up some 43,400 net acres across various counties in the Midland Basin and 8,780 boe/d, but the sweet spot is a 4,900-acre block straddling Midland and Ector counties rich in Spraberry and Wolfcamp targets complementing an existing position.

And riding an updraft of E&P stocks in the fourth quarter, Earthstone's shares have more than doubled since October.

Investor *spoke with Anderson shortly after finalizing the deal.*

"We've always looked to fight another day, and if you can't be in a position where you can get up tomorrow and fight, then you're doing something wrong in your organization."

Investor What was your motivation for doing a deal at this time?

Anderson Earthstone has a great platform, and we've got a good business strategy, but we're small. And as a small, public company, it's somewhat inefficient because you've got a certain amount of cost just to be public, and investors don't really pay attention to small, public companies. Now we're a bit unique in that we're healthy, so investors give us a little more attention than they would somebody who's highly levered.

The other point is that EnCap owned a little more than 60% of us prior to doing the IRM deal. Now they're down to just under 50%. Our job is to get our equity into investors' hands where it can be traded and that helps create share value because folks want it. With EnCap holding a big chunk of it that was never going to happen.

Also, this gives us one more area to go look to drill wells when the time's right.

Investor Why this particular company and assets?

Anderson The assets were a good fit. It was a big, chunky, PDP [proved developed producing] asset with lots of cash flow, and we like that first and foremost because it's easier to finance. In this case the bank market was receptive, and we increased the size of our revolver. We did it with bank debt and equity, which is our MO to keep our balance sheet simple and reasonably levered. And this deal will take us to a little over 1x leverage debt-to-EBITDA, and that's very comfortable for us.

Investor Did you get any upside, and were you looking for upside?

Anderson We always look for inventory that either is better than what we have or can least fit into an allocation of capital in a program. And so this comes with inventory. We see 4,900 net acres with 70-plus horizontal locations in the Spanish Pearl area, which is at the Midland-Ector county line, very similar to what we have in our own assets in Midland County.

Investor There was also a large acreage package in the southern Midland Basin.

Anderson It's definitely PDP, but it does have upside; there's been some horizontal drilling in the Wolfcamp as well as other horizons. We'll tear it apart, look at it, get the help of IRM during this transition to understand it, and then figure out if it's got some upside that maybe just needs a higher oil price, or maybe some exploration opportunities. We'll sit on it for a little while and figure out how it folds in, but that was not a focus of the acquisition.

Investor What were the acquisition metrics on that?

Anderson IRM third-quarter production was about 8,700 barrels of oil equivalent per day. The $183 million purchase price gets you roughly to 20,000, 22,000 per boe flowing, and we were $10 million valuation above PDP value at strip pricing. So, we paid for a little bit of upside. We did it at a reasonable valuation on a flowing metric compared to historical deals.

Given where the market is today and what valuations are, we thought it was fair and win-win for both sides because they got equity. Since we've been talking about the deal that equity has gone up more than twice in value to when we got to closing, so that's a pretty good run. We think that's the upside and the allure to doing something with Earthstone: We have a piece of paper that is somewhat liquid and has the ability to grow in value quite a bit. We're both pretty pleased with the outcome.

Investor Do you see the A&D market as ripe for opportunistic deals at the present?

Anderson I think it's always ripe for opportunistic deals as long as the volatility with prices isn't going nuts. That's why deals in the first six or eight months of 2020 couldn't happen because of that volatility. But toward the end of the year, we saw a lot of deals and mergers of equals—including us—because of less volatility in prices. I think there are still more opportunities out there that will happen this year.

Investor Are you looking to add in the Eagle Ford also?

Anderson We have looked at Eagle Ford for deals, and we'll continue to look there for deals. The Midland Basin is our primary focus, and we'll continue to hopefully grow there, but we've got a small footprint in the Eagle Ford and for the time being our plan is to keep our Eagle Ford and keep looking because there are deals out there. We're seeing some deal flow of marketed processes.

UPSIDE IN A DOWN YEAR

Responding like most E&Ps in 2020, Earthstone laid down its one rig and shut in about 70% of operated production in response to the oil price collapse early in the year. The forced pause resulting from the COVID-19-induced global supply glut had its benefits: capex for the year dropped by more than half, from $160 million in 2019 to an estimated $70 million for 2020. And as production was brought back online after a brief one-month hiatus, the company posted positive free cash flow for the first time—some $70 million projected by analysts. A basket of $60/bbl average hedges put in place in 2018 didn't hurt either.

"2020 was a very difficult year for a lot of people, but it was pretty good for Earthstone," said CEO Robert Anderson. "I'm really pleased with what we accomplished in 2020."

Prior to the unforeseen events of the year, the company was already posturing to cash-flow neutral entering 2020 by dropping from two rigs to one to appease investor sentiment on volume growth and debt levels.

The suspension of Earthstone's drilling program in May left 11 uncompleted wells in waiting, all in its core area in Upton County, of which six were completed and brought online in the fourth quarter. Those results will be made public in the company' fourth-quarter report, but the production boost was enough to put total year 2020 production output in the growth category year-over-year, Anderson said. The remaining five wells will be completed in first-quarter 2021 before mobilizing a rig.

With the Permian's stacked-pay opportunities, Earthstone tries to keep its drill-and-complete program simple by targeting one formation at a time with a top-down approach rather than developing all the zones in a defined cube at once. However, it will co-develop formations if it believes the reservoir will suffer damage if not developed simultaneously, which is what it did on the two Upton County pads now being completed.

"We felt strongly that they needed to be developed all at the same time or we were going to have issues trying to come back to one of those zones in the future. We drilled two Wolfcamp As, and the rest were Bs. We did drill one C there because there's been some good C development offsetting us."

Here, laterals average 8,500 ft in length spaced 880 ft to 1,000 ft apart. Completions are pumped at 2,500 lb of proppant and 50 bbl of water/ft on 160-ft stage spacing. "We don't want to extend our fracs out too wide," he said.

Earthstone also uses artificial intelligence technologies in its operations to lower costs. MWD tools are now accompanied by AI sensors that, using algorithms, make projections on where to turn the bit to stay in horizon. Completions are monitored in real time to determine the effectiveness of the hydraulic fracture. "Are we fracking it the right way?" he asked. "Are we rubble-izing the rock or creating a pipeline to the next well over?"

In March, Earthstone completed three wells in southeastern Reagan County in the southern Midland Basin, a carryover from the 2019 drilling program and an area that gets overlooked, Anderson believes. Two Lower Wolfcamp B wells flowed 1,617 bbl/d (85% oil) on an average 27-day peak rate before being temporarily shut in due to the COVID-19 outbreak. A Wolfcamp B Upper well averaged 1,483 bbl/d over those 27 days. With fewer land restrictions here, laterals average 10,000 feet.

"That's an area that flies under the radar screen," he said. "It's an area that most people think is really gassy and has low rates. Over time those wells ended up being about 50% or 60% oil, so we know that the oil declines off and the gas increases, but we're pretty pleased with the outcome there. Wells over 50 barrels a foot EUR are not uncommon in that part of the world. They're pretty nice oil wells."

Investor What is your outlook for consolidation in the Permian?

Anderson I think there will continue to be consolidation. There are too many companies and so much fixed G&A that the margins aren't good enough, so sooner or later you have to consolidate and operate with a lot less. Companies individually have operated throughout 2020 with a lot less because they were forced

THE LODZINSKI CONNECTION

It's hard to tell Robert Anderson's story without mentioning Frank Lodzinski, Earthstone's executive chairman. Lodzinski has been a build-and sell-specialist since the 1980s and was the driving force behind the Southern Bay to GeoResources to Halcón exit. Anderson mentored under Lodzinski as a part of his executive team for 17 years before taking over the CEO role.

He quips, "My change to CEO was effective April 1 of 2020, a really good time, right?"

Anderson first joined Lodzinski and his core team in 2004 at AROC Inc., a Gulf Coast, Permian and Midcontinent private producer as vice president for A&D and engineering. AROC was a predecessor to Lodzinski's Southern Bay Energy, a platform that took over publicly held GeoResources. Anderson was executive vice president and COO over GeoResource's Bakken assets.

Following GeoResources' sale to Halcon Resources, Anderson rejoined the Lodzinski team at Oak Valley in 2013, and the rest is history. Lodzinski stepped out of the day-to-day operations early in 2020, handing Earthstone's controls to Anderson.

"He's been a lot more than just a boss or a partner. He's taught me an incredible amount about being in this business. I spent a year or so as president, and maybe I've been groomed for this for a long time, so he finally got [me] to the point where I knew enough and he could turn the keys over."

Anderson noted a number of Earthstone employees and investors preceded even his arrival on the team.

"Some of these guys have been with Frank for over 20 years, in the office and in the field." The culture, he said, gives everyone autonomy to do their job, with a voice at the table. "It's a team sport and everybody has to pull their weight. And everybody gets some kind of reward out of it."

Investors, too, have stayed on board for the long haul. Besides EnCap Investments, which is on its third placement with the Earthstone management, other individual and institutional investors have placed their faith in the team for up to 30 years, he said.

"We've created a culture for creating value with those guys and they're still with the stock."

Anderson said he feels a duty to continue Lodzinski's core beliefs. "I have the duty to make sure we keep a financially sound company, to continue to grow shareholder value and grow the culture among our employees like we've had for the last 17 years when I came the first time, which is work hard."

to but, as an industry, to become further investable whether publicly or privately, we need to have some of those fixed costs removed from the system.

Investor By necessity then?

Anderson By necessity. We've exploded with the number of companies. If you look at the late '90s, we had a lot of private and public independent companies, but we lost some of those names through consolidation because people thought that oil prices were never going to recover. Then with the recovery in oil prices and access to capital over the last 10 or 15 years, the proliferation of companies was tremendous. I think we've reached that point now where it's saturated and it will come back down.

Investor What makes Earthstone an aggregator?

Anderson We've got a great platform and great people. We have a tried-and-true track record of creating shareholder value, and we want to continue to do so. We've got a good balance sheet. We've got great supporters in EnCap and now Warburg, two big, private equity sponsors that recognize we've created value and we can continue to grow. Ultimately, we've got public investors who like what we're doing, and the proof is in what happened over the last few weeks with our stock price and our volume. We're just not done. We've got more capacity.

Investor Why did you cancel the Sabalo acquisition in 2018?

Anderson Prices cratered. We signed the deal in October at $74 oil, and by December oil prices got very low. The amount of debt we were using and the leverage would have been just too great. You could make a case to go back and renegotiate, but we had raised a debt facility that was pretty big, we had equity going to the seller, we had some convertible preferred, and Sabalo had a drillco that was a tag-along, which also would have had to have been renegotiated. It just would have taken a lot of surgery to extract all the pieces and put them all back together again.

Also, Sabalo is an EnCap company. We had already offered as much equity as the sellers wanted to take and any more would make EnCap greater than a 75% to 80% owner [of Earthstone]. That would have made sense to probably go private at that point, but that didn't mesh up with their goals.

Investor Do you still consider it a good decision?

Anderson If we had a perfect crystal ball and knew by the middle of 2019 oil prices recovered, maybe we should have kept on going. But the leverage was just too great. Had we had everything hedged and closed much quicker, it probably would've worked. When you didn't have as much hedged as you needed to and oil prices fell as far as they did as quickly as they did, it was a good decision to walk away.

Investor How important is scale in the eyes of Wall Street investors?

Anderson I think small companies need scale to attract new investors. Does that mean we don't have good investors today? No, absolutely not. We've got great investors. We've got investors who've been around for quite some time owning our stock, and some of them were investors in GeoResources who made a significant return on that investment. But to get the long-only investors who do invest in oil and gas—and there may not be very many of them left—to attract them we need to be bigger.

And we also need to have more trading volume because these investors can chip away and can buy shares, but if they need to get out in a hurry for some reason, it's hard to do it when your volume is so small. And that's what we've recognized over the years.

When we had GeoResources, for instance, we had the same problem when we first got started, and we did three different equity deals along the way to get our volume up. Ultimately some big, long-only money managers noticed the scale, noticed the trading volume, and invested.

Scale is important but has nothing to do with the fundamentals of our business about being able to minimize LOE or maximize margins. You can do that at any size. But to get Wall Street interested, we've got to have scale.

Investor What does that look like? What kind of scale do you need to attract more Wall Street interest?

Anderson You've got to be in the billions [market cap]. Is that $1 billion or $5 billion? I don't know the answer. I think there's continually going to be investors who will play in the smaller-cap-scale companies and as you get bigger, you just get bigger investors. And that is what we're striving for.

Today we're at $500- or $600 million. We have 78 million shares outstanding as of this deal and we're trading at close to $6. In November we were under $3.

Investor Can a small-cap company compete for public investor capital in today's marketplace, or are they just off the radar for now?

Anderson You can't get back on the radar if you don't put up good metrics, if you don't have a good balance sheet. I'm not going to say 1x leverage is the answer. Maybe you can get away with 2x leverage, but you've got to have liquidity, lower leverage and be able to operate with the highest margins possible. And then you will get exposure to the public investor who is willing to play because the growth potential in a small-cap stock is obviously much higher than with a major or larger independent, for instance.

Right now we've all had the luxury of growing since last March or April when our stocks were beaten up badly. But at the normal status quo, a $50 environment, the little guy growing probably has the potential for an outsized return.

Investor My perception is that they're only going for the largest caps now.

Anderson In a very volatile, rough time, they're looking for security, right? If you're going to stay invested in the oil and gas space, you're going to go to the big guys for security. But as long as the small guy is operating and putting up good metrics, I think the investor will come back to us.

Investor You position Earthstone as a growth company but, from your perspective, how does the investment community view growth vs. returns for a company your size?

Anderson For small companies, return of capital is limited. Smaller companies get traded on some kind of cash flow or EBITDAX multiple, so if you're not spending capital and growing your EBITDAX, then your valuation is probably going down from a public company standpoint.

Now, if you can't spend capital because you're overlevered, and you're paying the banks every month, then you're in a difficult cycle. We are different in that we're not overlevered. We can run a one-rig program and still have free cash flow to continue to pay down debt. And so we're sitting in the best of both worlds where we have options to spending capital and growing.

Investor Are you generating free cash flow presently?

Anderson Yes, but we didn't spend any capital to speak of in 2020 because we stopped our drilling program in May. We completed some wells at the very end of the year, so we spent $70 million and analysts have us generating $140 million of EBITDAX.

Investor When did you pivot to free cash flow positive?

Anderson We were an outspender in 2019, but

"We are not trying to build the next empire. We are trying to create shareholder value, and we think the way to do it outside of putting a for sale sign out is just keep operating appropriately and—sooner or later—you will get noticed."

EARTHSTONE ENERGY INC.

Earthstone's six-well Ratliff 9-7 pad in Upton Co., Texas, completed in December after having been drilled in first-quarter 2020.

Earthstone Snapshot

Ticker	NYSE: ESTE
Headquarters	The Woodlands, Texas
Focus	Midland Basin, Eagle Ford Shale
Net Acres	43,600
Production	25,740 boe/d (58% oil; 81% liquids)
Gross Locations	512
Market Cap	$488 MM
Debt-to-EBITDA	1.1x

Source: Earthstone Energy

we were rotating to spending either a little bit plus or minus our cash flow in 2020 prior to March and the world shutting down. We can run a one-rig program now and have a little bit of both growth and free cash flow—and pay down debt. For a small company that's a great position to be in. And if we don't want to pay down debt, if we want to go and buy more assets, we have the luxury to do that. If we can find the right assets.

Investor Is that a new directive for Earthstone, or will you go back to debt-induced growth once prices justify it?

Anderson It's going to depend a little bit on what the investing community wants us to do, right? And we have that flexibility where we can turn it on or turn it off. We could run two or three rigs—well, probably not three. We can run two rigs quite easily and outspend cash flow, but only by maybe 10%. There'd be debt growth, but production growth would be pretty significant.

We're only going to do that if we get rewarded by the investors to have an outsized EBITDAX growth. If we're not going to get rewarded by the investors, then we can still have EBITDAX growth within a one-rig and cash flow program.

Investor Can you grow organically?

Anderson Just through the drill bit? You bet. And that's our plan. Acquisitions are somewhat serendipitous or, you know, just being in the right place at the right time with the right capital structure. We always continue to look for those opportunities because of gaining scale and wanting to be bigger in the public markets, but we always look at can we grow organically with a drill bit. And we can.

Investor But can you grow organically at the pace you want, or is M&A a better option at this time?

Anderson M&A is like big, giant stair steps, whereas organic drillbit growth is slow and steady. You've heard that when oil's low, you can look for it on Wall Street much cheaper than you can drilling wells? We want to make sure we have that flexibility to do both. We're compelled to continue doing consolidation for good, financially disciplined, technically disciplined acquisitions. And we're going to continue to do that. We will look for opportunities that make sense.

"We're compelled to continue doing consolidation for good, financially disciplined, technically disciplined acquisitions. And we're going to continue to do that."

Investor Your track record is building public E&Ps and then selling. Is your goal, therefore, to be a larger scale, investable public E&P, or is it to achieve a certain critical mass where you become a target for another company?

Anderson I don't think those are diametrically opposed. I think you can run your business so that either one of those might happen. It takes the right capital market and chemistry to be bought. We're going to continue to run the business and grow it, and if the chemistry and the market is right, then somebody will come along and talk to us at some point. That's no secret. Everybody knows the track record.

We always have a "for sale" sign out. We are not trying to build the next empire. We are trying to create shareholder value, and we think the way to do it outside of putting a "for sale" sign out is just keep operating appropriately and sooner or later you will get noticed.

Investor To what level are you aiming to pay down debt?

Anderson The question is what level is low enough? A half a turn of leverage? There's no reason to be zero. Using leverage at a 2% or 4% interest rate seems like a good idea to me if you're making 40% or 50% rates of return wells and you can do that consistently. So yes, there is a point where we say we don't need to pay down debt anymore. And if we're big enough, maybe that's okay. We pick up a second rig or we go buy some assets.

You do want leverage to be in a range low enough that you can survive these dips that we're going to continue to have. We've seen them throughout our entire careers. That's why we never want our debt to get to a point where it's 2x and all of a sudden it becomes 3.5x when oil prices go down. You've got to be disciplined about using debt. We've spent a lot of time focusing on making sure that in a down price environment it doesn't sink us.

Investor When do you plan to add back any rigs?

Anderson We don't want to get that cart before the horse. We want to make sure that we've got all our land and inventory ready to go, which we've spent the last year working on because we weren't drilling. We're looking at how do we incorporate the IRM acreage to allocate capital. Within the first half of the year, we'll have a rig running, and I hope it's sooner than that.

Investor When you do to put a rig back into play, where will it go?

Anderson To the highest return projects that we have. So Midland County, Upton County and then the Midland County IRM assets. We'll rotate between those three project areas.

Investor Do you intend to add a second rig any time this year?

Anderson We have a plan that shows a second rig and to see what that looks like. We're going to walk before we run. We'll get that first rig up and running, work out the kinks and get our team focused on that. And then we'll take a look at where the market is and oil prices and different options and see if it makes sense to run a second rig.

Investor What's your plan for the Eagle Ford assets? Will they receive any capex in the near future?

EARTHSTONE ENERGY INC.

The Ratfliff 9-7 pad targeted Wolfcamp A, B & C, with results pending fourth-quarter 2020 reporting. The location is on former Bold Energy acreage and various land swaps.

Anderson Everything that we could drill under a $50, $55 price environment we've drilled and everything else needs higher prices. I think over time maybe technology will help fix that as we change our frac designs.

Investor In the past, your start-up model was to buy producing assets essentially to cover G&A, then to reverse merge into a small public company. Is that strategy still viable today for somebody else considering it?

Anderson You haven't seen that in a while. It's getting harder now with the investing population being less. Coming out as a small, public company is pretty difficult today.

Then you have to have some ability to grow, and that by itself is constantly a challenge. Now, as consolidation happens and bigger companies start selling off assets, which I think will happen, I think you're going to find assets getting put into the market because they're not going to get any attention from the bigger guys. Maybe that creates the opportunity again for a small company to go out and acquire them.

Investor Are you suggesting that it would be better to stay private in the current environment because the public markets aren't there for growth opportunities?

Anderson Absolutely.

Investor What advice would you give to next-generation management teams to guide them through volatile events like we've seen in the past year?

Anderson Having lived through these environments like the past year, and really since the end of 2014 when oil prices crashed, makes you better manager and makes you recognize that if you get out over your skis, you're going to end up taking a tumble. Having good folks around you in all the different disciplines will help you succeed.

And watch the way you finance and structure deals. A debt leverage ratio at one oil price is a totally different leverage ratio when your EBITDAX drops in half because oil prices dropped in half. If you can't pay down debt fast enough to avoid those kinds of issues, then that deal probably isn't right for you. A combination of debt and equity are really important.

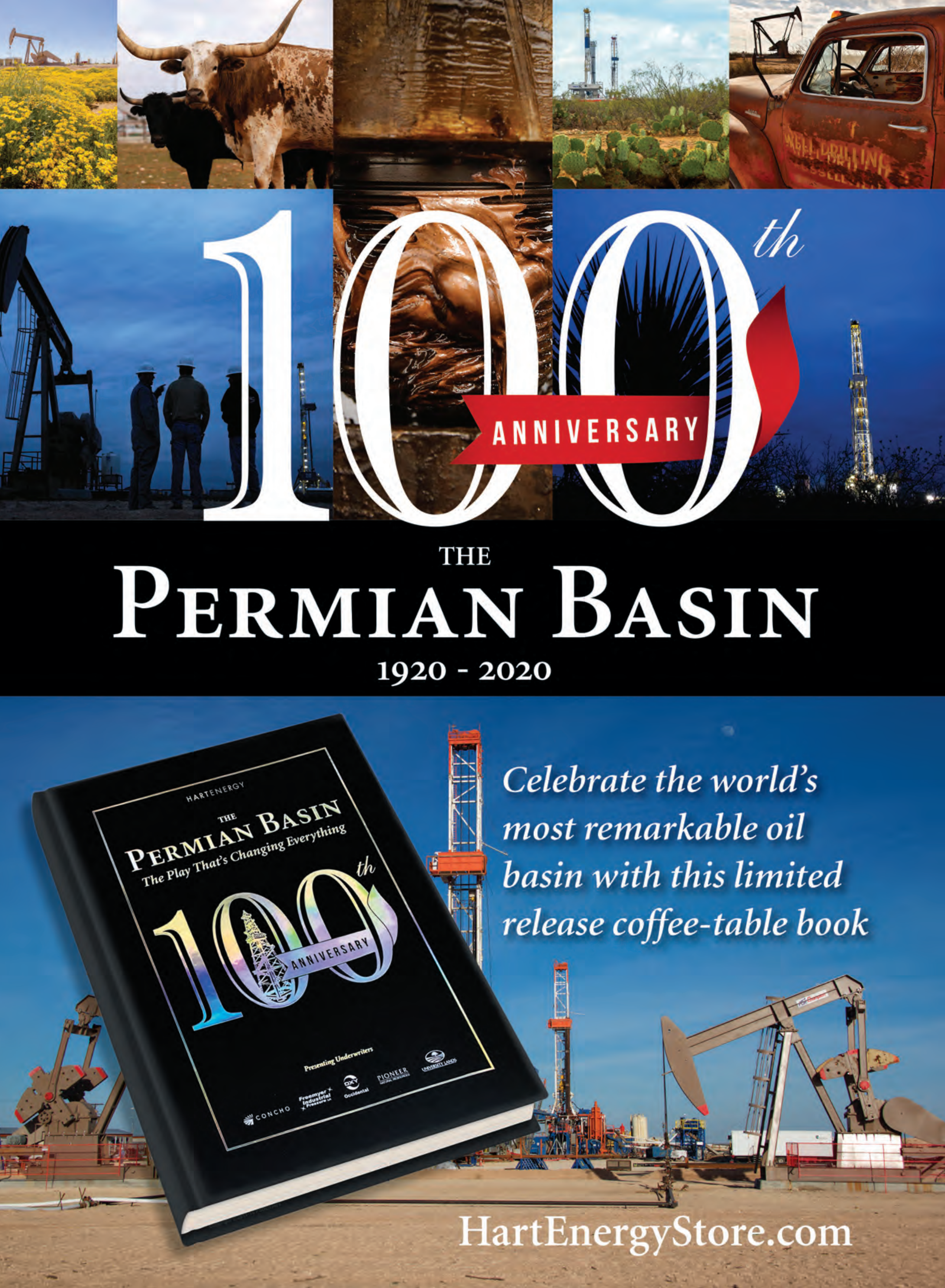
Then, you need a little luck. For several months we've seen the tide rise and we've all felt a lot better than we did last March and April. We've always looked to fight another day, and if you can't be in a position where you can get up tomorrow and fight, then you're doing something wrong in your organization.

Investor Why should an investor consider Earthstone at this time? What sets you apart?

Anderson For one, we've got a track record of returning value to shareholders. Two, we get up every day and we work hard on all the operating metrics, trying to make sure we have the highest margins possible and protecting for downside risk, meaning keeping leverage as low as we can. We continue to focus on hedging to protect some of that downside—not to make a call on where oil prices are, but to protect for 2020-like events.

And last, we're going to continue to be one of the survivors in this business. Many companies have had a rough go of it, and we actually feel that we're set apart from that in that we haven't had survival issues. Our issue in '20 was, how are we going to thrive through that environment? And I think what you saw at the end of the year with the IRM deal is an example of how we thrived, and we'll continue to look for opportunities to do that.

I'm looking forward to 2021. □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PRIVATE EQUITY'S TECH PIVOT

Private equity's interest in oilfield services is expanding the definition of what is investable.

ARTICLE BY
LESLIE HAINES

Private equity firms' interest in the oilfield services (OFS) space traditionally meant investing in hard assets: rigs, frac pumps and trucks, a sand mine or downhole equipment. Firms always focused on companies with emerging technologies that advance E&P efficiency, including the abilities to drill or complete a well more accurately and faster.

A lot of debt flowed into the industry as private equity-backed startups developed new technology or sought to buy divisions from larger companies such as Halliburton.

"That's all come unhinged," said G. Allen Brooks, managing director of PPHB LP, a Houston boutique focused on oilfield services. "The overriding environment for private equity in the service sector right now is trying to make their companies profitable. And, private equity itself is getting beat up, because it's suffering not only from the industry downturn, but from the fact that the funds they can raise [from limited partners] are drying up.

"The marketplace has changed and is going to be smaller."

Combine these travails with the fact that the oil and gas industry in general is slowly figuring out what its new role in the energy transition will be, and you'll find that private equity firms are expanding their scope of investments.

WHITE DEER ENERGY

Private equity firm White Deer illustrates the sector's expansion of what it defines as services investment. The firm no longer invests in E&P and recently bought an over 90% stake in EV Infrastructure, an electric vehicle charging infrastructure business.

The case for consolidation among OFS firms has rarely been stronger, said Simmons Energy managing director Sanjiv Shah.

"We're not going to own the resource, but we'll invest in companies that are helping to do anything related to production," said one source, who also invests in alternative energies. Increasingly, that means private equity is no longer turning to hard iron and downhole tools, and instead is considering anything digital, ranging from technologies involved in the supply chain leading up to a completion, to data management or software as a service (SaaS) concept.

"All of our companies are focused on enabling the efficient production of energy," said Ryan Gurney, managing partner of Cottonwood Venture Partners. The firm has made 10 platform investments in energy technology including MineralSoft (sold to Enverus in 2018). Cottonwood closed its second energy technology fund at $64 million in December 2020 and has raised approximately $100 million since its launch in 2017. Cottonwood closed its inaugural Digital Oilfield Fund at $32 million in October 2018.

Private equity funds focused on oilfield services took a serious pause during the bleak atmosphere of 2020. Now these funds will not open their coffers for new platforms. Rather, they may inject capital to stave off threats to their existing portfolio companies amid a wave of oilfield service bankruptcies, not to mention the near collapse of activity in the frac equipment and sand business lines. Some are making acquisitions of tech divisions being hived off the giants like Halliburton Co., Baker Hughes Co. or Schlumberger Ltd.

The 2020 downturn threw into stark relief a sad truth: The traditional OFS sector is suffering a glut of capacity. It has been overcapitalized for a long time, even before the pandemic, so a wave of consolidation needs to be underway. The total market for oilfield services keeps shrinking; companies must battle for market share amid the surfeit of equipment, clients demand discounts and stronger players are seeking scale.

Despite these hurdles, and a pullback in buyout activity for new OFS platforms, private equity firms continue to be active in OFS, albeit in new ways.

"For example, distressed M&A activity or debt-for-control investment activity is elevated," said Sanjiv Shah, managing director at Simmons Energy, a division of Piper Sandler & Co. "As such, firms that are active in new money OFS investing are not necessarily the same firms that have been active historically," he told *Investor*.

Tech software is the allure

For a while now, the most prominent private equity firms traditionally active in the E&P space have also been investing in energy technology—it makes sense, especially during the downturn as finding new efficiencies has become even more important.

PELICAN ENERGY PARTNERS

Pelican Energy Partners merged two companies to create Vault Pressure Control.

"People don't want to buy hard assets like drilling rigs or pressure pumping equipment. They want to back AI, software, anything digital," said PPHB's Brooks. "What we're finding is that people are innovating in things like managing access to remote sites. Somebody pulls up in a truck … and you keep track of all the vendors and contractors out there. Are they supposed to be there? What are their credentials? Are they trained in safety? These kinds of things are percolating throughout the industry."

Quantum Energy Partners, a leader in providing equity to E&Ps, has always made some investments of $5 million to $75 million in services or technology; these checks are typically smaller than what Quantum would provide to an E&P client, which has been anywhere from $300 million to $500 million. (Counting follow-on investments, the firm has up to $1 billion invested in some of its E&P portfolio clients, because they are building toward a strong exit later.)

"In oilfield services, however, the risk can be higher, [so you might advance less capital]. But, you can get a higher return, so you might make three to six times your money. It's more akin to what venture capital firms do," explained CEO Wil VanLoh.

Lately, Quantum has gone all in on digital applications for energy. "Investing in a sand company or a drilling rig, that doesn't get us as excited. But to create an ecosystem to capture, clean and store data, that's a theme you'll see more and more with us. We've really invested heavily on data science in the last three or four years, both internally, which has helped us in our own investing process and in our portfolio companies. We hired a chief technology officer this past year who was with Chevron to take us to the next level."

Quantum recently partnered with another private equity firm, Global Reserve Group, to infuse $11 million into Datagration Solutions Inc., which provides PetroVisor, a software for the upstream. Datagration is the sixth energy technology venture capital investment that Global Reserve Group has made with Quantum, said Jeffrey Harris, founder of Global and formerly a senior partner and principal for 29 years with Warburg Pincus.

"We've always looked at service companies. At any given time, we might have one or two of these per fund. It's a unique business where we see growth trends in 'smart iron' as opposed to 'dumb iron,'" said VanLoh. Speaking more broadly of the devastation suffered by the OFS sector in the past year, he added, "I do think, be careful how much you beat them up, because we need these companies if we're going to have an upstream business." Across Quantum's E&P portfolio, about 22 rigs are running on average all the time, so he certainly knows what the OFS sector contributes.

Two years ago, Quantum invested in RigUp, which provides contract labor to the oil and gas industry. But where once about 90% of its business was in oil and gas, today that's only about 30%, as RigUp expanded into residential, commercial and industrial sectors. It's a common theme as capital providers and service companies themselves diversify away from traditional equipment and services to digital, data management or to other sectors such as the downstream and industrial.

Tech takes many forms these days as the energy industry evolves. In December, NGP filed to take public its second tech-oriented SPAC, Switchback II Corp., which is looking "to evaluate targets across numerous sectors, including energy technology, clean and renewable energy infrastructure, … energy efficiency and battery storage…" and other energy-related opportunities, according to the S-1.

NGP IPO'd Switchback I in July 2019 (NYSE: SBE), raising $345 million. In September 2020, Switchback pulled the trigger, agreeing to buy ChargePoint Holdings Inc.—one of the world's largest public EV (electric vehicle) charging networks. (That deal was scheduled to close by December 31.)

This transaction illustrates what private equity firms are doing to expand their view of what is investable, based on what they think the future of energy may hold. According to Simmons' Shah, "In fact, many traditional OFS-oriented investors are now focusing on a broader definition of energy that includes downstream/industrial, power/utility, infrastructure and alternative/new energy exposure."

They are also taking a page from history: The people who made the most money during the California Gold Rush were not the prospectors. It was merchants, the middlemen who sold the prospectors picks, shovels, denim jeans and whiskey.

Private equity pivots

White Deer Energy is an example of how private equity pivots. Founded in 2008, it has $2.7 billion of assets under management and is still investing out of Fund III, which closed in 2018 at $557 million. Its mandate is broader now that the firm exited the E&P space altogether; it has not done any E&P deals since 2016. However, it continues to own a wireline company, a pressure control equipment rental company and a workover rig entity engaged in more conventional OFS businesses. But going forward it is expanding well beyond these traditional concepts, into equipment and services for refineries or for the budding EV industry.

