Oil and Gas Investor

NOVEMBER 2020

Delaware Basin operators adapt to operational and political uncertainties.

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Recent Private Financing Transactions

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EQUITY PRIVATE PLACEMENT	STRATEGIC PARTNERSHIP	ASSET ACQUISITION	EQUITY PRIVATE PLACEMENT
Sole Placement Agent	Sole Placement Agent	Financial Advisor	Sole Placement Agent
$100 MILLION	UNDISCLOSED	$22 MILLION	UNDISCLOSED
PRODUCERS MIDSTREAM	ROSEWOOD RESOURCES	Thunder Basin Resources	NOBLE ROYALTIES, INC.
EQUITY PRIVATE PLACEMENT	JOINT VENTURE TRANSACTION	EQUITY PRIVATE PLACEMENT	EQUITY PRIVATE PLACEMENT
Sole Placement Agent	Financial Advisor	Sole Placement Agent	Sole Placement Agent

Other Recent Minerals & Royalties Transactions

$28 MILLION	$28 MILLION	UNDISCLOSED	UNDISCLOSED
VIKING MINERALS	VIKING MINERALS	**Shadow Creek Minerals**	NOBLE ROYALTIES, INC.
ASSET DIVESTITURE	ASSET DIVESTITURE	ASSET DIVESTITURE	ASSET DIVESTITURE
Financial Advisor	Financial Advisor	Financial Advisor	Financial Advisor

$350 MILLION	$66 MILLION	$104 MILLION
VIPER Energy Partners	KIMBELL ROYALTY PARTNERS	KIMBELL ROYALTY PARTNERS
FOLLOW ON OFFERING	FOLLOW ON OFFERING	INITIAL PUBLIC OFFERING
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PRIVATE FINANCING STATISTICS	MINERALS & ROYALTIES STATISTICS
~$4.8 Billion	~$900 Million
Aggregate Capital Raised Since 2009	Aggregate Transaction Volume Since 2017
30 Closed Transactions since 2009	10 Closed Transactions Since 2017

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

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ABOUT THE COVER: The last of the discovered great U.S. shale basins, the Delaware was just approaching cruising altitude in capex and rig counts when the pandemic hit. Now operators are finding their footing and searching for the new normal in their go-forward strategies. Photo by Tom Fox.

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LATEST CONTENT

Pioneer Natural Resources to Acquire Parsley Energy in All-stock Merger

By Emily Patsy, Senior Managing Editor

The merger of the two shale producers, both Permian Basin pure-plays, follows a growing wave of consolidation, which Enverus' Andrew Dittmar described as a "historic winnowing of U.S.-based independent E&P companies."

BP, Chevron, Dril-Quip, Hess, Kosmos Talk Deep Water

By Velda Addison, Group Senior Editor

Energy industry leaders say technology and standardization are critical to lowering costs and improving efficiency offshore.

Contango Oil & Gas to Acquire Mid-Con Energy Partners in All-stock Merger

By Emily Patsy, Senior Managing Editor

The acquisition of Mid-Con Energy by Contango Oil & Gas is "simply the next step, and certainly not our last, in our stated goal of consolidating a sector that is in dire need of it," Contango CEO Wilkie Colyer says.

Chaparral Energy Emerges from Bankruptcy as Private Operator

By Emily Patsy, Senior Managing Editor

Chaparral Energy is now "better positioned to compete and will look to capitalize on future opportunities with an improved financial and cost structure," says Chuck Duginski, CEO of the Oklahoma shale driller.

Experts 'cautiously optimistic' about Africa oil, gas exploration

By Velda Addison, Group Senior Editor

More licensing rounds and ending lengthy regulatory delays could lead to more exploration investment for Africa's oil and gas sector, experts said during a recent panel moderated by the African Energy Chamber.

ONLINE EXCLUSIVES

US Shale Reinvestment Rate Falls

By Velda Addison, Group Senior Editor

Analysts say the recent wave of consolidation among shale producers could also eventually lead to the end of U.S. tight oil's growth story.

Analysts Review US Shale Recovery, 'New Normal'

By Faiza Rizvi, Associate Editor

The third-quarter uptick in activity was an industry restart, not a resumption of growth for U.S. shale, analysts say.

EIA: China Primed for Jump in Natural Gas Demand

By Joseph Markman, Senior Editor

Renewables will grow, too, as Asian electricity demand soars between now and 2050.

Hart Energy's Unconventional Activity Tracker

By Larry Prado, Activity Editor

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

HART ENERGY VIDEOS

By Jessica Morales, Director of Video Content

HartEnergy.com/videos

Baker Hughes VP of Drilling: Remote Drilling Is Here to Stay

Paul Madero, vice president of drilling services with Baker Hughes, explains why remote and autonomous drilling operations will enable better wells and better production.

Parker Drilling's New CEO Talks OFS Opportunities, Optimism

Sandy Esslemont, president and CEO of Parker Drilling, stopped by Hart Energy to discuss his new position with the international drilling service provider and outlook on the oil and gas industry as a whole.

Kongsberg Digital President Discusses Digital Twin, Shell Partnership

Hege Skryseth, president of Kongsberg Digital, sat down with Hart Energy to discuss leveraging digital technologies in the oil and gas industry plus the company's latest partnership with Shell.

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A SWELLING WAVE OF CONTRACTION

STEVE TOON, EDITOR-IN-CHIEF

Industry pundits have predicted—wished for, even—E&P consolidation for years. That time is nigh. Since July, six corporate combos have been announced; three in October alone. Surf's up, and the merger waves are crashing on shore.

The pain of 2020's sustained low oil and gas prices has prodded recalcitrant sellers to the bargaining table. Major integrated oil company Chevron Corp. stirred the waters first with its $13 billion absorption of Noble Energy Inc. That created surfable swells for Southwestern Energy Co. to buy Montage Resources Corp. ($865 million), Devon Energy Corp. to pair up with WPX Energy Inc. ($5.7 billion), ConocoPhillips Co. to woo Permian favorite Concho Resources Inc. ($9.7 billion), Pioneer Natural Resources Co. to roll in Parsley Energy Inc. ($7.6 billion) and even a joint run between microcaps Contango Oil & Gas Co. and former MLP Mid-Con Energy Partners.

All the deals were low-to-no premium, all-stock agreements.

Notably, the sellers in these instances were not distressed. Indeed, most were included in the top tier of companies with balance sheets, inventories and management teams positioned to weather the storm surge. What gives?

Scott Hanold, analyst with RBC Capital Markets, in an Oct. 22 report, said surviving is not thriving in this potentially elongated downturn environment, and the sudden industry flurry of public M&A is a proactive effort to create enough scale to enhance shareholder returns.

"We think a driving force for consolidation includes the inability to generate sufficient free cash flow at strip prices on a standalone basis to appease shareholders and pay down debt to more comfortable levels."

Management teams, he said, aren't willing to underwrite bullish oil outlooks anymore nor do strip prices allow much incremental cash to return to said shareholders. "We believe the recent macro volatility, lack of shareholder interest and ESG factors have taken a toll on past willingness to tough it out."

The jury is still out as to whether these combinations will be able to generate the returns needed to attract investor interest, Hanold said.

Leo Mariani, KeyBanc Capital Markets analyst, sees the trend as "very reminiscent" of the merger spree among majors in the late 1990s/early 2000s. Then, low valuations and investor apathy similarly drove financially driven mergers that focused on cost cutting, he said in an Oct. 22 research note.

"We see the current wave of consolidation very much in the same vein," he said. However, "The investment backdrop today feels far worse than the late 1990s given ESG concerns that were virtually nonexistent 20 years ago, worries over peak oil demand, potential regulatory headwinds from a [Joe] Biden White House, and a weighting of around 2% in the S&P 500 vs. 6% in the late 1990s."

Specifically referencing WPX, Concho and Parsley, Mariani noted, "We think these companies capitulated mainly due to a continued dearth of investor interest in energy."

Noble, he said, agreed to hand over the keys due to high leverage, and Montage's decision was related to low market cap issues. The company—itself a combination of Eclipse Resources and Blue Ridge Mountain Resources Inc.—had a cap of just $200 million, "which made it largely uninvestable." The same was likely true for both Contango and Mid-Con and still will be pro forma.

While most analysts see the consolidation wave as a needed shrink-to-grow phase for the industry, Simmons analyst Mark Lear was perplexed and less than pleased with Concho for selling up on the cheap.

"It's particularly surprising for a company such as Concho with a strong balance sheet and deep inventory runway to be selling in a low premium deal," he said in an Oct. 19 report, "and we think it would be difficult for Concho shareholders to stomach what could only be viewed as capitulation on or near the lows.

"We viewed Concho as one of the few companies that was positioned to thrive on the other side of this cycle, and it is difficult to see what additional benefit this deal would afford Concho shareholders that couldn't have been done organically."

One explanation: He interpreted comments by Concho CEO Tim Leach on the deal announcement call as "a condemnation of the standalone unconventional business model, in that the high base production declines inherent in shale make it increasingly difficult to answer the call by investors for increasing capital return."

Are we witnessing the beginning of the end for the shale model?

Morgan Stanley analyst Devin McDermott, in an Oct. 21 report, said, "In a backdrop of abundant resource, the long-term energy transition away from fossil fuels and, in effect, little room for shale growth, we have viewed consolidation-led scale as logical—and perhaps even necessary—for companies to compete in the next phase for U.S. energy: 'more returns, less growth.'

"Consolidation is necessary, and the trend appears to be here to stay."

The E&P universe is shrinking before our eyes. Catch a wave, dude—it could be a gnarly ride.

WELCOME TO 2020

DARREN BARBEE, SENIOR EDITOR

Future historians, we apologize if this timeline is a little messy. Most of the time, to be honest, we weren't sure what was happening either. However, if it helps, a lookback to October 2020 may be of some use in getting your bearings in the Year of Horrible.

Of course, there was the pandemic, which by October had killed more than 220,000 people in the U.S. But just as emblematic of 2020 was NASA's successful October launch of a $23 million space toilet.

Hopefully, this will put the duality of 2020 into context. In quiet moments, largely irrelevant things went A-OK while matters of consequence tended to crash and burn. For instance, the same day in October that NASA's zero-gravity potty passed the quintessential go-no-go, the most powerful and protected man on earth contracted the coronavirus.

So it went in October. We had some impressive moments and some colossal weirdness. Purdue University engineers invented a tiny robot that can travel through a colon by doing backflips. Also, yes, Ireland's Supreme Court ruled that Subway sandwich bread is technically more like a doughnut because of its high sugar content.

Alas, the oil and gas industry could also be viewed through this same split-screen of rationality and glazed-eyed madness.

In one frame, bankruptcies continued to unravel debt-laden E&Ps. Opposite that, massive megadeals fused together companies into Permian Basin behemoths. Around early October, large-scale M&A began to pick up with enormously expensive deals. Faster than you could say Sheffield-squared, Pioneer Natural Resources Co. agreed to merge with Parsley Energy Inc. for $7.6 billion, including assumption of debt.

With Parsley, Pioneer added three things that, ostensibly, Pioneer CEO Scott Sheffield has said he doesn't like or need: Delaware Basin acreage, debt and inventory.

Indeed, both companies have deep inventories that could last up to a decade or more. But Sheffield said on a call about the deal that the transaction "is not about inventory."

Sheffield said Pioneer pulled the trigger on the Parsley deal primarily due to the accretion, metrics and synergies the company offered. "It's really about the financial metrics in regard to free cash flow, earnings [and] corporate level returns."

He also said that Parsley's Delaware wells are more profitable because the company owns 100% of its net revenue interests.

Sheffield's larger thesis is that by the time the pandemic has subsided and oil prices recover, there will be a handful of survivors among independent E&Ps. These companies will have low leverage and market capitalizations of at least $10 billion. Pioneer's pre-deal market cap was about $14 billion.

"I really think there's only going to be three or four independents that are investable by shareholders," he said, naming EOG Resources Inc., ConocoPhillips Co. and possibly Hess Corp. among them. "And we hope Pioneer is one of those."

Still, Sheffield thinks the M&A engines will cool now.

"It seems like the best companies have been picked off in the last few weeks with Parsley and Concho and the other transactions," he said. "I've always said leverage is going to prevent consolidation for the next couple of years."

The Pioneer-Parsley merger was preceded by the Oct. 19 ConocoPhillips acquisition of Concho Resources Inc. In late September, Devon Energy Corp. and WPX Energy Inc. also said they were combining in an all-stock merger. In October, Chevron Corp. also wrapped up its merger with Noble Energy Inc. for $13 billion.

Asked on the call if there was a catalyst for the deals, Sheffield said each looked like clear-cut decisions. Noble had to sell because of too much debt. ConocoPhillips bought Concho because "they were weak in the Permian." Devon and WPX needed scale and to de-lever.

"Our deal is probably the simplest of the four," he said. "It's very contiguous acreage, very accretive. It's simplest from a shareholder perspective to evaluate."

Sheffield said more mergers along the lines of Devon-WPX could continue as companies look to bring together balance sheets that need improvement.

Multibillion-dollar mergers make sense to CEOs. Acquisitions don't.

Companies will have to wait on energy demand, oil prices, COVID-19 and potentially a vaccine for recovery. Sheffield said it's possible Pioneer will eventually divest some of its current or newly acquired acreage.

Still, he said, acquisitions aren't likely to happen. "There really is no market today."

EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2020				
COGA Annual Meeting	Nov. 12		Virtual	coga.org/annualmeeting
Rice Energy Finance Summit	Nov. 13		Virtual	business.rice.edu/rice-energy-finance-summit
DUG East/Marcellus-Utica Midstream	**Dec. 2**		**Virtual**	**dugeast.com**
A&D Strategies and Opportunities Conference	**Dec. 8-9**	**Dallas**	**The Fairmont Hotel**	**hartenergyconferences.com/ad-strategies-and-opportunities**
SPE Sustainability Innovation & Technology Convention	Dec. 10-12	TBD	TBD	spegcs.org/events/5739/
2021				
IPAA Private Capital Conference	Jan. 21		Virtual	ipaa.org
Virtual Executive Oil Conference	**Jan. 27**		**Virtual**	**executiveoilconference.com**
NAPE Summit	In person: Feb. 8-12 Virtual: Feb. 9-26	Houston	George R. Brown Conv. Center and Virtual	napeexpo.com
Innovation & Entrepreneurship Summit	Feb. 24-25	Houston	Norris Conference Center, CityCentre	spegcs.org/events/4637/
CERAWeek by IHS Markit	March 1-5		Virtual	ceraweek.com
Energy Capital Conference	**March 22-23**	**Houston**	**Omni, Houston**	**energycapitalconference.com**
25 Influential Women In Energy	**April 15**		**Virtual**	**hartenergyconferences.com/women-in-energy**
DUG Permian/Eagle Ford/ Midstream Texas	**April 19-21**	**Fort Worth, TX**	**Fort Worth Conv. Center**	**dugpermian.com**
Offshore Technology Conference	May 3-6	Houston	NRG Park	2021.otcnet.org
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**
Summer NAPE	Aug. 18-19	Houston	TBD	napeexpo.com/summer
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

Email details of your event to Bill Walter at bwalter@hartenergy.com.
For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com/events.

NewsWell

More rigs needed to avoid Appalachian gas production declines

Top U.S. gas plays have added horizontal rigs recently but not enough to lead to a sustainable recovery for the sector, analysts say, as companies keep purse strings tightened.

The optimism seen by some gas producers when the COVID-19 pandemic hit demand for oil, leading to a slowdown in oil production along with associated gas, was short-lived. With production at about 90 Bcf/d, oversupply remains.

The "growth story is over for the Appalachian Basin, at least in [the] short-term," according to Artem Abramov, head of shale research for Rystad Energy.

Appalachia, the biggest natural gas-producing region and home to the prolific Marcellus and Utica shale formations, overcame massive infrastructure obstacles to add nearly 12 Bcf/d in 2017 to 2019, Abramov said during Rystad's virtual summit on Sept. 22. However, producers are now in maintenance mode as base production matures.

Sequential declines could be ahead.

"We actually need 40 rigs now to see production maintenance next year," Abramov said. "We are slightly below that level, which basically means that the rig activity has to increase already in the next few weeks, couple of months, if you want to avoid production declines in Appalachia next year."

In the Haynesville region, where Rystad data show about 4.5 Bcf/d was added over the last three years, production can be held flat with 30 rigs. "We might even see some production additions next year if operators prioritize sweet spots and the best locations," Abramov said, though he called the significance uncertain.

Basking in the spotlight again was the Permian Basin, where associated gas production was described as "resilient" this year. Associated gas from the basin, the biggest oil producer in the U.S., accounted for the largest share of gas production growth from 2017 to 2019. Though the Permian is also in maintenance mode, activity in parts of the basin is recovering. Such areas include the gassier parts of the basin, including the western Delaware sub-basin's Culberson County in Texas, which Abramov said has some of the country's most productive gas wells.

"Contrary to the gas basins where these can be viewed as a negative story and pretty expected development this year, the Permian actually impressed the markets a little bit during the oil curtailment periods" with "dry gas not that far from the 12 Bcf a day level where it peaked early this year," he said.

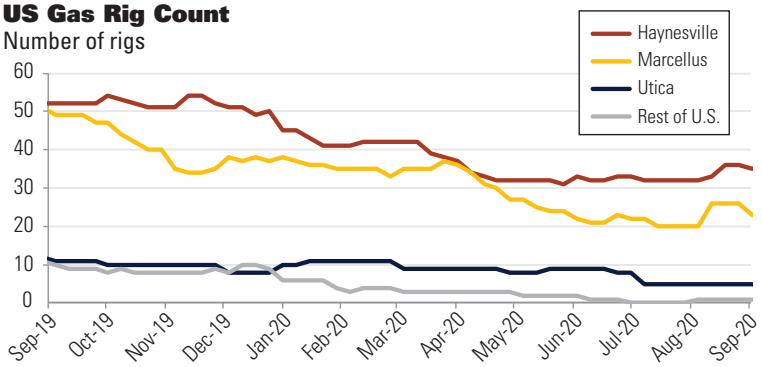
Rystad sees the Permian as a major driver for production growth in the medium term. How much growth will depend on how much oil and gas prices improve.

"If we assume that WTI prices recover to mid to high 40s next year or in 2022, such a price environment will immediately trigger continuous activity expansion in the Permian," the analyst said. "But even with declining oil production, gas output in oil basins tends to stay relatively flat."

Looking at the entire U.S., he said gas production is set for a gradual sequential decline in 2021, following three years of growth that saw production rise by around 25 Bcf/d to about 90 Bcf/d today. That's down about 6 Bcf/d from fourth-quarter 2019, Rystad data show.

US Gas Rig Count

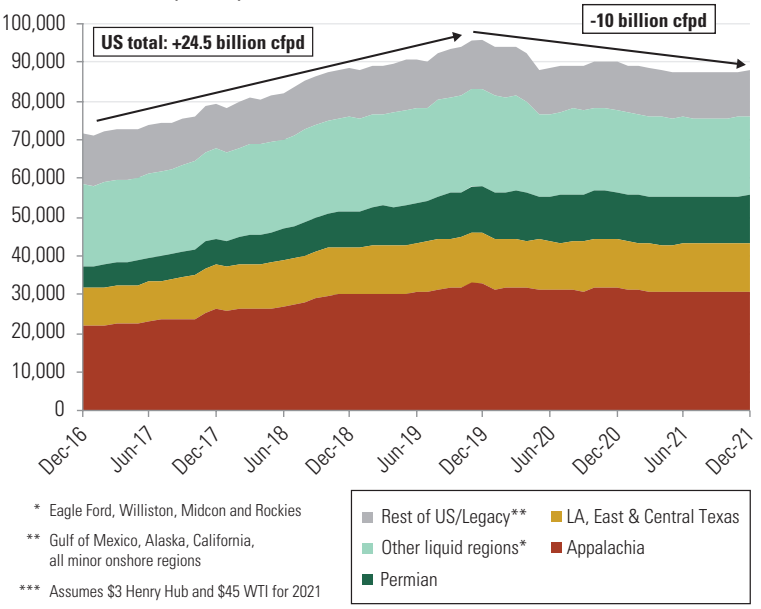
Number of rigs



Source: Rystad Energy, Baker Hughes

US Dry Gas Production

Million cubic feet per day



* Eagle Ford, Williston, Midcon and Rockies

** Gulf of Mexico, Alaska, California, all minor onshore regions

*** Assumes $3 Henry Hub and $45 WTI for 2021

Source: Rystad Energy

About 60 to 65 total rigs are currently running in gas basins, he said.

"If we look at the strip for 2021, it is kind of back to the normal level, averaging roughly at $3 per MMBtu," Abramov said.

However, the price is not high enough to "trigger a substantial recovery and increase in the activity in the gas basins," he added, noting it is already sufficient to continue maintenance programs. "Most companies still maintain pretty conservative budgets and prioritize their balance sheets and free cash flow generation."

—Velda Addison

EIA: Gas price will reach $3.38 by January

A colder winter will drive the average price of natural gas to $3.38/MMBtu in January, the U.S. Energy Information Administration (EIA) forecasts.

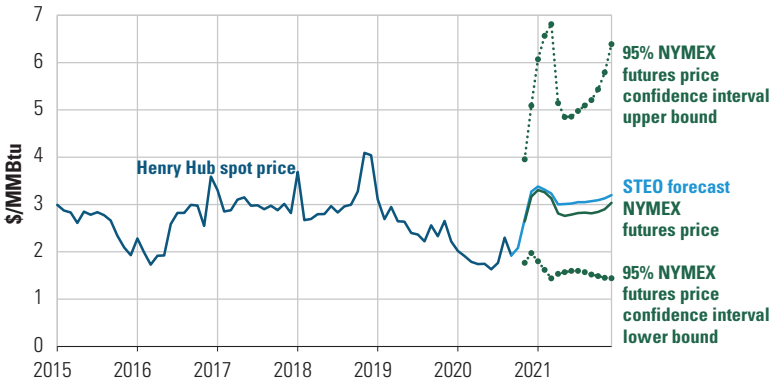
The EIA's newly released Short-Term Energy and Winter Fuels Outlook expects the average price of gas to soar from $1.92/MMBtu in September on rising domestic demand and increased demand for LNG exports, as well as reduced production. Even with inventories expected to reach a record 4 Tcf by the end of October, higher withdrawals than the five-year average will drag that total to 1.7 Tcf, 6% below the average for 2016 to 2020.

"Prices can be really volatile if the market is caught off-guard," Ed Morse, global head of commodities research at Citi Research, said during an Oct. 7 webinar discussing the outlook. "We've had a very unusual year with natural gas. We had an extremely mild northern hemisphere winter last winter. We had inventory levels at the end of the heating season at abnormally high levels across the planet."

EIA acknowledged that its October outlook was subject to uncertainty because responding to the COVID-19 pandemic has led to evolving mitigation and reopening efforts.

"Reduced economic activity related to the COVID-19 pandemic has caused changes in energy demand and supply patterns in 2020 and will continue to affect these patterns in the future," EIA said. The outlook assumes U.S. gross domestic product (GDP) declined by 4.4% in the first half of 2020 compared to that period in 2019. It also assumes that GDP will rise in third-quarter 2020 and grow 3.5% year-over-year in 2021.

Henry Hub Price Forecast



Note: Confidence interval and futures prices derived from market information for the five trading days ending October 1, 2020. Intervals not calculated for months with sparse trading in near-the-money options contracts.
Source: U.S. Energy Information Administration, Short-Term Energy Outlook, October 2020.

Also worth noting, the National Oceanographic and Atmospheric Administration (NOAA) estimates a 75% chance that La Niña conditions present in the Pacific during the summer will stay through the winter. The impact so far has been a reduction in wind shear, which is the contrast in winds between the surface and upper levels of the atmosphere. That has resulted in a very busy Atlantic hurricane season.

Looking ahead, La Niña winters in the southern U.S. tend to be warmer and drier. The northern part of the country and Canada can expect lower-than-normal temperatures. NOAA predicts above-average snowfall in Montana, Wyoming, the Midwest and northern Colorado.

"For us, this is actually fairly unusual," Mike Halpert, deputy director of the NOAA's climate prediction center, said during the webinar. "We don't really favor below average temperatures very often. It's not that it doesn't happen, it's just that it's very, very challenging to know when it's going to."

Increased energy consumption to meet higher space heating demand will push up spending by 6% on natural gas, 7% on electricity and 14% on propane compared with winter 2019 to 2020. Part of this is due to more people working and attending school at home because of the pandemic.

EIA sees a 1.8% drop in U.S. consumption of natural gas in 2020. It attributes the drop to lower residential and commercial heating demand in the early part of the year, leading to average usage of 13.1 Bcf/d. Reduced industrial consumption tied to the economic slowdown will likely drop the 2020 average by 0.8 Bcf/d to 22.3 Bcf/d. Total consumption in 2021 is expected to experience a 5.9% decline from this year as EIA expects rising gas prices to reduce demand in the electric power sector.

U.S. dry natural gas production is forecast to average 90.6 Bcf/d in 2020, down from 93.1 Bcf/d in 2019. The 2021 expectation is 86.8 Bcf/d, although EIA predicts production will start to rise in the second quarter as natural gas and crude oil prices increase.

"We have supply down in Appalachia," Morse said. "We have supply down in the gas-producing areas of the Southwest. We have supply down with associated gas because production of oil is down.

"We're in a period of a demand rebound, and supply is quite limited."

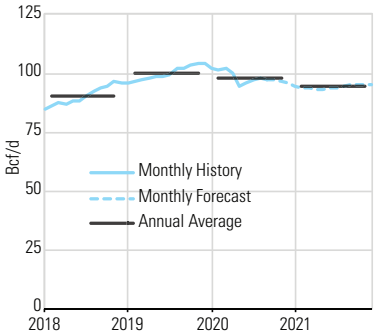
LNG exports, which rose to 4.9 Bcf/d in September from 3.7 Bcf/d in August, will return to pre-COVID-19 levels by November, EIA forecasts, and average more than 9 Bcf/d from December through February.

Morse noted how U.S. weather can drive global natural gas markets. For example, a 10% colder U.S. winter could lift the base price of gas from $3.40/MMBtu to $3.90/MMBtu. In that scenario, the European price would jump to $7.10/MMBtu from $4.60/MMBtu and Asia's Japan Korea Mark price for LNG would rise to $7.40/MMBtu from $4.90/MMBtu.

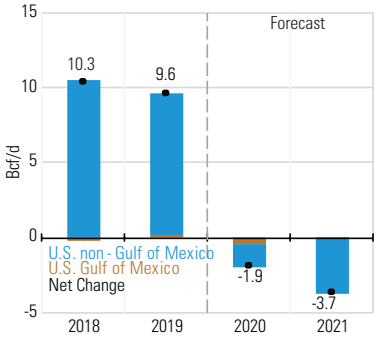
LNG exports, which rose to 4.9 Bcf/d in September from 3.7 Bcf/d in August, will return to pre-COVID-19 levels by November, EIA forecasts, and average more than 9 Bcf/d from December through February.

—Joseph Markman

US Marketed Natural Gas Production



Annual US Production Change Components



Source: Energy Information Administration

How US shale gas fits evolving global market

When it comes to natural gas demand in the U.S., there's good news and bad news if you ask Mark Finley, an energy and global oil fellow at the Center for Energy Studies at Rice University's Baker Institute.

"The bad news is there's still a lot of capacity to switch back and forth between coal and gas in power generation in the United States. … There's a lot more competition for other fuels—at least in the short term," Finley said during a recent webinar on the future of U.S. shale. "The good news is there's a global marketplace the U.S. producers can access through LNG."

Among the lingering questions is, will the global demand be large enough to uplift the U.S.? Will companies with gas-weighted portfolios grow gas production? How could associated gas production impact plans?

The natural gas sector, like oil, faces uncertainty. The pace of economic recovery remains in flux as the world continues to cope with the COVID-19 pandemic and falling demand amid a renewable energy push.

Having seen prices nosedive from more than $13/MMBtu to less than $2.40/MMBtu in the last 15 years with occasional dips

and spikes, the U.S. natural gas sector's rollercoaster ride continues. Production has gone from being in decline to abundance as the shale revolution unfolded, enduring several downturns along the way.

Unlike oil prices, gas prices never recovered from the collapse in 2008 to 2009, said Ken Medlock, senior director for the center and webinar moderator. The oil price recovery in the years since "really helped to kind of stoke growth in gas output more generally in the United States" as associated gas from oil-directed drilling added to plentiful supplies.

However, the oil and gas sectors are struggling. Medlock questioned what the future could hold for gas producers, particularly in a world where oil production could suffer.

"This is, we hope, the last year that we were going to have a negative forecast for natural gas," said Matt Portillo, managing director of upstream research for Tudor, Pickering, Holt & Co.

"We came into the year quite bearish on the fundamentals, which had to do with where the balances were, as well as our concerns that the global market from an LNG perspective was quite oversupplied given where European inventories were," Portillo said. "What we saw was a very significant pullback through the summer on LNG exports, and we've seen a fairly significant decline in the U.S. in aggregate gas production."

Gas production from major basins in the U.S. is expected to fall by 428 MMcf/d to nearly 80.6 Bcf/d in October, data from the U.S. Energy Information Administration's (EIA) Drilling Productivity Report show.

Entering 2020, the aggregate gas volume was about 96 Bcf/d, Portillo said. Given legacy basin declines in places such as the Barnett, Fayetteville and Pinedale along with declines in associated basins, he said the U.S. will exit the year in balance with about 89 Bcf to 90 Bcf of supplies.

Natural gas inventories had shown year-on-year increases since April 2019, the EIA said. However, that trend is expected to reverse. Production is forecast to decline through March 2021 with average production next year about 3.3 Bcf/d below 2020 levels.

Producers are trying to mitigate declines. Many have reduced spending. Some have shifted to new strategies with the energy transition in mind. And others have moved toward a dividend distribution and a free cash flow distribution model, Portillo said.

"There's not a lot of incentive for growth," he added.

Even in a $2.75 to $3 gas world, Portillo said he does not expect to see much incremental dry gas production coming from the Northeast or the Haynesville over the next few years.

"When you have 40 Bcf a day of supply coming out of those two basins, producers don't have a lot of wiggle room to grow," the analyst said. "If you get into a situation where every E&P individually raises their hand and says, 'I would like to grow 4% or 5% per annum,' all of a sudden you're pushing somewhere between 1.6 Bcf and 2 Bcf a day of gas supply into the market."

Add associated gas from oil growth of about 300,000 bb/d to 400,000 bbl/d to the scenario, and the supply stack increases by about 1 Bcf, according to Portillo's estimates.

"Producers are aware of that. They understand that the reason that gas has partially gone from $13 down to $1.50 at one point this year was the unending growth and the associated market's impact on that," he said. "And I think you're seeing a structural shift again behaviorally around the gas markets."

Higher prices could, however, be on the horizon, considering the decline in inventories forecast by the EIA. Its outlook shows Henry Hub spot prices averaging $3.19/MMBtu in 2021. That's about $1.02/MMBtu higher than in 2020.

"I think the big question there is, what happens coming on the back end of COVID, which, of course, opens the door to a lot of conversations about energy transition and shifting energy mixes in different places around the world," Medlock said.

Although the EIA forecasts U.S. consumption of natural gas to fall 2.7% to 82.7 Bcf/d in 2020 and to 79.1 Bcf/d in 2021 as natural gas prices rise, the outlook shows U.S. LNG exports will rise and return to pre-COVID levels by November.

Rising global gas prices in Asia and Europe in August led to U.S. LNG exports increasing to 3.7 Bcf/d in August from a 21-month low of 3.1 Bcf/d in July. The EIA forecasts LNG exports will average more than 9 Bcf/d from December 2020 to February 2021.

—Velda Addison

Upstream M&A struggles despite recent mergers

Oil and gas companies, under pressure from the coronavirus, continued a rash of shotgun mergers on their way to a third-quarter 2020 M&A tally of $21 billion, according to analysis by Enverus.

Still, the pace of deals during the quarter slackened, and the remainder of the year is likely to see more of the same: a start-and-stop lurch toward consolidation for lower-debt companies. The industry also seems likely to continue condensing as unfavorable commodity prices force companies to stretch their financial reserves to breaking, Andrew Dittmar, senior M&A analyst at Enverus, said in a recent report.

"There is a broad consensus that consolidation is a net positive for the industry," Dittmar said. "Including the corporate deals from 2019, that process looks to be well underway. There is room for further mergers, but it can be a challenge to find the right asset and balance sheet fits for accretive deals. It may take several more years for consolidation to play out."

A rebound in deal activity is thought to only be possible through the dual influence of higher commodity prices as well as additional capital investments.

Enverus noted that some private-equity capital sources have so far sat out 2020. The firm suggested that special purpose acquisition companies (SPAC) might be a potential source of capital and seems "to be gaining

Top Five US Upstream Deals Of Third-Quarter 2020

Date	Buyers	Sellers	Value ($MM)	Deal Type	Region
7/20/20	Chevron	Noble Energy	$13,000	Corporate	Multi
9/28/20	Devon Energy	WPX Energy	$5,631	Corporate	Multi
8/12/20	Southwestern Energy	Montage Resources	$874	Corporate	Appalachia
8/20/20	San Juan Offshore	Arena Energy	$466	Property	Gulf of Mexico
7/29/20	Castleton Resources	Range Resources	$245	Property	Ark-La-Tex

Source: Enverus

broader acceptance in the investment community with rising use across industries."

For the quarter, Enverus counted 28 deals, tying its rate of transactions with first-quarter 2020 as the worst showing in 10 years. A handful of large corporate acquisitions helped push total transaction values up, led by Chevron Corp.'s agreement to buy Noble Energy Inc. for roughly $13 billion and Devon Energy Corp.'s merger with WPX Energy Inc. for about $5.6 billion.

The Chevron and Devon deals were both structured with little premium and all-stock considerations.

With roughly 60% of the quarter's transactional value, Chevron's acquisition of Noble Energy would be the fourth largest global upstream deal since 2014 at close. It's also a notable return to the deal table for Chevron, following a failed attempt last April to purchase Anadarko Petroleum Corp. for $48 billion, including debt.

In a sign of how commodity prices have changed the M&A equation, Noble accepted an offer consisting of all-stock. Eighteen months ago, Chevron's offer for Anadarko consisted of 25% cash, or $8 billion. Anadarko was ultimately purchased by Occidental Petroleum Corp.

In shale territory, Devon's acquisition of WPX, which includes an oily position in the Delaware Basin, was notable for making up nearly all oil deal value in the quarter. Combined, the companies will represent $12 billion in enterprise value.

Permian Basin companies will likely continue to be the epicenter for shale consolidation because of their perceived advantages in economic well locations. However, natural gas consolidation, including Devon's sale of its Barnett Shale assets to Kalnin Ventures LLC, continues to make noise.

In what Enverus counted as the third largest deal of the quarter, Southwestern Energy Co. is acquiring Montage Resources Corp. for $874 million. As with its oilier cousins, the transaction was structured with little premium and all-stock consideration.

"Regardless of the targeted play, mergers have so far focused on companies with reasonable debt loads," added Dittmar. "Companies with impaired balance sheets are being left to find their own way, resulting in a spate of Chapter 11 filings."

Third-quarter bankruptcies including California Resources Corp., Oasis Petroleum Inc., Denbury Resources Inc. and Chaparral Energy Inc., had a combined total of $15 billion in debt—more than all of 2018's upstream bankruptcies combined, according to Enverus and Haynes and Boone data.

—Darren Barbee

Transformational change imminent, leading to 'shale evolution'

Decline rates and productivity, cost cutting and access to capital are among the concerns U.S. shale players may find themselves grappling with as they adjust business models amid commodity price uncertainty, analysts say.

The challenges come as the industry works to handle the consequences of a pandemic that has ravaged energy demand as supplies remain abundant, oil prices remain low and the world moves toward cleaner forms of energy. Transformational change may be on the horizon for the shale business in the U.S., where oil production has fallen from nearly 13 MMbbl/d earlier this year.

Oil production from the main U.S. shale plays was forecast by the Energy Information Administration to drop by 68,000 bbl/d in October to about 7.6 MMbbl/d.

"Shale is a mature business. In 2005, it was really about the shale revolution. Today, it's about shale evolution, and a big part of that is that a lot of these basins are reaching maturation," Matt Portillo, managing director of upstream research for Tudor, Pickering, Holt & Co. (TPH), said on a recent webinar by Rice University's Baker Institute on shale's future.

Looking at the Bakken, one of the more mature oil plays in the U.S., Portillo said TPH forecasts the play has only six to seven years' worth of Tier 1 inventory left to develop. He called those wells "barely economic" at today's commodity prices.

"The real question … is, what oil prices do producers need to generate a healthy and sustainable business model while at least maintaining production and potentially over the medium term, driving very minimal amounts of growth," Portillo said.

Oil prices had stabilized around $40/bbl but were down slightly Sept. 14 as rising cases of coronavirus continued to threaten demand. OPEC said world oil demand could fall to about 9.5 MMbbl/d in 2020. The organization also revised down its forecast for next year.

Some E&Ps, including EOG Resources, are vowing to stay disciplined.

"We are not interested in growing oil in an oversupplied market," Bill Thomas, the company's president and CEO, said Sept. 9 during the virtual Barclays CEO Energy-Power Conference.

Most companies are now only investing 70% to 80% of their cash flow, regardless of the commodity price cycle, according to Portillo. "E&Ps are committing, regardless of the upside in the commodity, to effectively capping their growth rate at a 5% level going forward, which is going to have profound implications on the U.S," he said. "If you look at our macro model in 2021 for the U.S., we expect essentially the entire industry to move toward a maintenance capital

scenario in a $40 to $45 commodity price environment, which is essentially holding production flat, exit to exit."

With more consolidation in the industry, focus is expected to shift from growth to free cash flow generation. TPH forecasts U.S. production will grow only about 300,000 bb/d to 400,000 bbl/d on average from 2022 to 2025.

Mark Finley, fellow in energy and global oil at the Baker Institute's Center for Energy Center, described oil companies' access to capital as "brutal," noting the sector's share in the U.S. stock market dropped to a record low and there are ESG pressures.

"Energy is not the flavor of the month," Finley said.

On the cost front, there is not much left to trim and oilfield service companies "have already been squeezed," he said. Plus, "technology has matured. The pace of learning is not as great as it was five years ago."

Finley pointed out, however, per well productivity in the main U.S. shale plays grew by 10%, according to Department of Energy data. Further improvement from lower activity levels are expected, he added, noting "We're left with the best crews, the best rigs, the best frac spreads and working only the best prospects."

It's unlikely, however, that such productivity gains will resemble the double and triple gains seen with the last downturn, Finley said.

Though most of the wells that U.S. producers shut in earlier this year are back online, the underlying decline rate has gotten bigger, Finley said.

"Heading into the crisis, it was well over 500,000 barrels a day every month. And as a result, today's weekly estimate of U.S. production from the U.S. Energy Department shows crude production right now is 3 million barrels a day below pre-pandemic levels," Finley said.

Portillo also spoke about the depletion of core inventory in the U.S. Accelerating the drillbit could translate to pulling down an inventory profile by five or six years, he said.

"If you get into that situation, you either have to start to drill Tier 2 rock, which tends to have a cost structure that's $10 to $20 higher than your breakevens on your Tier 1 rock, or you're going to have to go out and be more acquisitive again," Portillo said. "And so, there is little public incentive, given the equity performance today, to go out and grow."

Energy industry experts seem to agree that consolidation is needed and likely to happen in the U.S. shale space. Although deal activity has been sparse, analysts believe consolidation is imminent.

"There's a very good chance that we see industry consolidation take down 60% to 80% of the companies that we think about from a coverage standpoint," Portillo said.

Most believe each major play in the U.S.—excluding the Permian Basin and perhaps the Marcellus—needs only one or two champions, Portillo said, with mergers or equals being the correct formula for public companies.

"Those basins are at the point where they're actually peaking on maturation and potentially rolling over. And in that world, it's all about cost and scale going forward," he said, later adding "the market cap of a lot of these companies has faded to a point where they're just not relevant."

TPH believes the number of public companies left in the sector will fall to between 10 and 15 larger companies with perhaps up to five small- and mid-cap E&Ps with exposure in different basins. "Beyond that, we just don't see an investor appetite or public equity interest in really capitalizing companies beyond those levels."

—Velda Addison

Colorado oil regulators approve setback rule for drilling, fracking

The Colorado Oil & Gas Conservation Commission (COGCC) on Sept. 28 unanimously voted in favor of a preliminary approval establishing new 2,000-ft setback rules for drilling and fracking operations statewide.

The new series of rules within Senate Bill 19-181 (SB 181) increases the distance from the current 500 ft that wellpad surfaces must be located from buildings.

Steve Diederichs, vice president of RS Energy Group, noted the most impactful of the rulemaking involves extending setbacks, set to affect operators PDC Energy Inc., Extraction Oil & Gas Inc. and Occidental Petroleum Corp.

"Our recent analysis concludes that 89%, 73% and 71% of PDC Energy's, Extraction Oil & Gas' and Occidental Petroleum's respective total gross surface acres will be nonviable for placing wellpads under the new rules," Diederichs wrote in a research note on Sept. 28.

Additional setbacks from waterways are expected to be discussed next month, Diederichs added. A final vote on the rulemaking matters is scheduled for early November.

The new rules within SB 181 will go in effect Jan. 1, 2021.

Diederichs also noted that on Sept. 28 the COGCC clarified that the rule changes will be promulgated and applied to pending permits. The rules will not apply to existing facilities or approved permits, "a point the commission stated has made clear to stakeholders throughout the recent rulemaking process," he wrote.

Earlier in September, Dan Haley, president and CEO of industry group Colorado Oil & Gas Association (COGA), responded to COGCC's proposed 2,000-ft setback calling the recommendation "completely arbitrary, not based on science." He added the rulemaking was being made without considering its impact on employment and Colorado's economy.

"Nonpartisan COGCC staff, which has decades of experience protecting public health and safety in Colorado, put forward recommendations based on their years of working with stakeholders," Haley said in a statement on Sept. 10. "Those recommendations were dismissed by commissioners who promised to be guided by science and data, but instead today turned to arbitrary and unjustified setbacks distances that provide no additional protection and will stifle Colorado's economic recovery."

—Hart Energy staff

Report discusses path to change for oil, gas sector

As the oil and gas industry continues to lay off workers—more than 107,000 to date this year by Deloitte's estimates—with an aging workforce on the downside of another cycle amid heightened focus on sustainable energy, challenges may seem abundant for the sector.

However, these challenging times also reek of opportunity, according to analysts who have tracked the impact of the global coronavirus pandemic on the oil, gas and chemical sector's workforce, business operations and other market forces. Companies, and the workers powering them, could transform themselves and win back investors.

Key to making the shift is sustainability as a way of business, digitalization transforming work, recoded careers to build a workforce of the future and organizational agility for new business models, Deloitte said in a recently released report.

"The oil, gas and chemicals industry was built on human ingenuity, innovation and grit, and it is that same spirit that will forge the industry's next reboot and revitalization," Duane Dickson, vice chairman and U.S. oil, gas and chemicals leader for Deloitte LLP, said in a statement. "Companies that choose to see the coming decade as an opportunity for transformation will likely not just outlive this compression but may even lead the industry into the future of work."

Deloitte highlighted levers that oil, gas and chemical companies could pull to transform, possibly paving the path toward a brighter future.

Deloitte said the industry should see the 30% and 17%, respective, drop in transportation-driven fuel demand and global greenhouse gas emissions during first-half 2020 as a "wake-up call to decarbonize their hydrocarbon 'work.'"

At 6% to 8%, the return on invested capital of oil and gas companies is just as good as those of top renewable companies, the report said. Embracing sustainability as a way of business could also attract investors, stabilize margins and lead to growth. "Even basic methane abatement measures, such as leak detection and repair, and device replacement, could bring net savings of US$2 to $4/MMbtu," the report said.

The firm's four-pronged energy transition pathway, as explained in the report, ranged from the initial "first steps" with a focus on HSE and "laying building blocks" with emissions, electrification and energy efficiency as a focus to higher impact objectives. These included what Deloitte called "new blueprints" with portfolios dominated by lower-carbon energy sources and carbon capture and the more impactful "winning the future" pathway. Here, the emphasis is on areas such as net-zero emissions from assets and influencing consumers to get on the net-zero path.

The industry overtime has increasingly turned toward digitalization to improve operations.

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The COVID-19 pandemic accelerated urgency, Deloitte said, though capital constraints remain.

"The power of digital transformation lies in a structured road map that extends structural changes from an individual asset level to the entire organization and creates a platform for innovation and collaboration," the report said.

The so-called human-machine collaboration involves mechanizing operations, or using sensors to link the physical and digital; using field data transferred to remote centers for real-time surveillance and optimization; educating and training the workforce and partners; and ultimately, streamlining remote operating centers and "virtualizing the entire business model through technology-enabled, human-driven decision-making using the technology-as-a-service model."

Essential to it all is the workforce, including different hiring strategies and techniques for attracting as well as retaining talent. A company's sustainability contributions and plans, digital avenues for work, and remote or flexible work arrangements could attract potential employees, according to Deloitte.

"Companies will need to build a new workforce architecture to attract new talent. This includes, but is not restricted to, building career paths for new roles, such as agile coaches, data scientists, emissions officers, or user-experience designers, to attract young talent," the report said. "These are necessary imperatives to move from an 'only fuels-based' to a 'solutions-based' business."

Without this, it could be more of the same on the hiring front. The firm noted that most of the industry's tenured personnel—more than 45%—will retire within seven years or sooner with dwindling replacements in the pipeline.

Deloitte also suggested developing the workforce by bringing together groups of in-house experts to solve problems and creating programs to leverage the knowledge of tenured workers with younger generations.

"By putting people at the core of business transformation strategies, the industry may hopefully regain its appeal and position itself for what's expected to be a much different landscape in the future," Dickson said.

With beliefs that the industry has exhausted most of the ways it previously gained efficiency to lower costs, Deloitte said now is the time to shift from operational to organizational agility by revisiting core parts of the business, resource management and partner relationships.

Among Deloitte's food for thought is revising operational visions for the entire business instead of taking a piecemeal approach for specific business units in areas such as digital and automation. Costs not aligned with the vision should be reduced, the firm said.

Companies could also realize savings by outsourcing intelligent process automation and cloud-based technology solutions, considering high technology costs and related personnel expenses.

"While extremely challenging, this downturn presents an opportunity for companies to reposition," said Kate Hardin, executive director for Deloitte Research Center for Energy & Industrials, Deloitte Services LP. "This is the time for strategists to make bold choices today that affect the work of tomorrow; and to adopt redesigned, cyber-physical teams and embrace a digital workplace culture as a basis for future innovation."

—Velda Addison

VanLoh: Shale binge spoiled US reserves

A fracking binge in the American shale industry has permanently damaged the country's oil and gas reserves, threatening hopes for a production recovery and U.S. energy independence, according to one of the sector's top investors.

Wil VanLoh, CEO of Quantum Energy Partners, a private-equity firm that through its portfolio companies is the biggest U.S. driller after Exxon Mobil Corp., said too much fracking had "sterilized a lot of the reservoir in North America."

"That's the dirty secret about shale," VanLoh told the Financial Times, noting wells had often been drilled too closely to one another. "What we've done for the last five years is we've drilled the heart out of the watermelon."

Soaring shale production in recent years took U.S. crude output to 13 MMbbl/d this year and brought a rise in oil exports, allowing President Donald Trump to proclaim an era of "American energy dominance."

Total U.S. oil reserves have more than doubled since the start of the century as hydraulic fracturing, or fracking, and horizontal drilling unleashed reserves previously considered out of reach.

But the pandemic-induced crash, which sent U.S. crude prices to less than zero in April, has devastated a shale patch that was already out of favor with Wall Street for its failure to generate profits, even while it made the country the world's biggest oil and gas producer.

The number of operating rigs has collapsed by more than 60% since the start of the year. U.S. output is now about 11 MMbbl/d, according to the U.S. Energy Information Administration, or 15% less than the peak.

"Even if we wanted to, I don't think we could get much above 13 million" bbl/d, VanLoh said. "I don't think it's physically possible, because we've messed up so much reservoir. I would argue that what the U.S. was touting three or four years ago, in theoretical deliverability, is nowhere close to what we think it is now."

He said operators had carried out "massive fracks" that created "artificial, permanent porosity," inadvertently reducing the pressure in reservoirs and therefore the available oil.

The comments will cause alarm in the shale patch, given the crucial role of investors such as Quantum Energy Partners in financing the onshore American oil business.

The Houston-based investor has assets under management of about $11.2 billion, according to data provider PitchBook, and is one of the few private-equity groups still focused on shale.

Private companies account for about 30% of U.S. oil production excluding Alaska and Hawaii, or

about 2.7 MMbbl/d, according to consultancy Rystad Energy.

Other private-equity investors have warned that the shale growth story has ended, despite an oil-price recovery in recent months to about $40/bbl.

"They were making lousy returns at $65 a barrel," said Adam Waterous, head of Waterous Energy Fund. "You need at least north of $70 before you start achieving a cost-of-capital return in the U.S oil business."

Production from the Permian, the prolific shale field of West Texas and New Mexico, peaked even before the crash this year, Waterous said. At current prices, only 25% of U.S. shale was economical, he added.

Analysts also say U.S. oil output will struggle to recover its previous heights. Artem Abramov, head of shale research at Rystad, said production would remain between 11.5 MMbb/d and 12 MMbbl/d at $40/bbl. S&P Global Platts forecasts a decline to 10 MMbbl/d by mid-2021.

But the crash could create opportunities for Quantum Energy Partners in the short term, VanLoh said, especially if prices recovered.

While listed producers had mostly sworn off production growth, some Quantum Energy Partners-backed companies, such as DoublePoint Energy—which played host to Trump during the president's July fundraising visit to Midland, Texas—were increasing drilling activity. It says its Permian acreage can still be profitable at current prices.

Quantum Energy Partners' portfolio companies would increase output this year by about 25%, to 500,000 bbl/d of oil and gas, VanLoh said.

"The next five years may be the best five years we've ever had for hydrocarbon investing," he said.

But he is also adjusting his company's strategy to reflect investors' growing disquiet with fossil fuels. Quantum Energy Partners' new 10-year fund, VIII, would be launched in early November, he said, with $1 billion of about $5.6 billion of total capital commitment reserved for "energy transition" investments.

The company would soon appoint someone from outside the oil industry to enforce better environment, social and governance performance at Quantum Energy Partners' companies, VanLoh added.

He said they would have to improve ESG "because ultimately you're not going to get capital from us if you don't … And we won't be able to get capital from our limited partners if you don't."