Partner Joe Bob Edwards said that when he started in the business in the late 1990s, the way to make money was to consolidate E&P assets and companies. Then shale came along, and for about 15 years the way to make money became growing E&Ps at all costs. Today, he says, the energy world has changed once again, and it's in the early stages of OFS consolidation. The new growth capital opportunities are in the energy transition or alternatives space.

"Most of what we've done lately is what we call the energy supply chain," he said.

"That's OFS, midstream infrastructure and, increasingly, downstream and industrial equip-

The overriding task for private equity is trying to make their companies profitable, said G. Allen Brooks, PPHB LP.

"There are too many of us in the OFS segment. It's over-capitalized," said Joe Bob Edwards, partner with White Deer Energy.

ment and services, such as anything that helps refineries, and anything involved in the energy transition. To us that means any form of power production or alternative fuels such a solar, wind, batteries, ethanol or biodiesel.

"We buy companies that assist in producing all of the above," Edwards said.

Its most recent deal in 2020 was to buy, in an auction process, an over 90% stake in EV Infrastructure, a business that designs, builds and installs electric vehicle charging infrastructure. To that end, it helped one of its clients, FedEx, convert a truck hub to EV from diesel, analyzing what the hub would need in terms of power and design.

"For the last couple of years, even before COVID-19, we recognized that this is a trend that's happening, and we said, 'How can we capitalize on this?'"

Edwards said the deal was relatively smaller than most other private equity firms might be interested in, but White Deer believes EV Infrastructure will grow, partnering with the management team that also put in some equity.

Earlier, White Deer invested in a Houston company, Unicat, which manufactures catalyst materials used in large-scale chemical processes such as those found in a refinery.

"These deals are indicative of how broadly we are looking at opportunities in energy," Edwards said. "I think this is an emerging trend among the energy private equity universe, which itself is in transition. We cannot ignore that the world is changing. Every firm has to come to grips with this."

Consolidation waves

Simmons' Shah noted that there is what he calls "a huge" installed base of private equity-backed OFS companies of vintages that exceed five years. This raises the question, should they exit now, and how can they exit? Although valuations are down, are they being forced to exit by the downturn?

"The case for consolidation has rarely been stronger," Shah said. "With a lack of cash exit options at acceptable valuations, private equity-backed portfolio companies are more open to combining with each other and into public vehicles. While these transactions don't represent true immediate exits, they provide the best path to value creation/recovery."

Shah said that bank debt appetite continues to be apathetic toward the OFS sector, which limits the options an OFS company has, but on the other hand, he said we might see more private equity-led PIPES (private investment in public equity) or heavily equitized corporate carve outs.

The folks at Pelican Energy Partners also said the name of the game is consolidation, not startups or growth equity deals. "We are very actively working on several consolidation deals," said partner Mike Scott.

In November Pelican purchased the Baker Hughes wellhead business, combined it with one of its existing portfolio companies, and rebranded the new entity as Vault Pressure Control. This was the largest company Pelican has ever purchased.

"The opportunity was made available because of the magnitude of this downturn. We are seeing a tectonic shift in the OFS company landscape," Scott said. "Several of the larger players are selling business units that they don't want to deal with anymore. Those are generally getting purchased by competitors in consolidation transactions, which is a very healthy thing for the industry and needs to happen.

"We are currently in several conversations with other OFS players that are potential consolidation transactions with several of our portfolio companies. Private equity is taking a leading role in this wave of consolidation. We have seen private equity funds combine their own portfolio companies; in fact, we recently just combined two of our portfolio companies where there was a very good strategic fit."

Is there any way to create a good exit these days? To create value? Everyone we spoke with said the same thing: The short answer is 'no.' This situation is the greatest headwind blowing against the oil and gas sector today, especially for OFS companies.

Nevertheless, several consolidations were announced in 2020 amongst portfolio companies of different private equity funds, such as Innovex Downhole Solutions Inc. (backed by Intervale Capital LLC) agreeing in November to combine with Rubicon Oilfield International (backed by Warburg Pincus) in early 2021. Covenant Well Testing (backed by NGP) has combined with Stuart Pressure Control (a White Deer Energy client). Covenant is the surviving company.

Smashcos between entities backed by the same private equity firm are also taking place as the OFS sector adapts to tough conditions. In July, The Woodlands, Texas-based EnerCorp Engineered Solutions combined with Pro Oil & Gas Services LLC of Houston, which provides well flow management and well construction products in the Permian and Haynesville plays. Both companies are backed by Intervale, which since 2006 has invested in over 50 companies engaged in infrastructure, energy and industrial end markets.

Intervale also sold Torc Sill Foundation LLC, based in Pasadena, Texas, to a new entity primarily controlled by White Deer in October. Torc Sill provides engineered piles and anchor foundations to energy, power and industrial clients.

Dollars available

Pelican Energy Partners' third fund is only about half deployed, so plenty of capital is left for new opportunities in this disrupted market. "We have kept capital available in our first two funds as well," Scott said. "In fact, the Baker Hughes wellhead transaction, which is now branded as Vault Pressure Control, was done out of our second fund because that's where our portfolio company resided, which got consolidated into Vault. We were fortunate to have enough capital available in our second fund to facilitate that transaction, keeping our third fund's capital available for other opportunities."

The thesis at Cottonwood Venture Partners is that energy is going through a renaissance in terms of digital adoption yet, to date, not all that much capital has been invested in energy software, said Gurney. "We have three criteria: software as the primary product or service, customers must be in the energy space, and we invest in companies that are post revenue.

"When prices are low, and oil and gas companies, and energy broadly, have reduced headcount, how do they handle jobs? Software. It enables operators to do more with less. You have 25% to 30% fewer hands across the industry, yet companies are looking to increase activity in 2021."

Cottonwood has made 10 investments since inception and typically holds for three to five years. Gurney noted that the buyer universe has changed for exits, with stalwarts such as Halliburton and Schlumberger already owning various large software platforms.

Its most recent deal was to back HUVR, which manages inspection data (including drone video footage) for equipment in heavy industries such as wind turbines and downstream refineries. ExxonMobil is a HUVR customer.

"It's hard to repurpose a frac pump," Gurney said, whereas software applications or data technologies for the oil industry can be applied in other industries.

Scott said at the moment, Pelican is not purposely seeking out green technologies as this doesn't fit its mandate or strategy. "Green technologies, or any energy technologies, that are early stage and don't have an established business footprint are too risky for us to expose our investment funds to, as we don't want to take venture risk in any of our investments," he said.

Even if it were to consider downhole technology deals, Pelican needs to see that the business opportunity in question has arrived at the growth equity stage—meaning it already has multiple customers, repeat business and a track record of growth. He said opportunities in more mature companies with a green technology product offering don't screen very well in Pelican's return analysis. "We would certainly be open to those investments, but we have not found any that have met our return criteria," he added.

The outlook

Conceptually, Scott said Pelican believes 2021 will be a good time to put money to work in the OFS sector. "We expect that it will be a long, slow ramp of recovery that will go beyond 2021, so it would be getting in closer to the bottom than the top. But investing in startups is a different question and we probably won't be doing many growth equity investments in 2021," he said.

"The market doesn't need any more capacity. It needs less capacity, which will happen through attrition and consolidation. So, we don't want to be adding capacity in any aspect of the oilfield sector today.

PELICAN ENERGY PARTNERS

Pelican Energy Partners' combination of two portfolio companies to form Vault Pressure Control is one of several private equity consolidations that took place in 2020.

"That means an investment target needs to have a pretty revolutionary product that will induce customers to leave their current solution, which is most likely already paid for and a sunk cost, and be willing to spend fresh capital on something they already have a solution for. Those sorts of breakthrough opportunities are few and far between. I would guess we might see one or two deals that fit those parameters in the entire year of 2021."

It's a fascinating time to be navigating the oil and gas sector. "We are certainly seeing stronger headwinds than we have since the 1980s due to increasingly negative sentiment on fossil fuels, as well as pandemic-induced demand destruction, some of which may become permanent based on consumer behavior shifts," Scott said. "While we believe these factors will have a significant impact on the long-term trajectory of the oil and gas sector, we also believe that cognitive bias exaggerates short-term causes on long-term effects."

For decades, growing oil and gas demand has been highly correlated with global population and GDP growth, and that dynamic continues for several years, experts say. But changing attitudes have created new chances to invest, he said.

"Since there are now many people who no longer believe that [oil and gas demand shares a positive relationship with global population and GDP], we are seeing much more flexibility and capitulation amongst current asset owners. As a result, we are finding more opportunities than we have for quite a long time. We will continue to be active investors throughout the next year or two while these conditions persist," Scott said. □

"We are seeing a tectonic shift in the OFS landscape," said Mike Scott with Pelican Energy Partners.

NATGAS SHINES

Oil is rebounding but is forecast to continue to be constrained by excess production potential at a higher price. Meanwhile, U.S. natgas is all dressed up with lots of places to go.

ARTICLE BY
NISSA DARBONNE

A warmer-than-usual U.S. winter has dragged on natural gas futures, but sub-$3 won't last, according to forecasters. Asian demand has rebounded. Industrial demand has rebounded. And supply remains reduced by less oil-well associated gas production.

Near term, however, there's still too much natgas, according to Rusty Braziel, executive chairman of energy-markets consulting firm RBN Energy LLC.

"U.S. natural gas is now totally dependent on exports to balance supply and demand," he wrote shortly after New Year's Day.

As LNG exports "have recovered with a vengeance" and natgas prices "clawed their way back" to more than $2 in the second half of 2020, "the lesson was learned," he wrote.

"With Lower 48 production in the 90-plus Bcf/d range where it is today, without exports the U.S. market is vastly oversupplied and, if exports are curtailed, prices will respond accordingly."

Rusty Braziel, executive chairman of energy-markets firm RBN Energy, foresees the continued aging of shale oil wells to pose a problem for the natgas market's stability over time. Why? "Because as shale wells age, they tend to get gassier," he said.

U.S. LNG shipments began 2020 at 8 Bcf/d, grew to 9.5 Bcf/d in early April and slid to 3 Bcf/d in July, according to J.P. Morgan Securities LLC energy analyst Arun Jayaram. They more than recovered by December, setting a new high of 11.6 Bcf/d.

Tankers loaded an average of 11 Bcf/d during the first half of December. Of that, 4.02 Bcf/d was loaded at Sabine Pass, which is the largest U.S. export terminal. The balance of orders was filled at Freeport, 2.03; Corpus Christi, 1.98; Cameron, 1.94; Cove Point, 0.79; and Elba Island, 0.22.

Sheetal Nasta, fundamentals analyst for RBN, wrote at year-end, "Talk about whiplash! Not that long ago, the global LNG market was reeling from the effects of the pandemic: stunted demand, severe oversupply, brimming storage and record low prices—all of which led to a squeeze on offtaker margins and mass cancellations of U.S. cargoes.

"Within a matter of months, however, the market has done a 180."

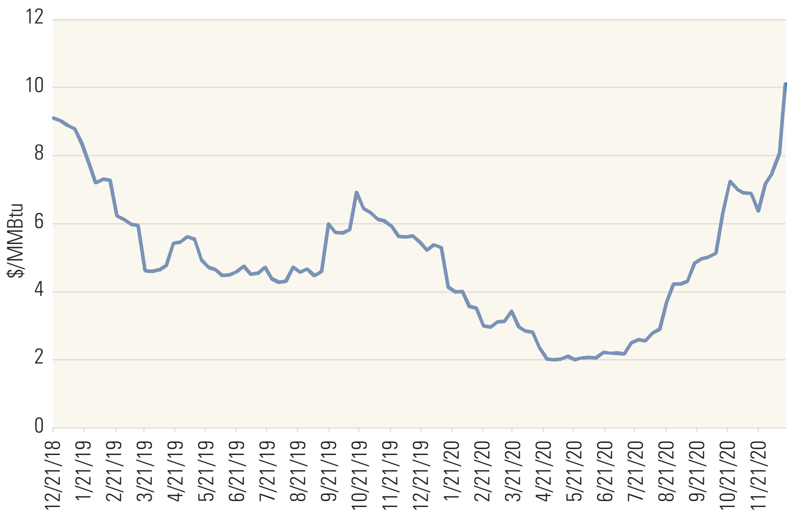
All U.S. export terminals were operating at or near capacity approaching year-end. The smallest among them—the Kinder Morgan Inc. 51%-owned Elba Island, Ga., terminal—entered full operation in August. Its capacity is 350 MMcf/d, of which 100% is contracted by Royal Dutch Shell Plc.

Meanwhile, a meaningful amount of improved demand came from Mexico. Exports were 4.6 Bcf/d exiting 2019; in December, they were 6.3 Bcf/d, and the 2020 average was 5.7 Bcf/d, according to J.P. Morgan.

Winter

But the record exports, even amid reduced production, weren't showing up in a higher

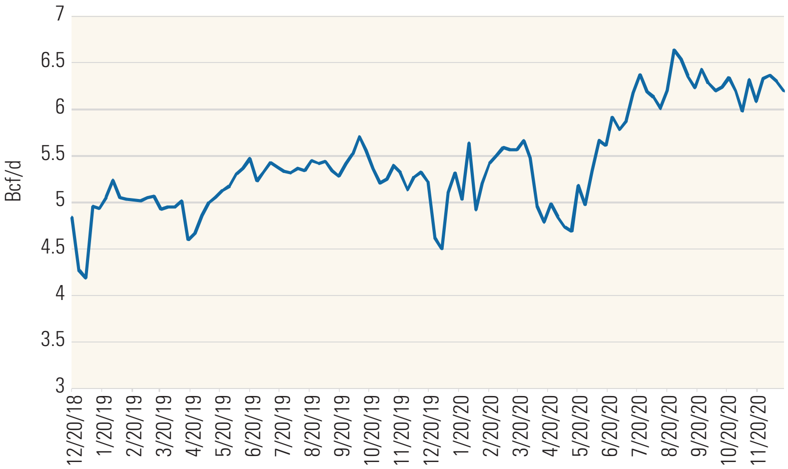
Japan/Korea LNG Prices



Source: J.P. Morgan Securities LLC

The JKM plummeted during the summer to $2 but soared toward year-end to more than in the past two years.

Dry Gas Exports To Mexico



Source: J.P. Morgan Securities LLC

Exports to Mexico continued to grow during 2020, posting their lowest volume in only January 2020.

Henry Hub price. Ed Morse, global head of commodity research for Citigroup, said it's because the U.S. has had a relatively mild winter.

"U.S. [natgas] prices are weaker than they otherwise might have been, largely because of weather-related issues," he said.

In December, for example, U.S. weather was 4% colder than during December of 2019, but it was "8.5% warmer than normal," according to an American Gas Association report in early January.

Meanwhile, Asia has had an extraordinarily cold winter, Morse said. Compared with $2 in May 2020, the JKM/Asia LNG price improved 500% to more than $10 in December, which also was the highest price in two years, according to J.P. Morgan's Jayaram.

The Dutch TTF/Europe price, which was sliding to nearly $1 in May, improved to $5.73 in December.

"The JKM is going to come down," though, Morse said. "The Chinese government put out an orange alert yesterday [Jan. 4], which said, because the cold spell is so awful, they have to ration gas for commercial and industrial reasons and keep it for power and heating."

Except for the weather, the JKM didn't have much reason to be as high as it became. "The JKM is twice as high as we reckoned it would be and that's all weather-related," Morse said. "It's going to come down fairly sharply over the course of 2021."

As the Dutch TTF improved at year-end, is the economy there rebounding? Morse said the European price improved because the Asian price improved, for the most part.

"Asian prices had lifted European prices. The European market is actually weaker than the price would otherwise indicate."

It was fortunate for Asia, then, that the U.S. was experiencing a mild winter and had excess supply, it seems. Morse said, "You might say 'fortunate for Europe' as well."

Another factor is in play too, according to J.P. Morgan: An unplanned outage in Qatar "has led to 18% of Qatari vessels that are anchored or at less than 25% of capacity, including 10 vessels anchored off the coast of Ras Laffan, per Platts," the firm reported.

Record LNG exports and reduced natgas production in 2020 haven't resulted in a noticeably higher Henry Hub price. Ed Morse, global head of commodity research for Citigroup, said it's because the U.S. has had a relatively mild winter.

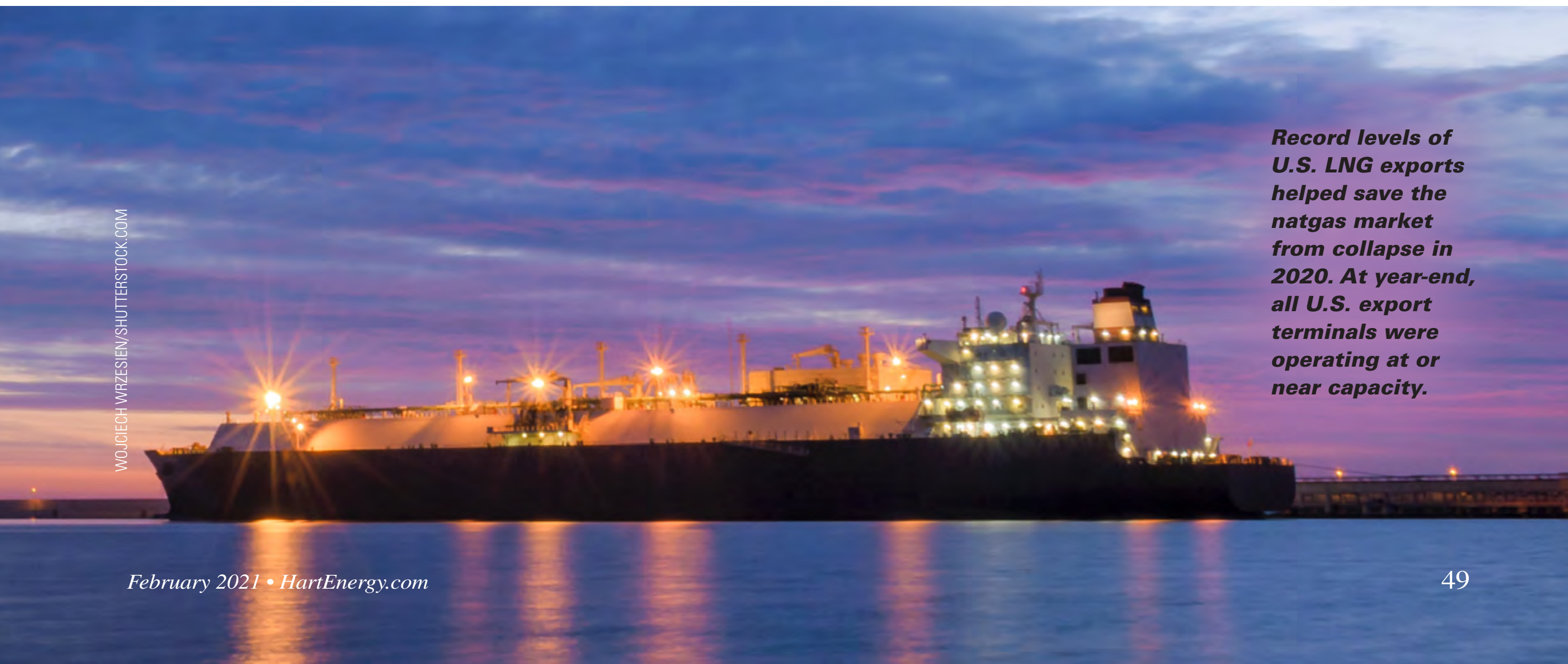
Dodging 'a complete meltdown'

The U.S. sub-$3 natgas this winter is certainly better than sub-$2 natgas, but it could be so much worse as "the U.S. gas market this injection season just barely managed to avoid a complete meltdown," RBN's Nasta wrote.

As summer was waning, U.S. natural gas was looking at topping off storage capacity—despite a 5 Bcf decline in production.

"It wasn't until [September and October] that the market tightened enough to escape a major storage crunch," she wrote in December.

While Asia and Europe were helped this winter by a mild U.S. winter, resulting in access to



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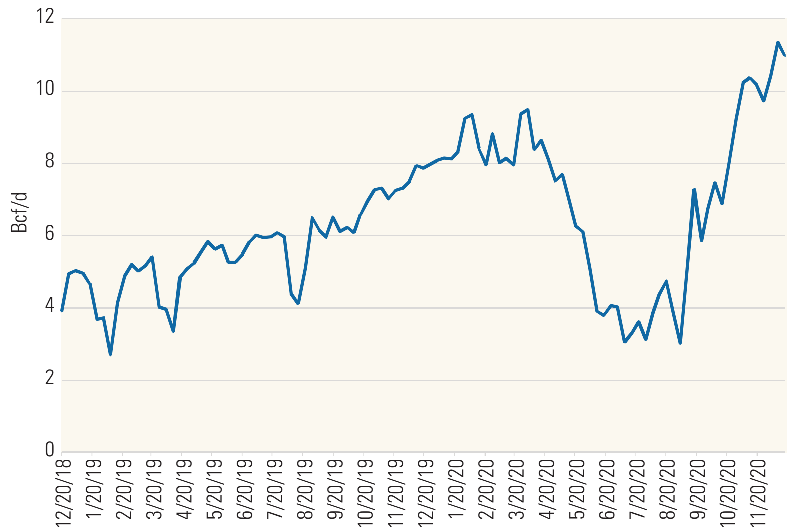
Record levels of U.S. LNG exports helped save the natgas market from collapse in 2020. At year-end, all U.S. export terminals were operating at or near capacity.

excess U.S. natgas supply, the U.S. gas-storage situation was helped by other weather: hurricanes.

"In reality," Nasta wrote, "it took the multipronged effects of production cutbacks—in part from hurricane-related disruptions—higher LNG and pipeline exports, and cooler fall weather to make that happen."

Gulf of Mexico production entered 2020 at 2.55 Bcf/d and exited at 1.72 Bcf/d—and thrice fell to nearly zero during storm shut-ins, according to J.P. Morgan. Five named storms struck the Louisiana coast in 2020, and all nine of 2020's Gulf storms traveled through production fairways, according to National Weather Service tracking.

US Total LNG Net Flows



Source: J.P. Morgan Securities LLC

A plummeting overseas price for LNG during mid-2020 resulted in cargo cancellations, but shipments rebounded to new records approaching year-end.

Appalachian and Louisiana onshore (Haynesville, mostly) production grew by about 2 Bcf/d combined in 2020, according to J.P. Morgan. In particular, Appalachia reached 33.8 Bcf/d.

Meanwhile, Permian, Oklahoma, D-J Basin and Gulf production declined from a combined 25 Bcf/d in January 2020 to 22 Bcf/d in December. In the Bakken, production entered and exited 2020 at mostly the same level: about 2.2 Bcf/d.

Overall, U.S. natgas output, which was a record high of 97 Bcf/d in December 2019, according to the Energy Information Administration (EIA), was 90 Bcf/d this past December, according to J.P. Morgan. And it was as little as 87 Bcf/d in June.

"The production decline reversed a three-year trend of consistent growth in U.S. natural gas production," Kristen Tsai, a "Today in Energy" coordinator for the EIA, reported. The full-year average was 89.8 Bcf/d.

"Talk about whiplash," said Sheetal Nasta, fundamentals analyst for RBN Energy, in describing the LNG market's motion through 2020. At the onset of COVID-19, the market found itself reeling but by year-end "the market has done a 180," she said.

The 'Amazon effect'

The natgas-demand side hasn't been as whipped as crude oil demand—in fact, natgas demand grew in some sectors in 2020, instead. J.P. Morgan shows demand exiting 2020—and lacking much of a winter, still—was 6.5 Bcf/d greater (102.7 Bcf/d) than when exiting 2019 (96.2 Bcf/d).

For plant fuel, that was unchanged at about 5 Bcf/d, and pipeline losses were mostly unchanged.

On the power side, demand was about 1.5 Bcf/d less. But a bright spot there is continued growth in natgas share of the powergen market: It reached 31.6 Bcf/d in 2020, up 2% from the 2019 average, according to the EIA's Tsai.

"This increase occurred despite slightly lower total U.S. electricity consumption this year," she wrote. In July, power plants set a new one-day record of 47.2 Bcf, she added.

According to the U.S. Bureau of Labor Statistics (BLS), 23.7% of the U.S. workforce was teleworking in December. (The labor subsector that includes dry cleaning lost 12,000 jobs.)

Greater demand was from the industrial sector: up 5.2 Bcf/d. Morse said, "We had December U.S. manufacturing growing at the fastest rate in basically two and a half years.

"It's the fastest production growth in factory numbers in a decade, which is the real rebound in the COVID-19 slump."

What is all of this industrial demand while a sizable share of U.S. incomes remained diminished by shuttered or pared in-person jobs? The BLS reported on Jan. 8 that unemployed in December was 10.7 million—that is, 6.7% of the labor force.

"Although both measures are much lower than their April highs," the BLS added, "they are nearly twice their pre-pandemic levels in February—3.5% and 5.7 million."

The growth in industrial demand—for goods, that is—reflects what Morse said is a K-shaped recovery: A part of the broad U.S. industry is curtailed, such as in-person retail, while part of it is growing.

It's an Alexa thing. "So we have an economy that is confusing," Morse said.

"You can see the confusion in what happened to [physical store] retail sales, which were down in the fourth quarter. On the other hand, deliveries to households were at a record level.

"That's the Amazon phenomenon: People were spending money, buying things; they just were not doing it out of retail shops."

Compared with February 2019, employment in leisure and hospitality was down in December by 3.9 million, or 23.2%, according to the BLS. Meanwhile, professional and business services gained 161,000 jobs, with 68,000 of these being temp.

Tech jobs, including gig-industry hardware, gained 20,000. Courier and messenger jobs grew 222,000.

$3-plus gas

J.P. Morgan's Jayaram forecasts natgas prices averaging more than $3 this and next quarter, "given the lack of weather-related demand in November and the larger-than-anticipated increase in production in the fourth quarter," he reported.

For the second half, he expects more than $3—of course all of this being "at the mercy of Mother Nature." For 2022, he also expects an average of more than $3.

Citi's Morse is seeing $3-plus too. "We think natural gas in the U.S. is going to be decent and strong through 2021," he said, with this quarter being the poorest performer of the year.

Coming out of that, "We think Henry Hub will be over $3 most of the year after the winter is over," Morse said.

To just put more and more U.S. natgas into LNG tankers is less of an option going forward, he added. "On the gas side, new development of LNG projects is coming to an end."

But an upside to that is less new competition for LNG-cargo buyers, if more plants aren't coming on worldwide: "The global gas market could be settling in at higher prices in 2022 and 2023," Morse said.

New supply?

On the supply side, rigs drilling for natgas reached a record low of 68 in July, and the count remained "relatively low throughout the rest of 2020," the EIA's Tsai reported.

Bernstein Research senior analyst, natural gas, Jean Ann Salisbury looked at gas-well performance in December and found that "gas wells have almost stopped improving. Will this eventually translate into higher prices?"

On a percentage basis, new wells in 2019 had averaged a 5% larger IP but minus 1% on a per-lateral-foot basis—an ongoing trend of "all gains in well productivity tied to drilling longer wells," she wrote.

Producers may have found the edge of the envelope: "This may be as good as it gets in gas basins."

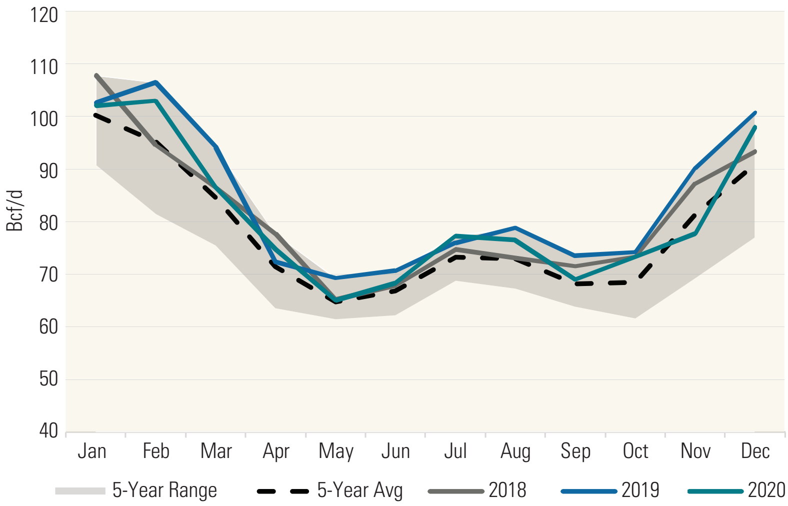
That—along with continued lower associated gas production and ongoing Appalachian bottlenecks—is good news for generating a higher gas price going forward, she added. But that's "only if capital discipline holds—that is, behavior will matter more than efficiency."

When doing natgas math today, how Appalachian and Haynesville economics are faring is still the most crucial factor in the equation. "The gassiness of gas wells versus oil wells can't be overstated," she wrote.

"Appalachia and Haynesville accounted for only 13% of total horizontal wells in 2019 but some 50% of new gas."

She concluded that, with gas wells' productivity not improving per lateral foot any longer, it's "a bullish signal for long-term gas price. One lever—improving wells—is effectively gone."

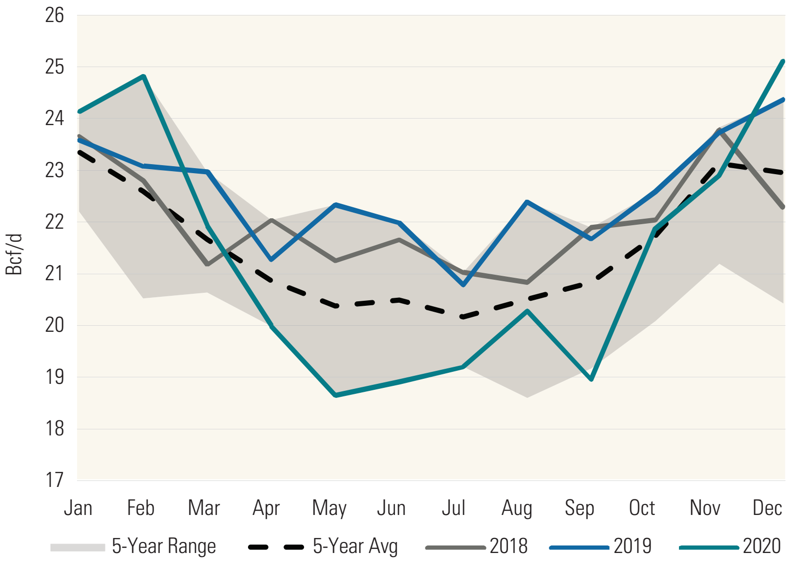
Total Natgas Demand



Source: J.P. Morgan Securities LLC

U.S. natgas demand exited 2020 at nearly the same level as the year began.

Industrial Consumption



Source: J.P. Morgan Securities LLC

Industrial demand exited 2020 at more than in January 2020.

RBN's Braziel wrote in early January that there is one drag. In 2019, 80% of the growth in U.S. natgas production was coming from oil wells. While new oil wells were far fewer in 2020, Braziel found that "natural gas has another problem: As shale wells age, they tend to get gassier."

And the outlook for significantly more new oil wells in the near term? Morse said, "The oil market is either going to hold steady or collapse, and it's very hard to figure out which of those things is going to happen.

"I happen to think Iran will not be putting 2 MMbbl/day of oil back in the market anytime soon, but other people are thinking it will. So, it's an issue of a lack of consensus globally." □

ENERGY INSIGHTS ROUNDTABLE

A 2021 OIL AND GAS PREVIEW

A panel hosted by Stephens Inc. provided perspectives on 2020 and the outlook for 2021, addressing a variety of fundamental topics. How should companies feel as the New Year kicks off? Cautiously optimistic is the suggestion, but that's in part simply because the alternative is so depressing.

MODERATED AND EDITED BY LESLIE HAINES

ILLUSTRATION BY ROBERT D. AVILA

Despite the roller coaster of 2020, Stephens Inc., the investment banking firm, closed six deals representing $6.3 billion in volume, three of those being M&A transactions in the oilfield services space. It also worked on restructuring for Martin Midstream Partners and private-equity-backed MP Resources, and it was involved in California Resources Corp.'s restructuring as well. Recently it's been adding to its A&D group in anticipation of a busier 2021.

Building on many years of experience, in December, the energy team hosted the third in a series of webcasts that looked at all the major themes that affected the oil and gas industry in 2020 and discussed what they expect in the coming year. Investor *was pleased to be asked to moderate that panel discussion. The topics ranged from how private equity is thinking about the space, to SPACs, to President Biden and the energy transition and the rise of natural gas. What follows is a transcript, edited for length and clarity.*

The participants were Keith Behrens, head of the energy investment banking team at Stephens, who was joined on the panel by his colleagues Paul Moorman and Brad Nelson, both managing directors, the latter specifically in Stephens' energy capital solutions group. Also speaking was Holt Foster, a partner with the law firm Thompson & Knight LLP in Dallas, and Artem Abramov, partner and head of shale research at Rystad Energy, the noted consulting firm based in Oslo, Norway.

A challenging macro

Abramov 2020 was obviously a challenging year for both E&Ps and all service companies. Last year was actually a transition year for E&Ps toward a new business model; they went from multiyear periods of very aggressive spending, systematic production growth and very ambitious production targets toward more disciplined programs and a focus on free-cash flow-generation. And then suddenly we had the unprecedented downturn, especially from the perspective of global liquid demand destruction, which peaked at almost 40 million barrels a day of lost demand in April. Now, many regions across the world are experiencing the second wave [of the pandemic]. So, the recovery in global liquid consumption is not as rapid as many people hoped for in quarter two, quarter three last year.