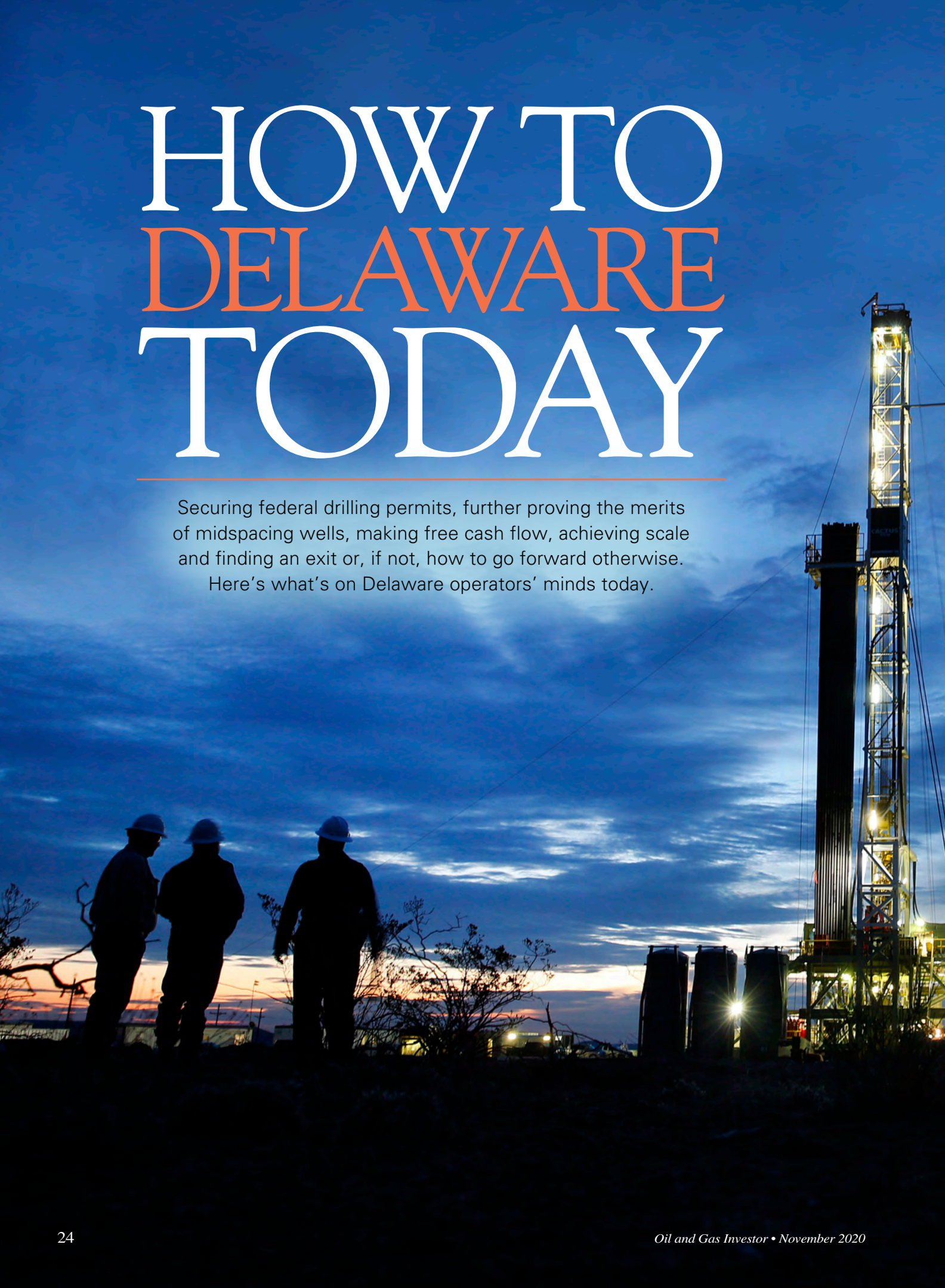
A more efficient U.S. shale sector would reemerge from the crash, VanLoh said, but it would be smaller and require a reduced workforce. He is now advising his friends' children not to pursue a career in oil.

"I tell all of them—honestly, it's a very risky bet and, if I were you, I would not go into it today," he said.

—Derek Brower, Financial Times

HOW TO DELAWARE TODAY

Securing federal drilling permits, further proving the merits of midspacing wells, making free cash flow, achieving scale and finding an exit or, if not, how to go forward otherwise. Here's what's on Delaware operators' minds today.



TOM FOX

ARTICLE BY
NISSA DARBONNE

The nature of well spacing has shifted with the industry's orientation toward free cash flow, said Bernadette Johnson, vice president, market intelligence, with Enverus. "You can't drill twice as many wells for 100% more cost and only get 60% more production. It simply doesn't work."

In the northern Delaware Basin in the past couple of months, operators with leases on federal land were rushing to secure their drilling permits. U.S. presidential candidate Joe Biden has said he will forbid new drilling on federal land.

And those leases weren't cheap. Matador Resources Co. paid up to $95,000 an acre in 2018 in a Bureau of Land Management (BLM) sale.

Bernstein Research senior analyst Bob Brackett reported in early October that, in the 28 months prior to February 2020, the ratio of federal-to-state permits issued in Eddy and Lea counties, N.M., was nearly always less than 60% federal.

That jumped to 70% in February and 80% in March and has been at least 70% each month since, according to Enverus data.

"E&Ps are stockpiling federal permits to be on the safe side," Brackett wrote.

Matador holds 127,600 net lease and mineral acres in the Eddy and Lea counties and in Loving County, Texas; about 28% of it is on federal land. About 62% of that is HBP, the company reported in an update in July.

Once its Stateline property is HBP before year-end by putting online at least one more well (at the Voni unit), 70% of its federal acreage will be HBP, it added. The rest of its federal leasehold doesn't expire before 2028.

Meanwhile, it had 218 permits, and 68 more were underway that it anticipated receiving before year-end.

In Matador's second-quarter earnings call, Mike Scialla, a managing director at Stifel Financial Corp., asked what percentage of Matador's leasehold could go undrilled if Biden wins and forbids new permits.

Joe Foran, Matador chairman and CEO, said that "The chances of them saying you can't drill on your leasehold are fairly slim" since the federal government would probably have to use imminent domain and, if winning that, then "they've got to pay for it."

If a permit has already been issued, "I think they're going to allow you to drill it," Foran said. "The federal government is going to need the money."

Matador and other operators with federal permits have two years to drill the wells that have already been permitted. BLM leases are for up to 10 years.

If needed, though, Matador has "a lot of A-plus wells that are not on federal leases," Foran said. If it couldn't drill the federal land, "there's still plenty of opportunities out there" on state and private land.

At the state level, New Mexico's governor has been supportive of the industry, he added. Should there be any changes on any front, "I think we're nimble enough to change with them."

Spacing, Contango, Pecos County

Meanwhile, Matador and other Delaware operators have done most of the science-ing needed on well-spacing during the past few years. Early tests of tighter and tighter spacing hadn't gone well.

Bernadette Johnson, Enverus vice president, market intelligence, told attendees in Hart Energy's virtual DUG Permian conference in September that there is a midrange.

In one case study, Johnson focused on Contango Oil & Gas Co.'s Wolfcamp A program on the southern edge of the Delaware in Pecos County. Other formations are being targeted by operators in the area, but Wolfcamp A is the most common, thus examining that one, she said.

"In the entire Delaware Basin, you can see a bit of upspace behavior," she said.

Operator spacing in Contango's area is different than the basin average and further differs within the study area. "There is a pretty big disconnect between how the wells were spaced from 2018 to 2019," Johnson said.

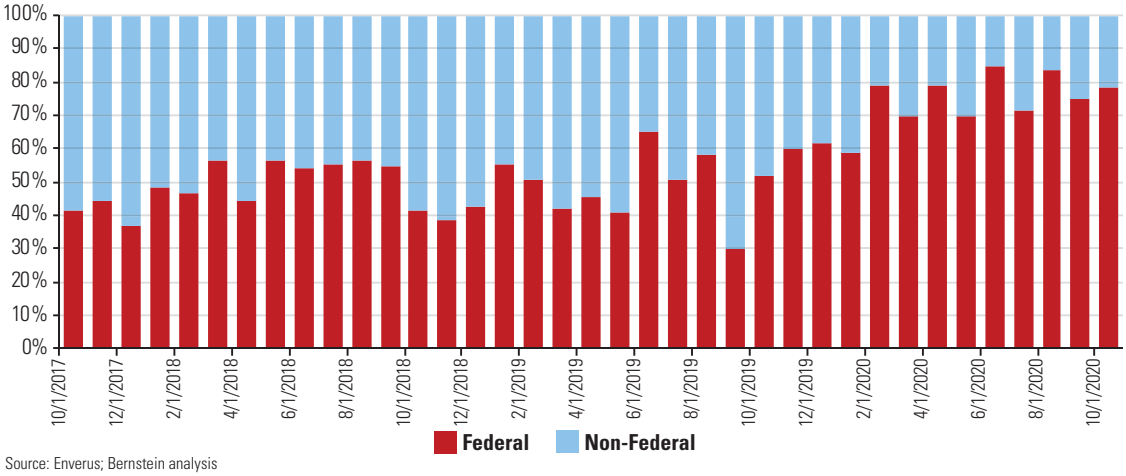
"So, even in the area with very similar rock, you do see different behavior from different operators and different results reflect that."

Noble Energy Inc. (now owned by Chevron Corp.) and Occidental Petroleum Corp. have upspaced significantly, "which seems to have a positive impact on their well productivity."

There is also staggered development. Noble, for example, is wine-racking.

"This doesn't work everywhere, but [here] it allows you to target at different depths and

Overall Growth In Drilling Permits In Eddy And Lea Counties



Source: Enverus; Bernstein analysis

Operators are securing permits for drilling on federal lands ahead of the presidential election this month.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TOM FOX

Keeping pace with changing times, private E&Ps "aren't just land business development shops anymore," said Dena Demboski, vice president, operations, with UpCurve Energy LLC.

where you can squeeze a few more wells in without degradation of the type curves and, of course, the corresponding free cash flow," Johnson said.

Normalizing laterals to 10,000 ft, 2,500 pounds of proppant and 60 bbl of fluid per foot, "Your very tightly spaced wells have your lowest EURs," she added.

The highest EUR is derived from spacing between 1,110 ft and 1,220 ft (an EUR of about 800,000 bbl). Meanwhile, too wide makes for poorer results (725,000 bbl or about the same as wells spaced between 930 ft and 1,050 ft).

"It's not always that you spread out your wells enough and you will continue to see EUR improvement," she said. "There really is an optimal way to drill these wells based entirely on what the rock looks like, how you complete them and the type of communication you see between them."

Of course, more resource can be recovered from tighter and tighter spacing, she acknowledged. But, for a 1,220-ft-spaced well and for a 660-ft-spaced well, EUR declines from 804,000 bbl to 632,000 bbl.

"You have twice as many wells here with the 660 [ft-spaced well], but you get about 60% of production."

Before 2018, "You would have drilled [the tighter-spaced] wells all day. You would have been going out with the intention of primarily growing your production volume," she said.

But the focus is now on free cash flow: "You can't drill twice as many wells for 100% more cost and only get 60% more production. It simply doesn't work."

Spacing, Noble, Reeves County

Moving north, Johnson looked at Reeves County. "Noble has had the most drastic changes to spacing design in this time period," she said.

It went from about 1,491 ft to 691 ft then up to 865 ft. The 691-ft wells led to a higher IP, but "EUR is significantly better with the 865-ft program," Johnson said.

The poorest EUR was from the 1,491-ft wells. But those are older—"They weren't completed the same way"—and the data isn't normalized.

When normalizing the 1,491-ft wells and others to 10,000-ft laterals, 2,500 pounds of proppant and 50 bbl/ft of fluid, EUR is 1.9 MMbbl (three times more than the smaller drilled and completed) from the 1,491-ft versus 1.5 MMbbl from the 865-ft well and 980,000 bbl from the 691-ft well.

In the 865-ft development scenario, the IRR is 65% at $55 oil, $2.30 natgas and $20 NGL. Six of these can fit in one section (versus four 1,491s and eight 691s).

TOM FOX

For Noble in Reeves County, "Choosing to space wells at six per section instead of eight potentially added about $250 million of free cash flow," Johnson said. It's an example of "rolling up all the different pieces."

It isn't enough to "maximize production volumes anymore. It's all about free cash flow. And in this specific area, it's the 865-foot spacing program that really generates the best return for Noble."

Spacing, WPX, northern Delaware

WPX Energy Inc., which is merging with Devon Energy Corp., bought Felix Energy II LLC in March, taking up its 58,500 net acres that were primarily in Loving, Winkler and Ward counties, Texas.

As private-equity-backed Felix's strategy was to sell, "You're testing new zones and really stretching things out," Clay Gaspar, WPX president and COO, told conference attendees. The testing "was even beyond what we did in Stateline."

It included some "interestingly" spaced and staggered wells in megapads that "we did not like." But Felix had already backed off of this by the time WPX was talking to them, Gaspar added.

"They had moved away from that and were drilling wells much farther spaced."

The megapads are appearing in public data now and, as the new owner, they're showing up as WPX-operated wells. "And it's just not very impressive," Gaspar said.

"What I would ask everyone to look at is the better-spaced wells. [They] are phenomenal."

WPX was completing the Cathedral wells on University Lands on the former Felix property in early September. "And we can tell the ones that we steer versus the ones that Felix steered," he said.

"We know we're going to get better well results and better cost structure as well—a compounding effect that juices the returns that we had underpinning the acquisition model."

In spacing, there are two considerations: How close the wells are and "how big of a bite do you take?"

In one unit, say there are ultimately dozens of wells. There is the temptation, of course, to place as many as possible—say, 12 at a time rather than six—paring the cost of having to go back to the unit twice as many times to fully develop the unit.

But it will take twice as long to get all 12 wells online than six, Gaspar noted. "So, we have to think about, as we scale, what's the appropriate bite size? Those two components are both very important.

"I think we understand spacing a lot better than we ever have. I think in the Williston—very,

WPX Energy president and COO Clay Gaspar said that taking risks in the field is still a crucial aspect of the E&P business. "The new exploration today is all about understanding that technology and innovation. That could be on the computer front or it could be on the drillbit-front—and anywhere in between."

very, very mature basin—we've conquered that. We've understood that for years.

"In the Delaware, to be honest, we're still figuring it out." And the approach changes at $40 oil from $65 oil, he added.

WPX has upspaced its Delaware wells, including on the Felix property, and "that's proving to be very substantially better-quality wells."

Wells landed and completed at one time are somewhere between six and 10. "As we continue to scale up as an organization over the years, we can afford to take bigger bites."

(Editor's note: Gaspar's remarks were made prior to the WPX-Devon merger announcement.)

Spacing, UpCurve, Reeves County

Using the Enverus spacing tool that Johnson used in the Delaware case studies, Dena Demboski, vice president, operations, UpCurve Energy LLC, said spacing can come to what is the E&P's business model.

"Selecting optimal well locations would be much easier if we all knew our exit date. It becomes much harder when you start looking at full-field development."

UpCurve has about 10,000 contiguous acres producing 7,000 bbl/d (about 11,000 boe/d) from 17 horizontals in central Reeves County, Texas, including 150 proved undeveloped wells (PUDs) in the Wolfcamp A-Upper, Wolf B and Wolf C.

The E&P was founded in 2015 by ConocoPhillips colleagues, including Demboski, backed with $120 million from Post Oak Energy Capital LP. The Reeves position began with 2,000 acres purchased from Elevation Resources LLC.

Like what Enverus' Johnson found in the Noble case study, the average spacing in Reeves County is six wells per bench per section or 880-ft spacing.

Demboski said, "We're seeing a 13% degradation in the EUR for child wells across Reeves County." The first 10% comes from spacing among parent wells; the additional 3%, from the child well.

UpCurve's own results are in line with the data, she added. "We're also looking at doing some preloads prior to coming in and fracking our infilled wells to help protect the parent," she said.

And diverters may help. "So, rather than reduce sand volumes, we're looking at maybe tweaking the diverter design—whether it's the multiple diverters mixed together and then deploying them a few different times during the actual stage.

"So, I'm hoping to see some good success with that as we have DUCs coming up."

Managing choke, UpCurve

Most of UpCurve's wells are 2 miles. It had two DUCs in early September that it planned to complete by year-end, and it plans to resume drilling with one rig in the first quarter of 2021.

It's flaring less than 1% of its gas, while the basin average is about 3%. It expects to be free-cash-flow positive in 2021.

Adjacent neighbors include Colgate Energy LLC (25,000 boe/d; 30,000 net acres); Camino Natural Resources LLC (15,000 boe/d; 35,000 net acres); Tall City Exploration III LLC (8,000 boe/d; 23,000 net acres); and Primexx Energy Partners Ltd. (30,000 boe/d; 40,000 net acres).

Demboski cited a Simmons Energy report that ranked private Delaware operators. "Across the Delaware, you can see a trend where the six-month oil cume per 1,000 feet has declined for the last couple of years, which is likely a factor of infill drilling."

UpCurve is pumping some 3,200 pounds/ft of sand with 87 bbl/ft of fluids, making it "one of the more aggressive" privately held operators in the Delaware in completion design, she said.

The basin average is 2,300 pounds/ft and 49 bbl/ft among the privately held Delaware operators that Mark Lear, Simmons senior research analyst, examined.

UpCurve's six-month production outperformed the 2019 Delaware average by 15% with 17,400 bbl per 1,000 lateral ft versus an average of 15,100 ft. The UpCurve production is 80% liquids.

"We have proven with these results that our area, which was originally thought to be non-core, competes with anything else in the basin," Demboski said.

An advantage is the presence and thickness of a carbonate barrier between Upper and Lower Wolfcamp A in the UpCurve leasehold, she said. "This carbonate feature is not present across the entire basin as a whole. And it fluctuates in thickness."

It has also managed wells for cume versus IP. "Our strategy hasn't been to chase IP right off the bat," she said.

"We strive to reach a strong IP of around 1,200 bbl/d early on and manage our choke to plateau production closer to the peak production with minimal decline for about three months."

Matador Resources is among E&Ps securing federal permits in advance of the 2020 presidential election results.

Matador Resources Drilling Permits On Federal Lands

Delaware Asset Area	County	Undrilled Permits Approved And Received	Undrilled Permits In Progress
Antelope Ridge (Rodney Robinson)(1)	Lea	21	2
Antelope Ridge (All Other)	Lea	31	10
Arrowhead	Eddy	48	37
Ranger	Lea	23	6
Rustler Breaks	Eddy	28	11
Stateline (Boros)	Eddy	31	—
Stateline (Voni)	Eddy	36	2
Total		218	68

(1) Does not include permits approved for six Rodney Robinson, 13 Boros and six Voni wells that have already been drilled.

Source: Matador Resources Co.

TOM FOX

Ameredev II LLC's southern leasehold has a distinct gas-oil ratio, said Parker Reese, president and CEO, but GOR drops quickly when moving north into the black-oil phase. "We have a very strong low-GOR black-oil reservoir all the way to the north of our position."

M&A 1: 'Make what you have work'

Permian E&Ps' valuation by prospective buyers and investors is explained only half by individual wells' returns, Bernstein's Bracket wrote in early October.

"The market focuses on P/CF [price-to-cash-flow ratio] more than EV/EBITDA. We believe this is a function of trust in cash flow more than EBITDA and a belief in the ability to look past net debt."

The market's valuation of Permian pure-play operators is more obvious, he added. It's divided into "a cheap 'overly levered' camp and a rightfully more expensive better-balance-sheet camp."

On March 5, before WTI crashed, Brackett wrote, "Permian consolidation would be a tough way to play E&Ps." Since then, Chevron Corp. has acquired Noble, WPX is merging with Devon, Concho Resources Inc. is being acquired by ConocoPhillips and Parsley Energy Inc. is merging into Pioneer Natural Resources Co.—all of the sellers Delaware-focused.

"But near-zero premiums seem to be the starting point of the negotiation," Brackett wrote. "Or perhaps it starts with 'We'll offer you a 30% premium to where your stock will be when we get around to calling back.'"

UpCurve's Demboski said the E&P business model "that got us through the past seven years won't get us through the next seven. Focus has transitioned from 'growth at all costs' to 'make what you have work.'"

The traditional private-equity-backed model of "build and flip" to another—usually publicly held—E&P "is no longer a viable strategy," she said.

Instead, private E&Ps are transitioning to full-field development of PUDs rather than only building an inventory of them. The goal: free cash flow, a self-funding model, lowering LOE and completing the infrastructure.

"Skillsets at the privates are evolving," she said. "They aren't just land business development shops anymore. There's more emphasis that's been made to develop the in-house technical operating and land expertise within."

In addition, "There are several opportunities here to consolidate quality positions in the basin," Demboski said. UpCurve, in particular, "is in the top quartile of production for the Delaware Basin.

"We have proven highly economic inventory and multiple benches. We are free-cash-flow-positive in 2021 and looking for growth opportunities across the Permian Basin."

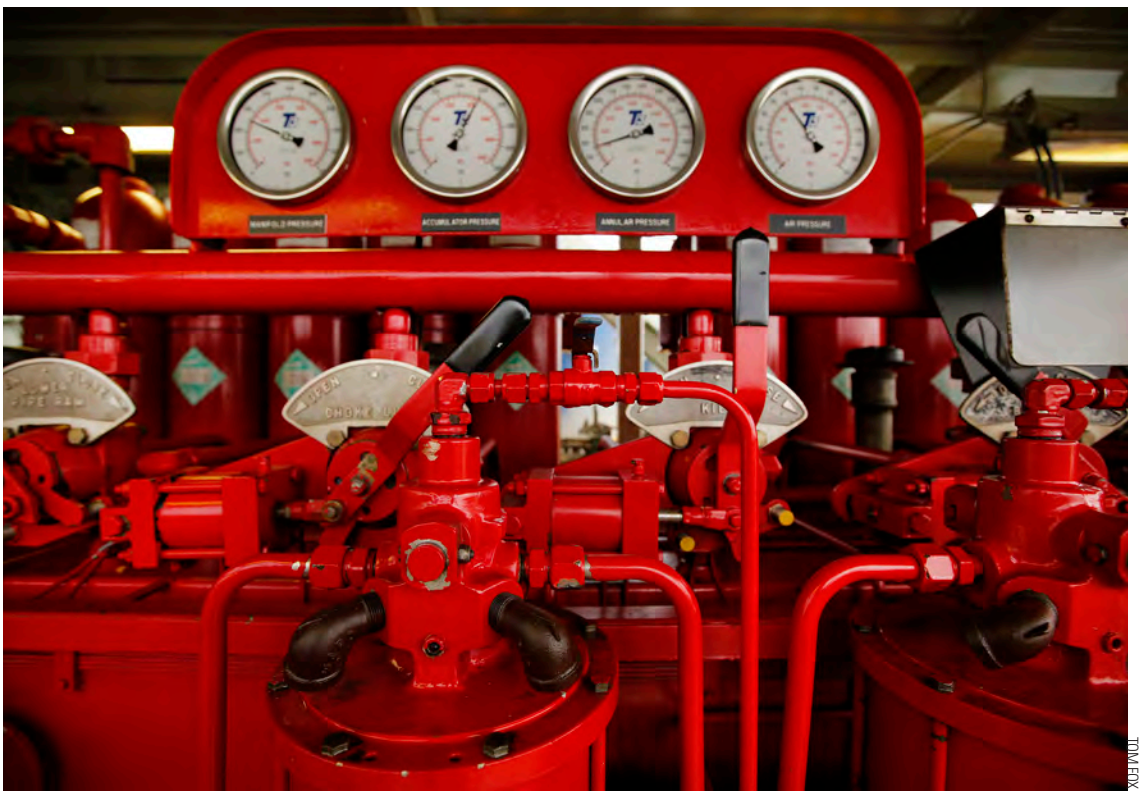
M&A 2: 'Permanent disadvantage'

Parsley's roughly 250,000 net acres are in the southern Delaware (111,000 acres) and across the Midland (137,000 acres). In January, it picked up Jagged Peak Energy Inc., which was flaring "a materially higher percentage of their gas" versus Parsley's sub-3%, David Dell'Osso, Parsley executive vice president and COO, said in the conference.

"A big part of that acquisition was leveraging our combined scale in solving this problem." Bringing in Jagged, Parsley's flaring jumped to 20%. It's gotten it down to sub-2% now.

"And we're not done," Dell'Osso added. "We aim to eliminate routine flaring across our asset base as we go forward."

He expects some smaller Permian operators may be, "probably frankly, at something of a permanent disadvantage" in achieving scale.



TOM FOX

"So, I feel like there's going to be a subset of companies that are simply going to be forced to consolidate in some manner [and] not going to be the consolidator."

(Editor's note: Dell'Osso's remarks were made prior to the Pioneer-Parsley merger announcement.)

Parsley is in the upper half in size among Delaware E&Ps on myriad metrics.

"I think we demonstrated with our Jagged Peak acquisition that we can very effectively be the consolidator," Dell'Osso said.

"However, that was a very special transaction that was directly adjacent to our acreage footprint and that we knew well … There are only so many of those types of opportunities out there."

Parsley has plenty of inventory, meanwhile, he added. But "I think consolidation has to occur.

"I just don't know who is going to be the acquirer in some of these. But there's no doubt in my mind the small folks are permanently disadvantaged."

M&A 3: 'No loss of our hunger'

WPX's acquisition of Felix was after a roughly three-year hiatus from buying. WPX was looking all along, though, Gaspar said. "There was no loss of our hunger during that period."

(Felix I, which focused on Oklahoma's STACK and surrounding play, was bought by Devon in 2016. Felix II, now owned by WPX, will become part of Devon as well via the Devon-WPX merger.)

Arun Jayaram, E&P analyst for J.P. Morgan Securities LLC, wrote when the deal was announced that Felix's wells tended to have lower IPs "but lower declines and higher oil cumes than WPX's wells due to [a] 'slowback' choke-management strategy."

Gaspar said in the conference the deal "plugged a hole between some incredible [WPX] Williston, high-oil-cut opportunities to some really incredible, economic [Delaware] Stateline opportunities that are about 50% oil cut," Gaspar said.

Felix brought to WPX a 70% oil cut. "It filled that niche between 85% [Williston] and 50% [WPX Delaware]." And it gave WPX more running room, he said, adding another 1,500 gross 2-mile drillable locations.

"We know we are in the business of consumption. We consume our very best wells every day of the year. If we're not replenishing, then we will run out at some point."

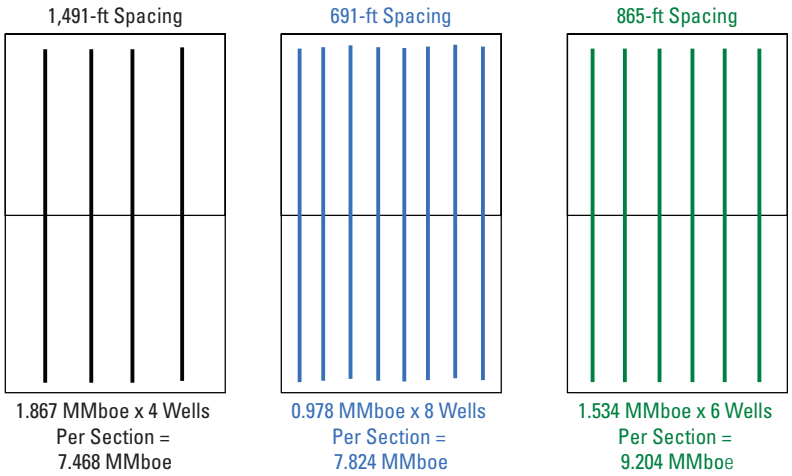
It wasn't a near-term concern, he added, "but having a little bit more scale to your opportunity set causes you to always high-grade and you end up with a better result."

Ameredev, northeastern Delaware

Ameredev II LLC's property sits among major E&Ps in the northeastern Delaware. Its acres are in a solid block approaching the Central Basin Platform, resulting in distinct, tight carbonate layers that limit vertical frac growth.

It "gives us some flexibility around which zones we co-develop or not in our initial development," Parker Reese, Ameredev president and CEO, said in the conference.

Well Spacing Development Scenario Outcomes



Source: Enverus

Spacing schemes are suggesting more net profit from fewer wells versus more gross oil from more wells.

There is also an abundance of proximal sediment, contributing to matrix porosity and high permeability. "It works really well where we are due to the kind of binary nature of lithology between hard carbonates and nice organic shale with high porosity."

Ameredev's first wells are showing strong performances from Wolfcamp X, Y, A and B. "We see EUR spaced off of that performance between 1.5- to nearly 2.5 million barrels equivalent for 2-mile laterals."

Ameredev's south-central Lea County property is the largest privately held contiguous position in the northern Delaware, he added. Formed in May of 2017, its 27,352 net acres (31,931 gross) were put together from 42 acquisitions, four trades and three divestments in its first 15 months.

Inventory is 400 locations. "It's all set up for long-lateral drilling," Reese said.

Production is about 6,500 boe/d, 70% oil. "It's a WTI-spec barrel. On the eastern side of the Delaware, we are producing not condensate but real, black oil."

Ameredev's leasehold is updip. That drives low water saturation—less than 1.5 bbl per bbl of oil. In some wells, it produces almost no water.

"That means that we have more oil in place for a given volume," Reese said. "We have more drive energy because that hydrocarbon is much more compressible than the water would be. And it means we have less water to dispose of."

The southern end of Ameredev's leasehold has a distinct gas-oil ratio (GOR), he added, "that we've subsequently spent a lot of time understanding and delineating."

GOR drops quickly when moving north into the black-oil phase. "We have a very strong low-GOR black-oil reservoir all the way to the north of our position."

Ameredev's Holly unit was being drilled in March. Those five wells were DUCs in early September. Starting back up this fall, Ameredev planned to drill a sixth Holly. The DUCs and the sixth well should be online in the first quarter, Reese said.

In the Permian, "Consolidation has to occur," said Parsley Energy Inc. EVP and COO David Dell'Osso. Uncertainty remains about who will be the acquirers, "but there's no doubt in my mind the small folks are permanently disadvantaged," he added.

Free cash flow is growing toward $100 million a year, he added.

Bone Spring

UpCurve's Demboski said that, in addition to the prevailing Wolfcamp drilling in the southern Delaware, there has also been some Bone Spring development "that could potentially open up a new bench for us in the future."

It's something the team is keeping an eye on.

Up in the northeastern Delaware, Ameredev has taken core and logs in the Bone Spring, Reese said. On the eastern side of the Delaware, "The data we're seeing is showing this to be a superior geologic setting."

WPX is doing spacing in the Third Bone Spring before moving to development mode, Gaspar said, but it "competes with the greater Wolfcamp A that is our bread and butter."

In the Wolf A, "We've got a recipe, we love it and we're plowing through that. The Third Bone, I would say we're pretty close."

Second Bone Spring is also promising. Crossing the state line into New Mexico, Gaspar said, "It becomes the primary source. You go south of the state line, it just becomes quiet."

WPX isn't investing much in Second Bone right now, though, while it is "working through these very trying times in this very precious capital environment to invest in [Wolfcamp and Third Bone] and still put the oil in the tank every single day, every month, every quarter, so we don't fall out of favor with the investment community, which is always a challenge."

Meanwhile, Matador completed its first Third Bone Spring carbonate test, it reported this summer. In Loving County, its Larson 136H came on with 1,668 boe/d, 68% oil, or 224 boe/d per 1,000 ft of the 7,443-ft lateral.

"Matador believes this test result … indicates the prospectivity of the Third Bone Spring Carbonate, not only in [this] asset area, but also in other of the company's asset areas throughout the Delaware Basin," the company reported.

It planned more tests.

The 3-mile lateral

WPX jumped to 2-mile laterals in the Delaware not so much as a technological leap, although "you take a pretty good leap of faith in doing so," Gaspar said.

As 1-mile-plus laterals were clearly working in the basin, WPX jumped to 10,000 ft as soon as it had the contiguous land.

"We've since drilled 15,000-ft laterals—as a necessity; it's not routine," he said. "But we are understanding the effectiveness of those completions, of that flowback. Are you really getting that 3-mile incremental value?

"What do the economics and the value really say about that? There's a lot in the industry going on there."

Meanwhile, there's spacing—tighter, both vertically and horizontally. "And we knew you're probably going to step over the line," he said.

"At some point, you go too far, and you have to kind of dial it back, and we've experienced that."

But timidity isn't a hallmark of the E&P industry; one doesn't know what will be found if one doesn't go there. "If you always leave your putt short, you're never going to make the putt," Gaspar said.

"So, we want to make sure and understand where that line is."

Of course, he added, an operator wants to "be thoughtful about the scientific approach of taking that step and then being able to figure out 'Okay, in today's commodity environment, where is that line and how do we get to that optimal point of view?'

"That willingness to take that risk, that's what our businesses is built on. The new exploration today is all about understanding that technology and innovation. That could be on the computer front or it could be on the drill-bit-front—and anywhere in between.

"We have to innovate to maintain our position and even garner a few incremental spots along the way."

Getting your data right

There's the fundamental stuff to technology too. During the past couple of years, WPX went about the "incredibly unsexy work" of something as simple as getting its data right, Gaspar said.

It's making sure the well's name is consistently the same in the mother database, for example. Is it the Smith 1 or the Smith #1? Is the working interest 66.7% or 66.67%?

Inconsistencies "can make the simple work and the really tough work equally more difficult than it should be," he said.

Productivity and achieving the best results are lost if "our most brilliant employees spend about 80% of their time gathering and curating and upping the quality of the data, massaging it to the point that they can do their 20% of real value-accretive work."

The internal goal is, "If we can simply double that 20% to 40%—and 60/40 is nothing to brag about—you double the productivity of your best and brightest around the organization."

After getting the mother database into shape, the team that did it would, rightly, "try and brag about it. 'Hey, we did 75,000 records and we cleaned all this up.'"

They received "a collective yawn because 'Ah, data.'"

But Gaspar gets it. "It's the foundation that everything else is built on." About 1.5 years later, "some of the tools and apps and really cool things that took us weeks and weeks to do before [now take] a press of a button."

Maybe that's a bit of over-simplification, he said, but, by reducing the time to get the data, "We're able to do more and more iterations to get to the better answer.

"And ultimately that creates very significant value." □

TOM FOX

CLOSED TRANSACTIONS 2020

AE&J Royalties
Mineral & Royalty Assets
Lea County, NM
January 2020
DETRING ENERGY ADVISORS

AOG ANTHEM OIL&GAS INC
Mineral & Royalty Assets
Delaware Basin
January 2020
DETRING ENERGY ADVISORS

SR SIERRA RESOURCES
Op. Working Interest
Various Counties, TX
January 2020
DETRING ENERGY ADVISORS

Rio Oil and Gas II, LLC
Non-Op Working Interest
Ward County, TX
February 2020
DETRING ENERGY ADVISORS

Apache
Op. Working Interest
Northwest Shelf
February 2020
DETRING ENERGY ADVISORS

MAVERICK NATURAL RESOURCES
Op. Working Interest
Central Basin Platform
February 2020
PETRO DIVEST ADVISORS

eog resources
Op. Working Interest
Lea County, NM
April 2020
DETRING ENERGY ADVISORS

T Titan Energy
Op. Working Interest
Appalachia
June 2020
DETRING ENERGY ADVISORS

M MERIT ENERGY COMPANY
Op. Working Interest
Powder River Basin
July 2020
DETRING ENERGY ADVISORS

GRIZZLY ENERGY LLC
Op. Working Interest
Claiborne Parish, LA
July 2020
PETRO DIVEST ADVISORS

STRANDED OIL RESOURCES CORPORATION
Op. Working Interest
Caddo Parish, LA
July 2020
PETRO DIVEST ADVISORS

Private Seller
Mineral & Royalty Assets
Lea County, NM
August 2020
DETRING ENERGY ADVISORS

Private Seller
Mineral & Royalty Assets
Appalachia
September 2020
PETRO DIVEST ADVISORS

Atinum ENERGY INVESTMENTS
Non-Op Working Interest
Appalachia
Negotiating PSA
DETRING ENERGY ADVISORS

Atinum ENERGY INVESTMENTS
Non-Op Working Interest
Various Counties, TX
Negotiating PSA
PETRO DIVEST ADVISORS

STRANDED OIL RESOURCES CORPORATION
Op. Working Interest
Natrona County, WY
Negotiating PSA
PETRO DIVEST ADVISORS

GRIZZLY ENERGY LLC
Mineral & Royalty Assets
Karnes County, TX
Under PSA
PETRO DIVEST ADVISORS

FCP Four Corners Petroleum, llc
WI & Royalty Interest
Ward & Winkler Co., TX
Bids Due 12/9/2020
DETRING ENERGY ADVISORS

International Seller
Op. Working Interest
Offshore GoM
Coming Soon
DETRING ENERGY ADVISORS

Winfield Resources
WI & Royalty Interest
Appalachia
Coming Soon
DETRING ENERGY ADVISORS

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petrodivest.com

A PINPRICK OF LIGHT AT TUNNEL'S END

2020 has been a dark year for A&D, but a variety of factors point toward bright spots in the foreseeable future. Leaders from Detring Energy Advisors, EnergyNet and UBS Investment Bank share their thoughts on why.

ARTICLE BY
EMILY PATSY

Entering the final quarter of a lean year, veteran dealmakers in the oil and gas industry are likely ready to see 2020 dead and buried. Though hyperbole is rampant in the industry, the shale generation has never seen a downturn so deep, a market so confused or the descriptor "unprecedented" so overused but correct.

For buyers, downturns have typically been windows of opportunity, ephemeral periods ripe for potential acquisitions for lower than normal prices. Not this time. Investors' pressure on returns have tamped down deal activity even before the pandemic. Coupled with a tight capital market, the start of the '20s has been abysmal for A&D activity and values.

Despite this, gas deals have shown relative strength this year, which Enverus attributed to more optimism around that particular commodity versus oil. Additionally, a rash of upstream mergers helped bolster total transaction value from June to September, though money and assets changed hands at historic lows.

In third-quarter 2020, Enverus counted 28 upstream deals in the U.S., tying it with the first quarter as the worst showing in a decade. Meanwhile, the second-quarter deal total was only the third lowest transaction haul in a quarter since 2009.

Ever optimistic, Derek Detring, president of Detring Energy Advisors, Chris Atherton, CEO and president of EnergyNet, and Dan Kohl, head of A&D advisory at UBS Investment Bank, recently joined Investor via Zoom for an in-depth discussion on the current state of the oil and gas transaction marketplace, as well as what they see for the year ahead.

Investor Starting off looking at this year so far—what type of A&D opportunities, if any, are you seeing develop in the current state of the market?

Atherton It's been a very challenging year for the oil and gas industry, as well as the mergers, acquisitions and divestment sector of the industry. The A&D opportunities that EnergyNet, our firm, is seeing that seem to have the most buyer appetite and buyer interest are PDP [proved developed producing] heavy deals. These may be legacy conventional assets previously owned by majors or super independents. We're also seeing inter-

"There seems to be a large segment of the buyer universe that is looking to acquire deals that generate steady cash flow that don't have huge drilling obligations and commitments in this price environment. They want to look back in five years, 10 years, and say I was acquiring assets in 2020."

—Chris Atherton, EnergyNet

"Once investors start holding [tech companies] accountable like our public companies are forced to live within cash flow, I could see some money flow back into the sector as well, and we could see public company acquisition activity again."

—Derek Detring,
Detring Energy Advisors

est in gas deals and oil deals that are more mature in their life of the unconventional plays and fields.

There seems to be a large segment of the buyer universe that is looking to acquire deals that generate steady cash flow that don't have huge drilling obligations and commitments in this price environment. And they really want to put money to work because they see this as an opportunity with the low prices. They want to look back in five years, 10 years, and say I was acquiring assets in 2020. It would be like I was acquiring assets in 1986 from their perspective. So, there's a lot of opportunistic pressure, I believe, to get deals done.

But in the big scheme of things, there's not a lot of deals on the market right now or the sellers seem to be, in EnergyNet's view, sometimes reluctant to go to market because they're not sure if they want to see the results of the valuations of the sales and they were forced to make a decision to sell the asset for that price. There's tremendous competition for some of these proved developed producing heavy assets and royalty and mineral type deals. But I think sellers are somewhat reluctant to go to market at this time unless they have to because there may be a situation where they are simply selling a deal to take the money and pay back their lender or they may be in more distress where it doesn't necessarily make sense to run a divestment process at this time.

Detring Particularly what Chris is saying on the more conventional side of things and mineral/royalties, we're seeing that still drive the market. That really started to drive market activity at, say, late 2018 and really all of last year, as well.

As Wall Street and a lot of capital providers pulled back from the sector, that made public companies more hesitant to acquire, and they were typically the group that paid the most, with the lowest cost of capital, which made great exit opportunities for private and private-equity players. As that capital retreated in the latter part of 2018, 2019 was really driven by assets that public companies traditionally had shifted away from like conventional assets, and we saw minerals and royalties activity start to come up quite a bit.

We've seen a continuation of that trend this year with a quarter or two gap there where sellers were really trying to figure out which way was up after COVID-19 and OPEC+ hit the supply and demand. When we take this conventional assets or minerals/royalties to market, we are seeing probably about 25% or maybe even a third more participants in the VDR [virtual data room] this year than we would have expected last year. Now, that's primarily due to a lack of asset supply on the market.

So, we are seeing good buyer participation. The buyers haven't really retreated too much. To us it's more the sellers not wanting to sell in today's market. And with oil staying down in the $40s and gas having a bit of a run here lately, we are seeing more life in the natural gas side as well.

And I definitely agree with Chris, we're also seeing at Detring that it is tough to get paid beyond PDP value outside of mineral and royalty assets in this environment. Even nonop working interest deals, for example, are almost more of a capital avoidance type play now and not necessarily trying to maximize value per acreage.

Callon just announced their nonop sale and at less than five times cash flow, which implies it's almost a PDP level valuation for great Permian and Eagle Ford acreage. Again, Wall Street wants these public companies to stay within their cash flow. These nonop assets that Callon or any public company have can be $20 million in nonop AFEs in 2021 or it could be $120 million. You just don't really know. So, I think that's steered some of those groups away from nonop as well.

Investor The Permian Basin has largely been a driver of activity. However, in the Permian, we've seen per-acre valuation for acreage fall sharply in the past 12 months. What's changed in terms of well density and inventory to lower the price of Permian deals? Also, now that the "Permania," as it was once called, is over, should investors conclude that companies overpaid?

Detring In the Permian, in particular, I wouldn't necessarily say that companies overpaid. They were just paying for assets in an environment where they were able to live outside of cash flow and fund that development outside of cash flow with debt and the equity capital markets. It was just a higher price environment. That supported the $30,000, $40,000 and more per acre that we were seeing being paid beyond PDP in 2018 and earlier.

So, I wouldn't say anybody overpaid. They were making prudent decisions for the capital markets environment and the pricing environment at that time.

But right now, it is tough even if you've got a core package to find a buyer who's going to pay beyond PDP for working interest deals in the Permian and elsewhere. Royalty or mineral deals are still continuing to transact and receive value beyond PDP from the buyer universe. And I'd also add that the larger the package, I'd say that's really where it's tough to find a big buyer universe in that

winning group who will pay to meet the bid-ask spread.

We play the middle market at Detring. We are seeing more groups come out, and they're still being competitive and aggressive. But the large universe—again, that typically was acquired by public companies—those groups are still treading water right now, and it's tough to find a buyer who will pay for acreage in a large package.

Kohl The challenge buyers are experiencing across all basins, but specifically the Permian Basin, is the ability to finance deals significantly beyond PDP valuations. We have all seen the equity markets for oil and gas face headwinds and lending banks are focusing on only financing the producing barrels. The combination of the two, coupled with market perception, makes it difficult for buyers' valuation to significantly exceed PDP.

Atherton During 2016 through 2018, publicly traded companies were encouraged by investors to become a pure-play Midland Basin player, pure-play Delaware Basin or other areas. And there was a scarcity principle in play that caused them to say, 'if I don't buy this acreage or pay this price, then I may miss the boat on what my investors are asking me to do.' So, there were very high multiples paid, but it was at a higher commodity price.

Assumptions made by public and private companies in terms of well density and EURs of those wells, that the parent-child relationship that each well would be the same and it would be a manufacturing process going forward, haven't necessarily panned out according to plan in certain areas. There was certainly good rock, and a lot of these companies now own that good rock, but with these prices it's difficult to make the investment case that was made at the time of the acquisition.

Investor What do you see driving the recent jump in gas deals? Also, do you see the trend continuing into next year?

Kohl Yes, I see gas-rich deals continuing to succeed into next year, with three significant factors contributing to the relative strength of gas-rich assets in the current market.

First, last year there was an overhang of low gas prices and reduced investment interest in the commodity, largely stemming from the associated gas thesis, stating that the volumes coming out of the Permian Basin were anticipated to swamp Lower 48 gas markets. Now, we have seen the Permian rig activity significantly drop, removing that overhang on gas prices. Naturally, the gas futures have risen.

Secondly, there's an element of cyclicity. Specifically, we observed last year that gas assets were largely undervalued because A&D markets were focused on oil-rich deals, and now, in 2020 we are seeing these opportunities that were held back in 2019 start to transact because buyers are willing to get more bullish on valuations.

Lastly, in our discussions with investors, we see a long-term movement toward investments that are considered transition fuels. For better or worse, ESG [environmental, social and governance] is becoming a major consideration in the oil and gas business, and gas is viewed as a cleaner, transition commodity. Additionally, it's very challenging, if not impossible, to replace natural gas in the U.S. market, both for its use in power generation, specifically as a replacement for coal, but also as the primary fuel for building heating. While I fully believe the oil industry is not going away in my lifetime, decision makers are cognizant of this long-term overhang, coupled with pressure coming from LP investors to target cleaner technologies.

"Right now, it is tough even if you've got a core package to find a buyer who's going to pay beyond PDP for working interest deals in the Permian and elsewhere. And I'd also add that the larger the package, I'd say that's really where it's tough to find a big buyer universe in that winning group who will pay to meet the bid-ask spread."

—Derek Detring,
Detring Energy Advisors

Investor Overall, commodity prices this year have remained at levels that will break many small- and mid-sized companies carrying substantial leverage. Some have speculated that distress and consolidation will transform the industry into about 10 to 15 companies. What's your view? Will the industry shrink that radically and do you think it needs to?

Atherton I definitely don't think it's going to shrink to 10 to 15 companies and if it does, it's going to take a considerable amount of time. I

"Most A&D professionals have spent significant time on the inside, managing oil and gas assets, and have a strong technical background that can help to provide unique insights to help solve some of the corporate finance challenges that we're trying to overcome in the industry presently. There has been a lot of pain for in 2020, but things are looking much better for 2021."

—Dan Kohl,
UBS Investment Bank

would say that the 2020 bankruptcies and Chapter 11s that are occurring, the pain is probably healthy for us. These companies were overlevered and, from an A&D standpoint or M&A standpoint, it really sidelined a lot of companies from participating either as a buyer or a seller because their debt load was too much for them to bear and to operate. So, as these companies restructure, equitize their debt and reemerge, I'm hopeful this time that they will reemerge with more capital discipline that will allow for a more healthy A&D market.

Consolidation is being asked for by the investor community. It's difficult to accomplish. With, for example, Chevron buying Noble, I didn't really see that coming. WPX and Devon, I didn't see that coming. Those are two different deals, but it takes out two big parts of our large-cap, publicly traded E&P space.

I expect more mergers of equals to take place, but there is a social aspect to the WPX and Devon deal, the management team being interlaced. But there are not many companies that want to relinquish their jobs and their companies for the stock of another company. So, that makes it somewhat difficult to have this merger of equals and low premium, no premium deals to take place. It may accelerate, but it does take a meeting of the minds of the two companies.

Investor On the subject of consolidation, M&A activity has been relatively quiet this year. Do you see Chevron's acquisition of Noble Energy as a precursor for further consolidation executed by the supermajors? Or should we expect more "mergers of equals" similar to the Devon/WPX deal?

Detring We'll see more of both. I agree with Chris that seeing just 10 public companies would be a scary situation that would hopefully take a long time. But some consolidation is good for the industry and healthy—where it makes sense, and for the larger groups that have the capital availability and the balance sheet capability do so. We'd like to see Chevron buying Noble where it really helps supplement and buttress their existing positions across some key basins, allowing for longer laterals and key synergies beyond just G&A management reductions.

Mergers of equals also make a lot of sense now for balance sheet reasons, but also when you look at how many rigs were running 12 months ago, now we're down to much less than half of that amount. It takes a lot of people to run those rigs from the management team's perspective with the geologists, engineers, all the technical teams that are required to do that. So, you just think about that from that perspective as well. Do we really need all this G&A out there for all those teams running a quarter—or whatever we're down to now—of the rigs that we had 12 months ago?

That's a big reason of it as well. It is unfortunate. We all have friends who have lost their jobs or some [who have] been at companies that had to restructure or file Chapter 11. It's definitely the least fun time I've ever had in the industry, but likely it will continue. It definitely is painful for a lot of our personal friends and colleagues, but there is some health to it and rationale for it, and we definitely expect more of that to happen over the next several years.

Kohl Consolidation is certainly merited in many cases, to capture synergies in addition to all the reasons Chris and Derek mentioned previously. That said, the United States has an incredibly diverse set of oil and gas assets and smashing everything together into 10 or 15 companies does not mean that you're delivering more value to your equity shareholders. You've got assets located in different basins, states, regulatory regimes, offshore, onshore, deep water, waterflood, tertiary recovery, unconventional—there will always be a place for lean, more focused organizations that can deliver value to shareholders above and beyond simple G&A synergies. The industry will always merit a diverse mix of private, small-, mid- and large-cap firms.

Investor Deal values through the third quarter are less than $30 billion in the U.S. with more corporate deals than asset deals. While it feels like a bottoming out, where does this year rank in A&D activity and value? And when are you expecting a rebound in the A&D market?

Kohl 2020 has been an extremely challenging year for A&D activity. However, I expect there's a light at the end of the tunnel, quickly approaching in 2021. Various macro-economic factors will be driving the industry in a positive direction.

First, there is line of sight to a COVID-19 vaccine such that, at some period in 2021, we expect to see a significant demand increase as economies around the world open up.

Second, rig count is at an all-time low, and as Derek mentioned, this is going to continue to drive production decline across the United States. Both those points indicate future price increases. If this drives commodity futures into a steeper contango, we expect the sellers who were holding back for a perceived market bottom will market those packages, depleting the pent-up inventory that has built throughout 2020.

And third, today we have discussed industry consolidations, and generally when you have major M&A activity, there are significant noncore assets that need to be pruned from the pro-forma entity. I do see 2021 being a good, strong recovery year for deal flow, and I'm ready to jump into it.

Investor Final thoughts on the industry's path forward? How do companies maneuver through current challenges the industry is facing to successfully end up on the other side of the downturn? And how do you see A&D's role in the recovery? Also, any emerging trends emerging for 2021?

Atherton Right now is a difficult time for the industry and a low mark for the A&D market. I do think there are some bright spots. Again, the restructurings that are going on will create a more healthy industry. The survivors from this downturn will ultimately be stronger, and that's not just going to be the E&P companies, but that's going to be service companies and auxiliary players that facilitate and help the oil and gas industry do what it does. There will be more capital discipline going forward, but it is going to take some time to get energy investors and generalist investors back to the table and to really be able to fund the industry going forward.