Only in quarter three did some operators start coming back in a very cautious manner. We actually saw that some private operators came back in a pretty opportunistic manner, a little bit faster than their public peers.

As for the outlook for 2021, I would say Rystad is seeing improving sentiment, especially among our service company clients and suppliers. Right now, we have around 120 frac spreads active in the whole country, oil and gas basins combined. Many service companies are currently assuming 140 to 270 spreads as an average for 2021. There is an overall expectation that we'll see an upward shift in activity in quarter one 2021, with the majority of operators targeting maintenance capital programs.

We're not talking about any production recovery in 2021, but we're definitely not seeing any further sequential declines. It is really flat, for U.S. production levels, somewhere in the 10.5- to 11 million barrels a day range; this is something we could expect in the foreseeable future.

On private equity

Behrens In the upstream, it's been really slow. There weren't a whole lot of new investments made by private equity funds in 2020, and I expect that to be the same going into 2021. A lot of funds have older portfolio companies, and that constrains them from making new investments. They need to take care of those older investments. Where there's going to be activity with the private equity funds is on the M&A side; there's been a lot of cramming companies together, and I think there's some noncore assets that could be sold as a function of that. Or, if the market comes back in A&D, there could be some outright portfolio company sales. Until that happens, new investment activities can be a little slow amongst traditional upstream-focused private equity funds.

Moorman From an oilfield services and midstream perspective, it's very consistent with how Keith just positioned it. To me the biggest opportunity out there (at some level, you've got to think about it as bifurcated in two pieces) is that there's a lot of private equity investment that's been made over the past couple of years. By definition, they are going to have to deal with their energy investments first, so … I think the bulk of the activity is absolutely going to be from an M&A standpoint, whether an outright sale, or some strategic combination, which I think is going to be the preponderance of the activity out there, and where we're spending the most time.

As for new platforms, private equity is open to the conversation, but they're being much pickier. With an absence of traditional banks and some of the traditional lending sources, as things start to ramp up there's going to be a need for new capital to fund things, even if it's just rehab of existing equipment. I do think private equity could play a role there as well.

Up until this point, the midstream has been a little bit more insulated, as it always is; it's just a little bit different. We're definitely seeing private equity have an interest, but like everything else, they continue to be cautious. There have been a lot of pipelines built over the past two years particularly, and with the decrease in volumes, ultimately, what is the right play here: Is it crude? Is it gas? Is it a combination thereof?

People have made a lot of investments in water too, which has been sort of the crossover midstream investment. At Stephens we've been involved in a couple of situations recently where there's been a lot of private equity interest in midstream assets, but I think the challenge is the bid-ask spread, particularly for what private equity is willing to pay. Look, they are getting creative and there's a lot of ways to structure things, which ultimately will allow deals to go forward.

Family offices

Nelson As you know, Stephens has been a large family office for almost 90 years and … the family really went into the energy space in the '50s, so we've been active for almost seven decades, both in the upstream and midstream business. About a decade ago, we formalized that effort.

We have a full team in our Little Rock office that basically covers about 200-plus families from coast to coast. I would say the average net worth of those families is probably in the $500- to $750 million range; it's been a very active platform for our firm. Since 2018, we've closed about 12 transactions with families; I think we've raised about $2.5 billion, give or take.

Pre-COVID-19, we've had a number of energy mandates that included family offices, and they've been very active. Of course, now, these families are reading and hearing everything that their private equity brethren are, and they're being awfully selective in this market. Out of our network, I would say 20%, plus or minus, of families will take a look at energy investing.

And as Paul [Moorman] alluded to earlier, there is a bifurcation between midstream and infrastructure vs. upstream. I think these families are probably more interested in looking at cash flowing assets, which are more associated with midstream and infrastructure. We do feel that the upstream sector, being as capital intensive as it is, is going to be a struggle, at least here in the early part of 2021.

ESG issues for investors

Nelson Pre-COVID-19 and pre-2020, ESG had been a constant conversation, a constant theme, for probably three to five years. For all of us on the panel today, there's been an active dialogue with all of our private equity relationships. I would say that every fund that we deal with is taking ESG seriously. They either have hired full time consultants to advise them through that transition or process or are working with external parties.

These big funds have to basically align themselves with their capital, have continuous conversations with their capital base. We are hearing them talk to their big investors about what they're seeking, what they're needing. You have

"At the end of the day, it is money and technology that's really going to drive the [energy] transition," said Holt Foster, partner at Thompson & Knight LLP.

"There will be at least one other upcycle for the oil industry before global liquid consumption peaks structurally," according to Rystad Energy partner and head of shale research Artem Abramov.

conventional energy funds that have been investing in the sector for 25 to 30 years; some of those will stay investing along those lines. Then there are funds with multiple strategies that are probably going to include more and more renewable and ESG-focused strategies.

We think it's a transition that's been going on for a while, it will continue to happen, and it will absolutely be a priority.

One question we get is, "What are some of the niches or particular verticals that these groups are investing in?" It's wind development projects, solar, geothermal, battery storage technologies and hydrogen strategies, to name a few—and those would be direct investments.

We're also seeing groups invest in those services such as software and technology that are also invested into this ESG platform as well. It's a trend for the last four or five years, and we look for that continuing in 2021.

Moorman To me, ESG is similar to the safety dynamics that the industry itself imposed upon itself a number of years ago. The industry has taken a lot of steps to cut emissions, do things more efficiently, have less of a carbon footprint, all those sorts of things. Regardless of whether Biden ultimately imposes more restrictions on that or not, to me, the industry is already somewhat [policing] itself.

Biden and the energy transition

Foster Over the last two years, or even more, there's been a big push on the ESG side, so at Thompson & Knight what we're looking at is, what effect is the political environment going to have on any incremental change in that transition? Three things drive how rapidly that transition to alternative energy will occur: the regulatory regime and how that overlays, the investors … and technological developments.

You need to take a step back and look at the politics that drives it. Biden is walking a very thin tightrope, because on one hand, he has the far left of the Democratic Party that really is pro radical change and wants to move toward alternative energy.

On the other hand, Biden is a dyed blue, Wall Street Democrat who understands what Wall Street's impact is on the economy. And he is beholden to them somewhat, with respect to where capital for his campaigns came from. Biden himself has said, "Look, this transition to alternative energy is not going to be radical; it's going to be gradual."

But you'll see him fund programs such as infrastructure needed for the transition, like charging stations or battery technology. That will create investment opportunities, and when investment opportunities are created, you really start driving that transition.

I think you'll also see more source-specific regulations on greenhouse gases like on power plants and oil and gas production, as well as carbon credits. There's a carbon tax credit in process; it's in the regulatory comment period, but I think you'll see that emerge more rapidly.

The big issue is fracking. Some people are convinced he's going to ban fracking, some people think he will narrow his ban on fracking to federal lands. And some people say he won't do it at all.

What you also need to understand is the United States is not alternative energy-ready. So, if he were to significantly decrease the amount of oil and gas that is utilized for our economy, there's not a viable alternative yet.

Plus, energy independence, which fracking helps us get, really impacts the global politics, which may play into the Biden administration. These type of rule changes take time; you can't pivot on a dime.

I think you can see some state-level regulatory regimes that will kick in that are more pro green, but that's going to be in a patchwork way. For example, in California you have significant restrictions on fracking, but in Texas, you do not. For a transition to green energy or alternative energy, from a practical standpoint you have to do that at the federal level, not a state level.

At the end of the day, it is money and technology that's going to drive the transition. A lot of the traditional oil and gas companies are moving very aggressively into alternative energies, be it battery production, EV, or whatever it may be. You're going to see a slower transition than some may hope, because that's going to be buoyed by the realities of the economy, etc. And you'll continue to see oil and gas, but they will be produced in a cleaner, more cost-effective way. And a lot of money will be funded for alternative energies.

Breakthroughs and breakevens

Abramov We are still seeing continuous and structural improvement in the economics of these producers. A lot of these improvements come from the fact that the U.S. industry has this unique feature: a very long supply chain with so many participants. The lower you are in this supply chain, the less pricing power you have, so when the market gets kind of oversupplied, there is a downturn, like in 2015 and '16, or 2020 this year.

There is continuous pressure on the suppliers and service companies to propose new solutions. The most significant improvements in the economics, in breakeven prices, have always materialized during these downturns. And operators keep adapting to the price reality which they observe in the current markets.

Some real technological breakthroughs are also happening. We're seeing continuous automation in several segments of the industry ... there are some new completion methods being adopted by the industry only this year.

In my view, we will keep seeing these gradual improvements in the well economics; this process is not over yet. The U.S. will become even more competitive in the global context in the next two to three years.

On SPACs

Behrens It's been good to see the SPAC activity. There's been no public equity market activity in the energy space, so it's good to see some activity that is somewhat related to energy. Just an astounding amount of capital was raised for SPACs in 2020, something like $60 billion, which is a record. I think the previous record was $13 billion. There's actually one energy SPAC that just went public named Breeze Holdings that raised $100 million. And we know of two possible SPACs that were watching that deal.

We think there'll be two more coming now that we know of … and there's maybe five to 10 that I could see, focused on oil and gas acquisitions, by the end of the first quarter of 2021. There have also been 13 SPACs raised that focus on ESG or renewable alternative energy. We think some of those will also focus as a sub-sector on oil and gas. And then there's 30 general-focused SPACs out there, and I think some of those will also have upstream oil and gas as a focus area.

We have one of the SPACs in one of our A&D processes right now, and they're potentially good buyer candidates. This is a really good thing for the upstream oil and gas space, to have this type of capital come into the sector.

On natural gas

Nelson Generally speaking, there's a lot less headwinds facing gas stories than oil, for obvious reasons. As the oil side of the equation fell into a tough market in 2020, particularly on the demand side, gas has certainly benefited to some degree. At the moment, the rig count chasing gas is about 25% of the total count. The last time the gas rig count was that high was briefly in 2015. In the last three to four quarters, we have seen drilling and completion costs go down by 25% to 30%, and of course, gas is getting the benefit of that.

Operators are seeing their economics or capex on the front end being reduced dramatically. At the same time, we've had an uplift in gas prices. As everyone knows, we were $1.50, $1.70 in the middle of 2020, but we've been as high as $3.

I would say that the economics associated with these gas stories have gotten a lot better, and they are sustainable.

From our perspective, even if gas does fall off a little bit, we still see a lot of activity at the field level. The three basins that are predominantly gas are very active at the moment, being financed by very good balance sheets.

What about public deal activity in 2021? Again, that's tough to call, but I would say that there's a lot of activity on the private side of the equation.

If the numbers and economics continue to play out in 2021, I can see there being some appeal for either gas-weighted IPOs, or even secondaries associated with gas stories. And then, as everybody knows, gas is cleaner than oil, and … since gas is cleaner, it's easier for these fund managers to dedicate capital to a natural gas story. All that being said, we see momentum for sure picking up in 2021 for gas.

On debt

Moorman Debt funding in the energy space continues to have a high bar. At the end of the day, it boils down to, lenders ultimately want some certainty that they can be paid back. With the volatility that's happened, I'd argue … the number of lenders in the space has continued to decrease. Ultimately, companies can best position themselves for 2021 if, at some level, they're [willing] to develop new relationships.

The traditional senior lender, which may have had a branch on the corner that they knew sort of socially as well as from a business perspective, is really no longer there. So, they're going to have to work a little bit to develop relationships with these alternate alternative lenders, institutional lenders, that may be in other cities, or that they've not known before.

There are probably three key ways [companies] can set themselves apart.

They've got to prove themselves to be operating a profitable business that produces free cash flow.

They have to minimize the quantity of debt that's ultimately necessary, and what I mean by that is—from an oilfield service perspective—leverage of one to two times is probably a realistic goal. For midstream, maybe you get up to three times.

The last thing would be to figure out ways to set themselves apart from an operating model perspective, whether that's becoming a market leader in their particular niche, whether their services or niches are considered to be more defensible, and/or just having a better ESG reputation out there. All those things are going to be important.

Foster Starting in mid-2019, you saw most of the bank and lending institutions either limit the amount of exposure they had to the oil and gas sector, or decide they're going to pivot out of that sector altogether. We think banks are

> "I think these families are probably more interested in looking at cash-flowing assets, which are more associated with midstream and infrastructure."
>
> —Brad Nelson, Stephens Inc.

going to continue to hold that approach for 2021. And so, we're seeing a number of different alternatives.

Other financing options

Foster People in the private equity world are some of the smartest people in the industry, and they have lots of tools in their kit. The banks initially were asking for overriding royalty interest (ORRI) throughout the process, particularly toward the end of lending, so that was kind of an equity kicker. But as banks tend to exit, the ORRI is not as viable an option, not as many people are looking for just that small tranche.

Rather, you're seeing a number of other items. First, there's net profits interests, which are analogous to an override royalty interest, but you have exposure to management or costs. So, it's a structured financing that has many more restrictions and is more complicated and tax driven. And it's when most of that money is going for the acquisition or the development of the assets, as opposed to just an operating loan or an RBL [reserve-based loan].

They take a lot of time to do, and once they're in place, it's very difficult to sell the assets by the grantor without a number of consents. So, you're seeing companies and private equity funds reach into their toolkits and do a number of things.

First, there's still a lot of roll-ups to save G&A. A lot of these nontraditional lending sources—be it hard money lenders, private equity funds, family offices or whatever—a lot of them are coming to the industry and saying, "Hey, we will loan you money."

You're seeing a lot of these companies issue debt in lieu of equity, but these debt products are structured like equity. The economics are more similar to what an equity investment might have been the year before. But the beauty about it is, because it's debt, you can get a security interest in the asset and you have priority over the equity.

I'm seeing preferred equity; with asset values being down, some people who are bullish on the long term of energy are stepping in because they're getting assets. You may have up to a billion dollars invested, but you're getting preferred equity at a valuation that is literally pennies on the dollar. You're not only able to prime the existing common, but you're coming in at a significant pro-lender valuation, or pro-preferred equity valuation.

The nuance is, if you're trying to bring in a new management team to manage those assets, or if you're trying to keep a good management team that just happens to be a victim of a bad economy, what do you do with their incentive units? Do you ratchet their incentive units down so that they kick in at the lower valuations, without making the original equity providers feel like they've been shortchanged?

I'm even seeing real creative things such as seller financing, where a company says, "If I can get money now that I can put on my books and make a distribution, even if it's an ultimate loss, but a distribution to my investors, I am willing to take a slug of money up front and even do a seller financing over the next one to five years, which is something crazy you wouldn't have seen beforehand."

We're also seeing "IUs," incentive units for capital providers. The borrower tells them, "Hey, if you come in for preferred equity or a debt instrument, and if we meet a certain threshold, if we have a home run, then I'm going to give you an incentive unit or profits interest."

Companies are realizing that the banks are kind of closed for business, so it's kill or be killed, and they're being very creative.

On restructuring

Behrens I think it will continue, at least for the next six months or so, until demand comes back. There are still a lot of heavily levered companies out there that are in challenging situations. There have been a lot of bankruptcies, where those companies have emerged with better balance sheets, so I think they're in pretty good shape. But there's a lot of high-yield issuers out there, with maturities that are coming due, but there's just no high-yield market for them to refinance into. Those companies are pretty challenged right now.

Generally, the banks kicked the can down the road in the spring, hoping there'd be a quick recovery out of COVID-19, but that didn't happen. [Coming] out of the November 2020 borrowing base redetermination season, there could be some restructuring activity.

We do have a light at the end of the tunnel now with all this positive vaccine news, but some companies aren't going to make it until demand returns. It takes a while for demand to return.

If M&A doesn't pick up, restructurings will be strong. And then there's always private equity deals. There are some bottom fishers out there in tough times that are looking for deals. Maybe the sources of those deals aren't really traditional private equity groups as much going forward; maybe they're high net worth groups, but there's definitely going to be private equity deals to be done.

On 2021 supply/demand

Abramov A few months ago, many people were saying that it would be a W-shaped recovery. I think now we're heading toward the environment where another market crash is not impossible, at least before we really get to the structural recovery phase. I think market volatility will remain pretty high in the foreseeable future.

When it comes to the oil industry specifically, we have two sides of the equation; we have demand, and we have supply. Even in the most optimistic scenario, we see global liquid consumption averaging 97-, 98 million barrels a day next year, which is basically 2% to 3% below where we were in 2019. But as I said, this is the most optimistic scenario, where so many different things have to contribute to the demand positively in the same direction. Most likely demand will average somewhere in the 95- to 96 million barrels a day range.

In particular, jet fuel consumption is lagging … Even if you vaccinate the whole world, there will be some structural behavioral shifts, and we think people won't travel as much as they did previously, so it will take several years for the airline industry to truly recover to pre-COVID-19 levels.

On the supply side, I would list three main factors, which we should all watch. First, we shouldn't forget about uncertainty around U.S. oil supply. We feel there is quite strong consensus about 2021 right now, but we need to remember that the U.S. oil industry has a very long track record of outperforming consensus estimates on the production side. Maybe we're not talking about the same magnitude of outperformance as we saw in 2018.

We might get some positive surprises for gas production, but it will be negative for the global supply-demand balance. Then we have Libya, which came back very quickly. The government of Libya already announced that it's returning to 1.2 million barrels per day. Some people don't believe it. I could tell you that we monitor Libya with satellite data in near real time, and it's almost back to the level when they were producing [that much.] But to maintain these production levels next year will require them to invest quite a lot; a lot of damage has been made during the shutdown phase.

And finally, there is the OPEC-plus strategy and behavior of some key members. If they really go back from 8- to 6 million barrels per day cut already from January, any demand weakness can send oil prices back to the $40s, probably, in the short term.

One quick comment about the longer-term perspective: I would say that we are almost confident that there will be at least one other upcycle for the oil industry before global liquid consumption peaks structurally.

Most companies revised their long-term oil consumption peak; they moved it closer in time. We now see global oil consumption peaking somewhere at 102-, 103 million barrels per day in the late '20s. But the actual dynamics are very complex.

The most significant structural changes are happening within the transportation segment. Specifically, I mean light duty vehicles, where we see a rapid penetration of EVs, as we move toward the '40s. It will take a little bit longer for trucks and buses to see full adoption of EVs. So global oil consumption in these segments will continue growing into the mid-'40s.

Petrochemicals will probably grow through the late '40s.

Even with all these growth sectors in the medium term, we have all these other smaller segments, which combined account for around 25 million barrels per day of oil consumption. That's agriculture, buildings, industry use, power segments, and energy's own use. These segments have been declining structurally since 2010.

We don't anticipate that the long-term peak in our consumption will be much higher than the pre-COVID-19 consumption records.

"This [SPAC activity] is a really good thing for the upstream oil and gas space, to have this type of capital come into the sector, said Keith Behrens, head of the energy investment banking with Stephens Inc.

Parting thoughts on the recovery

Foster I'm optimistic. It would be depressing to say otherwise. But I think that you have seen a transition as the year 2020 progressed, where people are starting to have a little bit more faith in the economy. I think some of the concerns about politics and who the next president is going to be have resolved themselves.

While there's still a separation between the bid-ask, I think people are starting to get comfortable that maybe there's not a falling knife. I think creativity is going to be rewarded. I think patience is going to be rewarded. But as money moves out of the industry, that's going to create opportunity for those that are willing to put money in, and hopefully we can all participate in that.

Nelson At Stephens, we agree with everything that Artem and his firm are saying, and of course, we're reading a lot of the data and numbers that Artem and others are publishing.

Looking at the last two down cycles that we've come out of, one a decade ago being the credit crisis, and then, 2014 through mid-2016, the recoveries were real, robust, fairly rapid. After a little bit of a healing period, you saw capital being deployed pretty quickly.

Our view, at the moment, is that we are cautiously optimistic. We feel like there will be a recovery, albeit methodical and cautious. Coming out of the credit crisis, and then coming out of 2014 through 2016, you still had quite a bit of capital, net-net, coming back into conventional energy. I think the difference today is you've got quite a bit of capital either sitting on the sidelines, not quite sure if they want to get back into conventional energy or not.

We've all talked about ESG and capital going into renewable strategies, and that certainly competes for capital with conventional activities. I would say that gas will probably recover quicker than oil based on what we've previously discussed. □

KEY THEMES FROM THE 2020 E&P BANKRUPTCY WAVE

As upstream oil and gas companies emerge from Chapter 11, they'll need to be mindful of exit credit facility terms and requirements that may reflect a shift from their prior experience—and will likely affect their future borrowing base redetermination.

ARTICLE BY
JIM ALLEN AND
DAVID MORRIS

ILLUSTRATION BY
ROBERT D. AVILA

Themes from early bankruptcies in the upstream oil and gas sector may provide insight regarding exit financing for the next wave of companies entering the restructuring process. The current industry downturn, fueled and exacerbated by impacts from the COVID-19 pandemic and the Saudi Arabia/Russia oil price war, has led to a series of bankruptcies beginning in early 2020.

Initial filers are now starting to emerge with revamped capital structures, including new bank credit facilities, offering information regarding the terms of those credit facilities and the process/requirements for securing agreement between lenders and borrowers. These exit credit facility terms and requirements also portend what banks will expect on a continuing basis for conforming reserve-based loans (RBL).

Simply put, a DIP-to-exit financing allows the debtor to convert outstanding loans under the debtor-in-possession (DIP) facility into the exit financing.

Resetting the borrowing base

The rapid decline in oil prices in March and early April 2020 reemphasized the importance of disciplined business plans, risk management measures and strong balance sheets to sustain operations in a depressed demand/low-price commodity environment.

Lenders and their advisors are performing comprehensive and enhanced evaluations of debtor business plans and cost-reduction measures to appropriately size RBLs and establish ongoing financial covenants for the reorganized companies. The typical evaluation begins with a thorough review of the oil and gas reserves database underlying the business plan, similar to a semiannual borrowing base redetermination, but with more scrutiny of proved undeveloped reserves (PUD).

Projected IRR, price sensitivity, development risks and the borrower's ability to fund the specified PUD capital expenditures are examined in-depth. Additionally, banks are increasingly requiring more symmetry between the reserves database and the business plan forecast with respect to capital expenditures for PUD, eliminating the historical practice of some companies to include relatively more assumed PUD capital expenditures in the reserves database. That practice may lead to an overly optimistic view of the timing and volume of future oil and gas production and an overstatement of value attributed to the reserves.

Lower bank price decks, reflecting current price forecasts that are generally lower than index pricing, have driven down the overall value of company reserves. Further, lenders are taking a conservative position in setting borrowing base limits based on the evaluated reserves to obtain an acceptable level of asset/collateral coverage. Banks often establish a borrowing base at 1.5x coverage of the value (e.g., PV10) of total proved reserves or by applying tiered advance rates to various reserve classifications. Many banks are taking the additional step of considering limits (e.g., 1.2x–1.5x) according to the PV15 value of company reserves using current index pricing.

Borrowers are generally expected, if not required, to hedge at least a portion of their projected proved developed producing (PDP) volumes for approximately two years at emergence, and such requirement may apply on a continuing/rolling basis for the term of the credit facility. Should a hedging program not be established for any reason, the banks' targeted collateral coverage thresholds would be increased.

In general, the net effect of the aforementioned factors has been significantly lower borrowing bases for most debtors as they emerge from bankruptcy, which in turn has driven requirements for new cash equity investments to paydown RBL balances. Additionally, lenders may require the option to exercise a midcycle/wildcard redetermination as a means to further reduce the borrowing base as partial protection in the event that industry conditions or borrower circumstances indicate increased credit risk.

DIP-to-exit financing

Simply put, a DIP-to-exit financing allows the debtor to convert outstanding loans under the debtor-in-possession (DIP) facility into the exit financing. Done in conjunction with a restructuring support agreement, a DIP-to-exit financing has important advantages for an E&P, including the following:

- Provides certainty of financing for the bankruptcy case subject to negotiated milestones, as well as upon emergence of the reorganized company;
- Helps ensure a shorter Chapter 11 case;
- May enable the debtor to maintain prepetition commodity hedges through the case and/or execute new hedges during the case; and
- Depending upon the circumstances, such structures can provide strong incentives for recalcitrant banks to participate rather than dissent.

Frequently, a DIP-to-exit financing is provided by the debtor's prepetition RBL lenders. In that case, although the administrative agent bank leads efforts around determining the facility terms, each prepetition RBL lender will simultaneously undertake a reevaluation of its business relationship with the debtor and decide on its level of participation in the exit facility, if any.

In effect, this will constitute a new underwriting process through which each lender will consider and scrutinize the debtor's business risks, management teams and overall corporate governance policies and procedures.

In addition to the typical RBL in an exit financing for an E&P, it may be necessary in some cases to introduce a term loan with very

Management should proactively seek to engage in a collaborative process, both leading into and throughout the restructuring process.

unattractive/weak terms and economics into the proposal to encourage recalcitrant banks to commit to the exit financing. While these coercive term loans are often contemplated in exit financing term sheets, they rarely appear in the exit credit agreements because they effectively compel lenders to commit.

Below are several of the key terms the debtor and DIP lenders (assuming the RBL banks are the DIP lenders) will negotiate.

- *New money DIP amount*—Sizing of the new money loan amount is a case-specific exercise, but plans for capital expenditures during the case are often a hot button issue for both E&P borrowers and the DIP lenders, assuming the banks in the RBL are providing the DIP facility.
- *Roll-up of prepetition debt*—Having a meaningful roll-up amount can help in the syndication of a DIP facility, particularly if there are recalcitrant banks in the RBL.
- *Pricing*—Recent DIP facilities have had a loan spread of 4% to 6% over LIBOR with a LIBOR floor of 1% to 2%.
- *Term*—This is another case-specific point where the borrower and DIP lenders often will differ, but borrowers should take some comfort in the fact that it's generally much easier to extend the tenor of a DIP facility during the case than it is to increase the size of a DIP facility.
- *DIP budget and variance test(s)*—How often will the budget be updated during the case? Will variance testing be on multiple line items, a single aggregate test, or both? What specific line items of the budget will be tested, and how frequently?
- *Milestones*—The milestones will set outside dates for entry of the final DIP order, filing a plan of reorganization (plan) and disclosure statement, court approval of the plan, and effectiveness of the pan, among other things.

Exit facility terms

As previously mentioned, lenders want to ensure that debtor business plans are based on disciplined and realistic development plans and appropriate estimates of capital, operating and G&A costs. Further, they're intently focused on liquidity and the ability for borrowers to absorb the impact of industry volatility. To that end, common conditions precedent to closing of exit RBL facilities include one or more of the following:

- Required equitization of all or most of a debtor's unsecured and/or junior lien debt obligations.
- New cash infusion, typically in the form of equity, but potentially subordinated debt.
- Minimum commodity price hedging requirement.
- Minimum liquidity threshold (including credit facility availability).

The scrutinized debtor business plans also serve as the foundation for tailored ongoing financial covenants, which typically include leverage limitations (e.g. debt-to-EBITDA of no more than 3.0x or 3.5x rather than 4.0x, which had become commonplace) and liquidity measures (e.g., current ratio of at least 1:1). Further, the financial covenants may tighten over the term of the facility (e.g., decreasing debt-to-EBITDA ratios) and other financial covenants also may be required.

Other trends embedded in the provisions of recent exit RBL facilities include:

- *Anti-cash hoarding provisions:* Lenders are increasingly reintroducing limitations on the amount of cash borrowers can maintain without a required paydown of outstanding balances on their RBL. After being added to many credit facilities during the industry downturn in 2015 to 2016, this requirement had fallen off in prominence over the past few years.
- *Higher pricing:* Pricing on exit RBL facilities has trended upward from historical levels as lenders seek to realign interest rates with the risks of lending to E&Ps. Going forward, there may be greater differentiation in pricing for RBLs based on company size, capital structure and access to capital markets, in contrast to the historical tendency of pricing for RBLs with conforming borrowing bases to be relatively consistent regardless of borrower-specific factors.
- *Tighter limitations on restricted payments:* Reflective of lenders' focus on liquidity, greater limitations on restricted payments (e.g., dividends, distributions and equity repurchases) should be expected.

Benefits of a collaborative process

Addressing the current industry challenges faced by oil and gas companies, coupled with a time-consuming and costly Chapter 11 reorganization process, poses a considerable strain on a company's management and resources. These impacts can be reduced with respect to a key aspect of the reorganization process by efficiently securing exit or DIP-to-exit financing with a company's current RBL lenders.

To achieve this, management should proactively seek to engage in a collaborative process, both leading into and throughout the restructuring process. Doing so streamlines the process of negotiating mutually acceptable terms, mitigates overall restructuring costs and helps ensure the lender syndicate remains intact in an environment in which certain banks are looking to reduce or eliminate their oil and gas loan portfolios. □

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REBUTTING THE NORTH FACE

A viral letter by the CEO of a Texas-based service company sparked a social media frenzy by oil and gas supporters bringing the importance of industry messaging to the forefront.

ARTICLE BY
LEN VERMILLION

Adam Anderson, CEO of Innovex Downhole Solutions Inc., only wanted to buy his employees a Christmas present. Little did he know he'd be thrust into a social media frenzy and become the unlikely center of attention in an ESG movement that is increasingly gripping global businesses, including the oil and gas industry.

It all started when his order for 400 jackets from popular outdoor apparel brand The North Face was rejected. Why? According to Anderson, he was told by his distributor that The North Face rejected the order because Anderson wanted to put the Innovex logo on the jackets, and the company rejected the idea of placing an oil and gas services company logo on its jackets.

It was a curious stance for The North Face to take considering Anderson had received lower quantity orders with his company logo on The North Face jackets in the past. In addition, as many Twitter and Facebook users pointed out, the jackets are made with Nylon, which is a petroleum-based product.

While Anderson never received a direct response from The North Face or its corporate owner VF Corp., the distributor told Anderson it was told it could not put the Innovex logo on the jackets because it was "not consistent with its brand standards, which they told him was because we are an oil and gas company," Anderson told Hart Energy in an interview.

"Officially, they don't put that in their terminology, but they told him it's because if you look at their official disclaimer it references other companies they wouldn't want to be co-branded with such as alcohol, tobacco, porn," he said.

Anderson was able to find another company to sell him the jackets through the distributor—Eddie Bauer. For many executives that may have been the end of the story, but for Anderson, the episode awakened a frustration he said he's felt for a long time.

"The jackets are one thing and the solution to that problem isn't really a big deal, but I think it really hit a nerve—the idea of the population in general and even within our industry of apologizing for what oil and gas does," Anderson said. "What we do is good for humanity and good for the world. Like everything, there's trade-offs. But I think somehow in the oil and gas world, we only talk about the small portion of challenges. We don't talk about the 99% of oil and gas which is great for humanity."

He's not alone. Industry messaging in the rising age of ESG concerns among investors and anti-fossil fuel sentiment among the public has become a prime topic of discussion within oil and gas circles. Hart Energy's own virtual DUG conferences held this fall had their fair share of passionate discussion on why and how the industry should speak up for itself.

Anderson decided he would speak up

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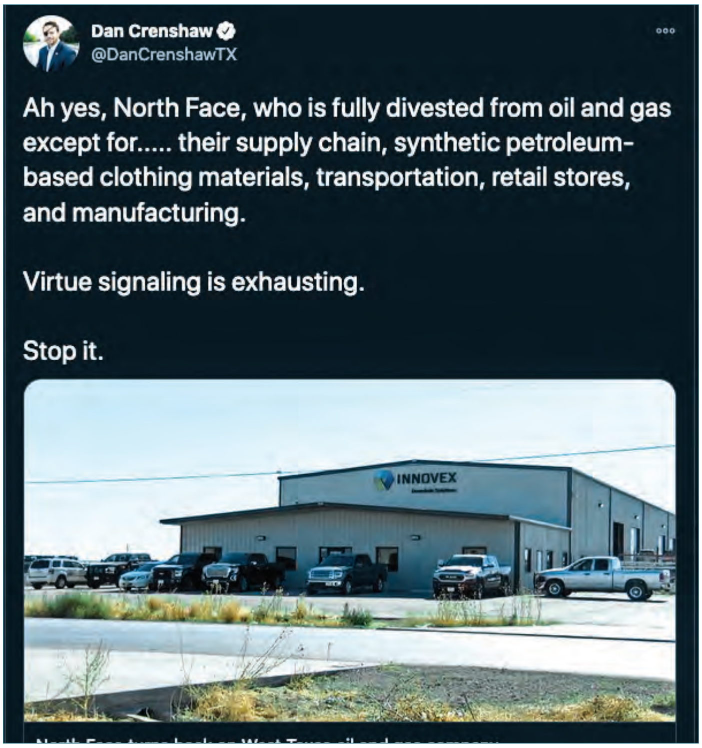


Industry supporters took out their frustrations of The North Face's actions on social media.

and penned a letter to VF Corp. CEO Steve Rendle in which he wrote "low-cost, reliable energy is critical to enable humans to flourish."