One of the things that we see in some the divestment processes we run is that there is a sentiment among the buyer community that there will be, as Dan mentioned, a volatile price going upward, and they want to take advantage of that. I do think with the lack of investment, drilling rigs, the lack of things going on, that it's going to snap, but there may be a lot of casualties along the way before it does snap back up.

Detring We've analyzed the past two crises at our firm, and it does seem to take between four and six quarters typically from the peak to fully recover. We're definitely a few quarters into it now. I think there's only about $4 billion of disclosed asset level deals this year through October 1. That's absolutely horrible. So, it's by no means an exaggeration to say that this is the worst market that a lot of us have been through.

I do see a light at the end of the tunnel. It is a real property market. It will come back. We have seen investors flee the sector and into tech—how long until tech has to live within cash flow? We see a tech company IPO, I think two of those a day, that loses money at $20 billion valuations. So, that may be one catalyst. Once investors start holding them accountable like our public companies are forced to live within cash flow, I could see some money flow back into the sector as well, and we could see public company acquisition activity again.

But it starts with the smaller deals, the more auction-type platforms and then it gets bigger and bigger. Eventually, the larger deals will come back in vogue as more large-cap acquirers are back in the market. And we are seeing the middle market gain momentum where our firm plays. It's definitely picking up. We've gotten several attractive mandates engaged for this quarter and next quarter. We are starting to see more activity, so we have been encouraged over the past couple weeks.

"We have all seen the equity markets for oil and gas face headwinds and lending banks are focusing on only financing the producing barrels. The combination of the two, coupled with market perception, makes it difficult for buyers' valuation to significantly exceed PDP."

—Dan Kohl,
UBS Investment Bank

Kohl Much like Derek, we do see the fourth quarter and first quarter launching mandates picking up. I think we're going to see a lot more deals on the market as far as the traditional, regular-way A&D.

But certainly, what A&D professionals can do to assist struggling companies is step outside of their typical reserve report, data room, broad auction process mechanics and seek unique solutions for clients. And that's where a lot of our focus has been over the last six months, providing help to combat reduced debt capacities, finding alternative financing solutions outside of simple divestitures.

Most A&D professionals have spent significant time on the inside, managing oil and gas assets, and have a strong technical background that can help to provide unique insights to help solve some of the corporate finance challenges that we're trying to overcome in the industry presently. There has been a lot of pain in 2020, but things are looking much better for 2021. □

NOT THEIR FIRST RODEO

These industry veterans share what they learned in previous downturns and how to best recover in the days ahead.

ARTICLE BY
LESLIE HAINES

If you could sit down over a cup of coffee with some industry veterans who have lived through more than one boom and bust cycle, what would you ask them? What did they see, and what did they do to cope? They lived through the devastating 1980s, when the natural gas bubble that torpedoed prices lasted so long that people began to call it the gas sausage.

They remember when houses and office space in Midland and Houston became empty shells, sad reminders of the boom that had swept through the oil patch in the late 1970s. People joked that you could store hay in those buildings. Drilling rigs and other assets of all types were sold for 10 cents on the dollar.

What lessons can we learn from those days? Is now the best time to wait and see and preserve capital? Or should a company tear up the playbook and revamp everything: job titles, the organization chart, the strategy, the asset base, the end game?

"This is not our first rodeo, but I sure hope it's the last one like this," said Paul Zecchi, CEO, Central Resources LLC, in Denver. "My main advice is, 'Any old port in a storm.' Sometimes that port is not the one you wanted, but you'll take it. Don't be too picky because I think we're in for a slog. Those business models that say, 'I need to be a certain size' need to be put on the back burner for now.

"And I think you have to think out of the box and move on to new thinking or a new frontier, at least for a while." To that end he has been busy trying to buy and sell a few assets in an admittedly tough market. He favors long-term assets that keep producing; he is not drilling any wells at this time.

We spoke with several other executives and financiers who lived through the historic busts of the 1980s, 1990s and early 2000s, and all the subsequent recoveries. Here, we share some of their advice on what companies did right and what they did wrong, how they kept afloat during the downcycles, and, just as important, how they rode the recovery wave on the other side.

Many of them agreed that cash is king, debt is deadly and focus is required. Several questioned the economic viability of the shales and what that implies for the recovery to come. "Production went up, but making money did not," said one source. "It was such a craze to get into this shale and be king of the hill."

"You can't rely on raising capital [whenever you need to] as your business model."

—T. Frank Murphy
managing director
Janney Montgomery Scott

Many think opportunities are opening up now, especially for investment in distressed asset classes. Others noted that international investors seem to be getting interested again: after all, they're looking at zero interest rates in their home countries. "At some point, they'll realize there is a real value play unfolding here," said Tim Murray, a former energy financier for Wells Fargo, Guggenheim and other groups.

His family company, Active Iron Energy, is looking to raise a fund to buy conventional assets that were overlooked during the shale boom, a thesis several other investors are pursuing.

Meanwhile, coping and recovering is the main event in the arena. For an E&P team working to survive another round, or an investor who has just been bucked into the dirt, "It's difficult to double down when the dealer just raked half your chips off the table," said Murray, also a managing partner of Bayou City Capital Advisors, his new firm that is advising some E&Ps at the moment. He noted that in some good companies that have not been in this much distress before, management doesn't seem to know the language it should be using to work through the situation.

"There is no magic pill in this industry that can change the entire complexion of your business," he said. "It's just the basics: Reduce costs and overhead, negotiate better supply agreements with your vendors, be prudent. Only do things that produce cash—and make sure everything you do is underpinned by today's price, not betting on tomorrow's price."

Here's a summary of what some other veterans shared with *Investor* as they recalled old challenges and pondered new opportunities.

"There is no magic pill ... it's just the basics."

—Tim Murray
founder
Active Iron Energy

Capital access is not a given

Armed with a degree in economics, T. Frank Murphy entered the industry in 1978, working for several E&P companies and investment bankers. Today he is a managing director and co-head of oil and gas investment banking for Janney Montgomery Scott LLC, and he is a board member on the Energy Infrastructure Council (formerly the MLPA).

At one time Murphy became assistant to the CEO and vice president of finance for American Exploration Co., one of the largest sponsors of public and institutional income partnerships during the 1980s, which were meant to acquire and exploit producing assets. That business model went by the boards as tax laws changed, so Murphy is no stranger to industry difficulties.

"When prices collapsed in the '80s, you had been dependent on those public partnerships and the tax write-offs—well, too much money flowed to the industry, and a lot of bad wells were drilled. That's also what happened during the shale boom," Murphy said.

"You can't rely on raising capital as part of your business model. When the music stopped in the '80s and investors went away, the companies that depended on raising capital were no longer viable. It's the same thing today. There are too many companies, both upstream and midstream, that were hurt when capital markets dropped in 2014—they kept outspending their cash flow on the theory that they could always raise money in the debt and equity markets.

"You can't ignore the laws of economics in the pursuit of growth for yourself."

Many companies entered this period they're in now with too much leverage, and they can't

"You've got to change your thinking and be willing to take a chance."

—Jim Trimble
retired E&P executive

keep their heads above water. "You've got to manage your balance sheet in ways that allow you to withstand conditions when the equity markets are closed," Murphy advised. "The problems besetting companies today are largely because they can't access capital anymore. It's a real parallel to what we saw happening in the '80s."

Egos block mergers

Many companies that should merge will not be deemed attractive merger candidates until they clean up their balance sheet. First, a wave of bankruptcies and deals with bondholders will probably be a multiyear process, observers said. The pending merger between Southwestern Energy Co. and Montage Resources Corp. could be the tip of the iceberg.

But putting two underperformers together doesn't necessarily solve anything, noted Bill Finnegan, partner with Latham & Watkins LLP. "You really have to work with your financial adviser and get your cost structure in place. Once you become the most efficient operator, you have to be careful about the deals you do; they have to make sense. Just getting bigger probably won't accomplish what you wanted to do—what is your real strategic goal?"

One of the biggest hurdles to a merger that does makes sense is management's unwillingness to accept the new reality. Big egos run big companies—and hate to let go.

Letting go is tough also because valuations have tumbled. "If you thought your assets were worth $100 million, well, now they might be worth only $60 million, so it might not be helpful to sell now, if your debt is too high," said Murphy. "Sometimes people will sell their best assets to survive, but that leaves them with poor assets."

"There are a lot of managers who don't want to let go. These social or cultural aspects are really tough to work through."

Still, as one source noted, this industry is full of tough people who can handle the pressure even as they suffer emotionally from being forced to lay off staff and they lament selling prized assets.

"I'm a real proponent that this industry is going to survive and continue to be a major component of the U.S. economy," said Jim Trimble. The veteran E&P executive has mostly retired after heading up several companies where he was called in by the board to serve as interim CEO during restructuring and before a sale. These included Stone Energy Co. and PDC Energy Inc. At one company, he had to whittle 22 vice presidents down to five or six, but he hated it—it was dealing with real people's lives.

"But you've got to change your thinking and be willing to take a chance."

Back to basics

Thinking creatively can allow for these changes, but a few basics remain beyond question. Many sources lament that the E&P industry wandered away from the basics as the shale boom unfolded, and they advised that both companies and investors need to look anew at traditional rules. "We need to get back to this: 'If I give you a dollar, what will you give me back?' In the last 10 or 12 years, too many people focused on the number of acres they have, dollars per acre, wells per acre, the number of undrilled locations. That isn't the way we used to evaluate a company," said Murray.

"It used to be, 'What is your cash flow, what is your return on capital, what is the investor return?' All that went out the window during the shale boom with these spreadsheet jockeys on Wall Street. Don't talk to me about what price you paid per acre."

Murray said he thinks we'll see new opportunities for cooperation where operators, mineral investors and the service companies work together to get things drilled and share in the proceeds. The industry has always been imaginative as far as deals and how things get done.

"You never want to look away from something that is messy. You have an opportunity to unravel the knot."

—Matt Silverman
head of exploration
Robert L. Bayless Producer LLC

However, regardless of business strategy or new partnerships, a competitive asset is needed to survive any downturn. That means low cost of development and operation, said one source who has worked for six E&Ps over a long career. "The old saying is true: The low-cost operator survives, aka survival of the fittest,"

he said. "It does not necessarily take scale to have low costs. Employ only the most essential people and outsource what you can. Low G&A per barrel keeps your company from being trash-compacted into another more efficient company."

Unravel the knots

Matt Silverman, a former president of the Rocky Mountain Association of Geologists and current president of the Petroleum History Institute, has seen a lot in a career of more than 40 years. Silverman said he was stunned when, earlier this summer, not a single rig was working in Wyoming.

The widely published geologist, based in Boulder, Colo., has worked for Total, Texas Gas Exploration and consulting firm Gustavson Associates. For the past 20 years he has been a special project manager, and recently the full-time head of exploration, for Robert L. Bayless Producer LLC, a family firm since 1958.

He advises not to throw in the towel completely during a downturn, as that might affect how a company succeeds once it comes out the other side.

"What happens when companies get in trouble is their projects go cheap or get stopped, or companies get sold, but people who are farsighted can take advantage of these opportunities. It's a valuable lesson for companies of all sizes," he said.

"Executives who face facts and fully embrace the situation and get on with it fare the best."

—Michael Dillard
partner
Latham & Watkins LLP

"Just putting two underperforming companies together doesn't solve anything."

—Bill Finnegan
partner
Latham & Watkins LLP

"One thing companies can do right during a downturn is look at those as an acquisition or a turnaround opportunity. You never want to look away from something that is messy. You have an opportunity to unravel the knot. This is true for individual projects or entire companies."

He said the Bayless company has been able to move into new areas throughout the Rockies because someone else needed to move out, or was in trouble elsewhere in another play, and needed to sell a good project. The company has adapted to downturns in that way.

Mistakes to avoid

As E&Ps try to surmount the challenges of this downturn and return to better times, bad choices will be made. Zecchi said people can get caught up in the minutia of what they should make in a situation, instead of accepting what they can make.

"What's done is done. I say that your first loss is your best loss. Sometimes you're going to take it on the chin and so you might as well do it early and then move on. If you have to do something, move on it quickly, and then don't look back. Look to what you'll do in the future, not what you did in the past."

Trimble agreed, saying one mistake made often during a restructuring is that executives try to salvage a company and keep it the way it was before it got into trouble rather than look at what it should become. If new owners are financial people, not oil and gas people, they

OPTIMIZE OR SURVIVE?

Companies that think they have done enough cost-cutting probably haven't, said an industry veteran who asked to speak off the record. We believe some of his comments bear repeating:

"There is a big difference between optimizing and surviving. If I ran a company, I'd have a checklist, and the first thing out the door would be items or people of convenience. For example, I see one engineer with two techs. Why? He says he doesn't want to pull his data himself. Really? This is about survival, not optimization. Techs are items of convenience. Take away the company car and the jet. Look at your yard: how much pipe and wellheads do you keep in inventory? How many remote office facilities or yards do you still have? Sacrifice some growth in favor of keeping leverage down. Debt is the bane of this industry.

"Question everything, every person, every act—should we be doing this or not? A small company that has a full government affairs staff? No. Let the IPAA or Exxon Mobil do that. These are employees of convenience or ego, not necessity.

"Take away some perks and instead tell employees you'll pay bonuses based on how much money you make for your shareholders.

"This industry is a horrible allocator of capital. It has so many charming, handsome salesmen—sometimes they are snake-oil salesmen. Oftentimes they are a man's man, or a very good technical guy, yet even though they have destroyed capital, paid too much for assets, put the wrong people in charge and wrecked companies, investors keep giving them money to start again. Just because someone made you money once doesn't mean they can do it again.

"Keep ego out of it. If there's not a way to add value, don't do it. Don't think, 'It'd be fun to do something again,' if you can't justify it financially.

"And, don't blame your failure or being laid off on COVID-19—everybody else is dealing with that too, and yet not everyone is getting swept aside or having their company disbanded or going bankrupt. Ask yourself, what did you do wrong?"

try to run the company post-bankruptcy with the same old management in place, yet they expect a different outcome. "I just don't see that happening," he said. "You've got to have a board willing to make hard choices. It can't be business as usual."

Investors used to invest in E&P growth at any cost, but those days appear to be over, so Trimble favors a flat organization that's good for the long haul—it's a new world of changed expectations, new alliances and global oil demand turning down compared to the macros seen in prior oilfield downturns.

"A company has to respond differently than it did in the past. You have to be patient now and realize that growth is not the answer. You've got to run an organization that's more sensitive to regulatory issues and ESG."

The days of outspending cash flow should be over, said Jay Chernosky, a veteran of 36 years in energy banking. Semi-retired since last year, he runs Travis Energy Partners, his private investment vehicle, and serves on the boards of Colt Midstream and Jack Hightower's High Peak Energy.

He started his banking career in 1983 during a historic and prolonged downturn: His first assignments were workouts and restructurings. Oil had plunged to $8/bbl by 1986.

Like most oil folk, he remains optimistic today, yet he acknowledges the risky nature of the industry. "Look, oil and gas has always been volatile, and I think that will increase, not decrease. So, you've got to be prudent. E&P companies are well known for overspending when times are good, so you've got to be vigilant and be a low-cost producer."

Naturally, geologist Silverman thinks a key mistake companies make is slashing their exploration staff completely. Companies should keep some projects in the pipeline and keep some inventory, from concept to acreage to

"Oil and gas has always been volatile, and I think that will increase, not decrease. So, you've got to be prudent."

—Jay Chernosky
principal
Travis Energy Partners

maturity, he said. "You'll be glad you have these when prices turn around, which they always do. If you don't have good ideas in inventory, you'll be behind the eight ball," he said.

A common and all too human mistake during a downturn is denial, sources said, which delays responding to the crisis. "The

biggest problem of companies on the financial precipice is denial by the management team or the board. Executives who face facts and fully embrace the situation and get on with it fare the best," said Michael Dillard, who joined Latham & Watkins to open its energy office in Houston. Dillard has been an energy lawyer for some time and was formerly the head of the energy practice at Akin Gump Strauss Hauer & Feld LLP. During his career he's been involved in half a dozen large bankruptcies and advised on numerous restructurings or "liability management" such as debt exchanges.

"I can't think of a situation where a company was about to go into bankruptcy and something happened to increase the price of oil and save them. It's a possibility, but it's so remote," he said. "People should not say, 'If we can just hang on for six months or another year.' Hope is not a strategy, because then you're riding the wave down, and every day that goes by, the company has less value.

"Be realistic. Don't be in denial. Address the issues as early as possible—don't wait."

He labels the current situation as "Back to the Future," as it resembles what he saw in the 1980s bust, but the difference is then, private equity was not nearly as much of a force as it is today and most independents operated their assets and could justify buying something on the basics, not the goal of a quick flip. "They looked at cash flow and how quickly an acquisition could reach cash flow or payout. They built up their companies one brick at a time," he said.

In contrast, as many sources noted, in the past few years, shale companies were valued not on cash flow or returns but on tantalizing possibilities—many well sites in inventory and implied future drilling activity—even as they burned through capital and field development was a long way off. Additionally, some E&Ps are in the "wrong" basin or play and facing higher costs and less access to capital as a result, they said.

Trimble noted that many E&Ps are spread too thin, working in too many basins or plays, with staff trying to do too much. He thinks longer term, more assets will migrate to the bigger companies and mom and pop independents will have to plug their small wells.

But he admits consolidation is a tough game, with two boards that don't want to yield.

"Now, companies are being valued on positive cash flow, not the number of drilling sites they have, and I think CEOs are well aware of this," Dillard noted. Bankers are very tired right now as they work through dealing with multiple distressed clients and bankruptcy situations, he added. "The fulcrum security used to be high-yield debt, but lately, it's the first-lien holders (usually banks) that hold the most sway."

The new world

Despite all the problems companies now face, most will survive, and one reason is that its executives remain in love with the industry. "It's wrong to build expectations for the future based on what's happening today. That's not sustainable. But I do still love this business, and absolutely I would choose it again," said Zecchi.

"It's wrong to build expectations for the future based on what's happening today. That's not sustainable. But I do still love this business, and absolutely I would choose it again."

—Paul Zecchi
CEO
Central Resources LLC

The veterans we talked to remain convinced hydrocarbons must play a role in the future, despite the Great Energy Transition underway or the Green New Deal some foresee. "Make no mistake, the industry will recover," said Chernosky. "There's no replacement for hydrocarbon fuels—even electricity for EVs has to be made from natural gas or coal. We will make an energy transition... but it's going to take some time, and it's going to need natural gas."

For now and in the future, companies must manage what they can, hope to get lucky, and remain low-cost producers, said Curt Taylor, partner with Saddlebrook Ventures LLC, who has more than 30 years in oil and gas, including stints at Ralph E. Davis and Associates and 14 years in private equity at EIG Global Energy Partners. "You can't predict black swan events," he said.

"I think size matters. The next years belong to the larger companies (consolidation) that are converting inventory and managing it to survive. Woe to those who ended up the last man holding the bag on high-cost assets." □

SPACED OUT

After years spent jam packing as many wells on their assets as possible, E&Ps under pressure from prices and investors are beginning to see that less inventory is more.

ARTICLE BY
DARREN BARBEE

The near-mythic status of the U.S. shale revolution has long been rooted in the premise that North America's huge arsenal of wells could sway the world's markets and break the rules set by the all-powerful OPEC pact.

The truth is that shale inventories are already beginning to shrink. The persistent pounding of E&Ps by the market and the ongoing frailty of commodity prices have cut economic support out from under drilling programs that were designed to pack as many wells as possible into a section.

Along with economics, the irreconcilable estrangement of primary and infill—or parent and child—wells in the field continues to be the difficult reality crashing into shale dogma. For years companies have worked at achieving tighter spacing while, if not overcoming well interference, at least mitigating it.

Results vary by basin and geology, but in general the more densely drilled a section is—at, for instance, 500-ft intervals—the worse the child wells and the possible degradation of the parent wells.

"From what we've observed, a lot of the industry is not accounting for flow regime changes, and we're seeing that be more and more of a problem," said Thad Toups, president with Haas Petroleum Engineering Services Inc. in Dallas. In late September, Toups presented a case study to the Petroleum Engineer's Club of Dallas that zeroed in on deterioration of parent and child wells in New Mexico.

"Our worst clustering includes the tightly spaced child wells. This is going to be greater than eight wells per section (in the same zone) drilled mostly as child or co-completed wells," he said. "And then our optimistic and our best clusterings are going to include the wide-spaced parents and stand-alone wells."

Toups said that while some companies may not have publicly recognized the magnitude of well interference, which presents a sometimes greater than 30% reduction in EUR, "If you're in the technical reserves [area], I think it's understood."

The repercussions of 2020's great energy famine have reached a point of no return, in some respects, for shale players. Some public E&Ps have abandoned their furious drives to squeezing as many wells as possible into drilling sections. Others are capitulating. E&Ps have sought bankruptcy protection in 2020 for $53.7 billion—a value greater than the past three years combined.

Concho Resources Inc. has already started to transition to a wider well spacing program compared to 2019 and is now more in-line with 2018 and 2017, according to a September report by Barclays analysts. (Concho has since agreed to be acquired by ConocoPhillips.)

Cimarex Energy Co. likewise signaled a pullback in spacing, with Simmons senior research analyst Mark A. Lear likening the spacing decision to owning up to "past sins."

Simmons data analysis had confirmed performance degradation across the company's asset base in 2019, which coincided with increased well density and small completions.

With wider spacing and increased completion intensity in the Delaware Wolfcamp, Cimarex will likely see better well performance, Lear said in an August commentary.

"With eight to 10 wells per section resulting in some overcapitalization of its assets, [Cimarex] … expects to recover the same amount of resource moving to seven to nine wells per section," Lear said.

Other companies are already making tough choices as the price of a barrel of oil remains in the $40 range.

Ryan Keys, president of Permian Basin operator Triple Crown Resources LLC, said potential for interference is a 3D problem in stacked plays. Without enough vertical space, the need for economic performance overrides conversing inventory.

In the Wolfcamp, at current prices, that means focusing on one or two benches instead of five.

"Unless oil prices double, you're basically sacrificing that inventory forever," Keys said.

Haas Petroleum Engineering Services Inc. president Thad Toups said that while some companies may not have publicly recognized the magnitude of well interference, "If you're in the technical reserves [area], I think it's understood."

Infinite reservoir

During his well-spacing presentation, Toups quoted astrophysicist Neil DeGrasse Tyson regarding the "good thing about science.

In the early shale days, there was "technical tension" between what could be proved as producible and what companies' expected production cases showed, said Scott Rees, chairman and CEO of Netherland, Sewell & Associates.

"It's true whether or not you believe in it."

And it's in cosmic terms that Toups describes wells.

"When you first drill a well, it's going to feel like it's in an infinite reservoir. It feels like it's drilling the whole universe," he said.

Well production spikes up, accelerating like a racecar on the first straight of a track.

But then the well reaches a "boundary," usually the individual stages that begin to communicate. At this point the well has reached the End of Linear Flow regime, and the decline rates increase.

Inevitably, things begin to interfere. In the case of wells drilled too closely together, the inference is literal. The wells began to compete underground for the same molecules, pulling them in different directions.

Finally, the well begins to "feel all of its boundaries," Toups said, and begins to produce down like a conventional reservoir. The tighter the wells are spaced, the sooner the well reaches this Boundary Dominated Flow regime.

"The key point here is production forecasting accuracy improves when you honor these flow regimes that are changing over a well's life," Toups said.

It wasn't until additional data began to appear that the realization struck petroleum engineers that "We're getting the PDP [proved developed producing] forecast wrong a lot. So, let's go back and try to understand how to do that better."

However, the science behind shale reservoirs and the economic potential of concentrated well density began with more assumptions than evidence.

Scott Rees, chairman and CEO of Netherland, Sewell & Associates Inc. (NSAI), said that early on, wells were drilled primarily to hold acreage, which provided large amounts of data for isolated parent wells.

In cases where a second well had been drilled, the wells might show little to no signs of early interference, but with only two wells in a section, they were likely not representative of results if the area were more fully developed at that spacing, and this still reflected very limited data for conclusions on spacing.

"You had very limited data for the second, the children, wells," he said. "With such limited data, we all had to extrapolate a bit, but we could see evidence through the child well performance that those wells would have less total recovery than its offsetting parent well."

There was, particularly for smaller operators, what Rees called "technical tension" between what Netherland Sewell considered proved and what companies thought they could produce.

Netherland Sewell's primary job was to assess the proved, or most certain, reserves, taking into account the company's development plan. However, the company's business plan normally incorporates its most likely expectation of recovery per well, which is more equivalent to the proved plus probable categories.

Telling a company "No, the data only has proven this, not proven that yet" happened. "It made for some interesting conversations," Rees said.

"Luckily in the early days, because of the immaturity of the unconventional plays, the proven undeveloped locations and reserves were, by definition, conservative. Whereas the clients' and the public stock market's valuations were more based on an expected case as set out in PowerPoint [presentations] than on the proved reserves," Rees said.

In retrospect, those disagreements weren't "the end of the world if we said, 'For this pilot, these locations, we think your proved reserves could be 20%, 30%, less than what you're saying publicly as of right now,'" he said. "At the time, increased horizontal well lengths and improved completion design from year to year were allowing companies to have realistic expectations they could achieve better per-well ultimate recoveries."

Company presentations stated the most likely business case. What companies actually put on the books was proven and reasonable, Rees said.

Companies and NSAI looked for "analogies of tighter spacing" to support their reserves case, with the recognition that local geology in a play can vary widely even when separated by a few miles.

The challenge was and is to incorporate and understand the impact of the changing horizontal lengths, completion practices, well spacing, producing practices and geology across different areas and benches. Rees said their role was to determine what had been proven in this area and zone and what could be included by analogy as clients surveyed nearby wells and surmised, "that should work really well in our area."

As basins were explored, oil and gas companies in every basin conducted or closely observed neighboring downspacing tests. Rees said that companies are driven by economics to determine optimal spacing. Besides recovery per well, the pricing outlook has a major impact on well economics. "If prices had stayed where they were, that was probably not a bad thing to drill more wells," he said.

In 2016, Devon Energy's Thistle spacing pilot tested 400-ft vertical spacing in the Leonard Shale. Throughout the history of the STACK, operators plowed through eight to 14 wells in the Meramec Formation.

But perhaps the most infamous spacing test was Concho's Dominator Project, a $250 million boondoggle in Lea County, N.M., that was bent on cramming in wells with horizontal spacing of about 230 ft between wells. Most wells in the area, at the time, were drilled 600 ft to 700 ft apart.

After solid initial rates, the Dominator's 23 wells petered out.

Bernstein's Bob Brackett, writing about the 2019 Dominator, said Concho took a risk that, at the time, caused the market to shave $4 billion off the company's value.

"Moonshots are expensive. If successful, Dominator had the potential to 'unlock' 50% incremental locations," Brackett said. "Moonshots are risky. But we argue that the moonshot is behind us and the conventional development ahead."

Keys, whose acreage is on the Midland Basin side of the Permian, was initially shocked by the results and the closeness of the wells Concho drilled.

"I was like, 'My god, you just broke the Wolfcamp,'" he said.

But the tests were also valuable to other operators.

"There are some very high-profile tests that are failures. And thank goodness. Because we would have destroyed a lot of capital if we all tried it," he said. "So, we never got that aggressive. But we are grateful to Concho for providing the industry a useful bookend."

Space economics

Christopher Kalnin, CEO of BKV Corp. and Kalnin Ventures, with operations in the Marcellus and Barnett shales, said well spacing has the potential to rewrite assumptions about natural gas prices.

Partly, he said, that's because of diminished oil well inventory in the Permian Basin, resulting in less production of associated gas.

"I think that's been the cause for the rally, honestly, in the gas markets for the last couple of months, from where we were early in the year," Kalnin said.

Kalnin Ventures has analyzed the relationship between oil and gas prices in domestic onshore.

"What you see is that in order for associated gas to really grow, for example, in the Permian, you need $50-plus per WTI barrel of oil to start adding associated gas into the system," he said. "And then on top of that you need pipelines."

Kalnin also said gas plays may have to reckon with their own spacing problems.

"This issue of overspacing wells, stealing gas from each other's wells and overstatement of reserves, is quite significant," he said, adding that Appalachian producers inventory appears to be "hugely" overstated at current prices.

"We could make this work with higher prices," he added. "But at the current price, we're just not going to bring on these wells."

Beyond the physical constraints below ground, money and economics are a primary motivator for how wells are spaced. Companies' fidelity to investor cash flow demands is partly driving the down spacing of wells as commodity pricing remains essentially punch-drunk.

As Bernadette Johnson, vice president of market intelligence for Enverus, explained at Hart Energy's DUG Permian conference, tighter well spacing draws out higher volumes. In the Permian, for instance, EUR data suggests that tightly spaced well programs generate about 60% more volume—but require 100% more wells.

But in the Permian, spacing between wells has steadily declined since 2019. Child wells at first showed higher productivity, likely because of advances in completion techniques.

A more detailed analysis, however, showed that as spacing got tighter between parent and children wells in the Wolfcamp, by 2017 hydraulic fracturing jobs were big enough to negatively impact child well initial production, Johnson said.

Even though spacing started to widen again in 2018 and 2019, productivity didn't increase in the children wells, suggesting that operators are beginning to run dry of Tier 1 acreage.

Those details aside, the "cash-flow math" simply doesn't work anymore, she said. Enverus found that wells spaced between 1,110 ft and 1,220 ft produced the highest EURs in the Permian.

Keys said well spacing is simply a function of price. But with current drilling, the economics aren't going to be great even at higher oil prices because of the impact to reserves.

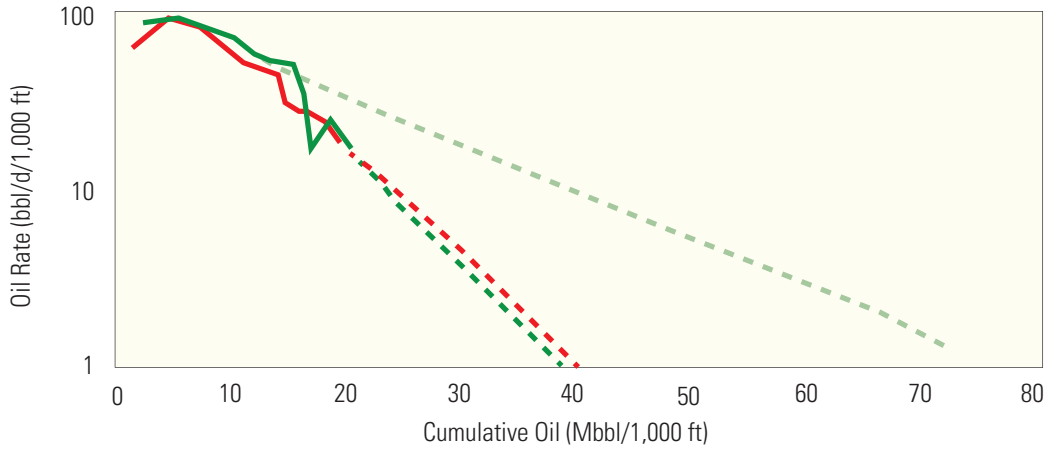
As he thinks about his peers, it's clear that, theoretically, many of the DUCs in the area work economically.

"There just aren't many frac spreads out there completing the DUCs, so it looks like there isn't going to be a wave of DUC completions," he said.

Keys speculates that many of the DUCs, especially in the Permian, may never be com-

Ryan Keys, president of Triple Crown Resources LLC, speculates that many of the DUCs, especially in the Permian, may never be completed because of poor spacing assumptions.

Parent Well Degradation Due To Child Inter-Zone Development



Well interference isn't a two-dimensional problem. In addition to inter-bench (same zone) communication, wells drilled in different benches can interfere with benches above or below. The green line shows Wolfcamp B wells' production diminishes when Wolfcamp A wells are brought online.

Legend

2018 Wolfcamp A — 2017 Wolfcamp B

Forecast

2018 — 2017 Post-Child Wells — 2017 Pre-Child Wells

Source: Haas Engineering, RS Energy

pleted. Wells drilled from 2016 to 2018 were perhaps drilled too tightly and, after the Dominator debacle, companies might conclude, "'That's not a great outcome. And it's better sitting on the balance sheet as a DUC, as theoretical value, than actually turning it into a production,'" he said.

But the inventory drain is real. With Wolfcamp A and B locations separated by 300 ft vertically, there's no way to conserve the inventory at current prices.

"We're basically sacrificing all that [Wolfcamp] A inventory right now because we are focusing on the B, and we want to make sure we get good economics. It's unlikely we'll ever get back to that A inventory because of the parent/child risk," he said.

If prices scale up dramatically, it's possible that some areas will eventually realize the hypothetical wells companies once promised.

But at $40/bbl oil, "You'd basically have to defy gravity in order to avoid destroying a lot of inventory. It's not possible, so there will be a reckoning. There will be a scarcity of quality locations sooner than most expect."

Had prices not dropped because of the pandemic, the previous spacing by companies probably would have supported many drilling programs.

However, at current prices, drilling fewer wells per section makes sense, Rees said. And if prices were to rise again, say over the next five years, to $100/bbl, economics improve for more tightly spaced wells. Companies would have to overcome more material depletion and interference issues for new infill wells than if they had drilled an area on tighter spacing all at the same time, Rees said.

Returning to those areas that have leaked off high pressures to offsetting producing wells is going to be something companies will have to optimize over time.

"No matter what you're doing, you're going to be wrong," he said. "Prices go up, you should have drilled more wells. Prices go down, you should have drilled fewer. Given the price cycles we have seen and will see again, the oil and gas companies are going to get criticized either way." □

INVENTORY AND REDETERMINATIONS

If a company's well inventory shrinks, it usually follows that its borrowing base does as well. But scaling back well inventory doesn't necessarily mean more pain during redetermination season.

Steve Hendrickson, president of Ralph E. Davis Associates, an Opportune LLP company, said he expects reduced drilling density assumptions to have a small impact on borrowing base redeterminations and that "They may actually generate a positive impact."

While each borrower faces its own set of circumstances, Hendrickson notes that lenders give relatively little value to proved undeveloped reserves (PUDs) in their borrowing base calculations.

"It's often the case that the borrowers' undeveloped inventory isn't all booked as proved. Changes to the probable undeveloped locations shouldn't impact the borrowing base materially," he said.

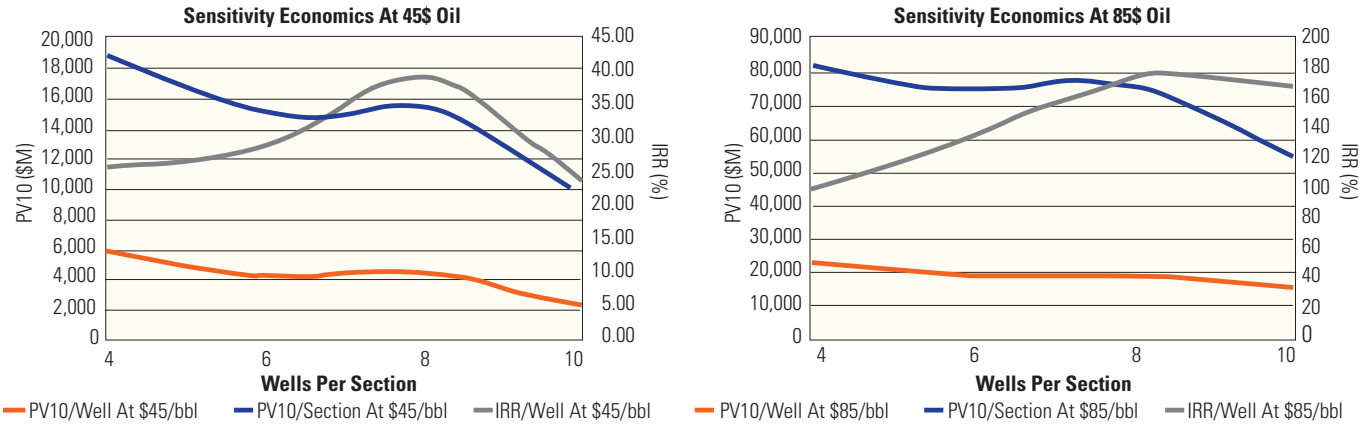
Reducing drilling density would reduce the remaining drilling inventory, but the reduction would occur at the end of the drilling schedule. "Due to discounting, the locations at the end of the drilling schedule have the least value," he said.

And reducing the drilling density may result in wells with higher recoveries per well. Improved economics would be favorable for the remaining inventory and, if the results were as expected, could "lead to the replacement of production with fewer wells and less capex in the near-term. That could be a positive for the borrowing base in the future."

Buddy Clark, co-chair for Haynes and Boone LLP's Energy Practice Group, had a different take with the same result. Clark said that to the extent producers upsize from their well spacing due to well interference, the future value of PUDs could be reduced. However, Clark said that banks have already severely restricted any borrowing base credit for PUDs.

"The impact of increasing well spacing may not be as great as it would have been when banks were giving some [borrowing base] credit for future wells," he said.

Well Spacing Sensitivity Economics Comparison



Source: Haas Engineering

Well spacing is dependent on oil prices, with higher prices leading to tighter spacing and lower pricing pushing wells farther apart. The charts above show the effect on PV10 values at $45 and $85 per barrel, assuming 100% working interest and 75% NRI.

THE POWER IN PARTNERSHIPS

The private independent U.S. Energy Development is actively pursuing partnerships and funding development drilling in U.S. shale plays as market conditions improve. The market is ripe, according to CEO Jordan Jayson.

ARTICLE BY
VELDA ADDISON

Where there's a will there's a way, as the saying goes, even in the oil patch during times of thinned budgets, limited access to capital and growing decline rates.

The way to lower costs and shared risk may be through U.S. Energy Development Corp. for some oil and gas companies.

The Texas-headquartered private is leveraging its 40 years of expertise developing oil and natural gas assets to acquire interest and form partnerships to make projects happen. The company, which specializes in direct energy investments, said it has deployed more than $1.5 billion on behalf of its partners, drilling more than 2,400 wells in North America.

"We look at over 300 deals on an annual basis, and this year's been no exception," Jordan Jayson, CEO of U.S. Energy Development Corp., said. "We've seen great opportunities, and we've been approached by several companies—large and small—for potential joint venture opportunities."

Among its latest moves was acquiring an $8.5 million interest in Shell Oil Co.'s Columbia Project in the Permian Basin. U.S. Energy's role in the project, which carries a $24.1 million total development cost, includes drilling three horizontal wells targeting oil in the Wolfcamp formation in West Texas' Loving County.

U.S. Energy raises capital via private placements, special purpose vehicles and institutional investors and family offices, Jayson said.

Despite being in a strong financial position and cash flow positive, he admits that raising capital has been challenging in today's environment. But the search continues for quality projects with favorable returns.

"We're actively in the market looking for additional acquisitions and strategic joint venture partners," he said. "We're looking for additional opportunities like Colombia, and we're empathetic to the current status of the energy industry in North America and hope for a swift recovery."

Focus, he added, is primarily on areas where wells will come online within the next 12 months.

Investor *recently spoke with Jayson, who shared more insight about the company, its strategy and latest pursuits.*

"We're looking for additional partnerships like the one that we've established with Shell. We're in a strong financial position and have access to additional liquidity to put to work in these types of partnerships and joint ventures."

Investor The latest collapse in oil prices prompted U.S. oil and gas companies to cut spending as the industry overall continues to see investment fall. What keeps U.S. Energy Development Corp. investing in U.S. shale plays?

Jayson Our team feels that there are several basins where the economics of U.S. shale remain attractive even at these prices. For companies like U.S. Energy, we have a low-cost

structure, and we also have the ability to structure deals creatively. And so that's allowed us to continue to invest in U.S. shale plays even during these lower commodity price cycles.

Investor I understand that U.S. Energy is currently funding development drilling projects in the Eagle Ford Shale, Denver-Julesburg Basin and the Powder River Basin. Why these areas and why now of all times?

Jayson They are focus areas for us right now due to the attractive rates of return at today's strip pricing. We're also seeing a trend of a number of companies that are selling down their nonoperating working interest in these areas. I think we've looked at close to $2 billion dollars' worth of developmental drilling deals over the past nine months. And these basins typically have enough supporting data to reduce geological and operational risk to a point that makes it attractive for ourselves and our partners.

Investor Tell me more about your typical deal structure. What are some of the ways you've structured deals creatively?

Jayson U.S. Energy is focused on structuring deals that are mutually beneficial to all parties. Our flexibility allows us to structure deals in a variety of manners—from traditional joint development agreements and farm-ins as the operator, to nonoperated working interest and PDP [proved developed producing] acquisitions, as well as wellbore-only arrangements.

Investor When looking to acquire assets or interest in assets, what qualities do U.S. Energy look for? What is your business strategy?

Jayson Firstly, the return profiles of the assets that we're looking at must meet our investment committee's objectives and also our partners' objectives. We're looking for low geological and operational risk. We're looking for strong offsetting production or wellbore control. Good takeaway capacity from a midstream standpoint.

Investor How do your economics work at today's oil and gas prices?

Jayson Well, all of our existing PDP is cash-flow-positive at today's current strip. But we monitor our operating wells daily and monitor whether they're free-cash-flow positive or negative. If they are negative, we react immediately on a daily basis and shut those wells in. With respect to new ventures, we don't acquire assets unless they support our necessary return thresholds.

Investor What are those thresholds?

Jayson Those would be a return on investment greater than 1.5x; internal rates of return greater than 20%. They're not generic metrics; those are metrics that we use as an investment committee prior to making decisions.

U.S. ENERGY DEVELOPMENT CORP.

Drilling in the Permian Basin has been an area of focus for U.S. Energy Development Corp.

Investor Are most of your assets conventional or unconventional? Do you have any appetite for more unconventional assets? Why or why not?

Jayson Being a 40-year-old firm—we're celebrating our 40th anniversary this year—our historical assets were conventional. And over the past decade, we've gradually moved into the shale plays and unconventional assets. We still have an appetite for unconventional assets. We currently operate 800 vertical wells—our conventional wells—in Appalachia, and we're currently looking at other projects that are conventional at this point in time as well. So,

we're a bit agnostic to unconventional versus conventional. More of our team's focus is on the return on investment and the basin.

Investor Let's talk about your most recent announced deal in the Permian Basin, acquiring interest in Shell's Columbia project. Can you tell me more about Columbia and how that transaction came about?

Jayson U.S. Energy's built several strong relationships with different large operators. As these operators choose to sell down their nonoperating working interest, U.S. Energy has been a potential acquirer of the nonoperating interests that some of these larger operators are choosing to divest of versus participate.

Investor Can you tell me a little bit more about the project itself? What are the breakevens? How much oil will be initially produced?

Jayson The project is in Loving County, Texas. Three wells have been drilled targeting the Wolfcamp horizontally. The wells are scheduled to be put in production in Q4 of 2020. The breakevens are roughly $30 per barrel of oil. I don't have a number for what we anticipate for our initial IP rates, but we've seen wells in that area come in well above 1,000 barrels of oil per day on average.

Investor Will you also provide an update on your three-well development in Ward County?

Jayson We entered into an agreement to buy an asset in Ward County last year. It had production and also some undeveloped acreage. Earlier this year, we finished drilling a three-well pad that was targeting the Wolfcamp B. We had great drilling success on average 46% faster than the acquired PDP while we reduced costs by 30% or greater. We anticipate completing those wells in Q4 of 2020 and anticipate drilling up to six wells in 2021 in our Ward County prospect.

Investor Looking specifically at the Permian Basin, what development challenges and opportunities could lie ahead in the basin?

Jayson Our biggest challenges in the Permian Basin are takeaway capacity, associated transportation costs and saltwater disposal costs. I think that's consistent for most operators or possibly for some operators as well in the Permian Basin. What opportunities lie ahead? We continue to see a great amount of deal flow on a weekly basis in the Permian Basin right now. We don't anticipate that slowing down in the near future and that creates opportunities for U.S. Energy.

Investor What are your thoughts on well spacing? Do you think high-density spacing can still work, or do you think that tighter spacing has been too aggressive?

Jayson We're in a unique position where most of our investments are at the well level rather than the asset level. … We're focused on the drilling and completing of wells that meet our return profile rather than increasing our well count to maximize reserves. So, we would prefer to see greater spacing. But it depends [on the] basin. The technology is changing so rapidly. In some areas, as you're aware, tighter spacing has been very, very successful. In other areas, ourselves and our joint-venture partners have decided that it was in the best interest for returns to increase spacing. So, we monitor it and study it closely, and we feel that it is specific on the area within a basin. But we would prefer generally for a wider spacing, for greater spacing, rather than the aggressive spacing that we've seen over the past several years.

Investor Some analysts have forecast that frac hydraulic horsepower demand won't recover to 2019 levels until 2025. What are your views on the outlook for hydraulic fracturing activity?

Jayson I'll limit my answer to the Permian Basin because that's where we're most active right now. U.S. Energy is not an oilfield service company, but obviously, our activity impacts oilfield service companies. We anticipate that there is plenty of running room in the Permian for additional drilling that will support greater horsepower needs. As prices stabilize and potentially escalate, we believe that the activity in the Permian is going to continue to grow and the need for horsepower will continue to grow in the Permian.

Investor How do you see U.S. Energy evolving within the next five years? Does the future include more acquisitions and partnerships like the one with Shell?

Jayson I would imagine that U.S. Energy will remain active in the E&P market. We're looking for additional partnerships like the one that we've established with Shell. We're in a strong financial position and have access to additional liquidity to put to work in these types of partnerships and joint ventures. We're in the best financial position that we've been in 40 years, so we'll hopefully continue to build upon that as we move forward from the current market conditions that we're in today.

Investor How much free cash flow does U.S. Energy have? Can you give a brief snapshot of financials?

Jayson We are a private company, and we do not disclose our financials. What I can say is we have remained profitable and free-cash-flow positive throughout 2020. Our debt has been reduced by 60% over the past several years while continuing to grow our reserves. These actions have put our team in a unique position to be able to transact during challenging times our industry is experiencing.

Investor Is there anything else you want the oil and gas community to know about U.S. Energy?

Jayson I would just add on one thing. The reason U.S. Energy is in our current financial position is because of our laser focus on driving free cash flow and minimizing our leverage over the past five years. I think our team's done a great job of navigating the last two downcycles, and I think that experience paid off during COVID-19; whereas, in 2015 we didn't react as quickly as we did when COVID-19 escalated. I give all the credit to our team in moving as quickly as we did to monitor free cash flow and maintain free cash flow throughout Q1 and Q2 of 2020. □

WAR BONDS

2020 wasn't looking like the kind of year an E&P could access capital—and certainly not at less than 2%. For Pioneer Natural Resources Co., it has been.

ARTICLE BY
NISSA DARBONNE

Pioneer Natural Resources moved rapidly at the onset of the oil crisis this year to secure liquidity—and it succeeded. "When the market is there for a transaction that you're willing to do, then push really hard to get it done because you never know—markets can change quickly," said president and COO Rich Dealy.

In late February, the Pioneer Natural Resources Co. team wrapped the year-end earnings call and was filing the 10-K while readying to refinance senior notes due 2021 and 2022.

In January, it had paid off its $450 million of 7.5% senior notes due this year, using cash on hand.

It had an undrawn $1.5 billion bank revolver. The 2021 maturing notes totaled $500 million. After that, it had $600 million maturing in 2022; $500 million in 2026; and $250 million in 2028.

Cash on hand was $631 million.

It was now Friday, Feb. 21. "We had our 10-K ready to be filed, along with a new bond offering ready to go—five- and 10-year bonds," said Rich Dealy, president and COO.

The 10-K was filed on Monday. The bond offerings wouldn't happen, though.

On Monday, "that's when the rug was pulled out from under everybody," Dealy said "All of a sudden, the impact of COVID-19 hit the capital markets, with the stock market falling, Treasury rates skyrocketing and credit spreads widening.

"On top of that, Saudi Arabia and Russia were starting to get into a price war."

By the end of the following week, it became clear that Saudi Arabia and Russia wouldn't agree on the production cuts necessitated by reduced oil demand as the virus spread across the globe.

When Pioneer had wrapped its earnings call on Feb. 20, the prompt-month (April delivery) WTI contract on Nymex was about $53. On March 5, it closed at $46.

At the end of the March 9 trading session, it was $31.

The refinancing was postponed, Dealy said. Until when? No one could be sure.

"The financial market just wasn't going to do a transaction. And, as we went through March, things were getting worse."

Should Pioneer do a short-term bank loan? It didn't need one. It had more than $600 million of cash on hand.

But should it, just in case? Yes, the board agreed.

"We went to our bank group and put in a 364-day unsecured credit facility just to have incremental liquidity. It was insurance against an extended low-oil-price environment and the potential for a long-term supply glut if the Saudi/Russia price war continued."

Getting in line

Pioneer wasn't alone; there was a line. "I mean, everybody," Dealy said. "It was probably one of the hardest deals [I've done] because banks were getting approached by not only energy companies but by just about every industry."

You name it. "Airlines, cruise lines, manufacturing, tech were all trying to shore up their balance sheets too. So banks were just getting inundated with liquidity requests."

Dealy got in the queue. With so many requests, bankers "were stingy about who they would deal with."

He was on the phone "it seemed like five days solid, just talking to banks, trying to get that credit facility put in place."

Pioneer got it done on April 3 for $905 million. "It was going to be a one-year facility. With so much going on, we wanted to make sure we had plenty of firepower to withstand a potentially tough year if things didn't open back up."

It only got worse, though. At the end of the April 20 trading session, next-month delivery of WTI closed at a negative $37.63.

After Pioneer's February earnings release, Mark Lear, senior research analyst for Simmons Energy, had written, "Raising the Bar: Big FCF Beat Complements Solid FY20 Outlook."

On March 25, though, he titled his report "Downgrading Seven E&Ps; Shale Will Survive but Uncertain Path Lies Ahead." He pared Pioneer and six other large independents to Neutral.

"We think we have yet to witness the worst of the current oil-market turmoil play out in the physical markets, which we expect to see in the coming months," he wrote. That came April 20.

0.25% money

Another option developed for Pioneer: Do a convertible senior note. "When we got toward the end of April, things started stabiliz-

ing," Dealy said. "You could tell the financial market was improving and the bond market was reopening, albeit at much higher rates."

In May, something remarkable happened: A door opened. "We had this opportunity to issue a low-coupon convertible bond."

Pioneer had done one of these in the early 2000s, when it and most of the U.S. E&P industry was making oil and gas from conventional rocks from vertical wells.

What it wasn't expecting in May was such a low interest rate: 0.25%. "In February, we were looking at issuing 10-year notes around 3% or so. In May, it would have cost 4%-plus."

This convertible senior note would cost 0.25% instead.

Pioneer had cash on hand, $700 million still undrawn on its bank revolver and an undrawn 364-day $905 million line of credit.

But five-year 0.25% money was an offer not to be refused. "The upside for our investors is it significantly reduced our cash interest cost. We tendered for our higher-cost near-term bonds and replaced them with 0.25% bonds."

It added a feature—a capped call—to effectively limit any share dilution as its stock price increases. With this, "We won't have to issue any more shares or come out of pocket with incremental cash unless [the] price goes above $156 per share," Dealy said.