In the letter, Anderson proudly trumpeted the benefits of oil and gas on society and the progress the industry has made in reducing harmful emissions into the atmosphere. He also pointed out the irony of The North Face's stance given the influence of fossil fuels on its products and businesses. "Without oil and gas there would be no market for, nor the ability to create, the products your company sells," he wrote.

It was that last point that helped the letter go viral thanks to industry social media influencers such as EnergyFinTwit (#EFT) and tweets from notable names such as U.S. Rep. Dan Crenshaw (R-Texas).

"Ah yes, North Face, who is fully divested from oil and gas except for … their supply chain, synthetic petroleum-based materials, transportation, retail stores, and manufacturing. Virtue signaling is exhausting. Stop it," Creshaw tweeted in response to a story by KOSA-TV in Midland-Odessa posted on Dec. 11.

"I was flabbergasted by the attention the thing has gotten," Anderson said. "I've gotten feedback from a couple of folks at much larger businesses that said they had the exact same issue with North Face in the last year or two years and they didn't do anything about it.

"I guess everyone gets themselves wound up in the ESG world and wants to apologize for what we do," he continued. "It's a problem. Leaders in our industry has become focused on this idea of what we do is a 'necessary evil.'"

Anderson also pointed out that he was inspired by the Alex Epstein book "The Moral Case for Fossil Fuels."

The North Face saw plenty of criticism over the weekend, particularly after The Financial Times reported on Anderson's letter. As speaker after speaker at industry events have pointed out recently, the risk of surrendering the messaging on fossil fuels to environmentalists and politicians can be lasting.

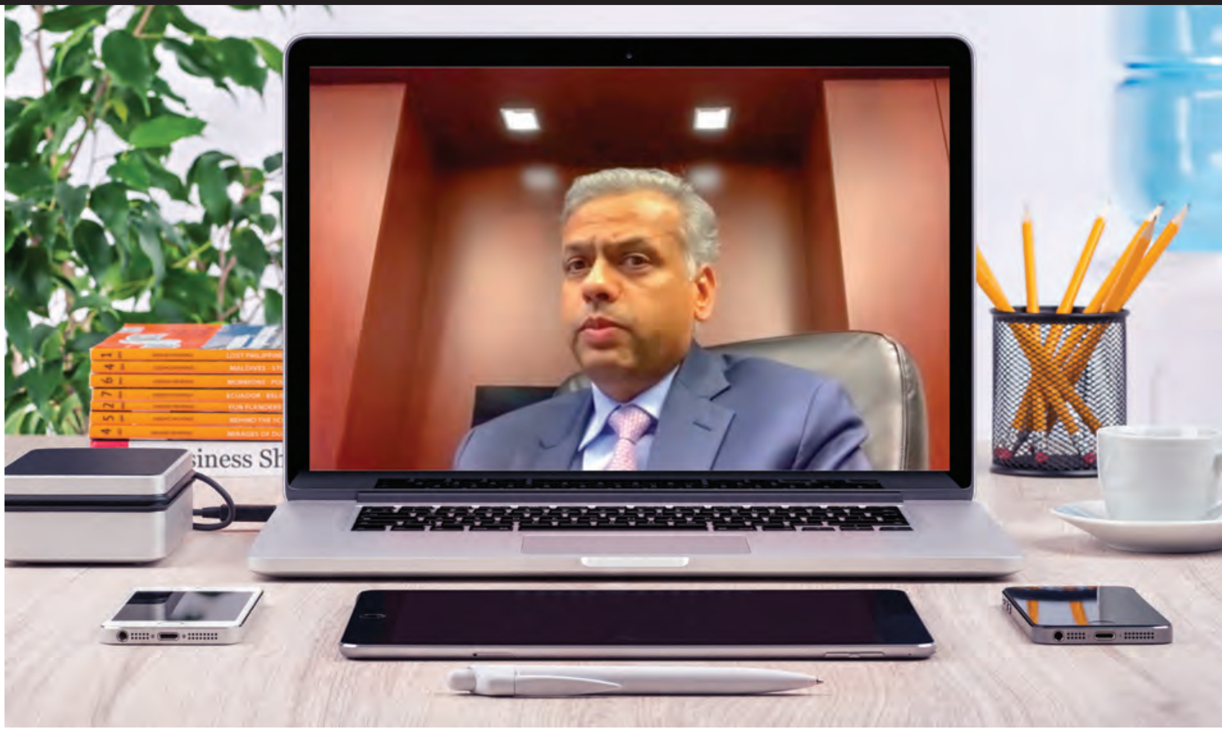
"The fiasco of 'The North Face' shows that 'reality' doesn't matter. That is scary since the implications are severe: once you are labeled, who knows what's next? Where is the outrage from the left about a company that dress them with cloth made from fossil fuel? #oil #OOTT," industry speaker Anas Anlhajji noted in a tweet.

Hart Energy reached out via email to VF Corp. for a response to Anderson's letter and has not received a direct response as of yet. However, in response to critical posts on its Facebook page, The North Face stated in a comment:

"Thanks for sharing your thoughts with us. We receive many requests from different companies or organizations to partner on co-branded product, and evaluate each individually based on multiple criteria, including product supply, time constraints, and if they align to our brand values. To respect the privacy of these organizations we keep the results of these decisions private."

The North Face had social media support for its decision as well with Twitter comments to The Financial Times post of its article generally showing support for the apparel company. Though, those comments in support were far outnumbered by industry supporters elsewhere on social media who took the opportunity to let out their frustrations.

Overall, Anderson said he's just a small player in the grand scheme of things, but he hopes the oil and gas industry begins to take better care of its messaging to the public. That's a sentiment shared by a growing number of industry executives and analysts. □



THE FUTURE OF OFS

According to Weatherford International's new CEO, Girish Saligram, the convergence of multiple technologies and the collective creativity unlocked through workforce changes such as remote collaboration will help OFS, and oil and gas in general, continue to provide much needed energy in an evolving world.

INTERVIEW BY
BRIAN WALZEL

In September 2020, Weatherford International named Girish Saligram the new CEO. Officially taking over a month later, Saligram heads one of the world's largest oilfield service companies. Weatherford's offerings include tools and systems for drilling, completions, production, formation evaluation, tubulars, interventions and abandonment.

Before joining Weatherford, Saligram served Exterran Corp. as COO and previously as president of Global Services after joining the company in 2016. Prior to Exterran, Saligram spent 20 years with GE as a business leader in industry sectors across the globe, including his last position as general manager of Downstream Products & Services with GE Oil & Gas. Prior to that, Saligram led the GE Oil & Gas Contractual Services business based in Florence, Italy. Before his eight years in the oil and gas sector, Saligram spent 12 years with GE Healthcare in engineering, services, operations and other commercial roles.

Saligram recently sat down via Zoom with Hart Energy senior editor Brian Walzel to talk about how he plans to lead Weatherford as the industry recovers from one of the most challenging periods in its history. He also discussed the energy transition, Weatherford's role in the transition as well as the importance of continuing to develop mature fields—both onshore and offshore—around the world.

What is your strategy leading Weatherford, particularly coming out of one of the most challenging times that the industry has ever faced?

I've been in the seat now for about five weeks and have spent the time trying to get to know the company and our team and our customers better.

"The industry has suffered through a series of challenges, and we've had our fair share, especially over the last couple of years, but this notion of sustained profitability and free-cash-flow generation is our mantra."

It's a huge honor and privilege to be entrusted with the responsibility of leading a company of the stature and the reputation of Weatherford. We have a terrific portfolio, very differentiated technology, a great footprint, especially outside the United States, and a great set of relationships and intimacy with customers.

So, first of all, [my strategy] is going to be continuing to leverage those strengths, to deliver innovative and value-added solutions for our customers.

Our main focus continues to be on driving sustainable profitability and free-cash-flow generation, and the way we do that is by leveraging those elements I mentioned earlier and coupling that with a tremendous focus on service delivery and service quality and making sure we have an engaged team at a global level.

The industry has suffered a series of challenges, and we've had our fair share, especially over the last couple of years, but this notion of sustained profitability and free-cash-flow generation is our mantra. That's what we are focusing on while making sure we are delivering to our customers.

Looking at the industry as a whole, where do you feel the energy transition is leading us?

Energy from a transition standpoint is a reality we're all facing today. It's not a question of "if" and "what"—it is happening; it's happening right now. Now, what none of us really knows is exactly how long is it going to take? Is it 20 years? Is it 10 years? Is it something smaller?

There is a transition happening, and we have a part to play in it, but production of conventional hydrocarbons and fossil fuels generate a very significant portion of the world's energy, and that isn't going to be completely replaced at any point soon. We have a responsibility to make sure that we partner with our customers and help them drive better, more sustainable operations on that existing production.

So, making sure that we are deploying technology, that we are helping [customers] decarbonize more sustainably—everything that we do around today's production—it starts with that.

We have a suite of capabilities and technology that we feel are well suited to play different roles in this transition. As an example, we have capabilities around carbon capture and CCUS, from a perspective of converting wells to store CO_2 better as well as monitoring solutions, and capabilities in automation drilling and wireline that play to areas like geothermal.

As service companies, we have roles to play while we all collectively figure out what is at the other end of this transition and build towards that in different ways in different companies.

Much of the industry understands the importance of things like digitalization, automation technologies, and of course, many companies have begun to adopt those technologies. What do you feel is next in this process?

In one simplistic word, it's convergence. As we see more of these technologies come together and their adoption growing, it's really the convergence of multiple technologies along with traditional aspects of physics or geology of the fundamental mechanical stuff that we've been doing over several decades, bringing all that together into more innovative, more [cost-efficient] solutions for customers that have changed the paradigm on how we do business today.

[For example,] you have the capability today of taking artificial intelligence, coupling that with automation, dropping in software and developing systems that automate fundamental tasks. We have a system in tubular running services, called Vero, that we recently announced and launched. It's in operation in multiple parts of the world. [Tubular running] is an operation that is inherently dangerous. It has a significant potential for injury. And especially if you're an offshore environment, it creates a significant challenge from a logistical standpoint and increases the carbon footprint as well.

When you deploy a system like Vero, which completely automates this process, and you have a single individual sitting inside a controlled cabin, managing that, it removes the number of personnel onboard. It improves the safety very significantly, and it improves the efficiency of the operation because it's all AI-controlled versus having human judgment involved.

So, you have better safety, better efficacy, better efficiency, and it's a more sustainable operation.

At nearly every location around the world, whether it be onshore or offshore, conventional or unconventional, there's been a continued focus on cost-efficient strategies for developing mature fields. What types of strategies can further be applied to mature field development?

A variety of different things play in, and [a critical strategy] from our perspective, and one that I'm very excited about, is production optimization.

We have a system called Foresite, and we've had it around for a while. It builds on a proprietary SCADA system called Centro. This allows operators to optimize their production from existing fields, which plays into this notion of mature field development. We've deployed it in multiple places. As an example, we have a customer in Indonesia [that has] achieved about 40% improvement in uptime and about the same percentage increase in production.

What we have is the ability to optimize the life cycle. We have integrated technology. We can bring in lift forms. We can bring in transition lift systems, all without the use of a rig. We can also help customers improve their wellbore integrity. We can diagnose issues and repair common production problems, in a rigless way, and sometimes without needing for a well to be shut in, which is a very important factor for customers, especially if they have a field that's already producing.

We also have unique abandonment solutions. In the world that we live in today, with the emphasis on increasing returns, with an emphasis on decarbonization, and really looking at things from both a cost and a sustainability angle, mature field development is very important, and we feel we have a full portfolio of complementary tools, technology and services that can help customers achieve those ambitions.

How does the oilfield services sector thrive in challenging environments?

We're all learning to adapt to whatever the new normal is and make the best of the situation. Despite COVID being a very predominant factor in all of our lives today, demand for energy hasn't really gone away. It has been reduced in a few sectors, sure, but overall, the world is still consuming energy. That makes that industry continue to be very important.

If you look at most of the companies in the space, we've all been categorized as essential workers during the pandemic and continue to have all our operations running. As the world has migrated to a work from home scenario in multiple different places, most of our employees are still out in the field, helping our operators, having our customers continue to drive production, which fuels the world today. That hasn't gone away.

Eventually, as news of vaccine development takes hold, as they get released and hopefully get distributed to greater parts of the population, we feel the world will come back to a degree of normalcy, which may be different from what we're used to in the past, but we'll continue to drive demand for industrial production and will continue to drive demand for energy.

We believe the industry as a whole will continue to be a very important part of the energy profile of the world for a while to come.

Over the past few years, ESG has of course emerged as a primary focus. How do service providers, and specifically Weatherford, help companies achieve their ESG goals?

[ESG] has become a really important term, and it's one that you have to make sure you have a strategy around and that has to be backed up by implementation. As we talk to our customers, it's no longer enough to just support them [in their ESG initiatives]. We have to have our own independent efforts to drive that ESG effort. First of all, it comes to understanding, what are your customers doing? What are their pain points, what are their pressure points and where do we fit into their operations?

"Remote collaboration creates a greater sense of equity, a greater sense of quality, and really democratizes the entire process of driving innovation in a much bigger way in our industry."

We talked about the energy transition—efforts around helping customers have more sustainable operations [are part of this.] Sometimes these things are relatively mundane, like reducing personnel onboard, reducing the number of miles we drive, but all these things that reduce our carbon footprint and fit into what our customers do as well have an impact.

It's also helping them have more effective, more efficient operations—driving automation, reducing the amount of time it takes to drill wells, the amount of time it takes to drive production, all of those factors have an impact on [customers], improving their operations and their overall sustainability.

What positive signs or trends are likely to emerge in 2021 and maybe further down into the future?

One of the interesting byproducts of the pandemic has been the adoption and the acceleration of adoption of technology. One of the trends I think is pretty interesting is remote operations. That's something the industry has always thought about and has tried a few different ways, but the pandemic has forced us by necessity to try a few different ways of doing it. The other trend that emerges from that notion of remote operation is an improvement in safety as well as efficiency and expertise.

In our industry, we still have a bit of a challenge in the skilled workforce and finding experts who have decades of experience that we deploy for our customers. Now, thinking about a world where instead of having a few experts that you have to get on a plane and move from place to place, you can now have them sitting in a control room and they can assist, you know, somebody in the morning in Argentina, and then switch around and in the afternoon they're helping someone in the Middle East and then someone in Asia, that ability is now made possible through the technology, through remote collaboration.

Continuing on that team of remote collaboration: To me, it's this notion of bringing together the collective creativity and the capability of teams around the world and the leverage that technology can give us of connecting people to create more innovative solutions, to harness the best minds together, regardless of where you are.

Remote collaboration creates a greater sense of equity, a greater sense of quality, and really democratizes the entire process of driving innovation in a much bigger way in our industry. It's something that happened in multiple other spaces already, but I'm very excited about that happening to a greater extent in our sector. □

SPECIAL REPORT

Arizona State University
Duke University
Oklahoma City University
Northeastern University
Rice University
Southern Methodist University
Stanford University
Texas A&M University
Texas A&M University-Texarkana
Texas Christian University
Tulane University

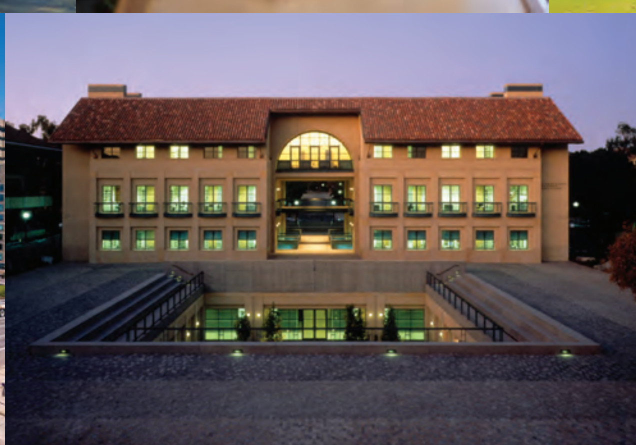
Executive ENERGY Programs
HARTENERGY

University of North Carolina – Chapel Hill
University of Colorado Denver
University of Georgia
University of Houston
University of Oklahoma
University of Phoenix
University of Tulsa
University of Texas
University of Texas – Dallas

EXECUTIVE ENERGY GRADUATE PROGRAMS






GRADUATE ENERGY PROGRAMS REPORT

Graduate energy education takes multiple forms, and it could help industry professionals, including executives, address the sector's present and future challenges. These brief overviews of U.S.-based graduate business and technical programs are intended to help readers identify programs relevant to them.

ARTICLE BY
BILL WALTER

Though extensive field experience inevitably forms the core of many energy executives' careers, graduate energy education can also provide invaluable information, skills and connections to help accelerate one's trajectory. For energy professionals, graduate business education, in the form of an MBA or an EMBA as well as technical M.S. programs focused on energy development, offers increasingly relevant opportunities to develop new knowledge as more research orients toward the energy transition and understanding its complex dynamics.

However, a career in energy takes a great deal of time, sometimes leaving little spare time for researching academic opportunities. To that end, *Investor* has compiled this list of U.S.-based graduate energy programs to show the diversity of relevant opportunities available in higher education.

This list does not constitute a ranking of the selected programs. Programs are arranged in alphabetical order, and the information for each program overview was pulled from publicly available data on university websites.

At the core of all these programs are commitments to specialized energy curriculum, flexible course formats and student-to-industry connections. Most of these programs also emphasize the international nature of the energy business, which is reflected in international residencies and coursework.

However, like the industry itself, several of the energy-focused graduate programs on this list have adapted their energy curriculums to account for the growing urgency surrounding the energy transition. Many of these programs have faculty that also work in the industry or advisory boards composed of energy executives, and several of them are hosted at universities with leading energy research centers.

2020 was a tough year for energy, and the future of the industry is filled with a number of questions. As part of the effort to help answer them, energy professionals would do well to consider graduate education in energy.

ARIZONA STATE UNIVERSITY
Executive Certificate in Global Oil and Gas Management

- **Program Highlight:** Globally focused, this executive certificate program provides a broad view of the different components of the oil and gas industry.
- **Tuition:** In total, the cost to earn the certificate is $2,300.
- **Web Address:** thunderbird.asu.edu/executive-education/online/certificate-global-oil-gas-management

Arizona State University's (ASU) Thunderbird School of Global Management has streamlined its global oil and gas management master's certificate into an all-online program that students can begin on demand.

Broken down into five chapters, this program prepares students for work in all industry sectors: upstream, midstream and downstream, with a chapter devoted to each.

According to the program website, the Thunderbird School emphasizes giving students an "entrepreneurial edge" that they can utilize across the global marketplace.

The certificate program is suitable for those who wish to enter oil and gas management from a different field or for those looking to advance an existing industry career.

The program's global emphasis broadens students' career opportunities, providing knowledge and practical skills that can be put to use in oil and gas management anywhere in the world.

DUKE UNIVERSITY
Global EMBA and Weekend EMBA

- **Program Highlight:** Duke EMBA students are structured into teams that will learn together and collaborate throughout the entire program.
- **Tuition:** For students starting in July 2021, total tuition cost is $152,000 for the Global EMBA program and


DUKE UNIVERSITY

$145,875 for the Weekend EMBA program.
- **Web Address:** fuqua.duke.edu/programs

Collaboration lies at the heart of the two EMBA programs offered at Duke University's Fuqua School of Business: the Global EMBA and Weekend EMBA. To mimic the experience of being part of a diverse business team, EMBA students are grouped into learning teams of five to six students who progress through the program together. As a result, they are able to share intensive knowledge and build connections throughout the entire program with their colleagues, many of whom represent countries from across the globe.

The Global EMBA program, with a duration of 21 months, and the Weekend EMBA program, with a duration of 22 months, each allow working professionals to enhance their leadership abilities in a hybrid learning environment that mixes distance learning with in-person residencies. The global program emphasizes international residencies; students participate in one-week residencies in Asia, Latin America and Europe through the months of October, January, April and July. Both the Global EMBA and Weekend EMBA include short residencies at Fuqua's campus in Durham, N.C.

For energy-focused executives, each EMBA program offers a concentration in energy and environment, which allows students to develop subject matter expertise in the intersection of energy and environmental issues that will affect the future of the business. Like the other concentrations available to EMBA students, the energy and environment concentration requires two courses from an approved list as well as an independent elective project.

OKLAHOMA CITY UNIVERSITY
M.S. in Energy Management and M.S. in Energy Legal Studies

- **Program Highlight:** Two distinct program tracks provide specialized learning outcomes for students, and both tracks are all online.
- **Tuition:** The 2020 to 2021 total tuition cost for both programs is $23,650.
- **Web Address:** okcu.edu/business/graduate/energy

The Meinders School of Business at Oklahoma City University offers two M.S. programs that provide energy professionals with specialized opportunities to develop their knowledge bases: the M.S. in energy legal studies program and the M.S. in energy management program.

Both programs are offered in 100% online learning environments, and their curricula are dedicated solely to the energy industry, providing ease of access and immediate practical relevance to working professionals. Together, they comprise the first graduate energy program accredited by the American Association of Professional Landmen.

OKLAHOMA CITY UNIVERSITY

Each master's degree track consists of 30 credit hours (10 courses), which are usually completed on a part-time basis over two years. All students complete two energy overview courses before pursuing course paths tailored to their degree focus: the Leadership and Management in the Energy Industry, which covers all sources of energy throughout generation and delivery cycles, and the Legal and Ethical Environment in the Energy Industry, which provides an overview of the industry's legal dynamics.

NORTHEASTERN UNIVERSITY
M.S. in Energy Systems

- **Program Highlight:** Northeastern's graduate engineering co-op places students in four- to eight-month positions with diverse companies.
- **Tuition**: The estimated total tuition cost for the 2020 to 2021 academic year is $53,200.
- **Web Address:** northeastern.edu/graduate/program/master-of-science-in-energy-systems-boston-5269

Because successful energy management requires awareness of both technological and financial developments, Northeastern University's M.S. in energy systems program provides relevant, strategically useful instruction for energy professionals. The program integrates the technology side of energy systems development with the financial planning needed to effectively implement them.

The all-online curriculum, which can be pursued on either a full-time or part-time schedule, usually takes one and a half to two years to complete and comprises a set of six core courses in engineering knowledge and finance and four electives that can be taken from any department within the College of Engineering.

A unique feature of the program, the cooperative education program (co-op) connects students to experiential learning and research opportunities in the energy industry. In 2019 the Graduate School of Engineering placed nearly 1,000 students in co-op positions. In general, these co-op positions span four to eight months in duration and occur in organizations ranging from large companies to startups.

RICE UNIVERSITY
Professional MBA

- **Program Highlight:** A global field experience provides all PMBA students with the opportunity to build lasting professional relationships and make a difference in local communities.
- **Tuition:** The total two-year tuition for the PMBA evening class of 2023 is $109,930, and the total two-year tuition for the PMBA weekend class of 2022 is $115,050.
- **Web Address:** business.rice.edu/rice-mba/professional-mba


RICE UNIVERSITY

Houston-located Rice University hosts a variety of energy-oriented educational and research programs, and its professional MBA (PMBA) with a focus in energy can help working professionals advance their careers or prepare to pivot in a new direction. Rice's MBA programs have risen steadily in national and global rankings, with U.S. News and World Report ranking the PMBA program at No. 13.

Built with flexibility in mind, PMBA students can complete the part-time program in evenings or on weekends, a process which typically takes two years to complete. An extended format, which allows student to complete the program in three to five years, is available and is taught by the same faculty with the same curriculum as the traditional two-year format.

Regardless of duration, the PMBA program takes place on Rice's Houston campus. However, to extend the opportunity for access, the university offers a travel subsidy for students commuting to Houston for the weekend-based program. The subsidy provides and pays for nearby hotel accommodations during students' weekend stay and involves an optional fee that is separate from tuition.

A core component of both the evening and weekend PMBA student experience is the global field experience, in which students work in small teams to complete consulting projects with local students, companies and nonprofits. This experience serves a dual function: helping PMBA students build lasting professional relationships and positively impacting the local community via a service project.

SOUTHERN METHODIST UNIVERSITY
EMBA, Online MBA and Professional MBA

- **Program Highlight:** SMU's Maguire Energy Institute provides research and networking opportunities for energy-focused MBA students.
- **Tuition:** The estimated 2020 total tuition costs for the three aforementioned

SOUTHERN METHODIST UNIVERSITY

programs were: $123,495 for the EMBA, $91,624 for the online MBA and $101,950 for the PMBA.

- **Web Address:** smu.edu/cox/At-SMU-Cox

Southern Methodist University's Cox School of Business hosts several highly ranked MBA programs that provide working professionals with diverse opportunities to develop their knowledge and leadership skills to advance their energy careers.

In 2020 the 21-month Cox EMBA program was ranked the top MBA program in the U.S. by Business Insider and No. 16 in the U.S. by Financial Times. The two-year online MBA program offers the same rigorous curriculum as the Cox MBA in Dallas but in a part-time, online learning environment. Also a two-year, part-time program, though not all online, the Cox PMBA is designed to accommodate existing careers.

Of note for energy professionals, the Cox School of Business hosts the Maguire Energy Institute, which supports energy-focused MBA students through its advisory board of leading energy professionals, who are accessible to students, and its deep network of industry contacts. A variety of energy-specific courses are available to MBA students through the partnership with the institute.

STANFORD UNIVERSITY
M.S. in Petroleum Engineering and M.S. in Energy Resources Engineering

- **Program Highlight:** Two M.S. tracks, both also scalable to a Ph.D., provide technical knowledge and skills to understand the energy development process.
- **Web Address:** earth.stanford.edu/ere/graduate-program

Stanford University's College of Earth, Energy and Environmental Sciences offers two graduate programs that are designed to develop in-depth technical knowledge of energy extraction and production. On one track, students may earn a M.S. or Ph.D. in petroleum engineering, and on another, they may complete a M.S. or Ph.D. in energy resources engineering. Both programs aim to provide a strong background in the basic sciences relevant to energy as well as the practical application of this knowledge to solve problems in the field.

"The objective of the M.S. degree in energy resources engineering is to prepare the student either for a professional career or for doctoral studies," according to the Stanford Bulletin, the university's official catalog.

The petroleum engineering track's objective is "to prepare the student for professional work in the energy industry, or for doctoral studies, through completion of fundamental courses in the major field and in related sciences as well as independent research," the Stanford Bulletin described.

Enrolled students in this program are expected to have an undergraduate background in engineering or the physical sciences.

TEXAS A&M UNIVERSITY
EMBA and M.S. in Energy

- **Program Highlight:** With an EMBA class composed of 50% energy

STANFORD UNIVERSITY

professionals and an M.S. program that focuses on cultivating industry expertise, TAMU offers multiple options to advance industry careers.
- **Tuition:** For Texas residents, the estimated total tuition cost for the EMBA program is $99,500; TAMU's website notes additional costs for nonresidents. The estimated total tuition cost for the M.S. in energy program is $30,000 for Texas residents and $40,000 for nonresidents.
- **Web Address:** mays.tamu.edu/executive-mba

Long known as a pioneering school for energy professionals, Texas A&M University (TAMU) offers multiple graduate programs that can enhance industry careers.

The EMBA program begins with a one-week residency at A&M's College Station, Texas, campus. The program is then primarily based out of the Mays Business School's private facility in Houston and utilizes an interdisciplinary curriculum to explore the connections among diverse business disciplines and to cultivate leadership skills.

Though not strictly energy focused, TAMU's EMBA program has a strong stake in the energy business, which is represented in its student composition: 50% of students in the EMBA class of 2020 work in the energy industry.

Also interdisciplinary, the 10-month M.S. in energy program focuses on theoretical and practical knowledge of all components of energy to create a new generation of energy experts, according to the program website. Faculty are drawn from diverse academic departments and include industry and government experts. The M.S. program has two tracks, one of which easily accommodates working professionals via its distance learning environment.

Though each program provides distinct pathways for energy professionals, both grant access to the university's alumni network of almost 400,000 former students around the world, providing an invaluable resource in an international energy business.

TEXAS A&M UNIVERSITY-TEXARKANA
MBA in Energy Leadership

- **Program Highlight:** TAMU-Texarkana's MBA-Energy Leadership program prioritizes affordability without sacrificing quality in an effort to make graduate energy education accessible.
- **Web Address:** tamut.edu/academics/colleges-and-departments/CBET/Graduate-Programs/MBA-Program/Energy-Leadership.html

Through partnerships with energy organizations, including the American Association of Petroleum Geologists and the Southern Gas Association, the College of Business, Engineering and Technology at Texas A&M University-Texarkana offers an energy-focused MBA track to working and aspiring energy professionals.


TEXAS A&M UNIVERSITY

The MBA-Energy Leadership program consists of 30 credit hours of coursework that is offered in an online learning environment, which encourages students to enroll from across the globe.

Affordability is a core value for the College of Business, Engineering and Technology. According to its website, the TAMU-Texarkana MBA program has been ranked among the Top 5 Best Value MBA Programs by Affordable-Colleges.com for the past three years and has been ranked among the Top 5 Best Graduate Schools for Business Administration by Grad-Source.com since 2016.

TEXAS CHRISTIAN UNIVERSITY
Energy MBA

- **Program Highlight:** Multiple completion tracks (standard and accelerated) and options for in-person and online coursework provide students with significant flexibility.
- **Tuition:** For the 2020 to 2021 academic year, the estimated total tuition cost for the standard-length Energy MBA is $85,458 and $74,784 for the accelerated track.
- **Web Address:** neeley.tcu.edu/energymba

With a faculty ranked No. 1 in the world by The Economist, Texas Christian University's (TCU) Neeley School of Business provides globally recognized graduate business education, and its Energy MBA program draws from the core Neeley MBA curriculum while adding select courses and experiences exclusively focused on the energy industry.

The 42-hour Energy MBA program consists of 25.5 hours of core courses, 10.5 hours of energy-specific courses, which include an international trip, and six hours of business or energy electives. An accelerated completion track is available, which cuts the total semester hours from 42 to 36 by eliminating certain courses, for students who meet specific requirements.

The Energy MBA program can be completed in person at TCU's Fort Worth campus or online. All students connect on campus twice during the program as part of program-wide student experiences. In-person and online courses are offered only in the evenings, which allows working professionals to continue their careers alongside their MBA studies.

TULANE UNIVERSITY
M.S. of Management in Energy

- **Program Highlight:** Unique course offerings and resources through the Tulane Energy Institute allow students to engage in complex learning environments.
- **Tuition:** For the 2020 to 2021 academic year, the estimated total cost of the MME program, including tuition and university fees, is $67,286.
- **Web Address:** freeman.tulane.edu/academics/graduate-programs/master-management-energy

The M.S. of management in energy (MME) program at Tulane University's A.B. Freeman School of Business has been designed with the input of energy leaders to provide students with knowledge and skills that are relevant and practical. In addition to accessing program faculty and curriculum, MME students are able to get involved with the Tulane Energy Institute, which includes its Trading Center, a facility that replicates real-world trading experience for students and serves as a laboratory for a variety of experiential MME courses.

Among the unique course offerings available to MME students, the Burkenroad Reports program stands outs. As the first university-sponsored securities analysis program, Burkenroad Reports assigns teams of Tulane graduate business students to follow public small-cap companies and write investment research reports on them. MME students who participate in Burkenroad Reports are able to write a comprehensive analyst report about an energy firm based on research and meetings with company executives.

The MME program typically can be completed in 10 months, though it can be extended to 18 months to involve a summer internship. The program notes it has a consistent 100% graduation rate.

UNIVERSITY OF NORTH CAROLINA–CHAPEL HILL
MBA in Energy

- **Program Highlight:** Coverage of the entire energy value chain ensures that the UNC MBA in energy students have a full understanding of the industry.
- **Tuition:** Estimated total tuition costs vary depending on state residency. For North Carolina residents, total tuition and mandatory fees come out to $51,152 and $66,840 for non-North Carolina residents.
- **Web Address**: kenan-flagler.unc.edu/programs/mba/full-time-mba/academics/concentrations-electives/energy

Over the course of two years, students at the University of North Carolina-Chapel Hill (UNC) can earn an MBA in energy at the Kenan-Flagler Business and receive a comprehensive education in the entire energy value chain. In courses based upon actual energy operations and deals, with faculty applying the skills they developed in their own industry careers, energy MBA students at UNC receive a specialized energy business education that is directly applicable to their careers.

As part of the program, students gain access to the Kenan-Flagler Energy Center, which enhances the student experience through career-focused events and conferences, research assistantships, curriculum development, internship assistance and access to faculty and industry professionals.

UNIVERSITY OF COLORADO DENVER
M.S. in Global Energy Management

- **Program Highlight:** CU Denver GEM's executive in residence program gives students direct access to industry leadership.
- **Tuition:** According to the program website, the total cost of tuition for the M.S. in global energy management is $54,000, or $4,500 per course.

UNIVERSITY OF COLORADO DENVER

- **Web Address:** business.ucdenver.edu/ms/global-energy-management

The University of Colorado Denver Global Energy Management (CU Denver GEM) takes an expansive view of the energy industry, providing a flexible curriculum that actively responds to the developing energy world.

Over the course of the 18-month program, students will be able to collaborate directly with three different energy executives through the CU Denver GEM program's executive-in-residence feature. This immediate student connection to the C-suite is a unique feature of CU Denver GEM. Combined with the program's faculty, all energy practitioners with an average 15-plus years of work experience create a learning environment that is closely connected to the industry itself. Students complete coursework online and attend a four-day on-campus weekend held in Denver every three months.

In addition to the M.S. degree, CU Denver GEM faculty offer several relevant certificate programs that demonstrate the school's energy-focused curriculum. These include the global energy financial management certificate, which is a for-credit program that strengthens hard skills in energy finance, and the energy analytics and Big Data for managers certificate, which provides an in-depth look at the practices of the increasingly relevant field of data analytics.

UNIVERSITY OF GEORGIA
EMBA

- **Program Highlight:** A significant portion of EMBA graduates report promotions and new responsibilities during the program.
- **Tuition:** The total program cost for the EMBA program for in-state and out-of-state residents is $77,000.
- **Web Address:** terry.uga.edu/mba/executive

Before enrolling in the EMBA program at University of Georgia's Terry College of Business, students must have acquired five years of experience. On average, EMBA students already have 12 years of management experience. As a result, the program is able to tackle problems directly relevant to executives, including those in energy, from the start.

Students earn their EMBA through 18 months of coursework, which is offered in a hybrid learning environment with a 50:50 mix of classroom and online learning. In-person commitments required of students comprise two week-long residences, 21 weekend sessions and a 12-day international residency. The international residency directly exposes students to challenging global business environments through multiple intensive learning experiences.

In an exit survey of graduating students, 39% of EMBA students reported that they were promoted during the program and 59% said they were awarded new responsibilities at work, according to the program's brochure.

UNIVERSITY OF HOUSTON

UNIVERSITY OF HOUSTON
EMBA and M.S. in Global Energy Management

- **Program Highlight:** University of Houston's EMBA and GEM programs provide specialized instruction and connections to Houston's energy industry.
- **Tuition:** The total investment for the Bauer EMBA program is $74,700 for Texas residents but differs for nonresidents. The Bauer GEM program costs $35,000 (tuition and fees) for Texas residents and $60,000 for international students.
- **Web Address:** bauer.uh.edu/graduate-studies

The University of Houston leads a number of energy-focused programs and initiatives. Its C.T. Bauer College of Business offers two separate graduate degree programs of notable relevance for energy professionals: the Bauer EMBA and the M.S. in global energy management, offered through the Gutierrez Energy Management Institute. Both programs benefit from University of Houston's deep industry engagement to provide distinct course offerings and student opportunities.

The Bauer EMBA program emphasizes the international nature of business and includes an intensive 10-day international residency, which takes place between the first and second year of classes. Available in weekend-only (20 months) and evening formats (22 months), the 48-credit hour EMBA curriculum comprises two separate but related tracks: the EMBA core and a leadership track.

The Bauer GEM program is the only M.S. in global energy management program offered in Texas and was created in response to the evolving needs of the industry. The 36-hour, 12-course program is most relevant for professionals working in energy management, energy finance and energy trading, according to the program web-

UNIVERSITY OF OKLAHOMA

site. In general, classes in the Bauer GEM program take place once a week from 6 p.m. to 9 p.m.

The Bauer GEM program is now an Energy Risk Professional program partner with the Global Association of Risk Professionals, a framework through which academic institutions can ensure that their risk management course offerings align with global industry needs and best practices.

UNIVERSITY OF OKLAHOMA
EMBA in Energy

- **Program Highlight:** OU's energy-only EMBA curriculum has been recently updated to provide executives with the full tools to navigate the energy transition.
- **Tuition:** The total cost of the program, including tuition and fees, is $85,500.
- **Web Address:** ou.edu/price/mba/embainenergy

University of Oklahoma's (OU) nationally ranked EMBA in energy program offers students a 15-month curriculum that will prepare them to thrive during the industry's transition to renewable and alternative energies. Unlike most other EMBA programs in the U.S., the program's curriculum is entirely focused on the energy industry, with all components of the program having been designed with the real-world needs and challenges of energy professionals in mind.

Adapting to the increased sense of urgency around transition, the EMBA program has developed new classes and revised existing curriculum to better prepare students to innovate and lead in the growing fields of renewable energy, alternative fuels and electrification.

An integral component of the EMBA program is its international residency module, which grants students the opportunity to take courses in Amsterdam and London. In addition to the international residency, the EMBA program has two domestic residencies that take place on campus, one at the start of the program and another at its conclusion.

Due to the intensive nature of its curriculum, which will equip students with knowledge on topics such as decarbonization and energy economics, the university recommends that students set aside at least 25 hours per week to absorb new materials, complete assignments and work with their classmates on team exercises.

UNIVERSITY OF PHOENIX
Online MBA

- **Program Highlight:** With a highly affordable tuition rate and cost-savings through transfer credits, the online MBA at University of Phoenix is a cost-effective means of earning a graduate business education.
- **Tuition:** The tuition rate for the program is $639 per credit, or $21,087 in total.
- **Web Address:** phoenix.edu/degrees/business/mba

To accommodate the needs of working professionals, the University of Phoenix offers an online MBA to teach students how to use technology, manage projects and human resources, direct operations and excel in finance and marketing. The program is accredited by the ACBSP.

The 33-credit program can be completed one course at a time, or 18 months in total. To save costs, the program offers students the opportunity to transfer applicable credits from other institutions they previously attended.

With a 19:1 student-faculty ratio, University of Phoenix students receive personalized feedback on their performance and assignments. Graduates of the program frequently find placements in management occupations, including the oil and gas industry.

UNIVERSITY OF TULSA
Online MBA in Energy Business

- **Program Highlight:** This is one of only three programs accredited by the American Association of Professional Landmen.
- **Tuition:** In 2019 the estimated total tuition cost for the program was $43,250.
- **Web Address:** business.utulsa.edu/energy-economics/masters-energy-business

With a focus on leadership and innovation, the University of Tulsa Collins College of Business MBA in energy business program affords students an opportunity to complete a nationally ranked graduate business program with their choice of concentration in energy law and regulation, energy economics/finance, or corporate strategy and commercial operations.

To meet the diverse needs of students, this 34-credit hour program is offered online with spring, summer and fall start options. The program is usually completed in 24 months. During this time period, students will travel to the University of Tulsa twice for executive-style weekend seminars that provide networking opportunities and include experiential learning activities.

The MBA in energy business program has received multiple forms of accreditation. Along with its AACSB accreditation, held by all Collins College programs, the MBA in energy business program in particular is one of three post-baccalaureate programs accredited by the American Association of Professional Landmen.

UNIVERSITY OF TEXAS
EMBA and Full-time, Evening and Weekend MBAs

- **Program Highlight:** UT's McCombs School of Business offers a diverse set of graduate business programs to meet varying student needs.
- **Web Address:** mccombs.utexas.edu/MBA

University of Texas' (UT) McCombs School of Business offers multiple MBA tracks to accommodate a variety of schedules and backgrounds. In addition to the full-time MBA and EMBA programs, the McCombs School of Business offers multiple working professional MBA formats: the evening MBA at Austin and weekend MBA programs at Houston and at Dallas/Fort Worth.

The full-time MBA offers more than 20 concentrations and study abroad opportunities for students to customize their two-year learning experience. For working professionals, the evening MBA based in Austin allows students to complete classes at night, without interrupting their careers. This program can be completed in two and a half years and still allows students to network and benefit from the classroom experience.

For students in Houston and Dallas/Fort Worth seeking to earn a degree while continuing their career, UT offers MBA programs that meet on alternating weekends with a two-year targeted degree time. These offerings focus on teaching students a broad set of business management skills in a cohort-focused curriculum.

Highly experienced professionals looking to develop new skills can enroll in the EMBA program, which allows optimum flexibility and fast degree turnaround. Students complete most coursework online and spend one weekend per month at UT's campus in Austin to collaborate with colleagues and professors. The targeted degree completion time for the EMBA is 20 months.

UNIVERSITY OF TEXAS-DALLAS
M.S. in Energy Management

- **Program Highlight:** Practical instruction drawn from real-world deals and executive mentorship helps graduates hit the ground running in energy.
- **Web Address**: fin.utdallas.edu/ms-energy-management

The Naveen Jindal School of Management at University of Texas-Dallas designed the M.S. in energy management program to provide a hands-on curriculum that addresses the myriad practical challenges involved in managing energy assets, technically and financially.

The 36-hour STEM program uses real-world contracts and case studies in its curriculum and takes students to diverse energy facilities as part of its experiential learning component. An overall mixture of traditional MBA courses and energy courses, 24 credit hours form the core curriculum, which all M.S. students complete, and the remaining 12 credit hours consist of electives. Students can follow one of four available specialized curriculum tracks, each tailored to specific career outcomes: energy risk management, energy analytics, international energy management and energy operations.

According to the program website, all students in the M.S. in energy management program are assigned energy executive mentors. □

UNIVERSITY OF TEXAS

EXPERIENCE IS EVERYTHING

For the pioneering University of Colorado Denver Global Energy Management Program, 'experience is everything' when delivering specialized business education to busy professionals.

Retaining top talent is one of the most critical and challenging priorities for energy executives today. The recent global pandemic, along with the latest downturn, has left many employees wondering if their careers should be rooted in an industry with so much uncertainty.

Since 2009, energy professionals from around the world have found a path forward through the Global Energy Management Program at the University of Colorado Denver Business School. The GEM Program's pioneering approach to delivering an all-energy business education has provided the skills and knowledge they need to secure the career opportunities in changing energy markets.

The GEM Program's success is directly related to the extensive experience students bring to the classroom. With an average age of 34, GEM students are accomplished professionals who want to propel their careers forward by pairing their current expertise with strong business acumen.

This acumen flourishes throughout their 18 months in the program because of the energy experience GEM faculty possess. Over the past decade, the caliber of the individuals GEM has recruited to teach its courses has been one of the program's most defining features. GEM's faculty blend real-world practice with academic theory by using deep expertise from their long careers in private equity, big oil, law, public utilities, national laboratories and leading renewable energy companies. Despite such diverse backgrounds and geographic locations, faculty work together to ensure a seamless curriculum that students can immediately apply to their jobs.

GEM expands students' sphere of influence by being the only program with a dedicated Executive in Residence (EIR) who is available to both students and alumni. GEM's EIR program is truly innovative; it rotates in a new executive from a different energy sector every six months. Through lectures and individual meetings, the EIR shares valuable insight, in-depth industry knowledge, and career guidance to both students and alumni.

The program also offers myriad experiential learning opportunities, which include two travel courses to both Washington D.C. and London. GEM also offers energy site tours to expand students understanding of different energy sources and how they are delivered.

"GEM offers a lot of standout experiences for students that help them make skillful career transitions. The travel course to London, for example, entirely changed my view of the industry. This course offers first-hand access to leading international companies, as well as meetings with key lawmakers and organizations that impact energy policy and markets," said GEM alumna Stephanie Pruett, vice president of business development at Data Exchange at Energy Link.

"Our students are passionate about the energy industry. They recognize that how energy is being developed and delivered is shifting, which means new opportunities for advancement. We help the industry retain its top talent by showing them that these opportunities exist in all sectors. Our students graduate feeling more impassioned and confident about their role in energy."

Sarah Derdowski, executive director, University of Colorado Denver GEM Program

The educational experience GEM delivers translates into proven results and an impressive return on investment for students; 55% of students have received a promotion and an increase in salary while still in the program, with 15% reporting an increase of 20% or more.

The program also measures its success by the global community of alumni. Derdowski said, "Our focus and commitment to students do not end at graduation; we continue to forge strong relationships with our alumni throughout their careers. Alumni can audit any course for free and meet with our executives in residence. We recognize that as they move up the ladder, the need to stay current on industry trends is even greater. When it comes to hiring, GEM alumni contact us first for recommendations on candidates to fill their positions."

As the energy industry continues its rapid evolution and strives to retain its talent, the GEM Program maintains its unceasing commitment to help drive the advancement of its employees. To learn more contact us at: 303-315-8436 or business.ucdenver.edu/ms/global-energy-management. ■



Visitor

TEACHING THE BUSINESS OF ENERGY

With a full value chain curriculum of 13 courses all taught by industry practitioners, the Kenan-Flagler Business School's Full-time MBA with Energy Concentration prepares professionals with a comprehensive industry education.

The Kenan-Flagler Energy Concentration focuses on teaching "the business of energy." Few business schools actually concentrate on teaching the keys to succeeding commercially in energy. We uniquely teach this business as "a strategic commodity business with a volatile price cycle." Because it is a commodity business, there is little product differentiation and price discovery is facilitated by benchmark postings on exchanges. These and other factors produce a capital-intensive business with high fixed costs and a fragile price structure. Those who succeed in this business must relentlessly focus on unit cost efficiency and prudent capital allocation across the price cycle.

These and other key lessons are taught by a faculty consisting entirely of current and former industry executives. These include the current senior vice president, refining, at Marathon Petroleum, the current chief tax counsel at Kinder Morgan, the current senior vice president at Duke Energy's Piedmont Natural Gas affiliate, the former president of Duke Renewables, and the former treasurer of ExxonMobil Chemical.

Students have the opportunity for both full quarter and intensive weekend classes in topics ranging from the business of oil & gas exploration/production to strategy of project finance and project development and financing of renewables.

The Kenan-Flagler Energy Center sponsors invitation-only conferences on topics critical to understanding the energy transition. We focus these events on questions "which we cannot yet answer." The events are conducted under Chatham House rules to assure the frankest possible dialogue. Recent events explored whether the U.S. hydraulic fracturing revolution would go global, the "all-in" costs of intermittent renewable power, whether new carbon capture technologies are ready for commercial deployment, and the prospects for long duration electricity storage. The Center gives select MBA students opportunities to undertake research related to these topics, which findings are presented at the events.

The program routinely places about 20 graduates in full-time energy related jobs and a similar number in summer internships with such firms as ExxonMobil, Chevron, Kinder Morgan, Duke Energy, NextEra, National Grid, Scott Madden Consultancy, Morgan Stanley and Wells Fargo. ■

KENAN-FLAGLER BUSINESS SCHOOL

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ENERGY GRADUATE
PROGRAM
INVESTOR MAGAZINE

AN EDUCATION FOR LEADERS OF THE TRANSITION

OU's EMBA in Energy program remains committed to its all-energy curriculum, a third of which it has revamped to prepare leaders to understand and engage with the complexities of the energy transition.

An Executive MBA in Energy from the University of Oklahoma (OU) prepares graduates to lead organizations in the ever-developing energy landscape. While all EMBAs are designed for professionals looking for career advancement, those coming from industries undergoing transformation, such as energy, need more. These professionals are more likely to benefit from a specialized EMBA that can enhance their prospects moving into leadership roles.

OU's 15-month hybrid EMBA in Energy does exactly this. It is an all energy, only energy innovative curriculum, put together and revised based on input from program alumni and industry leaders. Since 2014, when the program began, about one-third of the curriculum has been revamped primarily to address energy in transition. Through exposure to this collective content, which is spread through 23 courses, and opportunities to think critically about it, students can walk away prepared to effectively lead their organizations, no matter what the future holds.

"As energy markets change rapidly and environmental challenges rise, there is a strong need for a new generation of business leaders who understand the rapidly evolving trends in business models of energy companies, develop an entrepreneurial mindset and embrace change," said Dipankar Ghosh, a David Ross Boyd Professor of Accounting and designer and administrator of the EMBA in Energy program, which is housed in OU's Michael F. Price College of Business.

Through courses including Energy and Environment, Electric Utility Fundamentals and Renewable Energy and Alternative Fuels, students learn about energy transition and the change in the global energy mix from the perspectives of energy security, climate change and rising energy prices. And they learn from professionals who have lived it. C-suite executives and leaders in the energy industry teach several courses. In addition, students hear from guest speakers with similar backgrounds from around the world.

As part of the emphasis on energy transition, the program recently added Amsterdam to its international residency, which already included London. This addition puts students in The Netherlands, a country actively working toward decarbonization, giving them the opportunity to learn about and evaluate government actions, policies, company responses and more.

"OU's EMBA in Energy program is second to none. The combination of a relevant, forward-thinking curriculum including leadership development and global perspectives, experienced instructors from industry and academics, and a cohort composed of professionals with varied energy experience creates a program that equips its graduates to advance in the global energy business and be the industry's next generation of leaders."

Dipankar Ghosh, David Ross Boyd Professor of Accounting; designer and administrator, OU Executive MBA in Energy program

While in Europe, students examine challenging global energy issues in multiple ways. They take two courses—Energy Economics and Strategic Management—taught by instructors with extensive global experience; participate in company visits; and interact with senior energy professionals, government officials and energy consultants.

"Energy is a global commodity, and having a global perspective helps in being an effective leader in the energy industry," Ghosh said.

Beyond the program's curriculum, the makeup of each cohort is designed to augment the learning process. Program requirements call for students with a minimum of eight years of progressive work experience, with at least three in the energy industry.

With a cohort size of about 20 and everyone having experience across the energy value chain, discussions delve deeper into the industry's nuances, boosting classroom learning and practical applicability. This specialized program gives students the chance to surround themselves with a cohort, faculty and instructors who bring to bear top-tier industry connections for a strong networking advantage upon graduation. ■

TCU Energy MBA

Designed for working professionals

- Classes typically meet two nights a week on campus or remotely
- Graduate in 18-24 months
- Gain in-depth knowledge of the current business issues and practices unique to the energy industry
- Exposure to industry experts with extensive top-level experience in the energy field

GMAT

In light of recent events in our world, the GMAT/GRE is now optional for all candidates applying for admission into the Fall **2021** cohort. Additionally, all application fees will be waived, so there is not a better time to apply than now!

Energy focused classes include:

- Energy in the 21st Century
- Energy Macroeconomics
- Energy Legal and Regulatory Issues
- Energy Finance
- Energy Commodities
- Energy Analytics

The Oil and Gas Investor Magazine ranks the TCU Energy MBA program #1 in Texas

TCU

Neeley School of Business

Energy MBA

CONNECTING STUDENTS TO INDUSTRY

Through programs such as its energy innovation case competition, the TCU Energy MBA bridges the gap between academia and industry to help prepare future energy leaders.

The accelerating pace of innovation in global energy markets requires graduate business education to prepare market-relevant leaders through world-class programs like the TCU Energy MBA for working professionals.

Last year, TCU looked for an opportunity to offer energy innovation to its graduate students and reached out to NAPE and the AAPL to develop an energy case competition to attract top MBA students from all over the country. Not only was $40,000 up for grabs for the top 3 winning universities, but it also gave the opportunity for the winning team to present their case at the NAPE Summit in Houston.

The energy case was developed by TCU Neeley School of Business energy team, Rob Clarke, vice president of upstream research at Wood Mackenzie, and Dr. Ann Bluntzer, associate professor of professional practice in management and leadership and faculty advisor for the TCU Energy MBA. The energy innovation case asked the competitors to analyze the implications of the wide performance of U.S. E&P equities in 2019 and create innovative real-world solutions.

The response of universities interested in participating in the energy innovation case competition was remarkable. The case competition brought together MBAs from 11 top universities to compete. The teams had five hours to work on the case before presenting their energy knowledge to a panel of judges made up of leaders from industry and academia. The judges included senior executives from Chevron Corp., Enverus, Texas Commission on Environmental Quality, Wood Mackenzie and Centennial Resource Development Inc., and Sean Marshall, president of the AAPL Education Foundation, which sponsored the competition. The graduate students not only were able to network with other schools and meet impressive industry professionals; they also were challenged with big questions facing the energy industry.

"Our first case competition was a compelling success and an excellent example of collaboration between higher education and industry to solve some of the biggest issues facing the energy sector. It was inspiring to watch the next generation of leaders share their innovative ideas towards energy security in the future," said Ann Bluntzer.

TCU is excited and honored to partner with NAPE and the AAPL for the second annual energy innovation case competition in August of 2021. "TCU Neeley's partnership with NAPE helps meet the challenge of the accelerating pace of innovation in global energy markets by continuing to provide an experiential learning platform for top schools to showcase student expertise and deepen engagement with energy executives," said Daniel Pullin, the John V. Roach Dean of the Neeley School of Business at TCU.

The TCU Neeley School of Business delivers a world-class, global curriculum with an emphasis on experiential learning. In 2020 Oil and Gas Investor ranked the TCU Energy MBA program No. 2 in the nation. The Economist ranks TCU MBA faculty No. 1 in the world and Bloomberg Businessweek ranks the TCU MBA program No. 4 in Texas. TCU Neeley offers the TCU Energy MBA for working professionals, held evenings on the TCU campus and via virtual live learning accessible from anywhere. ■

TCU Neeley School of Business
Energy MBA
www.neeley.tcu.edu

TEXAS CHRISTIAN UNIVERSITY

The Neeley School of Business at Texas Christian University, located in Fort Worth, Texas, offers an Energy MBA program for working professionals.

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Connecting You to the Global Energy Industry

Diamondback Double Dip Mergers Roll-Up Rival QEP, Blackstone's Guidon

DIAMONDBACK ENERGY INC. plans to pay more than $3 billion on two corporate deals—the larger an all-stock acquisition of **QEP Resources Inc.**—as it joins a consolidating trend among E&Ps in the Permian Basin.

The pending QEP acquisition, together with the simultaneously announced acquisition of assets from Irving, Texas-based **Guidon Operating LLC**, will bring Diamondback's total leasehold interests to over 276,000 net surface acres in the Midland Basin and more than 429,000 including its Delaware Basin position.

Diamondback, based in Midland, Texas, said on Dec. 21 it plans to acquire QEP, based in Denver, in an all-stock deal valued at around $2.2 billion, including assumption of $1.6 billion of debt. Diamondback will pay 0.05 share per QEP share, for an implied value of $2.29 per share based on the Dec. 18 closing price.

QEP assets include more than 145,000 net acres in the northern Midland Basin and Bakken Shale. Production is more than 76 Mboe/d (63% oil; 18% NGL). Proved reserves are 382 MMboe. The Midland Basin assets include approximately 49,000 net acres with 47.6 Mboe/d production, with 48 wells drilled but uncompleted. The Bakken assets feature some 49,000 net acres flowing 48.6 Mboe/d.

Additionally, Diamondback said it also intends to acquire the northern Midland Basin assets of Guidon in a cash and stock deal valued at $862 million. Backed by **Blackstone**, Guidon formed in 2016 and is led by Jay Still.

Diamondback will pay 10.63 million shares and $375 million in cash on hand and revolver borrowings.

Guidon's assets include approximately 32,500 net acres, mostly in Martin County, Texas. Third-quarter production averaged 17.9 Mboe/d (11.6 Mbbl/d). Upside includes 395 locations and eight DUC wells.

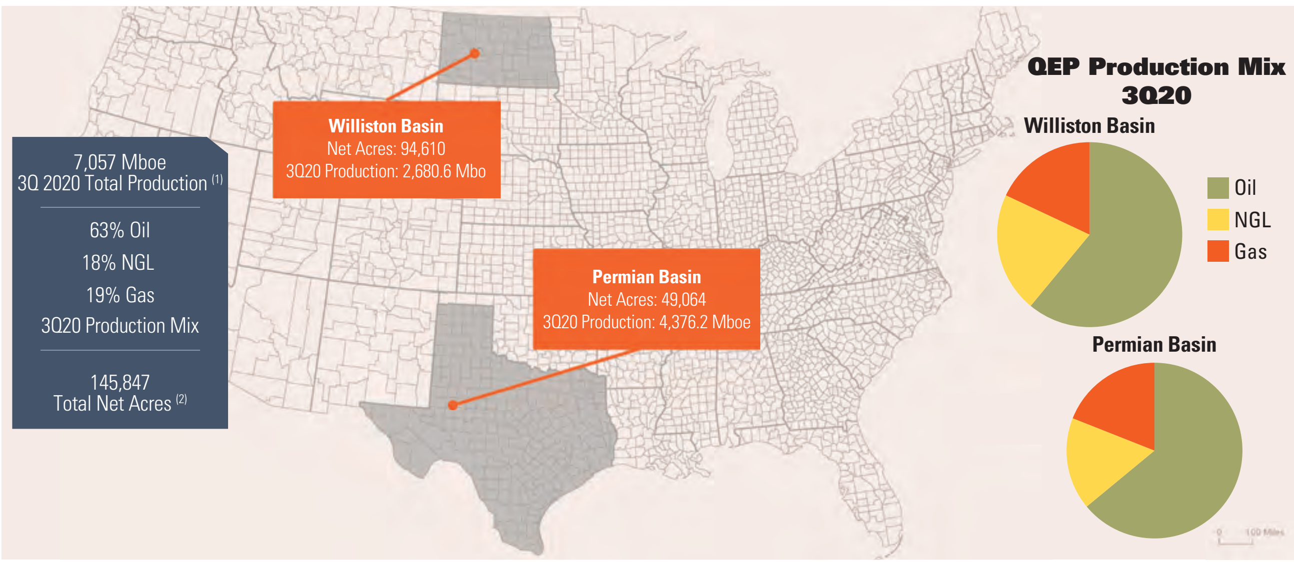
Truist analyst Neal Dingmann estimated Diamondback paid $14,513 per QEP acre, and $14,841 per Guidon acre.

Diamondback CEO Travis Stice said the dual QEP and Guidon transactions "are accretive on all relevant 2021 financial metrics including free cash flow per share, cash flow per share and leverage—even before accounting for synergies," which the company estimates to be $60- to $80 million per year. "Most importantly," he said, "the addition of this Tier-1 resource competes for capital right away in Diamondback's current portfolio, and we will now be able to allocate most of our capital to the high-returning Midland Basin for the foreseeable future."

QEP's Williston Basin assets, however, will be deemed noncore and will be divested or cash flowed to pay down debt, he said.

In Diamondback's third-quarter conference call, just a month before these deal announcements, Stice seemed to take a hard stance that the operator did not need further synergies of scale via consolidation to improve costs. When announcing these deals, he said, "As stated in past public commentary,

QEP Resources Assets



(1) Includes Other northern and other southern production of 0.2 Mboe.
(2) Includes other northern and other southern acreage of 2,173 net acres.
Source: QEP Resources Inc.

Diamondback does not need to participate in industry consolidation to simply get bigger. We participate in corporate development opportunities that we firmly believe will increase the long-term value of our stockholders' investment."

Enverus senior M&A analyst Andrew Dittmar described the deals as a significant enhancement to Diamondback's core Permian position.

"The focus of the QEP acquisition is their core acreage in the Midland Basin, supported by a significant midstream asset base. The midstream portion likely creates additional dropdown opportunities for Diamondback to its midstream affiliate **Rattler [Midstream LP]**," he said.

Diamondback's acquisition of QEP, he added, fits firmly within the mold established for 2020 public E&P consolidation. The deal is structured with no premium and all-stock consideration. It focuses on immediately boosting cash flow to fund shareholder capital returns and debt reduction. Diamondback also expects further support for cash flow through the anticipated synergies.

The buying of Guidon, similar to acquisitions of private equity-backed companies in prior years, is a mix of cash and stock with the value now tilted a bit more toward stock, according to Dittmar.

In addition, he said asset valuations have been reworked with a higher percentage of the total value targeting PDP and less being paid for undeveloped land in a lower rig rate environment.

"Combined, the two acquisitions significantly enhance Diamondback's core Midland Basin position and are expected to be immediately competitive for capital in its portfolio," Dittmar said.

"Both positions are contiguous with existing Diamondback leasehold across its core operating fairway in the northern Midland Basin. Commentary from CEO Travis Stice seems to indicate the company will be prioritizing capital allocations to its Midland Basin asset base, relative to its acreage in the Delaware Basin."

Pro forma, Diamondback equity holders will own approximately 87.4% of the combined companies, QEP shareholders 6.7%, and Blackstone 5.9%, per **Heikkinen Energy Advisors**.

The boards of both Diamondback and QEP have approved the deal, which is expected to close in the first quarter or early second quarter. The Guidon acquisition is expected to close by the end of February.

For the QEP merger, **Goldman Sachs** is lead financial advisor to Diamondback, with **Moelis & Co.** also advising. **Akin Gump Strauss Hauer & Feld LLP** and **Gibson, Dunn & Crutcher LLP** are legal advisors. **Evercore** is financial advisor and **Latham & Watkins LLP** is legal advisor to QEP.

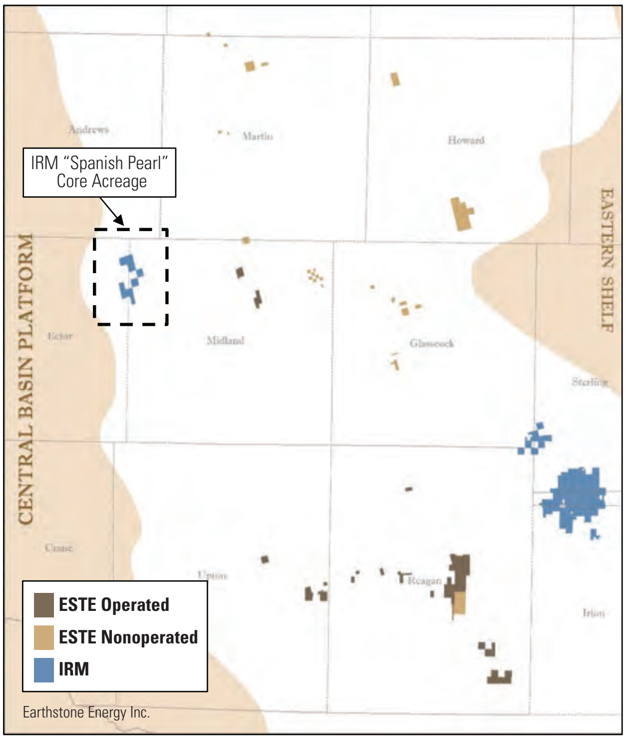
For the Guidon transaction, **Morgan Stanley** is financial advisor and Akin Gump Strauss Hauer & Feld LLP is legal advisor to Diamondback. **Citigroup Global Markets** and **RBC Capital Markets** are financial advisors to Guidon, with **Kirkland & Ellis LLP** as legal advisor.

—Darren Barbee

Earthstone Acquires Warburg-backed Midland Basin Operator

EARTHSTONE ENERGY Inc. completed a cash-and-stock transaction on Jan. 7 to acquire **Independence Resources Management LLC** (IRM), a privately held Midland Basin E&P company backed by **Warburg Pincus LLC**.

Combined Earthstone-IRM Midland Basin Acreage



Earthstone Energy Inc.


EARTHSTONE ENERGY INC.

The transaction, valued at about $185.9 million, is expected to roughly double both Earthstone's production and adjusted EBITDAX with minimal impact to leverage, according to Robert J. Anderson, the company's president and CEO.

"This transaction is another important step in the execution of our growth strategy to further increase our scale with high-quality accretive acquisitions," Anderson said. "This is consistent with our stated strategy to be a consolidator in the Permian Basin and positions us well for additional value-enhancing transactions.

"We will maintain strict financial discipline as we consider future transactions, both as it relates to valuation and to maintaining our balance sheet strength," he added.

Formed in December 2014 with a $500 million line-of-equity investment from Warburg Pincus, IRM, led by Rod Steward, holds about 43,400 net acres in two contiguous blocks in the Midland Basin of West Texas. The company's production averaged 8,780 boe/d (66% oil) during the third quarter of 2020.

About 4,900 net acres of IRM's Midland Basin position are located in Texas' Midland and Ector counties and includes an inventory of 70 undeveloped horizontal locations targeting the Middle Spraberry, Lower Spraberry and Wolfcamp A zones with an average IRR of 45% at strip pricing.

IRM Key Asset Statistics

Daily Production for 3Q 2020 (boe/d)	8,780
PDP Reserves (MMboe)	16.3
PDP PV-10 ($MM)	$173
Core Net Acres	~4,900
Total Net Acres	~43,400
% HBP / % Operated	100% / 99%
Gross Locations	70

Source: Earthstone Energy Inc.

The Midland and Ector county acreage is 100% HBP and 93% operated. The company also holds an additional 38,500 net acres in the eastern Midland Basin that is 100% HBP and 100% operated.

Anderson said the 70 gross drilling locations from IRM's core acreage carry a similar return profile to Earthstone's highly economic Midland Basin wells and will compete with the company's existing inventory for future development capital.

"With the large majority of IRM's production coming from its core acreage in Midland and Ector counties, the acquired assets have a very similar and complementary low operating cost, high margin profile as our existing assets, allowing us to maintain our peer-leading cash margin operating profile," he said. "With a minimal need for incremental general and administrative [G&A] costs, we expect to improve cash margins further by targeting an approximately 25% decrease in our go-forward cash G&A per unit costs."

Earthstone will target resuming drilling activity in the first half of 2021 through a one-rig program that Anderson said he expects to be fully funded well within the company's operating cash flows.

"This added scale and quality inventory enhances our development options and free cash flow generating capacity," he added.

The deal closed in the first week of January.

The purchase price of the transaction consists of an estimated $135.2 million in cash as of Nov. 30, 2020, but expected to be lower on the closing date based on current forecasts and approximately 12.7 million shares of Earthstone's Class A common stock valued at $50.8 million based on a closing share price of $3.99 on Dec. 16.

In conjunction with the transaction, Warburg will have the right to appoint one director to Earthstone's board. **EnCap Investments LP** will maintain the three existing EnCap-affiliated directors, resulting in a board of directors consisting of nine members.