At the time, Pioneer shares were trading in the low $80s, "so it made a ton of sense to reduce our overall financing cost as a company."

'Never dreamed'

Meanwhile, the low-cost money further freed up cash flow. "All of these steps we've taken [over the years] have been about improving free cash flow."

Borrowing 0.25% money (due 2025) and paying off 3% and 4% money (due 2021 and 2022) "was a tremendous cash-flow savings," all going toward generating more free cash flow.

"I would have never dreamed," Dealy said of the opportunity.

But it was true. The week of May 11, Pioneer sold $1.3 billion of 0.25% convertible notes due 2025 with interest payable on May 15 and Nov. 15 each year.

It used $113 million to pay for the base capped-call protection; bought back $50 million of shares; and retired $360 million of 3.45% senior notes due 2021, $356 million of the 3.95% notes due 2022, and $9 million of 7.2% notes due 2028.

And it canceled that 364-day credit facility.

The notes are convertible to PXD shares if they reach $156.21 before mid-May 2025—an 85% premium over the share price of $84.44 when the deal closed on May 11.

Simmons' Lear wrote, "Pioneer demonstrated the capital markets are not only open—for some—but the cost of capital is very attractive."

He estimated the transaction saved $15 million of debt-service cost a year.

1.9% money

Pioneer was set for at least another half-decade. But another opportunity came along.

Issuing new 10-year notes is what it had wanted to do in the first place—back in February. In August, that window reopened. And at 1.9%.

Pioneer offered $1.1 billion of 1.9% senior notes due 2030, priced at 99.205%.

"Our August transaction was really just opportunistic," Dealy said. "We didn't have to do anything in August."

But it was 10-year money for less than 2% a year—"something I never dreamed Pioneer would ever be able to accomplish. I think we'll never regret having gone out there and raised 10-year money at 1.9%."

Again, it had to move quickly. "One of the things we have learned as a company is that, when the market is there for a transaction that you're willing to do, then push really hard to get it done because you never know—markets can change quickly."

STEVE TOON

A rig drills for nonpotable source water near an existing Pioneer producing pad in the southern Midland Basin.

Of the August opportunity at 1.9%, Dealy said, "We knew it would be fleeting. Literally the week after we got it done, rates started moving up. We probably would have been 10 to 20 basis points higher had we waited over a weekend.

"Being prepared and being willing to push to get things done pays dividends when you're ready to transact at those levels."

Pioneer put the net proceeds of about $1.08 billion on its balance sheet. It's there to pay off the rest of the 2021 and 2022 bonds that weren't tendered. And it's there to pay off a portion of the 2025 bonds.

"From those two transactions—the 0.25% convertible and the 1.9% notes due 2030—we've reduced our cash interest cost by 2%-plus. It's incremental free cash flow year over year and lowers the overall borrowing cost of the company."

Pioneer's net debt to book capitalization at June 30 was 15%. Pro forma for the August transaction, cash on hand as of June 30 totaled $1.3 billion.

Gabriele Sorbara, senior equity analyst for Siebert Williams Shank & Co. LLC, had downgraded Pioneer to Hold on June 9, stating that the stock's price was higher than the company's asset valuation at oil prices at the time.

"We believe the recent stock price moves have been driven by passive/retail buying, quants and short covering, which have significantly elevated speculation/risks," he wrote.

On Aug. 13, though, Sorbara announced that "We are back on board with a Buy rating." His price target was $147.

"We believe PXD shares justify a large premium for the new framework, which should drive consensus estimates higher and further share outperformance."

'Too untenable'

Pioneer had been steering toward free cash flow and a low debt profile for years, said Dealy, who joined the company in 1992 when it was Parker & Parsley Petroleum Co.

It's resulted in a strong balance sheet and low debt-service cost. This year in particular, the conservative balance sheet paid off.

"As an industry, the vast majority of public E&Ps have too much leverage because they were borrowing money to grow. So, you've seen a number of companies declare bankruptcy," Dealy said.

Like Pioneer, many went to banks and bond markets this spring. "But they weren't issuing bonds at 25 basis points or 1.9%. They were issuing bonds at six, seven, eight, 9% interest.

"They were forced to just accept that because of their credit quality."

He concedes Pioneer hasn't "always had the balance sheet that we have today." Earlier in his career, the company was overlevered. "We had bonds that were seven, eight and 9%.

"And that was just too untenable to me—in this industry, being in the commodity-price environment. So, we worked hard over the last 10 to 15 years to really bring leverage down."

E&P investors have seen debtholders become the shareholders post-bankruptcy "and the equity-holders basically walked away with nothing." Investors won't stand for it any longer.

"You really see investors promoting companies to lower their leverage, have a strong balance sheet and return more cash to shareholders."

As the E&P business is now, "If you want capital, you need to start improving your balance sheets and, hopefully, lower the cost of your bonds in the future."

'No risk'

Pioneer's position is to generate cash flow that can pay off its debt in less than one year, if need. At the current rate, it could pay it off in nine months.

Fundamental to Pioneer's ability to improve its financial profile—despite 2020—is its assets, Dealy said. The company's wells generate some of the highest rates of return in all of the Midland Basin, he said.

STEVE TOON

Pioneer's Permian leasehold is concentrated in the Midland Basin with a position in every corner, north to south, east to west.

That's based on J.P. Morgan Securities LLC analyst Arun Jayaram's analysis in late September. Jayaram found that Pioneer's 12-month cumulative production per well was 25.1 boe per lateral foot (boe/ft) in 2018 and 25.9 boe/ft in 2019. Jayaram concluded that, "When comparing Pioneer's productivity with peers in the Midland Basin, … Pioneer delivered the highest well productivity in 2018 and 2019."

Meanwhile, Pioneer's drilling, completion and facilities costs have been pared, Dealy said. On G&A, that's lower now as a result of a 2019 reorganization and executive pay cuts.

As oil prices began to collapse, Pioneer cut its 2020 capex plan of up to $3.5 billion to top off at $1.6 billion.

"We were able to do these debt transactions from a position of strength," Dealy said. "There was no bankruptcy risk, no risk of not getting repaid.

"So, fortunately, we were able to tap the markets at opportune times during the year to prepare well for the future."

Jayaram wrote in early September that, even at $40/bbl WTI into 2025, Pioneer should be able to generate a return to shareholders of $17 per share. If $50/bbl, then more than $40 per share.

He reiterated his Overweight rating on the stock.

'At the bottom'

Dealy doesn't see another capital transaction in the near future. "We're well set up now. We really don't have any refinancing needs until four or five years from now—if then."

What debt it has, using its model of reinvesting up to 80% of cash flow and using the balance to pay base and variable dividends and to reduce debt, "We may be able to pay [the bonds] off with cash, given the cash that's sitting on the balance sheet."

The next maturity—the $1.15 billion of 0.25% convertible notes—isn't until mid-2025.

"You never know what your interest rates are going to be in the future, but I feel like we've executed near the bottom," Dealy said.

"It seems like rates can't get much lower. There is more probability that they're going to go up versus down."

But one never knows what a new year will bring. 2020 had Pioneer's teams dispersed, working from home. For a time, all of Pioneer's transactions were done by personnel working off-site. Many remained off-site in early October.

"We've been very lucky that we've not really missed a beat by having people work at home," Dealy said.

Of course, by September, employees were becoming weary of meeting via virtual platforms, he added. But the trade-off has been worth it: Everyone's been safe.

"I suspect we'll all look back at this year and say, 'What a strange year that we will remember forever.' In every scenario-planning and risk-planning, this is one you never thought of." □

With its planned acquisition of Parsley Energy Inc., Pioneer is set to expand into the Delaware Basin.

STEVE TOON

13 MILLION BARRELS

Has U.S. shale output reached its peak? Analysts discuss the outlook for the U.S. shale sector as it recovers from the latest downturn, awaiting higher global demand.

ARTICLE BY
VELDA ADDISON

The U.S. saw its oil output hit a high of about 13 MMbbl/d at the end of 2019 before the coronavirus-driven market collapse sent production into a nosedive earlier this year.

By the end of May, production had fallen to 10.3 MMbbl/d, triggered by widespread curtailments in an effort to help bring the global market closer to balance and improve tanking oil prices. U.S. producers of unconventional, offshore and conventional resources alike cut output along with other major oil- and gas-producing regions across the world.

In the months since, nearly all of the curtailed barrels have come back online, according to Leslie Wei, vice president of E&P research for the Norway-based energy consultancy Rystad Energy.

"The production cut from the U.S. was the largest among all countries, even higher than Saudi Arabia, which cut 2.5 million barrels," Wei said. "This highlights the flexibility of shale and the market working as intended."

However, will U.S. oil production ever return to 13 MMbbl/d again?

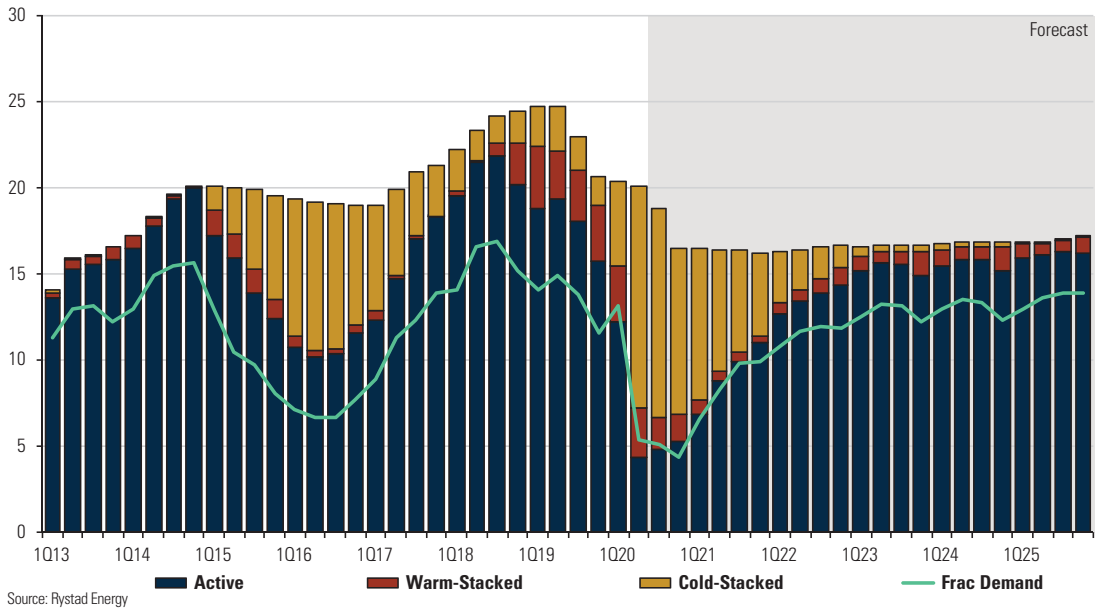
That was the question Wei posed Sept. 22 during Rystad's Americas annual summit. A crucial determining factor could involve what happens in other parts of the world.

Tracking fracking

Speaking during the virtual event, she explained how the number of hydraulic fracturing jobs in U.S. shale plays plummeted by 75% to 326 in June, compared to 2019. Activity has started to return, with 400 frac jobs in July and again in August, she said.

"The Permian Basin experienced the largest recovery, more than doubling from the bottom of 101 frac jobs in June to 227 and 246 frac jobs in July and August," she said. "Eagle Ford also shows signs of sustained recovery with about 50 new frac jobs in both July and August. On the other hand, fracking in the Bakken region is expected to return to the bottom as some producers are likely to revisit their plans after the potential shutdown of the Dakota Access pipeline."

Frac Equipment Supply Forecast
Million hydraulic horsepower (HHP)



Source: Rystad Energy

"In the short term, global production is expected to recover even without shale. But in the medium term, global production looks grim. … even OPEC can't save us."

—Leslie Wei, Rystad Energy

Rystad forecasts demand for frac equipment, which saw utilization hit record lows of 15% this year, will rise toward the end of the year—exiting at about 30%—as completion activity picks up and older equipment leaves the market.

"There won't be any surprises in activity for the remainder of the year," Thomas Jacob, vice president of research for Rystad, said.

Oil prices below $40/bbl don't help.

"We are expecting a 5% to 7% decline in completions activity in the fourth quarter due to the typical seasonality that you see frac holidays and end budget exhaustion," Jacob said.

Rystad doesn't expect hydraulic horsepower demand to recover to 2019 levels until 2025. "The road to recovery will be slow and painful," according to Jacob.

"Moving into 2021, demand will continue to go up, hitting 10 million at the end of the year," Wei said. "At the same time, the fleet size will remain constant at around 15 million. Therefore, implying a utilization rate of about two-thirds."

Currently, just over 100 frac fleets are working in the U.S., Jacob said. Demand is expected to rise to between 180 and 190 next year.

The segment remains oversupplied.

"We think the industry will easily be able to meet demand using 250 to 300 fleets, even in a sustained $60-plus WTI-type environment," Jacob said. "So, the days of requiring 350 to 400 fleets are pretty much done."

Looking ahead

Efficiency gained through the use of zipper fracs and simul-frac operations are driving down fleet demand as operators, working with oilfield service companies, cut nonproductive time.

"Capital discipline, well design optimization, service price deflation, efficiency improvements and a focus on ESG" will shape the decade ahead, according to Jacob.

Add base decline rates of existing wells to the mix, Rystad's outlook shows production from shale plays dropping until mid-2021.

At that time, Wei said an "oil price recovery should be sufficient to see a new wave of investments in shale and production will gradually increase again and exit the year around 7 million barrels per day."

Offshore is expected to help lift overall production for the U.S., given Rystad forecasts the sector will fully recover by the year's end. Yet, the boost won't be enough for the U.S. to recover to its peak output this year or in 2021.

What happens after that will depend on what happens globally in terms of supply and demand.

"In the short term, global production is expected to recover even without shale. But in the medium term, global production looks grim," Wei said. "We see that in 2025 global production cannot exceed even 94 million barrels. You might argue that OPEC could fill this gap. But in reality, OPEC's spare capacity is only 1- to 2 million barrels. So even OPEC can't save us."

Shale volumes will be needed, the analysts said.

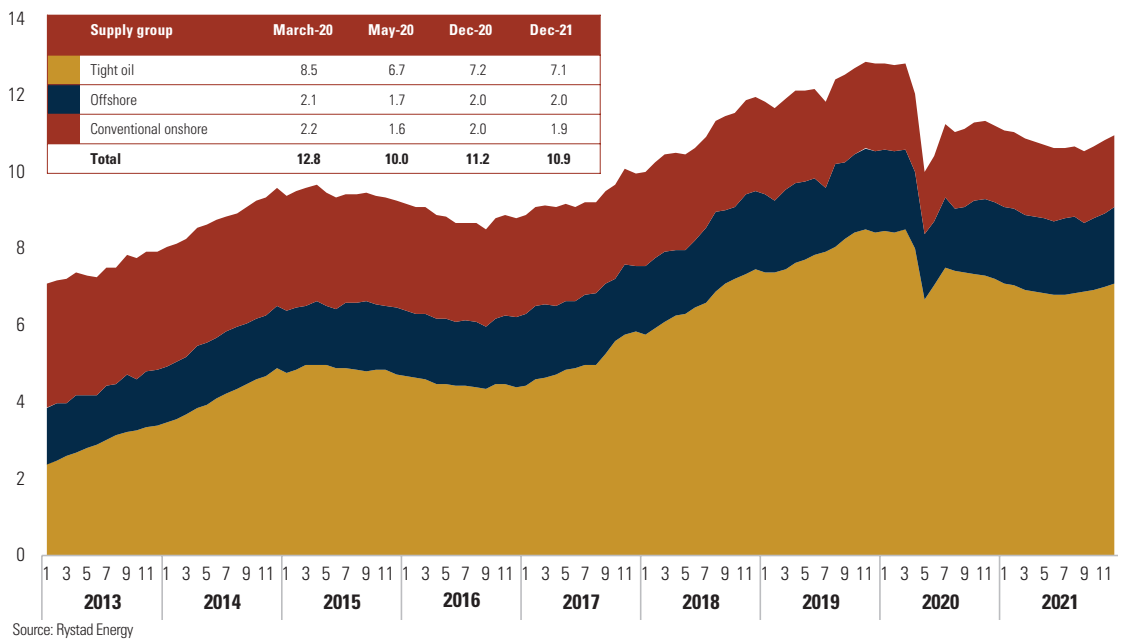
Wei said between 6 MMbbl to 11 MMbbl will need to come from shale wells not yet drilled. Analysts believe an oil price around $60/bbl would incentivize shale players to ramp up activity, commencing a new upcycle.

Rystad's outlook shows WTI averaging about $40/bbl in first-quarter 2021, exiting next year around $50/bbl and rising to the mid-$60s/bbl by 2025.

"We expect to see investments start to recover in 2022 before reaching $155 billion U.S. dollars per year by the middle of the decade," Wei said. "In 2022, we'll see an uptake in production again before returning to the 1 million barrels per day growth rate that we saw after the recovery from the previous downfall. So, to answer the question, we believe by 2024 the U.S. has a possibility to reach new all-time highs and hit 13.5 million barrels per day." □

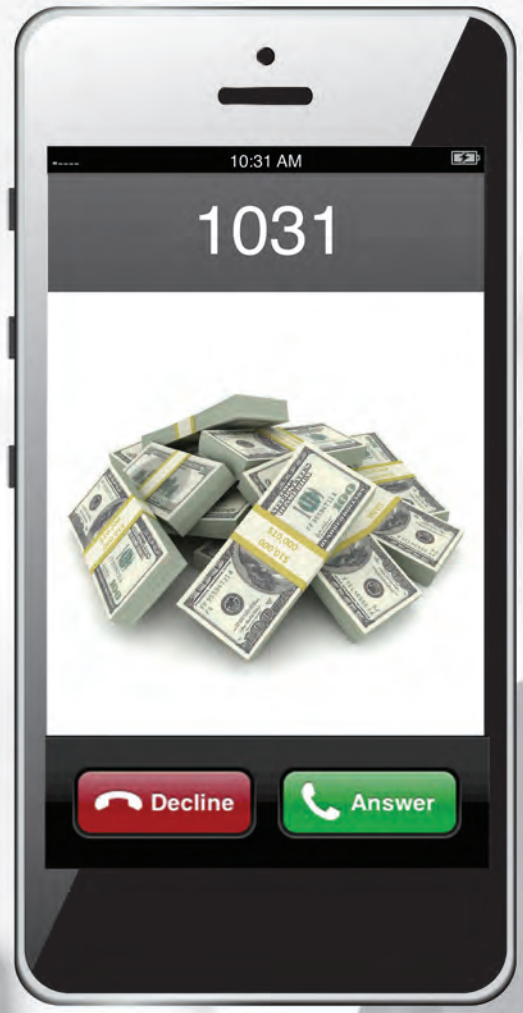
Total US Oil Production By Supply Segment

Million bbl/d



Supply group	March-20	May-20	Dec-20	Dec-21
Tight oil	8.5	6.7	7.2	7.1
Offshore	2.1	1.7	2.0	2.0
Conventional onshore	2.2	1.6	2.0	1.9
Total	**12.8**	**10.0**	**11.2**	**10.9**

Source: Rystad Energy



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E&Ps must allocate risk carefully when drafting contracts, with indemnities in particular demanding careful definition and enforcement.

ARTICLE BY
JIM NOE AND
TIM WOODARD

With very rare exceptions, oilfield contracts address allocations of the financial consequences of risks arising out of the performance of the work. This is usually done in some version of a "knock-for-knock" indemnity scheme where each party agrees to be financially responsible for claims related to its own people and property and to indemnify, defend and hold harmless the other party and its "group" of related/interested parties from and against such claims.

This includes protecting a party from a claim even where the loss at issue results from the negligence, strict liability or other legal fault of that party. Third-party claims, environmental responsibilities and claims arising out of catastrophic events such as a blowout are often addressed separately.

This allocation of financial responsibility is based in part on a desire to avoid protracted litigation driven by efforts to apportion fault for a loss among the many parties that are typically at a well site. Without a clear contractual allocation of risk, each party will engage counsel that will seek to downplay its own liability while seeking to find fault with the actions of others at the site. In doing so, defense counsel will engage in extended discovery (to the delight of the plaintiff's counsel) funded by multiple insurers.

While by no means a perfect solution, a knock-for-knock scheme allows a single party to focus on settling or defending a claim rather than attempting to establish the negligence and fault of others involved with the work. A knock-for-knock indemnity scheme also allows each party to more efficiently insure the risks presented by their operations and incentivizes employers to invest in safety and loss control to mitigate the likelihood of injury to their own employees (or those of their subcontractors) or damage to their property.

Certain exceptions to a knock-for-knock scheme are typically made where the party with the most to gain financially from the work at issue assumes more liability than the other party. For example, in drilling contracts, the oil and gas company stands to gain far more financially from the results of the drilling than does the contractor, who is merely earning a fixed day rate. As a result, the oil and gas company typically assumes the financial consequences

With multiple contractors working on wellsites that by the nature of the business contain safety risks, operators must have clear contractual allocation of that risk with third parties.

STEVE TOON

of catastrophic loss—such as a blowout or pollution flowing from the well—even if such loss is caused by the drilling contractor.

The role of insurance

In addition to contractual indemnity undertakings, and as a separate legal obligation, oilfield contracts require the parties to obtain insurance coverages and name and waive the indemnified parties to them, ideally "to the extent" of the relevant risk allocations and indemnity undertakings.

Insurance is required so that the indemnified party does not need to rely on the *willingness* or financial *ability* of the indemnitor to pay following a loss. Access to the indemnifying party's insurance is particularly important if the indemnified party caused the loss, as the indemnifying party may have very little motivation to reimburse a party where the loss materially impacted business, personal relationships and reputation. Even if the indemnitor wants to pay, it may not have the financial wherewithal to do so for a major loss.

An indemnified party that was named as an additional insured on the indemnitor's liability insurance has status and rights under the insurance policy that it can assert directly to protect its interest should the indemnitor fail to act. If they are not named, the party owed indemnity needs to rely on the indemnitor to pursue a claim under its own "contractual liability" coverage.

Naming and waiving are very important on property policies also as it should legally preclude the insurer from subrogating against the indemnified party following payment of a claim. As the insurer "steps into the shoes" of its insured to assert subrogation rights, subrogation should not be possible where those "shoes" come with an obligation to indemnify a party. But insurers do occasionally try and a party which is an additional assured on a policy will be very well positioned to rebuff such a claim.

Applicable state 'anti-indemnity' laws

Oilfield service contracts may be subject to maritime or state law interpretation and enforcement. Certain states have prohibitions against oilfield indemnities for one's own negligence that must be considered, while maritime law permits parties to contractually allocate risks.

The Texas Oilfield Anti-Indemnity Act (Texas Practice and Remedies Code § 127.001 *et seq*.) invalidates or limits indemnity provisions that purport to indemnify a person for property damage or personal injury caused by the negligence or fault of that person unless the indemnities are (i) mutual and (ii) covered by insurance. If the parties carry differing amounts of insurance, the indemnity is limited to the lower amount of insurance obtained by the parties. This means that a reciprocal knock-for-knock indemnity undertaking that is not supported by mutual insurance undertakings will be void or capped by the lower amount of insurance coverage carried by the parties.

Like the Texas statute, Louisiana's Oilfield Anti-Indemnity Act (La. Rev. Stat. Ann. § 9:2780) invalidates contractual indemnity for personal injury claims caused by the person claiming indemnity. (Louisiana does not nullify indemnities for property damage.) Unlike the Texas statute, the Louisiana statute does not contain an exception for insurance coverage. As a result, contracting parties cannot avoid the Louisiana statute merely by requiring mutual insurance coverages in support of the indemnity obligations.

> A knock-for-knock scheme allows a single party to focus on settling or defending a claim rather than attempting to establish the negligence and fault of others involved with the work.

However, Louisiana has developed a court-created workaround known as the *Marcel* exception. Under *Marcel*, a court will not void an additional insured undertaking where no material part of the cost of adding the additional insured to the policy was borne by the party owing indemnity. The thought is that where a party to be indemnified paid the full cost to be made an additional insured, it should get the benefit of the bargain with the insurer.

In light of the Louisiana and Texas anti-indemnity statutes, the role of insurance is of paramount importance, and the failure to include proper insurance undertakings will result in the indemnity being voided or capped if Texas law applies or will preclude access to a *Marcel* solution if Louisiana law applies.

This may not seem like a significant issue, as the overwhelming majority of oilfield agreements do contain reciprocal insurance obligations. However, from time to time we see contracts where the larger, more economically powerful party requires the smaller party to place coverage and name and waive the larger party but include no reciprocal undertaking by the larger party to place insurance and name and waive the smaller party or its group thereon.

The thought of the larger party is, presumably, that it does not want the other contracting party to have rights under its insurance or be able to directly pursue a claim under its policies. Instead, the smaller party will be forced to rely exclusively on the indemnity undertaking of the larger party, which can use economic clout to alter the financial impact of the loss.

But as discussed above, not having reciprocal insurance undertakings can void or cap the indemnity undertakings under applicable state laws, like those of Texas that require mutual indemnities supported by insurance.

We will also sometimes see contracts that contain reciprocal knock-for-knock indemnity undertakings that obligate each party to place insurance and name and waive the other party's group but limit the naming to some dollar amount below the actual limits of the naming party's liability program. We assume the thought is to protect the indemnitor's insurance from a "limits loss."

It is a worthy goal to protect your insurance program from excessive claims, but this approach may be short-sighted as the indemnity at issue likely is not capped or limited. Absent the application of the Texas Oilfield Anti-Indemnity Act (which should limit an indemnity obligation to the extent of available insurance), it is possible that insurers may try to avail themselves of a limit on liability and leave the indemnitor to bear the loss above that amount.