No changes to Earthstone management will occur in connection with the transaction.

RBC Capital Markets LLC and **Wells Fargo Securities LLC** acted as financial advisers to Earthstone. **Jefferies LLC** was financial adviser to IRM. Legal advisers included **Jones & Keller PC** for Earthstone and **Latham & Watkins LLP** for IRM.

—Emily Patsy

EP Energy Exits Permian Basin For $240 Million


EP ENERGY CORP.

EP ENERGY CORP. is set to transform into a two-basin operator following the recent announced sale that will mark the Houston-based company's exit from the Permian. EP Energy said it entered into a purchase and sale agreement with an undisclosed buyer to divest its assets located in the southern Midland Basin, according to a Dec. 11, 2020, company release.

EP Energy didn't disclose the terms of the transaction. However, a report it filed with the Securities and Exchange Commission said EP Energy would receive total consideration of $240.5 million in cash.

The company holds a large contiguous acreage position currently focused on the Wolfcamp Shale in Crocket, Irion, Reagan and Upton counties in Texas, according to its website.

Following completion of the Permian divestiture, expected by the end of January 2021, EP Energy will become a two-basin operator with positions in northeastern Utah and the Eagle Ford Shale.

"We are very pleased to announce this transaction that enables EP Energy to core up its portfolio and significantly reduce debt," Russell Parker, president and CEO of EP Energy, said in a statement on Dec. 11.

The company said it intends to use proceeds from the sale to reduce borrowings under its reserve-based loan (RBL) facility.

In early October, EP Energy emerged from Chapter 11 bankruptcy, successfully completing a financial restructuring that it said reduced its pre-petition debt by approximately $4.4 billion.

As part of the reorganization, EP Energy closed on a new $629 million RBL facility from the company's existing revolving loan lenders. At the time, the company had more than $200 million of available liquidity and approximately $400 million of debt net of unrestricted cash, according to an Oct. 1 release.

Pro forma for the Permian divestiture, the company expected to end 2020 with roughly $100 million of net debt and a net debt to adjusted EBITDAX at approximately 0.3x.

"Post divestiture, EP Energy will have minimal leverage, a strong liquidity position and an asset base that can generate attractive returns and free cash flow in the current price environment," Parker continued in his statement.

Pro forma for the divestiture, EP Energy will own approximately 410,000 gross (275,000 net) acres in northeastern Utah and the Eagle Ford. Average net production for third-quarter 2020 pro forma for the transaction was 48,400 boe/d, comprising 31,600 bbl/d of oil.

—Emily Patsy

SandRidge Energy Exits Colorado North Park

SANDRIDGE ENERGY INC. agreed to the multimillion-dollar sale of its North Park Basin asset, which completes the Oklahoma City-based independent's transformation into a pure-play Midcontinent E&P company as it looks to boost shareholder value.

According to company filings, SandRidge entered into a definitive agreement with Denver-based **Gondola Resources LLC** for the sale of its North Park Basin assets for $47 million in cash. The purchase and sale agreement was executed on Dec. 11, 2020, and the transaction is expected to close first-quarter 2021.

Gondola is backed by **Fulcrum Energy Capital Funds**.

The SandRidge North Park Basin asset comprises 93,000 net acres targeting multiple Niobrara benches in Colorado's Jackson County. According to the company website, oil content on its North Park position exceeds 80% of total cumulative production.

In a company release announcing the deal on Dec. 14, SandRidge said the North Park Basin accounted for less than 10% of its production during the quarter that ended Sept. 30 and less than 10% of its proved developed reserves as of year-end 2019.

Carl Giesler, SandRidge's president and CEO, believes the sale of its North Park Basin position significantly enhances the company's shareholder value.

"It monetizes an asset the value of which, we believe, has not been adequately reflected in our stock price and which had become increasingly noncore with the company's shift to a cash optimization-focused strategy," Giesler said in a statement.

Giesler was selected by SandRidge earlier this year to serve as its CEO amid a number of initiatives to boost shareholder value. He had previously led the turnaround of **Jones Energy Inc.**, which ultimately led to its $201.5 million all-cash buyout in January 2020.


SANDRIDGE ENERGY INC.

In the third quarter, SandRidge also closed the sale of its skyscraper in Oklahoma City for $35.4 million in net proceeds, a figure that represents more than half of the company's $61 million value on Wall Street. Proceeds from the sale were expected to go toward significantly reducing the company's net debt position and should alleviate any concerns that SandRidge would reenter bankruptcy after exiting bankruptcy in 2016.

SandRidge now primarily operates in the Midcontinent region in Oklahoma and Kansas. According to its website, the company's drilling activity is concentrated in the northwest STACK in Oklahoma. In particular, the company is targeting the Meramec across its 56,000 net acres in Major, Woodward and Garfield counties.

The effective date of SandRidge's North Park Basin sale is Oct. 1, 2020. **Jefferies LLC** provided a financial fairness opinion to the company. **Winston & Strawn LLP** was its legal adviser.

—Emily Patsy

TRANSACTION HIGHLIGHTS

POWDER RIVER

■ After nearly a half a century in business, **Samson Resources** has announced it plans to wind down the Tulsa, Okla.-based company.

In a company release, the privately held E&P said it agreed to sell all of its Powder River Basin assets to an undisclosed buyer for $215 million in an all-cash transaction. Following closing, expected in early March, **Samson Resources II LLC** will have divested substantially all of its upstream assets and will begin the process of winding down its affairs and moving toward final dissolution.

"When this sale closes, it will conclude the four-year process of monetizing Samson's assets and delivering a strong cash return to our equity owners following our emergence from bankruptcy in March 2017," Joseph A. Mills, president and CEO of Samson Resources, said in a statement.

According to its website, Samson holds the seventh largest acreage position in the Powder River Basin with about 132,000 net acres. The company exited 2020 producing approximately 8,500 boe/d (75% oil) from the Powder River Basin, the release said.

ALASKA

■ Privately held **Hilcorp Energy Co.** said on Dec. 18, 2020, that its unit completed a $5.6 billion acquisition of **bp Plc**'s business in Alaska, taking over the region the British oil major had operated in for 60 years.

Hilcorp's **Harvest Alaska**, a midstream services provider, said it received approval from the Regulatory Commission of Alaska on Dec. 14 to acquire bp's nearly 49% interest in the Trans-Alaska Pipeline System (TAPS) and 49% of Alyeska Service Co. and other Alaska midstream interests.

The 800-mile TAPS is one of the largest pipelines in the world and transports oil from the North Slope to the northern most ice-free port in Valdez, Alaska.

PICEANCE BASIN

■ **Terra Energy Partners LLC** has agreed to purchase assets from bankrupt **Ursa Piceance Holdings LLC** and various subsidiaries for $60 million, according to bankruptcy documents.

A federal bankruptcy judge in Delaware approved the sale in November 2020. The deal was expected to close Dec. 22 or soon after.

Ursa Resources, backed by **Denham Capital**, holds about 41,000 net acres of oil and gas properties in the Piceance Basin. The acreage is concentrated in Boies Ranch, Battlement Mesa and other areas. Ursa reported owning 579 gross wells producing natural gas, NGL and oil. In June of last year, the company averaged about 75 MMcfe/d of production.

Terra Energy Partners is a privately held oil and gas E&P company founded in early 2015. The Houston-based company partnered with **Kayne Anderson** and **Warburg Pincus** in early 2016 following its purchase of Piceance Basin assets from **WPX Energy Inc**.

EASTERN US

1 ***Pioneer Oil Co. Inc.*** is underway at a Jackson County, Ill., wildcat. According to IHS Markit, #1 Simonds has a planned depth of 4,000 ft and is targeting oil pays in Clear Creek from a site in Section 28-8s-1w. Several wildcats have been drilled in the area. The deepest previous test, #1 Heiple in Section 10, was abandoned in 1954 at a total depth of 2,382 ft. Nearby oil production in the county is about 7 miles to the north-northeast: #1 Overholt in Section 22-7s-1w was tested in 1941 pumping 12 bbl of crude per day from a Bethel Sand zone at 1,997-2,011 ft. The Elkville Field well was drilled to a total depth of 2,387 ft. Pioneer's headquarters are in Vincennes, Ind.

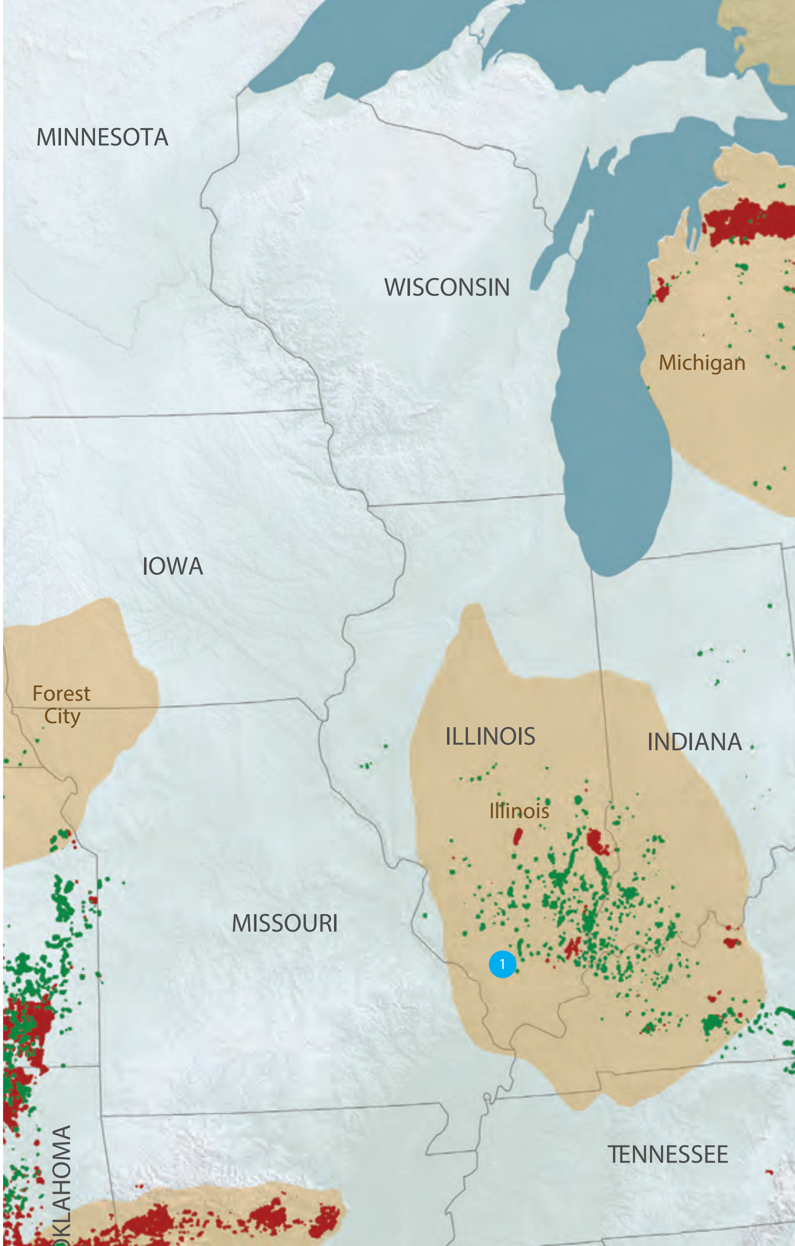
2 IHS Markit reported that ***Land & Natural Resource Development*** has staked a 5,200-ft gas test in the Black Warrior Basin in Pickens County, Ala. The #3 Cherie Ann Odom 32-16 is targeting pays in Pottsville A. It will be drilled in Section 32-18s-15w—a successful completion is expected to be placed in Burdine Creek Gas Field, a one-well reservoir 3 miles to the west. Nearby production is to the north at a Buncomb Creek Field well completed in 1988 by ***Samson Resources***: #1 Cherie Ann Odom 32-16 was online through 1995, yielding gas from a Carter Sand zone at 5,770-86 ft. Land & Natural Resource Development is based in Tuscaloosa, Ala.

3 A Utica Shale well was completed in Ohio's Belmont County by ***Rice Drilling*** at #1 SCL6H Big Tex. Located in Section 13-7n-4w, the well produced 21.122 MMcf of gas per day from perforations at 10,905-21,756 ft. The Saint Clairsville Field well was drilled to 21,853 ft and a true vertical depth of 9,213 ft. It was tested after 55 stages of fracture stimulation. Rice Drilling is based in Canonsburg, Pa.

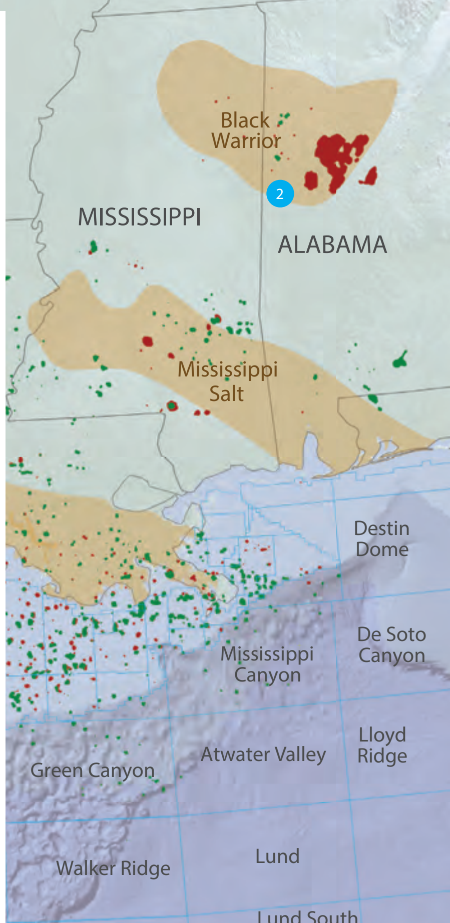
4 ***Ascent Resources***, based in Oklahoma City, announced results from a Utica Shale discovery in Jefferson County, Ohio. The #3H Thompson initially flowed 29.01 MMcf of gas per day for perforations at 9,454-21,231 ft after 68-stage fracturing. The Jewett Consolidated Field venture is in Section 24-8n-3w and was drilled to 21,354 ft with a true vertical depth of 9,082 ft.

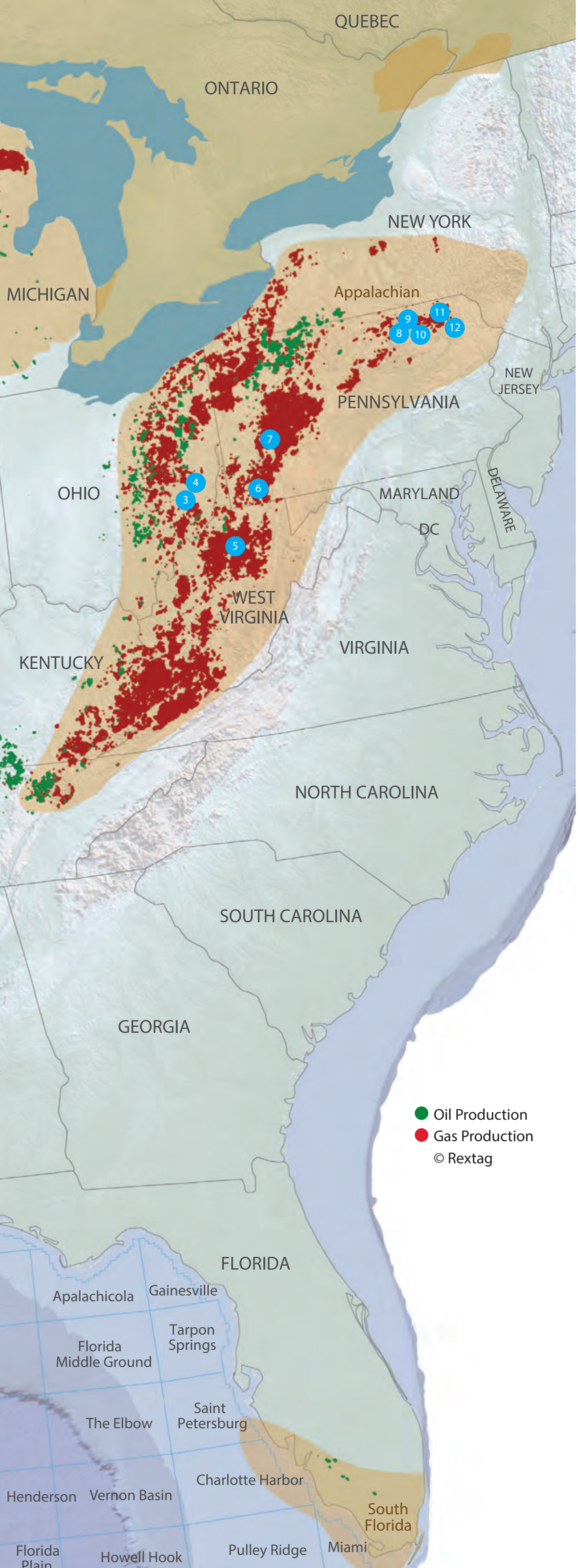
5 ***HG Energy*** completed two Marcellus Shale discoveries in Harrison County, W. Va. The wells were drilled from a pad in Union Dist., Milford West 7.5 Quad, and are in Jane Lew Weston Field. The #2H Stickel has a total depth of 20,309 ft (6,731 ft true vertical). It was tested producing 21.48 MMcf of gas per day from a perforated zone at 7,151-20,175 ft after 47 stages of fracturing. The #6H Stickel initially flowed 13.08 MMcf of gas per day. Drilled to 17,050 ft, the true vertical depth was 6,758 ft, and the well was also fracture-stimulated in 47 stages with production from perforations at 7,490-16,911 ft. HG Energy is based in Parkersburg, W. Va.

6 In Pennsylvania's Washington County, Pittsburgh-based ***EQT Production Co.*** completed three Marcellus Shale wells from a Daniels Run Field drillpad in Section 1, Ellsworth 7.5 Quad, Bethlehem North Township. The #4H Captain USA flowed 23.496 MMcf of gas per day from perforations at 8,461-23,377 ft. It was drilled to 23,378 ft with a true vertical depth of 7,993 ft. The #2H Captain USA was drilled to 23,692 ft, 7,963 ft true vertical. It was tested flowing 24.357 MMcf of gas per day from a perforated zone between 8,174 ft and 24,089 ft. The #6H Captain USA was drilled to 24,227 ft (8,009 ft true vertical). It produced 24.357 MMcf of gas per day from perforations at 8,174-24,089 ft.



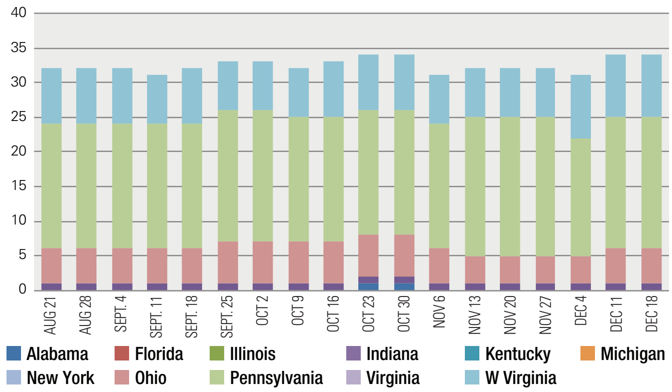
7 In Butler County, Pa., Pittsburg-based ***Penn Energy Resources*** completed three Winfield Field wells. According to the company, the wells are producing from the Union Springs, a lower member of Marcellus Shale. The discoveries were drilled from a pad in Section 7, Worthington 7.5 Quad, Winfield Township. The #2H PER W44 was drilled to 13,894 ft (6,589 ft true vertical) and tested after 32 stages of fracturing. It flowed 8.16 MMcf of gas per day from perforations between 7,250 ft and 13,600 ft. The #4H PER W44 was drilled to 14,467 ft (6,686 ft true vertical) and flowed 8.088 MMcf of gas per day from perforations at 8,572-14,320 ft after 29-stage fracturing. The #3H PER W44 was drilled to 13,320 ft, 6,421 ft true vertical, and flowed 7.272 MMcf of gas from perforations at 7,150-12,500 ft.





Eastern US Rig Count

Aug. 21, 2020-Dec. 18, 2020



Source: Baker Hughes Co.

8 ***Chesapeake Operating Inc.*** announced results from an Asylum Field-Marcellus Shale well in Pennsylvania's Bradford County. The #101HC Alexander is in Asylum Field. Drilled to 13,210 ft, the true vertical depth is 7,462 ft, and the well is in Section 2. Colley 7.5 Quad, Terry Township. It was tested flowing 36.869 MMcf of gas per day. Production is from perforations between 7,974 ft and 12,799 ft. Chesapeake's headquarters are in Oklahoma City.

9 In Pennsylvania's Bradford County, ***Chesapeake Operating Inc.*** completed two Herrick Field wells at a pad in Section 1, Laceyville 7.5 Quad, Wyalusing Township. The #102H MTL has a total depth of 17,825 ft and a true vertical depth of 6,834 ft. The venture was tested flowing 28.494 MMcf of gas after 42-stage fracturing and is producing from a perforated zone at 7,299-17,721 ft. The offsetting #101H MTL produced 33.649 MMcf of gas per day from perforations at 7,243-18,197 ft. It was fracture-stimulated in 44 stages and was drilled to 18,314 ft, 6,805 ft true vertical.

10 A Wyoming County, Pa., Marcellus Shale discovery was tested flowing 44.752 MMcf of gas per day. ***Chesapeake Operating Inc.***'s #4H Trowbridge was drilled in Section 9, Laceyville 7.5 Quad, Windham Township. The Mehoopany Field well was drilled to 12,639 ft and a true vertical depth of 7,128 ft. It was tested after 24-stage fracturing, and production is from perforations at 6,830-12,624 ft.

11 ***Cabot Oil & Gas Corp.*** announced results from five Marcellus Shale discoveries in Susquehanna County, Pa. The Dimock Field wells were drilled from a pad in Section 2, Hop Bottom 7.5 Quad, Brooklyn Township. The #6 Corbin J was tested after 57-stage fracturing flowing 30.3 MMcf of gas per day from perforations at 7,566-19,951 ft. Drilled to 20,027 ft, the true vertical depth is 6,653 ft. The #20 Corbin J was drilled to 20,293 ft, 6,902 ft true vertical, and produced 23.8 MMcf of gas per day from perforations at 8,729-20,215 ft after 53-stage fracturing. The #21 Corbin J has a total depth of 15,246 ft and a true vertical depth of 6,353 ft. It produced 16.7 MMcf of gas per day after 28-stage fracturing from perforations at 9,003-15,169 ft. The offsetting #23 Corbin J was tested after 59 stages of fracturing flowing 25.2 MMcf of gas per day from perforations at 9,384-22,010 ft. It was drilled to 22,098 ft, 7,398 ft true vertical, and tested after 59-stage fracturing. The #22 Corbin J was drilled to 14,370 ft with a true vertical depth of 7,090 ft. It was tested after 22-stage fracturing flowing 22 MMcf of gas per day from perforations at 9,452-14,297 ft. Cabot's headquarters are in Houston.

12 In Susquehanna, County, Pa., ***Chesapeake Operating Inc.*** completed a Silver Lake Field-Marcellus Shale well. Tested after 77-stage fracturing, the company's #22HC Maris flowed 39.797 MMcf of gas per day from perforations at 7,279-21,582 ft. It was drilled to 21,726 ft, 6,960 ft from a site in Section 7, Springville 7.5 Quad, Auburn Township.

GULF COAST

1 Two Karnes County (RRC Dist. 2), Texas, Austin Chalk discoveries were announced by ***EOG Resources Inc***. The Sugarkane Field wells were drilled at a drillpad in Section 2, Alexander F Mitchell Survey, A-202. The #105H Ginobili Unit was drilled to 15,602 ft with a true vertical depth of 10,254 ft. It initially flowed 1,369 bbl of 44° API oil, 1.759 MMcf of gas and 1,284 bbl of water per day. Production is from perforations at 10,696-15,531 ft. Tested on a 64/64-inch choke, the flowing casing pressure was 920 psi. The #108H Ginobili Unit was drilled to a 15,749 ft, 10,194 ft true vertical. It produced 1,951 bbl of 44° API oil, 1.143 Mcf of gas and 585 bbl of water per day from a perforated zone at 10,730-15,668 ft. Tested on a 42/64-inch choke, the flowing tubing pressure was 921 psi. Production is from perforations at 10,730-15,668 ft. EOG's headquarters are in Houston.

2 In Gonzales County (RRC Dist. 1), Texas, ***EOG Resources Inc.*** completed two Eagleville Field-Eagle Ford Shale wells. Located in Daniel Gray Survey, A-517, the #3H Atlantic C was drilled to 20,186 ft, 11,651 ft true vertical. It initially flowed 2,388 bbl of 45° API oil and 2.358 MMcf of gas per day. It was tested on 34/64-inch choke, and the flowing tubing casing pressure was 1,814 psi, and the flowing casing pressure was 640 psi. Production is from perforations at 12,366-20,114 ft. The #1H Atlantic A was drilled to 20,248 ft with a true vertical depth of 11,610 ft. It produced 1,976 bbl of 45° API oil and 1.913 MMcf of gas per day from perforations at 12,300-20,178 ft. Gauged on a 34/64-inch choke, the flowing tubing pressure was 1,470 psi, and the flowing casing pressure was 1,347 psi.

3 In Alaminos Canyon Block 857, Houston-based ***Shell Oil Co.*** completed a Middle Miocene well. The #0GB007S0B OCS G17571 ST00BP00 was drilled to 23,300 ft and produced 3,513 bbl of 35.5° API oil, with 2.12 MMcf of gas per day. Production is from a perforated zone between 19,813 ft and 20,967 ft. It was tested on a 57/64-inch choke with a flowing tubing pressure of 2,779 psi. Additional completion information is not currently available.

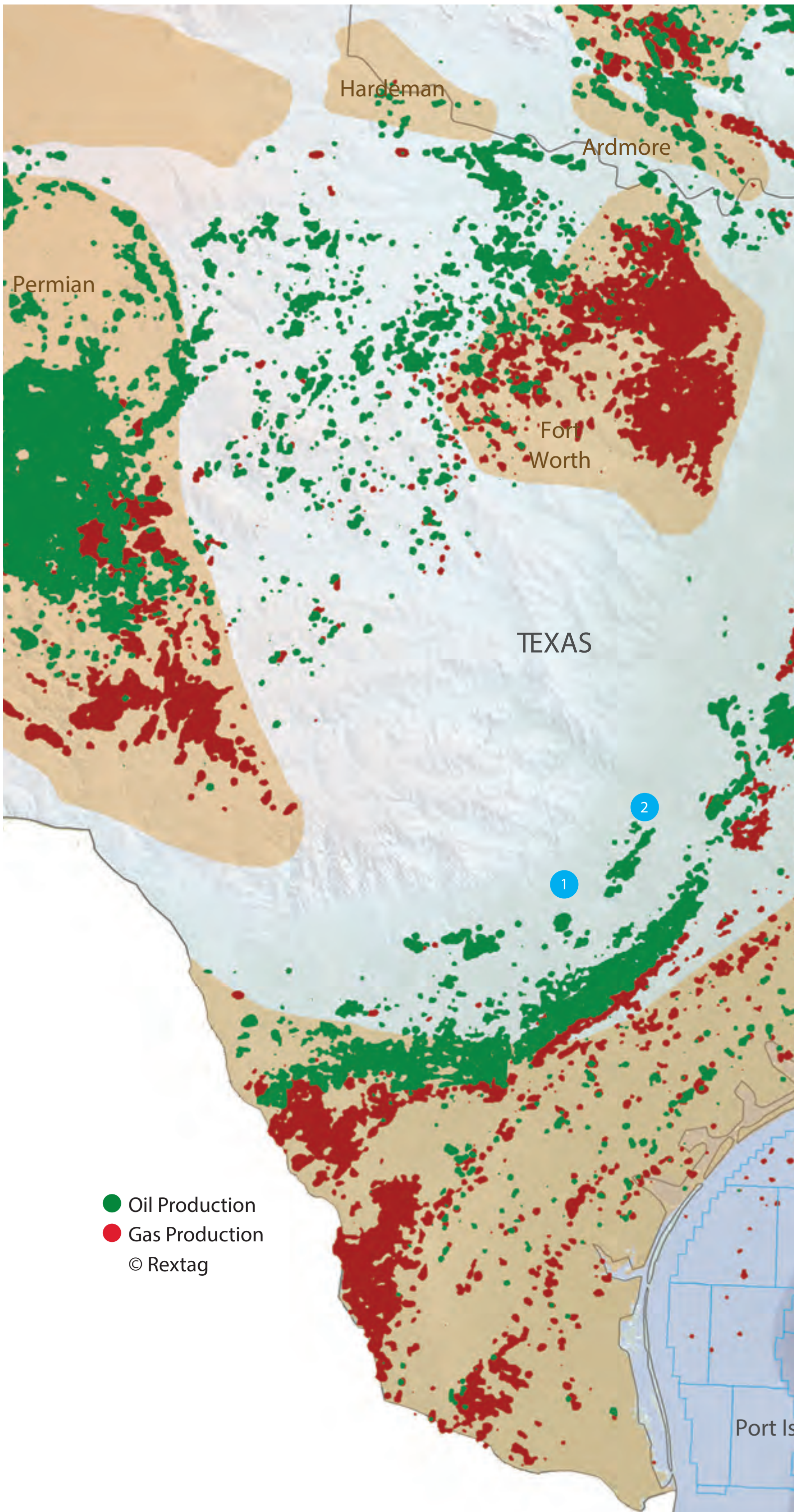
4 Houston-based ***Shell Oil Co.*** is drilling a Lower Tertiary development test in the company's Silvertip Field. The #2 OCS G19409 is in the southwestern portion of Alaminos Canyon Block 815. Area water depth is 9,600 ft.

5 A ***Buffco Production Inc.*** completion was reported in Rusk County (RRC Dist. 6) Texas. Located in Minden Field, #3 Rettig was drilled to 10,816 ft in Elijah Chisum Survey, A-170. The venture flowed 17 bbl of 52° API condensate, 131,000 cu ft of gas per day from commingled Travis Peak perforations at 7,474-7,526 ft and Cotton Valley perforations at 9,644-10,658 ft. Buffco's headquarters are in Longview, Texas.

6 Frisco, Texas-based ***Comstock Oil & Gas*** announced results from two Haynesville Shale completions in De Soto Parish, La. The Bell Bower Field wells were drilled from a pad in Section 20-13n-16w. The #2-Alt Holmes A 17-8 HC was drilled to 21,752 ft, and the true vertical depth is 11,564 ft. The discovery flowed 26.88 MMcf of gas with 1,003 bbl of water per day from fractured perforations at 11,833-21,591 ft. It was tested on a 30/64-inch choke with a flowing casing pressure pf 6,805 psi after 66 stages of fracturing. The offsetting #2-Alt Holmes 18-7 HC produced 26.248 MMcf of gas and 962 bbl of water daily. It was drilled to 21,410 ft, 11,524 ft true vertical. Gauged on a 30/64-inch choke, the flowing casing pressure was 6,689 psi after 48-stage fracturing.

7 Four Haynesville Shale wells were completed at a pad in Louisiana's Caddo Parish by Oklahamoa City-based ***Chesapeake Operating Inc***. The Bethany Longstreet Field pad is in Section 13-15n-16w. The #2-Alt Spring R 24-15-16H was drilled to 16,569 ft, 11,463 ft true vertical, and produced 17.328 MMcf of gas per day from perforations at 11,953-16,531 ft. Gauged on a 23/64-inch choke, the flowing tubing pressure was 7,268 psi. The #3-Alt Spring R 24-15-16H has a total depth of 16,335 ft and a true vertical depth of 11,588 ft. It flowed 18.24 MMcf of gas per day during testing on a 24/64-inch choke with a flowing casing pressure of 7,229 psi. Production is from perforations between 11,717 ft and 16,301 ft. The offsetting #3-Alt Spring R 13-15-16H initially flowed 18.288 MMcf of gas per day. Gauged on a 23/64-inch choke, the flowing casing pressure was 6,983 psi. It was drilled to 16,839 ft (11,568 ft true vertical), and it produces from perforations at 12,099-16,550 ft. The #4-Alt Spring R 13-15-16H was drilled to 16,352 ft with a true vertical depth of 11,283 ft. It flowed 20.592 MMcf of gas per day. Gauged on a 24/64-inch choke, the flowing tubing pressure was 7,015 psi, and it produces from perforations at 11,735-16,334 ft.

8 ***Contour Exploration & Production*** has completed two Hartburg Northwest Field wells in Newton County (RRC Dist. 3),



Texas. According to IHS Markit, #1 Falcon flowed at a daily rate of 2.784 MMcf of gas and 54 bbl of condensate from Nodosaria at 7,613-18 ft. It was tested on an 11/64-inch choke with a flowing tubing pressure of 2,584 psi. The directional gas well was drilled to 7,762 ft (7,574 ft true vertical) and is on an 80-acre lease in Section 8, George H. Burgin Survey, A-49. In 2014, the offsetting #4 Donner was tested flowing 485,000 cu ft of gas and 2 bbl of condensate per day from a Nodosaria zone. The directional well was drilled to 7,552 ft (7,509 ft true vertical). It was online for less than one year, and the well output totaled 125 MMcf of gas and 971 bbl of condensate. Contour's headquarters are in Dallas.

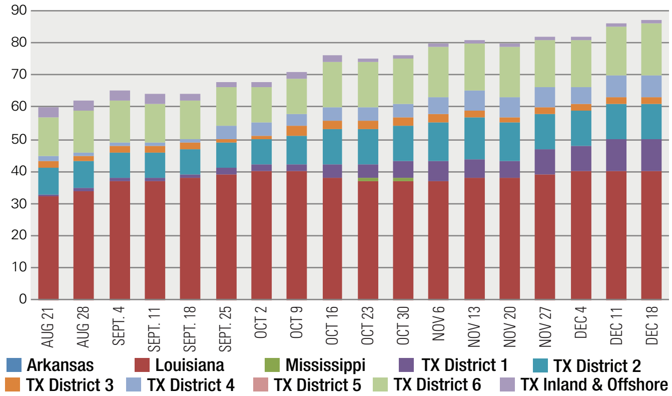
9 ***Vine Oil & Gas*** completed a Sabine Parish, La., Haynesville Shale well. The #3-Alt LA Minerals 28-33HC is in Section 21-9n-12w. The Bayou San Miguel Field venture was drilled to 21,424 ft, and the true vertical depth is 13,044 ft. It flowed 17.316 MMcf of gas per day. Production is from a perforated zone between 13,385 ft and 21,359 ft. Gauged on a 16/64-inch choke, the flowing casing pressure was 8,427 psi. Vine's headquarters are in Plano, Texas.

10 IHS Markit reported that ***Dunn Exploration*** completed two Miocene oil wells in South Louisiana's Mulvey Field. Located in Section 26-12s-1e of Vermilion Parish, #1 DLP Farm LLC flowed at a daily rate of 274 bbl of 35° API crude and 30,000 cu ft of gas from Duhon Sand (Miocene) at 10,950-70 ft. Gauged on a 11/64-inch choke, the flowing tubing pressure was 586 psi. The directional well was drilled to 11,210 ft (11,192 ft true vertical). Within one-half mile to the southwest in Section 26, #1 Touchet produced 272 bbl of 30° API crude per day from Duhon Sand at 10,943-10,953 ft. A deeper Duhon Sand zone at 11,071-11,082 ft flowed an additional 4 bbl of crude per day. The vertical well was drilled to 11,220 ft. Dunn is based in Houston.

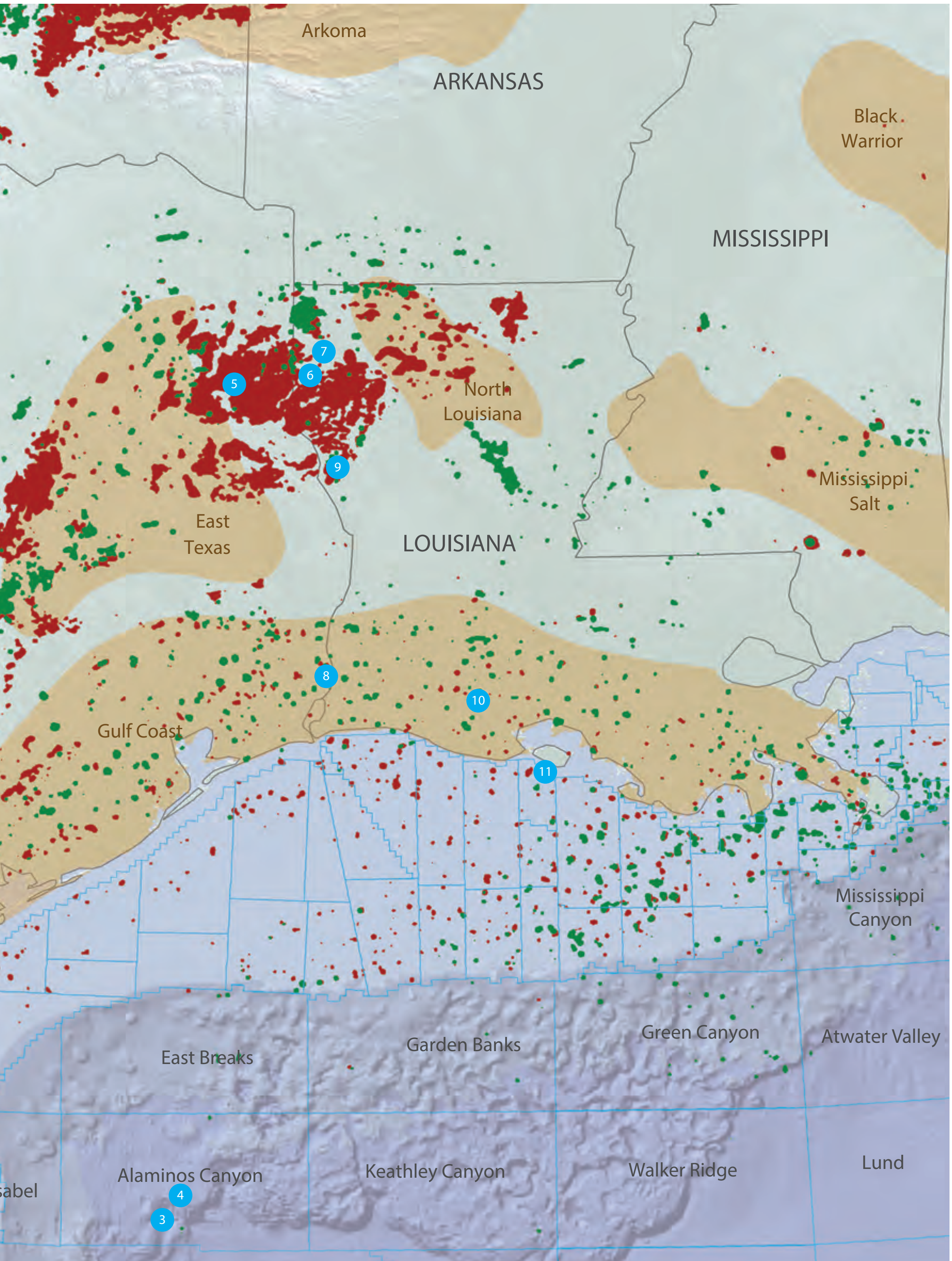
11 A Louisiana state waters recompletion was reported in South Marsh Island Block 214 by Houston-based ***Hilcorp Energy Co***. The #116 SL 00340 Mound Point was recompleted in Miocene at 11,514-90 ft. It produced 58 bbl of 54° API condensate and 5.832 MMcf of gas per day. Tested on a 22/64-inch choke, the flowing tubing pressure was 2,200 psi, and the flowing casing pressure was 2,200 psi.

Gulf Coast Rig Count

Aug. 21, 2020-Dec. 18, 2020



Source: Baker Hughes Co.



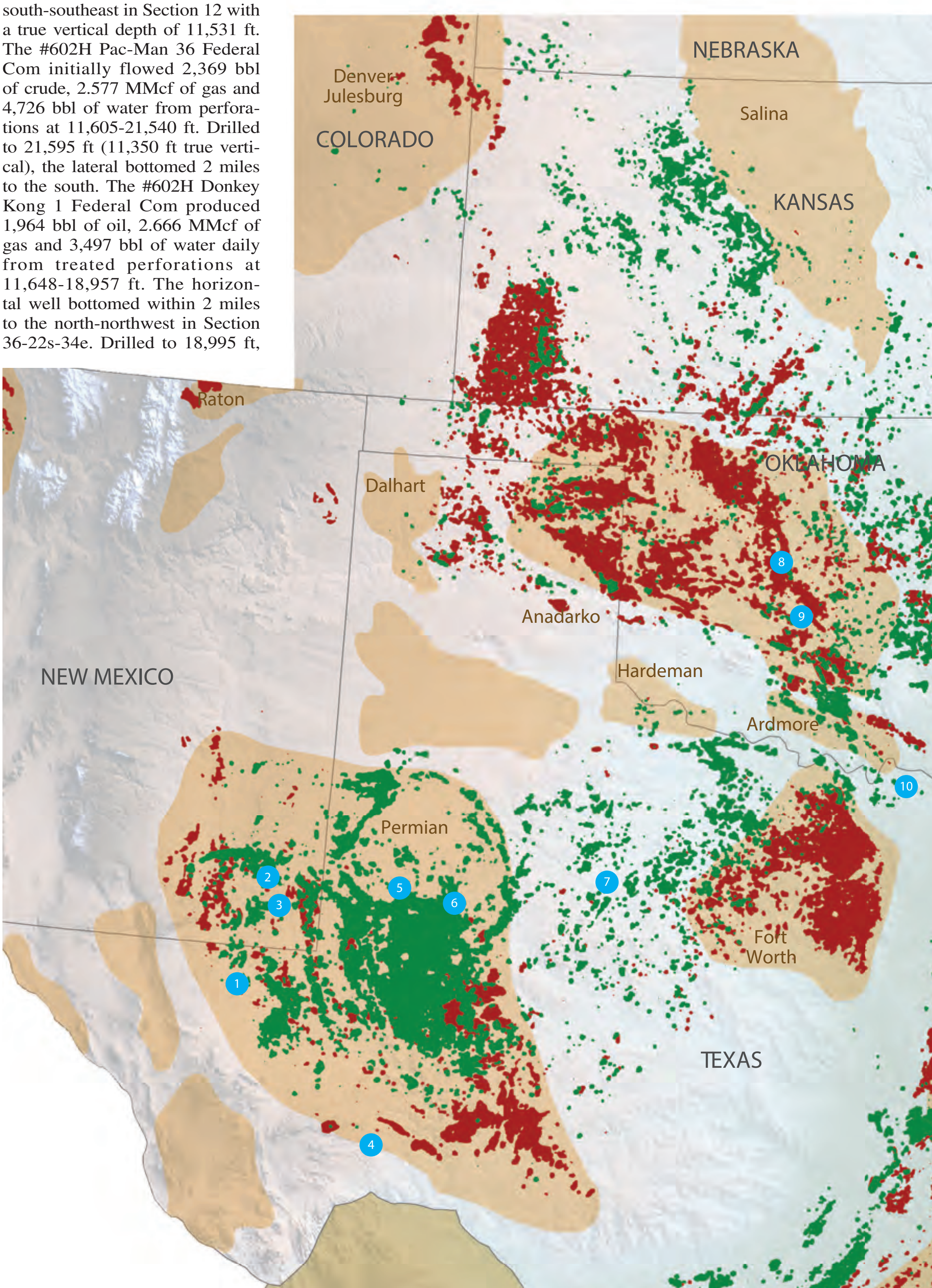
MIDCONTINENT & PERMIAN BASIN

1 Three Phantom Field-Wolfcamp completions were announced in Reeves County (RRC Dist. 8), Texas, by ***Diamondback Exploration & Production***. The wells were drilled from a pad in Section 4, Block 3, H&GN RR CO Survey, A-4212. The #603H Quarterback State Unit 3-4 was drilled to 23,464 ft (11,016 ft true vertical) and flowed 1,889 bbl of 46° API oil, 7.444 MMcf of gas and 3,940 bbl of water daily from perforations at 11,338-23,402 ft. It was tested on a 64/64-inch choke, and the flowing casing pressure was 1,900 psi. Within 1 mile to the south, #602H Liberty State Unit 9-69 was drilled to 19,849 ft, 10,862 ft true vertical, and produced at a daily rate of 1,959 bbl of 41° API oil, 7.051 MMcf of gas and 3,599 bbl of water from perforations at 11,246-19,678 ft. Tested on a 64/64-inch choke, the flowing casing pressure was 2,490 psi. The offsetting #603H Liberty State Unit 9-69 was drilled to 18,890 ft with a true vertical depth of 10,908 ft. Tested on a 64/64-inch choke, the well flowed 1.923 bbl of 41° API oil, 7.048 MMcf of gas and 3,665 bbl of water per day from 11,306-18,773 with a flowing casing pressure of 1,923 psi. Diamondback's headquarters are in Midland, Texas.

2 IHS Markit announced that Denver-based ***Centennial Resources Production LLC*** completed four Ojo Chiso South Field-Bone Spring wells from a pad in of Section 12-23s-34e of Lea County, N.M. The #601H Pac-Man 36 Federal Com was tested on gas lift flowing 2,991 bbl of oil, 2.654 MMcf of gas and 4,288 bbl of water per day through fracture-treated perforations at 11,661-21,982 ft. It was drilled to 22,016 ft. The 2-mile long lateral bottomed to the south-southeast in Section 12 with a true vertical depth of 11,531 ft. The #602H Pac-Man 36 Federal Com initially flowed 2,369 bbl of crude, 2.577 MMcf of gas and 4,726 bbl of water from perforations at 11,605-21,540 ft. Drilled to 21,595 ft (11,350 ft true vertical), the lateral bottomed 2 miles to the south. The #602H Donkey Kong 1 Federal Com produced 1,964 bbl of oil, 2.666 MMcf of gas and 3,497 bbl of water daily from treated perforations at 11,648-18,957 ft. The horizontal well bottomed within 2 miles to the north-northwest in Section 36-22s-34e. Drilled to 18,995 ft, the true vertical depth is 11,282 ft. The parallel #603H Donkey Kong 1 Federal Com was tested flowing 1,749 bbl of oil, 1,987,000 cu ft of gas and 2,087 bbl of water daily. Production is from perforations at 11,777-19,128 ft. It was drilled to 19,173 ft, and the true vertical depth is 11,331 ft.

3 In New Mexico's Lea County, ***Tap Rock Operating*** reported results from a Lea County, N.M., Bone Spring discovery in an unnamed field. Located in Section 33-24s-35e, #134h Gipple Federal Com was drilled to 22,465 ft, 12,146 ft true vertical. It was tested flowing at a 24-hour rate of 2,127 bbl of oil and 1.897 MMcf of gas with no reported water. Gauged on a 36/64-inch choke, the flowing casing pressure was 2,300 psi. Production is from a perforated zone at 12,217-22,323 ft. Tap Rock's headquarters are in Golden, Colo.

4 A horizontal Val Verde Basin-Woodford Shale well was completed in Vista Grande Field by Spring, Texas-based ***Brahman Resource Partners LLC***. Located in Pecos County (RRC Dist. 8), Texas, #1H King of the Hill 33 initially flowed 665,000 cu ft of gas and

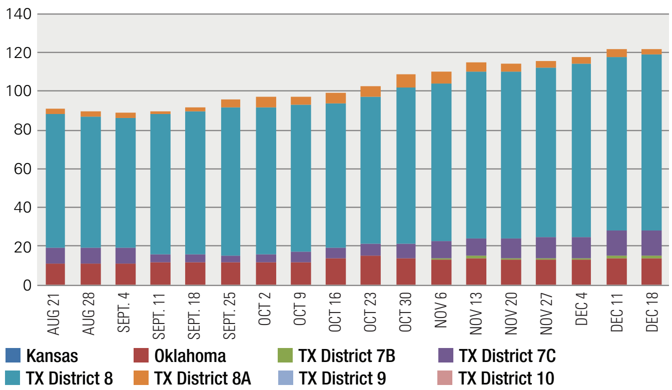


129 bbl of 52° API condensate through perforations at 13,516-16,912 ft. Located in Section 33, Block 102, J.H. Gibson Survey, A-1902, it was drilled to 17,261 ft (13,711 ft true vertical) and the nearly 1-mile long lateral bottomed to the southwest in Terrell County (RRC Dist. 7C) in Section 37, Block 102, J.H. Gibson Survey, A-1671, with a plug-back depth of 16,976 ft. Gauged on a 13/64-inch choke, the flowing casing pressure was 2,275 psi, and the shut-in casing pressure was 4,300 psi.

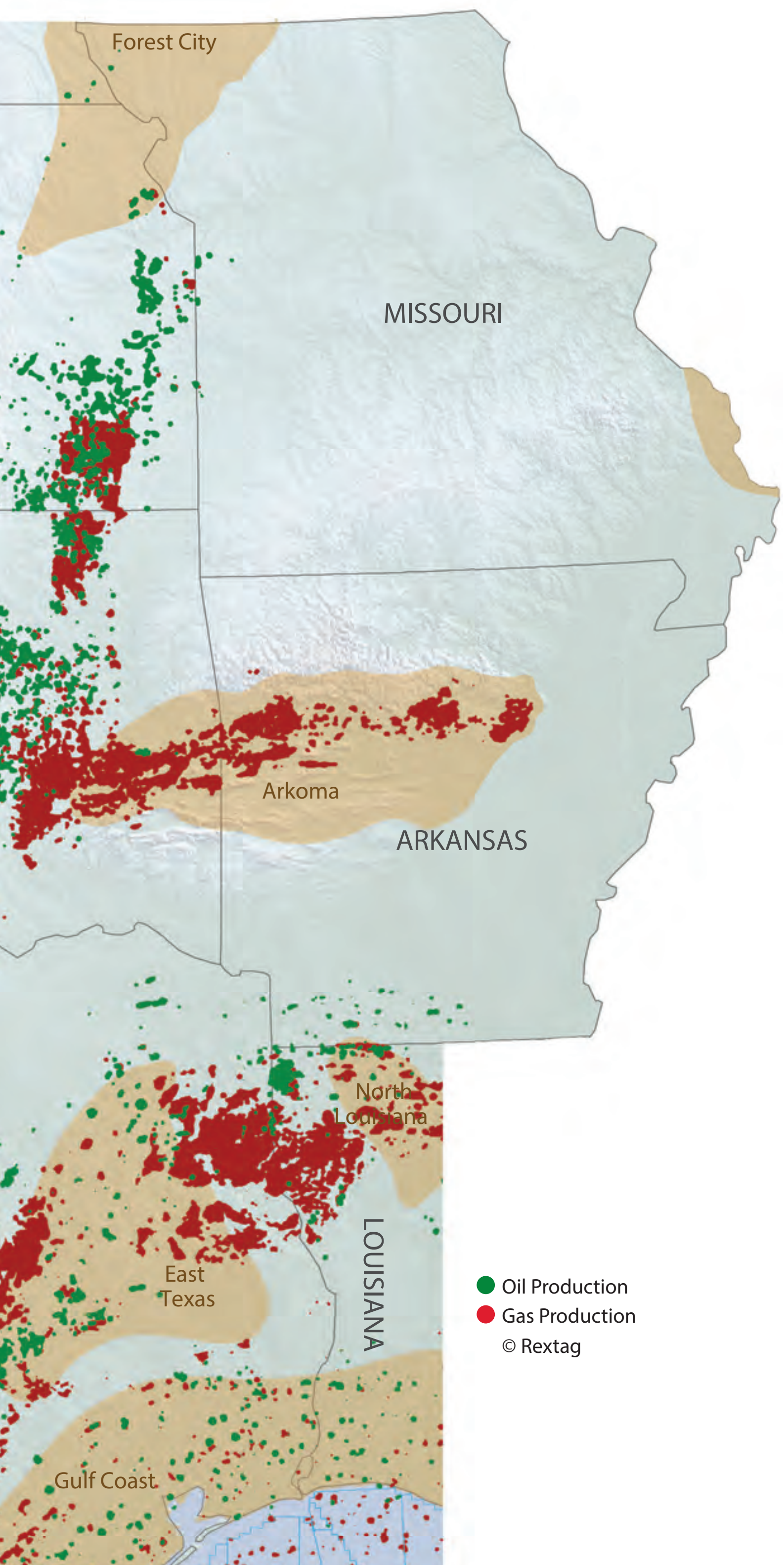
5 In Andrews County (RRC Dist. 8), Texas, ***Diamondback Exploration & Production*** completed two Spraberry Field discoveries at a pad in Section 2 Block 8, University Lands Survey, A-U220. The #4LS University Lands Leafcutter D was drilled to 20,724 ft (9,592 ft true vertical). It produced 1,302 bbl of oil, 846,000 cu ft of gas and 649 bbl of water per day from Spraberry at 10,389-20,604 ft. The #1LS University Lands Leafcutter A was drilled to 20,610 ft (9,593 ft true vertical) and flowed 1,483 bbl of 39° API oil, with 863,000 cu ft of gas and 581 bbl of water daily from Spraberry perforations at 10,129-20,461 ft.

Midcontinent & Permian Basin Rig Count

Aug. 21, 2020-Dec. 18, 2020



Source: Baker Hughes Co.



6 ***Crownquest Operating*** based in Midland, Texas, completed a Martin County (RRC Dist. 8), Texas, well. The #14HA Bigtooth Maple H initially flowed 1,222 bbl of 39° API oil, 929,000 cu ft of gas and 1,467 bbl of water per day from Dean. The Spraberry Field well is in Section 36, Block A, Bauer & Cockrell Survey, A-321, and was drilled to 15,982 ft, 8,108 ft true vertical. Production is from a perforated zone between 8,650 ft and 15,781 ft.

7 A Jones County (RRC Dist. 7B, Texas) Palo Pinto completion was announced by ***Overland Operating Co***. The #3 Green was tested flowing 60 bbl of 40° API crude per day from an openhole interval at 4,086-88 ft. The Obdurate Obelisk Field producer was drilled to 4,088 ft in Section 18, Block 2, SP RR Co Survey, A-905. Gauged on a 16/64-inch choke, the flowing tubing pressure was 60 psi. Overland Operating's headquarters are in Abilene, Texas.

8 A Canadian County, Okla., Woodford Shale well was completed by ***Camino Natural Resources***. The El Reno Field well, #2WXH Guthrie 1207 6-7, was drilled in Section 31-13n-7w to 21,239 ft and a true vertical depth of 10,521 ft. It produced 163 bbl of condensate and 1.657 MMcf of gas per day from acidized and fractured perforations between 10,935 ft and 21,118 ft. Tested on a 44/64-inch choke, the flowing tubing pressure was 752 psi. Camino's headquarters are in Denver.

9 Oklahoma City-based ***Continental Resources Inc.*** announced results from three Grady County, Okla. Woodford Shale completions in Tabler East Field. The wells were drilled from a pad in Section 18-7n-5w. The #3-18-19XHW Jacquez was tested flowing 204 bbl of oil, 431,000 cu ft of gas per day. It was drilled to 20,270 ft, 12,305 ft true vertical, and production is from 12,287-20,079 ft. Tested on a 40/64-inch choke, the flowing tubing pressure was 664 psi. The #2-18-19XHW Jacquez was drilled to 19,350 ft, 12,341 ft true vertical. It produced 564 bbl of oil, 890,000 cu ft of gas per day. Gauged on a 40/64-inch choke, the flowing tubing pressure was 794 psi. Production is from perforations at 12,381-19,155 ft. The #4-18-19XHW Jacquez was drilled to 20,663 ft and a true vertical depth of 12,317 ft. It initially flowed 419 bbl of oil, with 504,000 cu ft of gas per day from perforations at 12,211-20,468 ft. Tested on a 40/64-inch choke, the flowing tubing pressure was 834 psi.

10 ***Payson Operating LLC***, based in Longview, Texas, completed a sidetrack in Grayson County (RRC Dist. 9), Texas. IHS Markit announced that #1 Turner was tested flowing 25 bbl of 41.6° API oil and 250,000 cu ft of gas per day from acidized Viola perforations at 13,118-13,130 ft. The well is on an 81.9-acre Marietta Basin lease in Section 35, Block 1 11 15 16, W.B. Childs Survey, A-296. It was tested on a 30/64-inch choke with a flowing casing pressure of 35 psi and a shut-in casing pressure of 110 psi. The directional well was drilled to 14,173 ft (14,164 ft true vertical).

WESTERN US

1 IHS Markit reported that ***Major Oil International LLC***, subsidiary of Dublin-based ***U.S. Oil & Gas Plc***, has scheduled a remote Nevada wildcat in Nye County. The vertical #9 Eblana has a planned depth of 5,300 ft and is in Section 29-7n-50e. The venture is in the nonproducing Hot Creek Valley portion of the Eastern Great Basin Province. According to U.S. Oil & Gas, the well is targeting three horizons: Zone 1 at 4,420 ft (200 ft thick), Zone 2 at 4,920 ft (90-120 ft thick) and Zone 3 at 5,140 ft (30-60 ft thick). The well is within 1 mile to south of the company's #1 Eblana in Section 25-7n-50e. It was drilled to 8,550 ft in 2012. The company later reported that #1 Eblana had continuous flows of crude oil associated with formation water from two zones between 6,285 ft and 7,202 ft.

2 Results from a Uintah County, Utah, well completed in early 2020 were announced by Fort Worth-based ***CH4-Finley Operating***. The Bluebell Field venture, #10-19-2-1E Tryon, had a planned depth of 13,172 ft and is in Section 19-2s-1e. It was tested flowing 128 bbl of 38° API oil, 48,000 cu ft of gas and 147 bbl of water daily. Production is from commingled Garden Gulch (8,480-8,957 ft); Black Shale (9,112-9,381 ft); Castle Peak (9,398-9,607 ft) and Uteland Buttes (9,636-9,761 ft).

3 A Turner Sand completion in K-Bar Field was announced by Houston-based ***EOG Resources Inc***. The Campbell County, Wyo., producer, #558-0820H Broadhead, was tested flowing 1,443 bbl of 43.7° API oil and 968,000 cu ft of gas per day. It was tested on an 128/128-inch choke with a flowing tubing pressure of 3,820 psi and a flowing casing pressure of 168 psi. The venture was drilled to 21,163 ft, and the true vertical depth is 10,630 ft. Production is from a perforated zone between 10,892 ft and 21,145 ft.

4 ***Crestone Peak Resources***, according to IHS Markit, completed four horizontal Niobrara wells at a drillpad in Section 8-4s-64w in Arapahoe County, Colo. The #4-64 8-7 2CH Tiberius produced 692 bbl of 40° oil and 796,000 cu ft of gas per day from acid- and fracture-treated perforations at 7,791-17,737 ft. The flowing tubing pressure was 1,250 psi when tested on a 20/64-inch choke. It was drilled to 17,910 ft (7,638 ft true vertical). The offsetting #4-64 8-7 2DH Tiberius flowed 527 bbl of oil and 570,000 cu ft of gas per day from fracture-treated perforations at 8,254-17,795 ft. It was drilled to 17,981 ft, 7,731 ft true vertical. The #4-64 8-7 2AH Tiberius initially flowed 611 bbl of oil and 757,000 cu ft of gas from 7830-17,783 ft. Drilled to 17,893 ft, the true vertical depth is 7,666 ft. The #4-64 8-7 2BH Tiberius flowed 662 bbl of oil and 728,000 cu ft of gas from 8,083-17,776 ft after drilling to 17,960 ft (7,724 ft true vertical). The parallel laterals of the Denver-Julesburg Basin wells were drilled to the west and bottomed in Section 7. Crestone Peak is based in Denver.

5 A multiwell Denver-Julesburg Basin Niobrara drilling program, according to IHS Markit, is being planned by ***GMT Exploration Co.*** in Elbert County Colo. The first test will be #1HN Vulcan 6-64 10-8, and it will be in Section 10-6s-64w. It has a planned depth of 20,338 ft and a proposed true vertical depth of 7,852 ft with a bottom-hole location about 2.5 miles to the west in Section 8-6s-64w. The remaining 10 extended-lateral Caledonia Field tests will be drilled from the shared pad, which is about 1 mile south of the Elbert/Arapahoe county line. The Niobrara tests will all bottom beneath in Section 8. GMT's headquarters are in Denver.

6 Two Middle Bakken producers were completed at a Mountrail County, N.D., pad in Section 30-157N-94W by ***Hess Corp***. The #157-94-3031H-1 TI-Nelson flowed 1,490 bbl of 39.4° crude, 1.769 MMcf of gas and 2,503 bbl of water daily from fracture-treated perforations at 10,326-20,304 ft. The Tioga Field well was drilled to 20,478 ft (9,682 ft true vertical). The lateral bottomed 2 miles to the south-southwest in Section 31. The offsetting #157-94-3031H-2 TI-Nelson flowed 1,326 bbl of 40° oil, 1.349 MMcf of gas and 2,713 bbl of water per day from fracture-stimulated perforations at 10,151-20,128 ft. It was drilled to 20,307 ft (9,685 ft true vertical), and the lateral bottomed in Section 31. Hess is based in New York City.

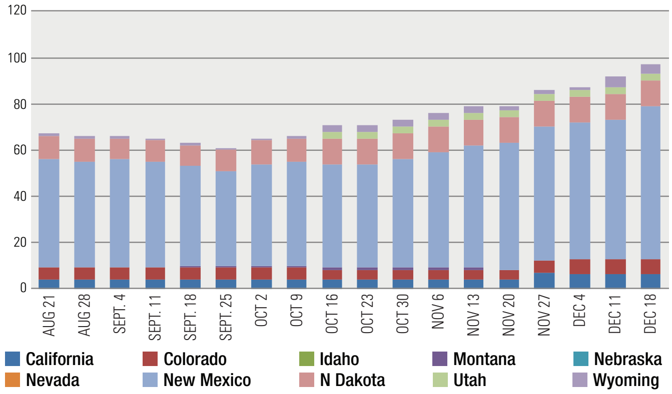
7 Two Dunn County, N.D., wells were completed by Oklahoma City-based ***Continental Resources Inc***. The Murphy Creek Field wells were drilled from a single pad in Section 4-145n-95w. The #6-4H Jack was drilled to 21,172 ft with a true vertical depth of 10,802 ft. The Middle Bakken producer flowed 1,339 bbl of 43° API oil,

798,000 cu ft of gas and 1,776 bbl of water per day after fracturing. Tested on a 25/64-inch choke, the flowing casing pressure was 197 psi. Production is from perforations at 11,344-21,108 ft. The #7-4H1 Jack was completed in Upper Three Forks flowing 1,220 bbl of 43° API oil, with 733,000 cu ft of gas and 1,739 bbl of water per day from perforations at 11,281-21,064 ft. Gauged on a 29/64-inch choke, the flowing casing pressure was 151 psi.

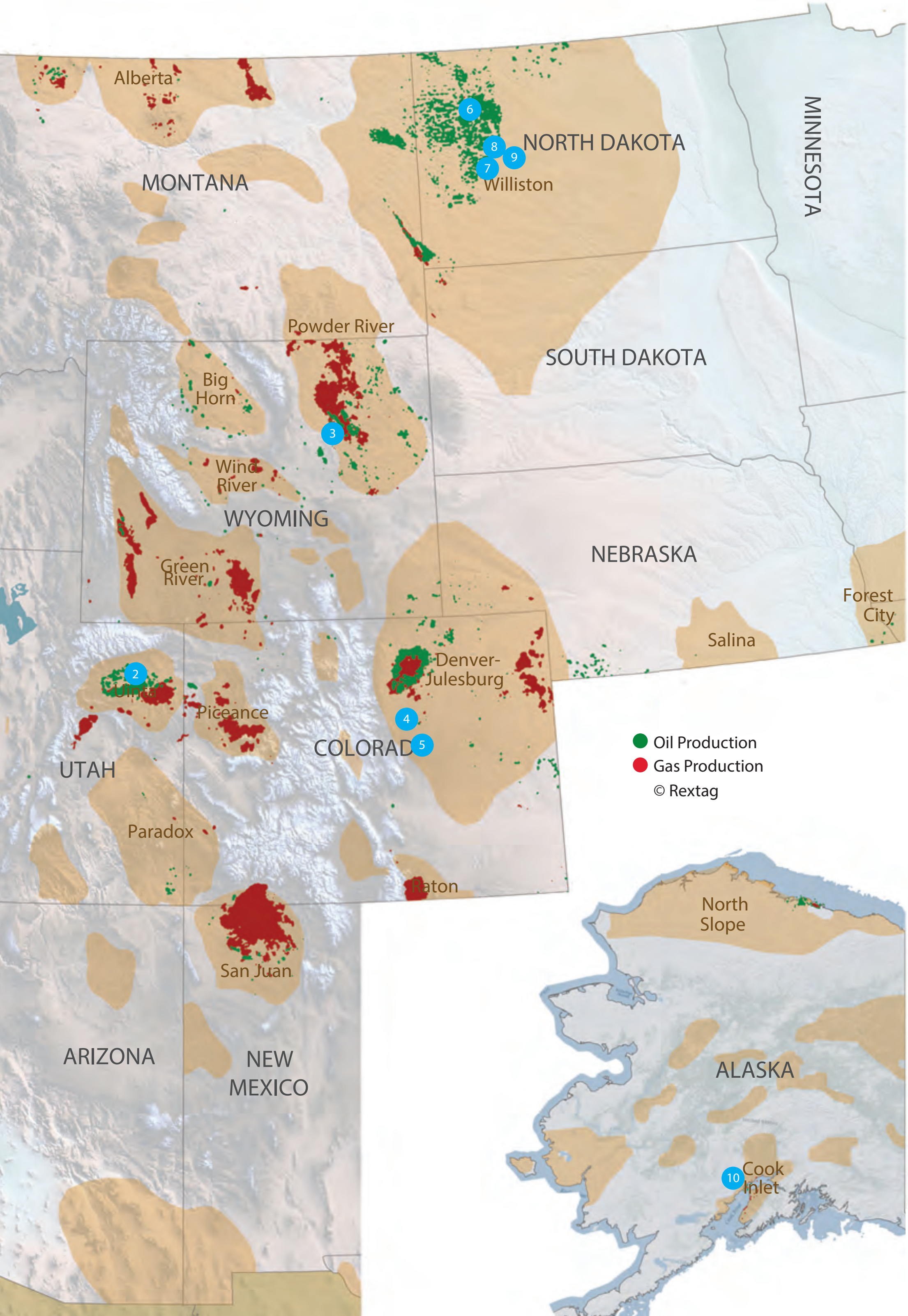
8 Two high-volume Squaw Creek Field-Middle Bakken wells were reported by ***WPX Energy Inc.*** in North Dakota's McKenzie County. The wells were drilled from a pad in Section 25-149n-95w. The #24-13-12HD Omaha Woman produced 7,542 bbl of 42° API oil, 3.76 MMcf of gas and 4.032 bbl of water per day. It was drilled to 26,706 ft (11,106 ft true vertical). It was tested on a 64/64-inch choke with a flowing casing pressure of 2,400 psi. Production is from a Middle Bakken zone at 11,491-26,539 ft. The offsetting #24-13-12HC Omaha Woman was drilled to 26,825 ft, 11,115 ft true vertical. It flowed 6,883 bbl of 42° API oil, 5.112 MMcf of gas and 3,240 bbl of water daily. Gauged on a 64/74-inch choke, the flowing casing pressure was 3,200 psi, and production is from perforations at 11,552-26,669 ft. WPX is based in Oklahoma City.

Western US Rig Count

Aug. 21, 2020-Dec. 18, 2020



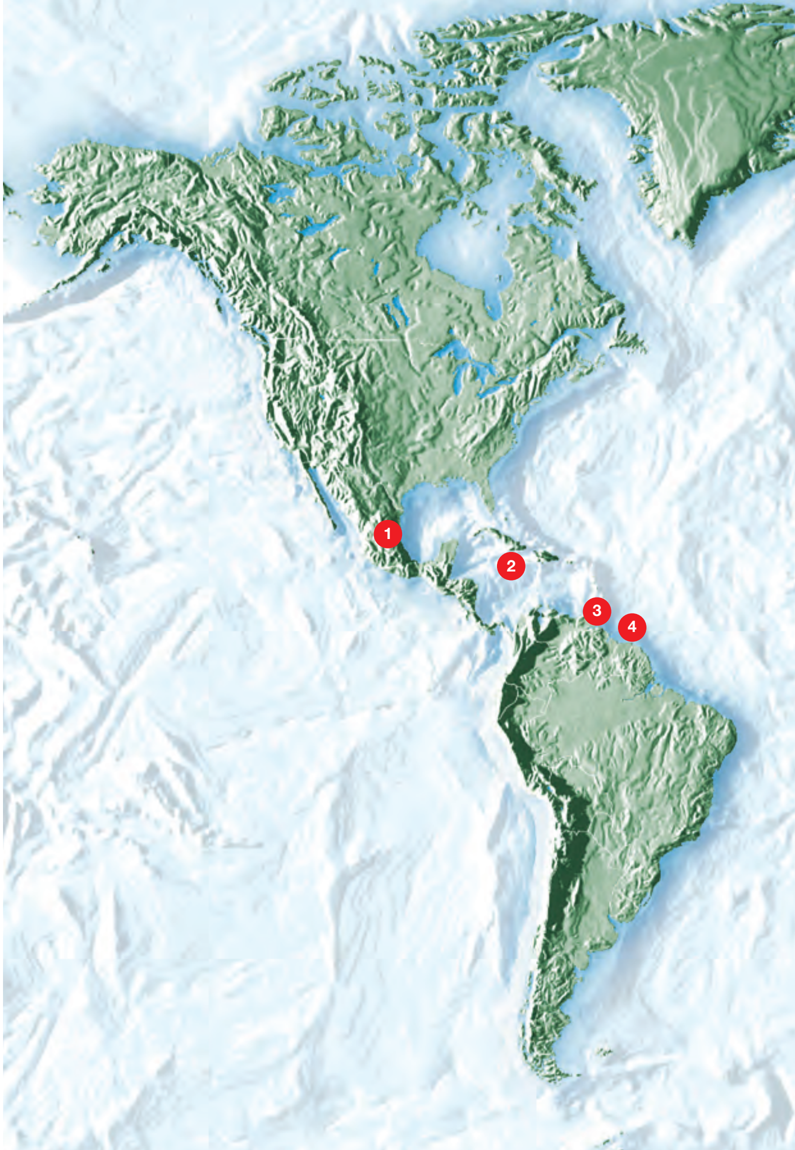
Source: Baker Hughes Co.



9 Two Dunn County, N.D., Williston Basin discoveries were announced by Tulsa-based ***WPX Energy***. The South Fork Field wells were drilled from a pad in Section 20-148n-93w. The #21-22HC Wolverine was drilled to 20,911 ft with a true vertical depth of 10,484 ft. It initially flowed 3,421 bbl of 42° API oil, 1.972 MMcf of gas and 2,222 bbl of water daily from Middle Bakken. Gauged on a 30/64-inch choke, the flowing casing pressure was 1,800, and production is from fractured perforations at 10,873-20,732 ft. The #21-22HY Wolverine is a Three Forks producer that was tested flowing 2,648 bbl of 42° API oil, 1.503 MMcf of gas and 2,200 bbl of water per day. It was drilled to 20,933 ft (10,554 ft true vertical) and produces from perforations between 10,991 ft and 20,775 ft. The flowing casing pressure was 1,900 psi and was tested on a 24/64-inch choke.

10 ***Hilcorp Energy*** announced results from a Beluga completion in Alaska. The #222-24 Beluga River Unit was directionally drilled in Section 24-13n-10w. The 7,627-ft well has a true vertical depth of 7,088 ft. It flowed 5.51 MMcf of gas per day from perforations at 5,767-6,493 ft. Tested on an unreported choke size, the flowing tubing pressure was 1,200 psi, and the flowing casing pressure was 380 psi. Hilcorp's headquarters are in Houston.

INTERNATIONAL HIGHLIGHTS



By a vote of Denmark's parliament, the government decided to cease all oil and gas exploration and production from the Danish sector of the North Sea by 2050. By halting oil and gas operations, the government is canceling its latest licensing round and all future rounds. The country agreed last year to reduce emissions by 70% by 2030 and to make Denmark climate neutral by 2050.

Denmark is the European Union's biggest oil producer and currently produces about 83,000 bbl/d of oil. The country first began producing oil and gas from the North Sea in 1972, and the revenues helped to make it one of Europe's richest nations.

Denmark's 55 existing oil and gas platforms are scattered across 20 oil and gas fields. The currently producing fields will continue extracting fossil fuels.

As of January 2018, Denmark's official reserves and contingent resources were estimated at 874 MMbbl of oil and 72 Bcf of gas. At the end of 2019, BP estimated that Denmark's proven oil reserves was approximately 400 MMbbl.

In the last decade, the government has turned its focus to clean energy, including offshore wind farms built by the state oil company.

—Larry Prado

1 *Mexico*

Pemex has received permission to explore the onshore Tampico-Misantla Basin in southeastern Mexico in the states of Tamaulipas, San Luis Potosi and Veracruz. Pemex will explore for unconventional shale-based resources. According to the Mexico City-based company, exploration wells will be drilled and tested in mature fields. With the development of additional resources, the country's present production could increase by about 300,000 bbl per day to about 1.9 MMbbl per day in 2021 and 2.4 MMbbl per day by 2024. Previously, Pemex decided to cease all exploration in unconventional areas as well as deepwater provinces to focus on onshore operations and on shallow water prospects. According to the country's National Hydrocarbons Commission, Mexico's unconventional resources amount to an estimated 67.8 Bboe, of which approximately 32 Bboe are in the Tampico-Misantla Basin.

2 *Jamaica*

A new prospective resource report for ***United Oil & Gas*** by Gaffney Cline & Associates indicates unrisked, mean prospective resources of more than 2.4 Bbbl of oil across 11 prospects and two leads in the Walton Morant license in offshore Jamaica. The report noted that the gross, unrisked mean prospective resource estimate for the Colibri Prospect is 406 MMbbl, which was compiled with an updated reservoir model based on a prestack depth migration study from a 3D seismic data set acquired and processed in 2018 to 2019. Dublin-based United is the 100% equity holder and operator of the Walton Morant license, which covers about 22,000 sq km. Eleven wells have been drilled to date, nine onshore and two offshore, with 10 having hydrocarbons shows.

3 *Trinidad*

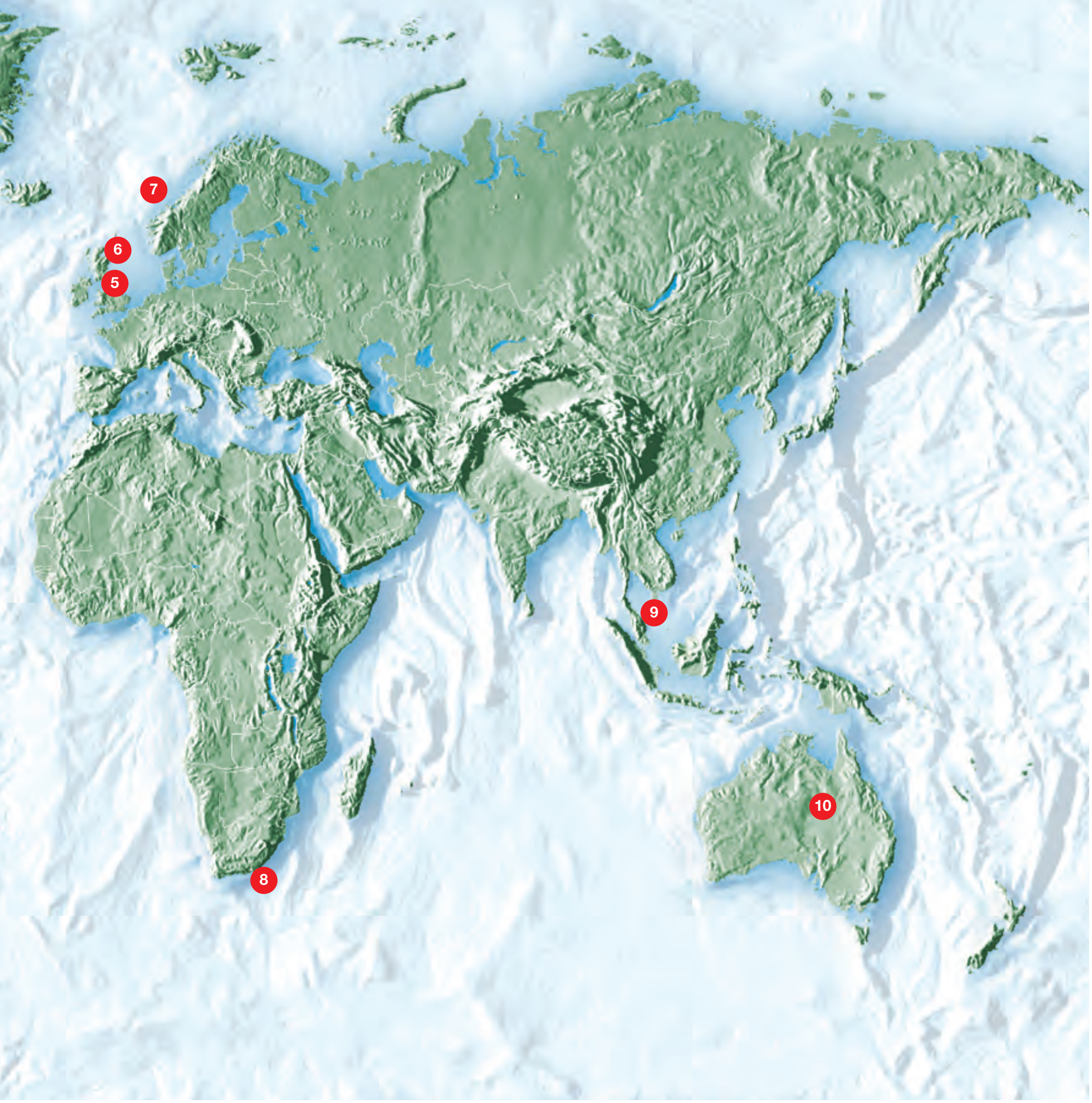
Touchstone Exploration completed an exploration well at #1-Cascadura Deep in the Ortoire Block, onshore Trinidad. The well was drilled to a total depth of 8,303 ft, and drilling operations were suspended due to high pressure gas zones encountered. The venture hit a total sand thickness of 2,100 ft in multiple, stacked thrust sheets in the Herrera section. According to the company, wireline logs indicated gas pay totaling approximately 1,315 net ft in four unique thrust sheets from a depth of 5,455 ft to total depth. In addition, an aggregate 1,007 net ft of gas pay was identified in the overthrust sheets, an increase of approximately 20% compared to the #1ST1-Cascadura discovery, and additional gas pay of approximately 308 net ft was encountered in two previously untested Herrera thrust sheets below the sands observed in #1ST1-Cascadura. The #1-Cascadura Deep is the fourth of the amended five-well exploration commitment under Touchstone's Ortoire license. Calgary, Alberta-based operator Touchstone holds an 80% working interest, and partner ***Heritage Petroleum Company Ltd.*** holds a 20% working interest.

4 *Suriname*

Petronas has announced a hydrocarbon discovery in offshore Suriname's Block 52 at exploration well #1-Sloanea. The Suriname-Guyana Basin exploration well was drilled to a total depth of 4,780 m and encountered several hydrocarbon-bearing sandstone formations with good reservoir qualities in Campanian. Further evaluation is planned to determine the full extent of the discovery. Kuala Lumpur, Malaysia-based Petronas is the operator of Block 52 and holds 50% participating interest with ***Exxon Mobil*** holding the remaining 50%.

5 *U.K.*

Operator ***Rathlin Energy***, based in London, announced preliminary results from #1BZ West Newton, a conventional appraisal well, in PEDL 183. The venture hit a hydrocarbon column within a gross 62-m interval in Kirkham Abbey. The #1BZ West Newton is a sidetrack from #1-West Newton. It was drilled to 2,114 m and 18 m of core has been cut and recovered from Kirkham Abbey. Wireline logging indicated a porosity of 14% with no oil/water contact. Planned flow



testing will help determine the development potential of the prospect.

6 U.K.

Jersey Oil & Gas announced a comprehensive subsurface evaluation across its licensed acreage and has validated its existing prospectivity. The study identified a significant new prospect, Wengen, in License P2170, directly west of the producing Tweedsmuir Field. The London-based company said that four of the Greater Buchan prospects have been matured to drill-ready status: Verbier Deep; Cortina NE (J64); Wengen (P2170) and Zermatt (P2497). The prospects have an aggregate P50 prospective resource of 222 MMboe, which includes upside potential to Cortina NE. An exploration well is currently planned sometime in 2022. Jersey Oil & Gas is the operator of License P2170 (Blocks 20/5b and 21/1d) with 88% interest in partnership with ***CIECO V&C UK*** holding the remaining 12%.

7 Norway

Equinor announced results from an offshore Norway discovery in production license PL 263 D. The wildcat well, #6407/1-8 S, is east of Maria Field. The objective of the well was to prove petroleum in reservoir rocks from the Middle Jurassic Age (Garn and Ile formations). The well encountered the Garn with a thickness of about 85 m, with reservoir rocks of moderate to very good reservoir quality. The well is dry in the Garn and Ile. The well hit a 9-m gas column in Lange (Late Cretaceous), and there were three thin sandstone layers totaling 4 m with poor-to-moderate reservoir properties. Preliminary estimates place the size of the discovery to approximately 5.65 MMcf of recoverable oil equivalent. It was drilled to a vertical depth of 3,518 m and was terminated in Ile. Area water depth is 295 m. The venture was not formation-tested and will be plugged and abandoned. Additional testing is planned in the area by the Stavanger-based company. This is the first exploration well in production license 263 D.

8 South Africa

Total has reported the results of drillstem tests at the #1X-Luiperd discovery in Block 11B/12B in the Outeniqua Basin, offshore South Africa. The venture intersected 85 m gross sands with 73 m (net) good quality pay in the main target interval. It was drilled to 3,400 m in 1,795 m of water. Gauged on a 58/64-inch choke, the well flowed 33 MMcf of gas and 4,320 bbl of condensate per day (approximately 9,820 bbl of oil equivalent per day). The choke configuration could not be increased due to surface equipment limitations. Block 11B/12B covers an area of approximately 19,000 sq km with water depths ranging from 200 to 1,800 m. The Paddavissie Fairway in the southwest corner of the block now includes both the Brulpadda and Luiperd discoveries, confirming the prolific petroleum system. Paris-based Total is the operator of the prospect and partners include ***Africa Energy***, ***Qatar Petroleum*** and ***CNR International***.

9 Indonesia

Medco Energi completed #1-West Belutm, an exploration and appraisal well in the Indonesian sector of the South Natuna Sea, Block B. The venture encountered an unreported amount of hydrocarbon resources after five drillstem tests. Additional testing and evaluation is planned. The company previously announced commercial exploration success on the South Natuna Sea Block B at #2-Bronang, #2-Kaci, and #5-Terubuk wells: these discoveries and the #1-West Belut discovery will be developed in 2021-22 along with the prior development of the Hiu Field. The South Natuna Sea Block B is operated by Jakarta-based Medco with 75% interest along with partner ***Prime Natuna*** holding 25%.

10 Australia

Vintage Energy announced results from flow testing at #1 ST1 Vali Well in the Queensland, Australia, portion of the Cooper/Eromanga Basin. The well is in ATP 2021, and it flowed 3.77 MMcf of gas after six-stage fracture stimulation. It was tested on a 38/64-inch choke at a wellhead pressure of 800 psi. Additional testing is planned using different choke sizes. It was fractured in one stage in Tirrawarra and five stages in Patchawarra. A downhole production logging tool test is planned in each zone to determine the gas contribution of each of the stimulated zones. The well will then be cycled through equal periods of shut-in and flow at various flow rates. Gas composition samples will be tested in a laboratory. An independent certified study estimate indicates that the 2C gross contingent resource is 37.7 Bcf. Project partners include ***Metgasco*** (25%) and ***Bridgeport*** (25%). Vintage is based in Adelaide, South Australia.

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount	Comments
BKV Corp.	N/A	Denver	$700 million	Received $100 million in preferred equity from Oaktree Capital Management LP toward the acquisition of Devon Energy Corp.'s assets in the Barnett Shale plus a commitment to invest an additional $600 million in future mutually agreed upon opportunities in natural gas. Guggenheim Securities was financial adviser to BKV, and Fox Rothschild LLP was its legal adviser. Kirkland & Ellis LLP was legal adviser to Oaktree.
New Fortress Energy Inc.	NASDAQ: NFE	New York	$150 million	Launched an underwritten public offering of shares of its Class A common stock. Underwriters have the option to purchase up to an additional $22.5 million of shares of stock. Proceeds will be used for general corporate purposes. Morgan Stanley is sole underwriter.
Talos Energy Inc.	NYSE: TALO	Houston	$73.4 million	Priced an underwritten public offering of about 8.3 million shares of common stock of the company. Underwriters have been granted an option to purchase up to roughly 1.3 million additional shares of stock. Proceeds will be used to facilitate its general financing strategy and to repay a portion of its outstanding borrowings under its reserve-based lending facility as well as for general corporate purposes. BMO Capital Markets Corp. is sole underwriter.
Core Laboratories NV	NYSE: CLB	Amsterdam	$60 million	Established an at-the-market equity offering program under which it may, from time to time, sell its common shares having an aggregate sales price of up to $60 million, and has entered into an equity distribution agreement with Wells Fargo Securities LLC as sales agent. Proceeds will be used for general corporate purposes, which may include, among other things, investments in the development of new products and technology, capex, repayments of indebtedness, working capital and potential acquisitions. Pending these uses, proceeds will be used for investments in investment-grade interest-bearing obligations, highly liquid cash equivalents, certificates of deposit, or direct or guaranteed obligations of the U.S.
Amplify Energy Corp.	NYSE: AMPY	Houston	$9.8 million	Closed an underwritten public offering of shares of its common stock by certain of its stockholders, which are affiliates of Fir Tree Capital Management LP, at a price to the public of $1.15 per share. Amplify did not receive any proceeds from the offering. Roth Capital Partners was sole manager.

DEBT

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Global Infrastructure Partners	N/A	New York	$2.8 billion	Raised two credit funds, GIP Capital Solutions Fund II and GIP Spectrum Fund, from institutional investors and high net worth individuals across North America, Europe, Asia and the Middle East. Proceeds will be used to make debt investments in infrastructure assets in sectors such as power, midstream oil and gas, transport and renewable energy, mostly in OECD countries.
Equitrans Midstream Corp.	NYSE: ETRN	Canonsburg, Pa.	$1.9 billion	Priced an upsized offering of $800 million senior notes due 2029 and $1.1 billion senior notes due 2031. Proceeds will be used by subsidiary EQM Midstream Partners LP to repay outstanding term loan borrowings, purchase a portion of its outstanding indebtedness in tender offers and for general partnership purposes. Any remaining proceeds will be used to repay certain of its outstanding indebtedness, including borrowings under its $3 billion credit facility, or to prefund capital expenditures and/or capital contributions to Mountain Valley Pipeline LLC.
Tallgrass Energy Partners LP	N/A	Leawood, Kan.	$750 million	Priced upsized offering of senior unsecured notes due 2030 at an offering price equal to 100% of par. Proceeds will be used to fund a concurrent cash tender offer to purchase any and all of its outstanding 2023 notes, to redeem the 2023 notes that remain outstanding following the consummation of the tender offer and to redeem outstanding 2024 notes. Vinson & Elkins LLP served as legal adviser.
Crestwood Equity Partners LP	NYSE: CEQP	Houston	$700 million	Priced unsecured senior notes due 2029 in a private offering made by subsidiary Crestwood Midstream Partners LP. Proceeds will be used to fund the separately announced tender offer by CMLP for any and all of its outstanding 2023 notes, including fees and expenses in connection therewith.

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Blue Racer Midstream LLC	N/A	Dallas	$600 million	Priced previously announced offering senior notes due 2025, upsized from the originally proposed $550 million offering, at par. Proceeds from the sale, along with borrowings under its revolving credit facility and, if necessary, cash on hand, will be used to fund its obligations under the separately announced tender offer for any and all of its outstanding 2022 notes, including fees and expenses in connection therewith, or redeem any of the 2022 notes that remain outstanding thereafter. Vinson & Elkins LLP served as legal adviser.
Range Resources Corp.	NYSE: RRC	Fort Worth, Texas	$600 million	Priced at par an offering of senior notes due 2029 upsized from the previously announced $500 million. Proceeds will be used for general corporate purposes, including the repayment of borrowings under its bank credit facility.
Antero Resources Corp.	NYSE: AR	Denver	$500 million	Priced a private placement of senior unsecured notes due 2026. Proceeds will be used to fund the redemption of 2022 notes. Vinson & Elkins LLP served as legal adviser.
EnLink Midstream LLC	NYSE: ENLC	Dallas	$500 million	Priced senior notes due 2028 at 100% of their face value. Notes will be fully and unconditionally guaranteed on a senior basis by subsidiary EnLink Midstream Partners LP. Proceeds will be used to repay a portion of the borrowings under its $850 million term loan due December 2021. Vinson & Elkins LLP served as legal adviser.
Talos Energy Inc.	NYSE: TALO	Houston	$500 million	Priced an upsized offering second-priority senior secured notes due 2026. Proceeds will be used to fund the redemption of outstanding 2022 notes issued by the company and Talos Production Finance Inc. and pay any premiums, fees and expenses related to the redemption and the issuance of the new notes. Any remaining proceeds will be used for general corporate purposes, which may include the repayment of a portion of the outstanding borrowings under its reserves-based lending facility.
Genesis Energy LP	NYSE: GEL	Houston	$550 million	Commenced a registered, underwritten public offering of senior unsecured notes due 2027 co-issued by subsidiary Genesis Energy Finance Corp. Proceeds will be used to fund the purchase price and accrued and unpaid interest for all 2023 notes that are validly tendered and accepted for payment in the concurrent tender offer and the redemption price and accrued and unpaid interest for any 2023 notes that remain outstanding after the completion or termination of the concurrent tender offer and the remainder for general partnership purposes, including repaying a portion of the borrowings outstanding under our revolving credit facility. RBC Capital Markets LLC led the joint book-running managers and co-managers.
Archrock Inc.	NYSE: AROC	Houston	$300 million	Closed private offering by subsidiary Archrock Partners LP of senior notes due 2028. Subsidiary Archrock Partners Finance Corp. is the co-issuer of the new notes. Proceeds will be used to partially repay outstanding borrowings under its revolving credit facility and for general partnership purposes.
Gibson Energy Inc.	TSX: GEI	Calgary, Alberta	$250 million	To issue subordinated notes due 2080. Proceeds will be used to fund the previously announced redemption of its outstanding convertible unsecured debt due 2021, to reduce outstanding indebtedness under its revolving credit facility and for general corporate purposes. CIBC Capital Markets and RBC Capital Markets lead a syndicate of investment dealers.
New Fortress Energy Inc.	NASDAQ: NFE	New York	$250 million	Intends to offer additional senior secured notes due 2025 in a private offering, subject to market conditions. Proceeds will be used for general corporate purposes.

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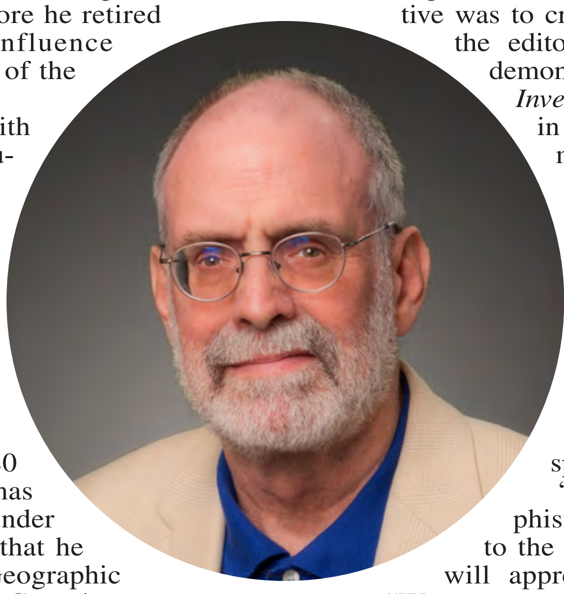
GOODBYE TO ONE OF OURS

ILLUSTRATION BY MARC CONLY

Oil and Gas Investor's original and long-time art director Marc Conly died in November due to COVID-19. His name appeared on the magazine's masthead for 35 years before he retired in 2016, and his influence remains in the design of the magazine today.



Conly's affiliation with *Investor* began a couple of years before its launch when he was a freelance commercial artist for Hart Publications, which published *Western Oil Reporter* and the *Rocky Mountain Oil & Gas Directory* in the 1970s.

One evening in 1980 at a company Christmas party, Hart Energy founder Don Hart told Conly that he and former National Geographic photographer Lowell Georgia were hatching an idea for a publication that would be "the National Geographic of the oil and gas industry." After all, most of the trade journals of the day were technically oriented and visually unappealing, often just black and white on cheap paper.

"Don's sense, prophetically, was that the nature of the business was changing, that the cliché of a guy in a 10-gallon hat, muddy cowboy boots, a big cigar and Rolex wristwatch was giving way to a much more sophisticated investor. He sensed the time was right to come up with a publication that somebody would be proud to have on their coffee table," Conly said in a previous interview.

The first issue debuted in August 1981.

Conly said he felt strongly that the look and feel of the magazine has been a catalyst of its success. "There was a sensibility that had not been brought to the oilfield before. The objective was to create teamwork between the editor and photographer to demonstrate that *Oil and Gas Investor* was on the ground in The Patch and was familiar with the operators," Conly said.

In addition to high quality, full-color photography, from the outset *Investor* featured original conceptual art to illustrate the theme of stories, another approach that made the magazine unique in its space.

"If you can bring sophisticated, visual imagery to the magazine, the audience will appreciate it," Conly said. "We try to come up with art that is pertinent to the emotional and psychological content of the story. We try to make the reader think about what they're reading in a visual way other than what they would expect from an industry trade magazine."

Originally from Buffalo, Wyoming, Conly was a true Westerner. He loved the expansive landscapes and the colorful history of the West. He also authored three guidebooks on Colorado's abundant waterfalls.

Conly produced 418 issues of *Investor* during his tenure. He stayed connected to the magazine until recently, producing maps and graphics in his distinctive style.

With sad hearts we say goodbye to a wonderful family man, a friend, a colleague and a brilliant artist. □

WRITING A NEW SCRIPT

LESLIE HAINES, EXECUTIVE EDITOR-AT-LARGE

Lately it seems my inbox is full of more news about the so-called energy transition and alternative energies than about oil and gas, the latter of which has been in a sort of COVID-19-induced, low-oil-price lull anyway. Admittedly, once you click on some topic like the energy transition, you start getting inundated. For example, we learned that New York just selected Equinor to provide the state with offshore wind power, in one of the largest renewable energy procurements seen in the U.S. to date. BP is a partner.

After the traumas of 2020, we see some positive signs in traditional oil and gas, although we are not naïve enough to think the industry will have smooth sailing from here on. The price of oil has recovered fairly well, although it's anybody's guess what lies ahead. LNG prices in Europe and Asia are soaring, which we hope will backstop U.S. gas producers this year. (Gas-focused producer and NGL exporter Range Resources Corp. already has been cited as the U.S. E&P whose stock rose the most last year.)

The oil and gas activity index in the 10th Federal Reserve District (this includes northern New Mexico, Colorado, Oklahoma and other energy-producing regions), jumped from 4 to 40 in fourth-quarter 2020, suggesting that a recovery has started, according to the Federal Reserve Bank of Kansas City in its quarterly survey of energy executives. Respondents told the bank they think drilling activity "will increase sharply" when oil and gas prices average \$56 per barrel and \$3.28 per MMBtu.

Other good news in the patch is:

Item One: In January, Halliburton revealed it had deployed the industry's first electric fracturing equipment—not diesel, not natural gas with their attendant emissions.

These new frac jobs were done for Cimarex Energy Co. on several well pads across Culberson and Reeves counties, West Texas. Halliburton said it completed almost 340 stages across multiple wells using this new power source, electricity from a utility.

"Grid-powered electric fracturing offers an alternative path to achieving the lowest emissions profile possible compared to both turbines and Tier 4 dual fuel engines," the company said. "Grid-powered electric fracturing also offers additional operational reliability and requires a lower capital outlay compared to turbines. Delivering a grid-powered fracturing solution is an example of Halliburton's commitment to leading in the energy transition by helping customers achieve lower emissions."

Cimarex vice president, Permian Business Unit, Michael DeShazer, commented in the Halliburton release, noting how this new frac method fits Cimarex's ESG strategy. "Cimarex has focused its infrastructure investment on creating operational efficiencies and reducing emissions, including ownership of the electrical grid on our Culberson and Reeves County acreage. These investments are enhanced by Halliburton's grid-powered fracturing operation."

A bonus to this environmentally friendly development: Halliburton's electric frac equipment is designed to allow its customer to achieve pumping performance that is 30% to 40% higher than with conventional equipment. Who could argue with that?

Item Two: We all know that the U.S. has done a masterful job in reducing its emissions thanks to increased use of natural gas and far less use of coal-fired power. In the API's annual state of the industry presentation, CEO Mike Sommers said emissions related to production have declined 70% in five of the largest producing regions from 2011 to 2019, according to data from the EPA and EIA. That's commendable.

Item Three: Rystad Energy announced that gross gas flaring from Permian Basin wells has fallen to a modern low. Only 1.6% of the basin's gas production was flared in fourth-quarter 2020. That's impressive—yet it still amounted to about 390 MMcf/d, during an industry lull no less. If companies can continue to tackle this, we'll all be the better for it, and that gas can be monetized. Rystad said in the second half of last year, of the 45 largest E&Ps in the basin, 20 had a flaring intensity of 1.2% and below.

Item Four: Despite the reluctance of private equity funds to commit new capital to new teams, some deals are happening. Several people we've spoken with lately say today is one of the best times to invest that they've seen in years, from a risk-reward standpoint.

The latest new deal? Industry veteran (and one of our 25 Influential Women in Energy) Claire Farley is back, this time to helm ARM Resource Partners LLC, a start-up that will acquire passive, nonoperated interests across the Lower 48, including minerals and royalties. The new firm is backed by Greg Davis' private equity firm, EIV Capital LLC, and ARM Energy Holdings LLC, a longtime advisor in the upstream and midstream.

More funds and firms are looking around and getting ready to tackle new business this year. Finally.


Oil and gas is here to stay.
And so are we.
The last few months have challenged everyone in extraordinary ways as a virus temporarily crushed demand. As we begin to ramp back up, our country and the world will need oil and natural gas, especially the light, sweet crude and abundant, clean-burning natural gas our domestic producers provide. Our industry continues to demonstrate its ability to adapt and to succeed. At Continental, we are built to meet all challenges and seize every opportunity. You would expect nothing less from America's Oil Champion. To learn more about us and our new ESG approach, visit clr.com.
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