Drafting issues

In addition to the impact of anti-indemnity laws, there are a number of other potential problems that need to be addressed in drafting indemnity provisions.

Poorly drafted clauses. Clauses are occasionally poorly drafted and may include errors resulting from "cutting and pasting" provisions from other agreements, which can result in incorrect descriptions of the parties owed indemnity, undefined or incorrectly used terms, and the like. Agreements also can unintentionally fail to comprehensively describe the activities that are covered by the indemnity (e.g., ingress and egress to work sites, loading and unloading of vessels).

The best way to avoid this issue is to have clearly defined terms that can be used throughout the agreement, including a definition for "Claims" that is appropriately broad (e.g., includes attorney's fees; costs of litigation, such as experts; interest charges), as well as a clear definition of the "Groups" to be indemnified and named and waived on insurance coverages.

Failure to meet applicable legal requirements. A knock-for-knock indemnity can obtain the desired benefit only where parties are indemnified for losses that result from their own negligence. Most jurisdictions require that such an indemnity be "expressly" stated and be conspicuous to the parties, which usually means the relevant wording is capitalized, in bold, and/or underlined. Otherwise, the parties are back to hiring counsel to determine percentages of fault for all involved.

One consideration here is whether the indemnity will extend to claims resulting from the indemnitor's sole or gross negligence. Some parties find this idea offensive and exclude such claims from the scope of the indemnity. Others want to include it for fear of having counsel engage in protracted—and expensive—efforts to show that a given claim fits within the exception such that no indemnity is owed.

An indemnity scheme also needs to be drafted in consideration of applicable state law prohibitions against protecting a party from the consequences of its own gross negligence or willful misconduct.

Sometimes indemnity undertakings will include provisions that seek to require courts to "reform" them if they are contrary to applicable law and in lieu of a court's just holding that they are unenforceable.

Failure to require the correct insurance. Contracts must clearly specify the insurance needed to support the risk allocations and indemnity undertakings in the agreement. This will be driven by the scope of work and include, as examples, operator's extra expense coverage for a contract calling for the drilling of a well or hull, and protection and indemnity and vessel pollution insurance in a contract requiring work using a vessel.

Contractual risk allocations are of paramount importance to E&P companies when engaging vendors and suppliers. To this end, steps must be taken to ensure the indemnities and associated insurance undertakings are appropriate in scope and enforceable.

Ideally, form agreements will anticipate operations that may require additional, specialized insurance and will state that such coverages will be placed "as needed" (e.g., a provision requiring aircraft liability coverage if any aircraft are used in performance of the work).

In addition to specifying the required coverages, the agreement needs to clearly state the endorsements and modifications such coverages need so that they will properly support the risk allocations in the agreement. Examples include making the indemnitor's coverage primary to the extent of the indemnity, requiring that parties be made an "alternate employer" with a waiver of subrogation on workers' compensation policies where "naming" them as additional insureds is not appropriate, and obligating insurers to pay for "voluntary" removal of wreck or debris.

As insurance is being relied on to finance the contractual indemnity, the agreement should require insurer notice to additional insureds 30 days prior to the cancellation of coverage. Parties may also want to seek prior notice of any "material changes" to coverage, but insurers and brokers don't usually agree to this for fear of litigation over what was material.

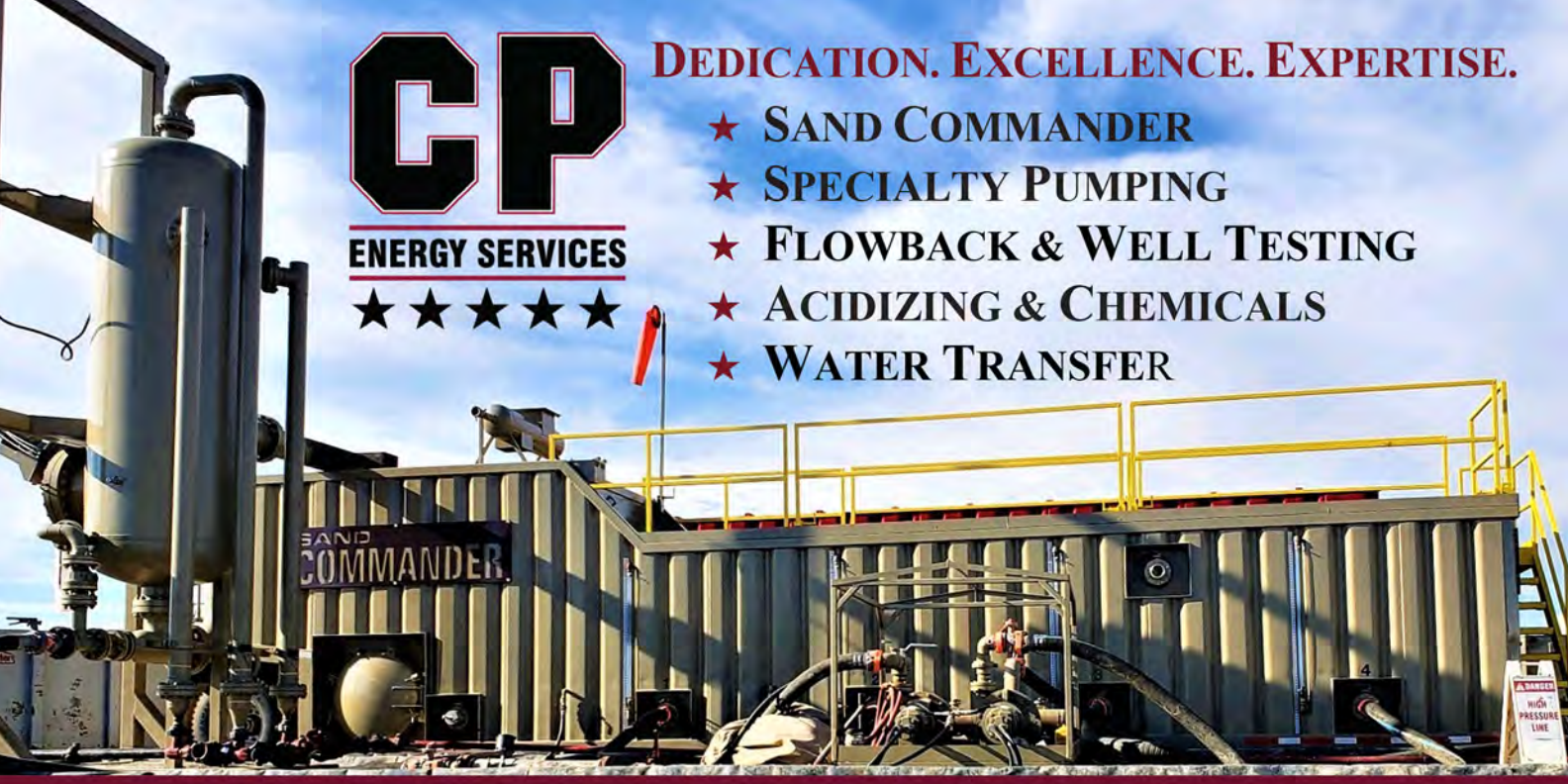
The agreement should also specify who will bear any deductible (usually the party owing indemnity).

Conclusion

Contractual risk allocations are of paramount importance to E&P companies when engaging vendors and suppliers. To this end, steps must be taken to ensure the indemnities and associated insurance undertakings are appropriate in scope and enforceable. ☐

Jim Noe is a partner at Jones Walker LLP who represents energy industry clients in transactions, disputes and government relations matters. He also managed multibillion-dollar LLOYDS of London insurance programs and administered risk management and claims management programs.

Tim Woodard is Head of Office – Louisiana for Lockton Companies, where he focuses on delivering risk management advice and insurance solutions to companies in the Marine and Energy industries.



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THE NEW ENERGY WORLD

Baker Hughes CEO Lorenzo Simonelli discusses the digital transformation, offshore technology, LNG, the energy transition and more.

ARTICLE BY
LEN VERMILLION

As an energy technology company, Baker Hughes' portfolio spans across oil and gas, alternative and renewable energy, as well as other industrial sectors, making it well positioned to respond to various market opportunities.

Lorenzo Simonelli, chairman and CEO of Baker Hughes, recently provided an exclusive interview to Hart Energy in which he shared his views on the way forward for oilfield service companies in a post-pandemic future.

The following is a reproduction of that Q&A, edited for style and clarity. The original Q&A as well as an accompanying video interview with Hart Energy's editorial director, Len Vermillion, can be found in the October 2020 issue of E&P Plus (https://epplus.hartenergy.com/issue/october-2020).

What will the oil and gas industry look like as it moves forward into a post-pandemic world? What does a field service company look like to you in the future? How is your company positioned to make that shift? How is digital helping make that shift possible?

Now more than ever, our customers will demand technology and solutions to support the productivity and efficiency of their operations, both to achieve their carbon reduction goals and to navigate the current macro environment. This gives us an opportunity to engage with customers on new commercial models based on outcomes and new technical and operational solutions focused on transforming efficiency, reducing emissions and maximizing shared value.

For example, the COVID-19 pandemic has accelerated deployment and utilization of remote and virtual operations. Remote drilling services, critical asset monitoring and virtual equipment testing limits HSE risks and nonproductive time, and it allows us and our customers to operate more effectively and efficiently.

Many of these capabilities also are beginning to be further enabled by the convergence

"The COVID-19 pandemic has required employees and customers to embrace new digital tools at an accelerated rate. For that reason, COVID-19 might be a digital tipping point. It's reduced the barrier to change, and we are seeing the benefits."

of digital technologies and artificial intelligence [AI] that will lead to more transformative outcomes and even higher levels of efficiency and productivity.

Where do you see offshore fitting in this new energy world?

Offshore will require continuous innovation to improve economics on both current and new projects, and digital capabilities will need to be expanded to enable further remote operations.

Already, our Subsea Connect business model helps customers accelerate time to production, maximize recovery over the life of the field and reduce their total expenditures. By connecting various work streams in a subsea development, we can fundamentally improve project economics—lowering the economic development point of individual subsea projects by up to 30%. That means adding tangible value to planned developments and potentially transforming uneconomic offshore assets into newly viable opportunities.

As we continue to lead in technology for the offshore space, access to reliable power will remain essential. We are currently developing new technology to provide high-voltage electric power distribution to subsea developments. Our high-voltage connectors for traditional subsea power distribution also have applications for the floating wind segment, which we can support with monitoring devices to detect costly and critical turbine failure modes.

Baker Hughes released its "Energy Forward: 2019 Report on Corporate Responsibility" in August 2020.

The oil and gas industry has a bit of a reputation for being slow adopters of new technology. How do you see the current downturn impacting technology adoption?

The rate at which our industry adopts new technology will likely accelerate. The industry has innovated before, but it tends to innovate from within, and we need to learn from other industries. The COVID-19 pandemic has required employees and customers to embrace new digital tools at an accelerated rate. For that reason, COVID-19 might be a digital tipping point. It's reduced the barrier to change, and we are seeing the benefits.

For instance, new digital solutions have proven vital to business continuity during the pandemic, ensuring customer projects move forward despite COVID-19 travel and social distancing restrictions.

As a result, an increasing number of customers are showing interest in our remote drilling services. We now deliver more than 70% of our drilling services remotely, up significantly from about 50% in 2019. Remote drilling is the new normal.

The benefits of remote operations extend well beyond business continuity and safety. We have been able to drive cost efficiencies, improve productivity, enhance well performance, reach new technical milestones and reduce emissions.

How is your company helping to transform the LNG space?

Baker Hughes has a long heritage of LNG innovation, built on a 30-plus years' experience in the space, and we have continuously invested in turbine and compressor technology. We also have paired our LNG technology with leading execution, testing, sensing and monitoring capabilities to increase project efficiency and productivity while reducing risks, total costs and carbon footprint.

For instance, our turnkey liquefaction modules shorten lead times to engineer equipment and simplify manufacturing and installation processes. The modules, proven in the most extreme conditions, can integrate with auxiliary systems and controls, so we can connect everything before delivery to further reduce project disruption. This can reduce installation time and costs by up to 30%.

Going forward, we have an important role to play as a partner to LNG customers by helping them lower their carbon footprint through our

gas turbine and compressor technologies.

One of the key differentiators is our LM9000 aeroderivative turbine. The LM9000 was recently validated as the world's most efficient simple cycle gas turbine in its class after its First Engine to Test for Novatek' Arctic LNG 2 project—a key milestone for the ongoing development of our technology.

With our installed base of over 400 mtpa of liquefaction equipment globally, our LNG service portfolio is uniquely positioned to offer upgrades and technology services that can extend equipment life, enhancing availability and performance, and contribute to further emissions reductions. This includes expanding our gas turbines' fuel flexibility, specifically around hydrogen blends, and applying technology to reduce potential methane leaks.

Disruption became the new normal years ago. It seems like the cycles of change are speeding up. How do you lead a company or go about planning for the future when those plans could become obsolete within minutes of being made?

In times like these, it is best to focus on what we do know and what we can control. We know that the world needs more energy, and the world needs more from energy. And we don't see that changing short term or long term.

For that reason, our purpose is clear, and our commitment is firm. We make energy safer, cleaner and more efficient for people and the planet.

I am proud that our people push the boundaries of what's possible. We use technologies that explore the future of design and manufacturing, AI and computing at the edge to evolve our portfolio to lead through the energy transition as a company and for our customers.

> "There is not one perfect energy solution without impacts to consider and mitigate. We need to continue driving informed discussions and cross-industry collaboration to overcome challenges and maintain a license to operate long term."

In early 2019, Baker Hughes was among the first in the industry to make a commitment to achieve net-zero carbon emissions from our operations by 2050 as well as use our own portfolio to help the industry control and reduce its emissions.

Ultimately, this commitment plays an important part in driving our strategic decision-making and R&D approach. Maintaining focus allows us to manage across market cycles in pursuit of a low- to zero-carbon energy future.

There are many E&Ps and service companies struggling and looking for a new strategy in today's environment. What would you say differentiates your company from others?

As an energy technology company, Baker Hughes stands apart from other service companies for its ability to offer truly differentiated technology at scale across a variety of energy sources—from oil and gas to alternative and renewable energy.

The scope and scale of our portfolio gives us a unique advantage to bring the most complete suite of low-carbon solutions to energy

BAKER HUGHES

Baker Hughes recently announced the successful test and application of the world's first hydrogen blend turbine for gas networks. The NovaLT12 turbine was tested in Florence, Italy, and it showed the turbine can be powered by a blend of up to 10% hydrogen and is capable of burning up to 100% hydrogen.

"I am proud that our people push the boundaries of what's possible. We use technologies that explore the future of design and manufacturing, AI and computing at the edge to evolve our portfolio to lead through the energy transition as a company and for our customers."

and other industrial markets. This is a capability our customers require and look for to reduce the carbon intensity of their operations, particularly on major projects.

We also continue to innovate on new low-carbon products and services to help our customers reduce their emissions within oil and gas operations as well as to support the future energy mix. Capabilities such as carbon capture, use and storage; hydrogen; and energy storage are becoming more relevant. These are all areas in which core technology can be applied today as our customers lean into the energy transition.

Internally, we have also taken several concrete steps to advance our own energy transition strategy. This includes actively reducing our emissions by conducting hundreds of facility energy audits as well as increasing our share of energy purchased from renewable sources.

With more people working remotely and in more dangerous locations, it appears the opportunities are limitless for digital systems. Where does digital—quite possibly the greatest disruptor of all—go from here?

Digital technologies are now fundamental to navigating today's market realities and tomorrow's uncertainties. The industry must find ways to reduce operating costs, maintain critical asset reliability and enable remote operations in order to survive.

Remote drilling services existed in various forms over the last two decades, but today restrictions due to COVID-19 limit travel and require social distancing at rig sites. In some instances, this means that if we can't drill or complete a well remotely, we can't drill or complete the well at all.

In order to overcome these challenges, the industry is accelerating adoption of differentiated technologies. As businesses gain more comfort with remote operations, we envision moving more personnel off the rig site and into a centralized location to further reduce costs and minimize HSE risks.

Digital technologies like AI are also helping to grow and enhance predictive maintenance, production optimization and energy management. The industry can benefit today from the deployment of AI because the underlying infrastructure is in place. AI is now an important mechanism to deliver productivity, efficiency and safety.

Our BakerHughesC3.ai joint venture alliance is critical to delivering enterprise-scale AI applications that energy companies can adopt across all sectors.

Climate change remains a dominant topic of conversation and concern. ESG is a front-burner issue for many investors and E&P companies. In building a new energy system that is renewable or more sustainable, how do we ensure the hard lessons taught to and learned by those in the oil and gas space are not repeated in this new energy system? Put another way, how do renewables learn from and not make the mistakes of fossil fuel?

One lesson the renewable power industry can learn from the oil and gas industry is to consider the full life cycle of operations and to be transparent with the public about that process early on, encouraging ongoing two-way dialog to build trust.

This is critical to helping people understand, assess and support the trade-offs required—costs and benefits as well as risks and rewards—in the development and use of various sources of energy.

For instance, renewables companies use oil and gas power generation during their manufacturing and disposal processes. And increasingly, oil and gas companies use renewables to power their manufacturing processes. We do as well.

In 2019, we announced a new agreement to purchase renewable electricity for our facilities in Texas, our largest global region for energy consumption. The renewable power agreement will eliminate a substantial portion of Baker Hughes' global carbon equivalent emissions over the 10-year term of the agreement.

There is not one perfect energy solution without impacts to consider and mitigate. We need to continue driving informed discussions and cross-industry collaboration to overcome challenges and maintain a license to operate long term.

We will also need a variety of energy sources to meet the dual challenges of decreasing carbon intensity, while increasing access to energy. Only by working in partnership will we be able to tackle the dual challenge successfully.

What advice do you have for those inventors of the next great technology that are struggling to get it accepted or adopted by the industry?

As I lead a company of inventors driven by continuous innovation, my advice is to focus on the outcome delivered by new technologies, not simply the applications. We also must accelerate the development of technologies as we enter the next few years and the energy mix changes, so speed is critical.

The energy transition to low- to zero-carbon solutions by 2050 is one of the greatest opportunities for innovation we've seen. We need inventors to think differently and at scale to help us take energy forward. □

ConocoPhillips To Buy Concho Resources

CONOCOPHILLIPS CO. agreed to acquire Permian Basin shale producer **Concho Resources Inc.** on Oct. 19 in an all-stock transaction valued at $9.7 billion.

The announcement continues a wave of consolidation across the E&P space, which has largely been shunned by investors due to the sector's reputation of generating poor returns. The trend is expected to continue as many believe it signals a path forward for the troubled U.S. shale patch.

"The leadership and boards of both companies believe today's transaction is an affirmation of our commitment to lead a structural change for our vital industry," ConocoPhillips chairman and CEO Ryan Lance said in a statement.

The transaction is the largest upstream merger entirely focused on shale since BHP bought Petrohawk for $15 billion in 2011, according to **Enverus** senior M&A analyst Andrew Dittmar.

"Conoco's patience waiting for the right deal appears well rewarded as the company is picking up one of the premier positions in the Permian at a fraction of the cost of other large deals in the basin over the last few years on a dollar per acre basis," Dittmar said in a statement.

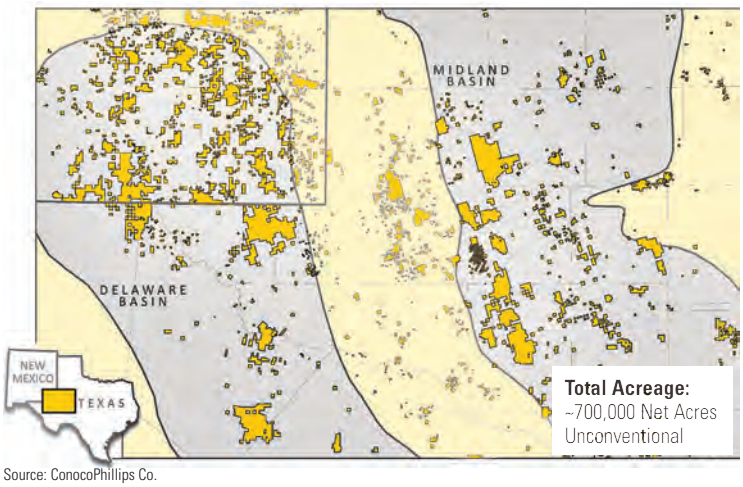
Based in Midland, Texas, Concho Resources is one of the largest unconventional shale producers in the Permian Basin, with a roughly 800,000 gross (550,000 net) acre position in both the Delaware and Midland sub-basins. The fifth-largest producer by volume in the Permian Basin, the company's total production for the second quarter was 319,000 boe/d.

Together, the companies will have about 700,000 net acres in the Permian Basin. The expanded Permian position provides a strong complement to ConocoPhillips' other globally diverse, low-capital-intensity legacy positions, according to a joint release from the companies.

Upon closing, Concho's chairman and CEO, Tim Leach, will join ConocoPhillips' board of directors and executive leadership team as executive vice president and president of Lower 48.

"From our position of strength and in light of market trends, our board of directors and management team evaluated a wide range of options and unanimously determined that combining with ConocoPhillips is the best path forward for Concho and our shareholders," Leach said in a statement.

ConocoPhillips-Concho Permian Acreage



Source: ConocoPhillips Co.

The deal swaps 1.46 shares of ConocoPhillips for each Concho share, which Dittmar described as a moderate premium of 15% to Concho's share price before rumors of a deal began to swirl on Oct. 13. Concho shares the morning of Oct. 19 were up a fraction at $48.65.

The combined company will have an approximately $60 billion enterprise value. Additionally, the companies expect to capture $500 million of annual cost and capital savings by 2022.

The new ConocoPhillips will also be the largest independent oil and gas company, with pro forma production of over 1.5 MMboe/d. In addition to its "core-of-the-core" acreage positions in the Permian Basin, the company will also have leading positions in the Eagle Ford and Bakken in the Lower 48 and the Montney in Canada.

Lance continued, "Opportunities to consolidate quality on the scale of these two companies do not come along often, so we are seizing this moment to create a company to lead the necessary transformation of our vital sector for the benefit for all stakeholders in the future."

In total, over $30 billion in announced E&P mergers are now on the books for 2020 including two deals over $10 billion. Even after this year's merger activity, Dittmar believes there is still room left for the shale industry to consolidate. A limiting factor, he said, will be the number of attractive sellers and buyers available.

"Even the total dollar amount transacted significantly understates the scale of consolidation going on in the industry given still depressed equity prices relative to past years," he said adding, "This is a historic turning point in the development of U.S. unconventional resources."

Dittmar sees other well-positioned independents in the Permian Basin with reasonable debt loads the most likely best prospects for a deal.

In light of the pending acquisition, ConocoPhillips said it has suspended share repurchases until after the deal closes. The transaction, subject to the approval of both ConocoPhillips and Concho stockholders, is expected to close in first-quarter 2021.

Goldman Sachs & Co. LLC is exclusive financial adviser to ConocoPhillips for the transaction, and **Wachtell, Lipton, Rosen & Katz** is serving as its legal adviser. **Credit Suisse Securities (USA) LLC** and **J.P. Morgan Securities LLC** are financial advisers to Concho. **Sullivan & Cromwell LLP** is legal adviser to Concho.

—Emily Patsy

Devon, WPX Energy Agree To Blockbuster Merger

DEVON ENERGY CORP. and **WPX Energy Inc.** agreed on Sept. 28 to combine in an all-stock transaction the two U.S. shale producers called a "merger of equals."

The combined company, which will be named Devon Energy, will create a leading unconventional oil producer in the U.S. with a dominant Delaware Basin acreage position totaling 400,000 net acres. Including the assumption of $3.2 billion in net debt, the all-stock transaction is valued at about $5.75 billion.

WPX chairman and CEO Rick Muncrief will serve as president and CEO of the combined company. Meanwhile, Dave Hager, Devon's current president and CEO, will serve as executive chairman of the combined company's board.

The combined company's executive team will also include Devon's Jeff Ritenour as executive vice president and CFO and WPX's Clay Gaspar as executive vice president and COO.

"This merger is a transformational event for Devon and WPX as we unite our complementary assets, operating capabilities and proven management teams to maximize our business in today's environment, while positioning our combined company to create value for years to come," Hager said in a news release.

Muncrief added that the "merger of equals" will help achieve the five-year targets WPX outlined in late 2019 alongside an agreement to acquire **Felix Energy II**, which boosted its position in the Delaware Basin.

"The combined company will be one of the largest unconventional energy producers in the U.S. and with our enhanced scale and strong financial position, we can now accomplish these objectives for shareholders more quickly and efficiently," he said in the statement.

The combined company will pursue a disciplined strategy with management committed to limiting reinvestment rates to approximately 70% to 80% of operating cash flow and restricting production growth to 5% or less annually. Targeting a cash-returns business model, free cash flow will be deployed by the combined company toward higher dividends, debt reduction and opportunistic share repurchases, the companies said in the joint release.

The companies expect capital activity plans of the combined company to focus on maintaining base production. Detailed forward-looking guidance for the full-year 2021 will be provided upon closing of the transaction, expected first-quarter 2021.

DEVON ENERGY CORP.

Maintenance capital of about $1.7 billion will keep oil production flat in 2021 versus 2020 fourth-quarter exit rates, an average of 280,000 bbl/d. Pro forma for cost synergies, these maintenance capital requirements in 2021 are estimated to be funded at $33 WTI and $2.75 Henry Hub pricing, according to the joint release.

Combined, the companies produce 277,000 bbl/d of oil with the Delaware Basin accounting for nearly 60% of the combined company's total oil production.

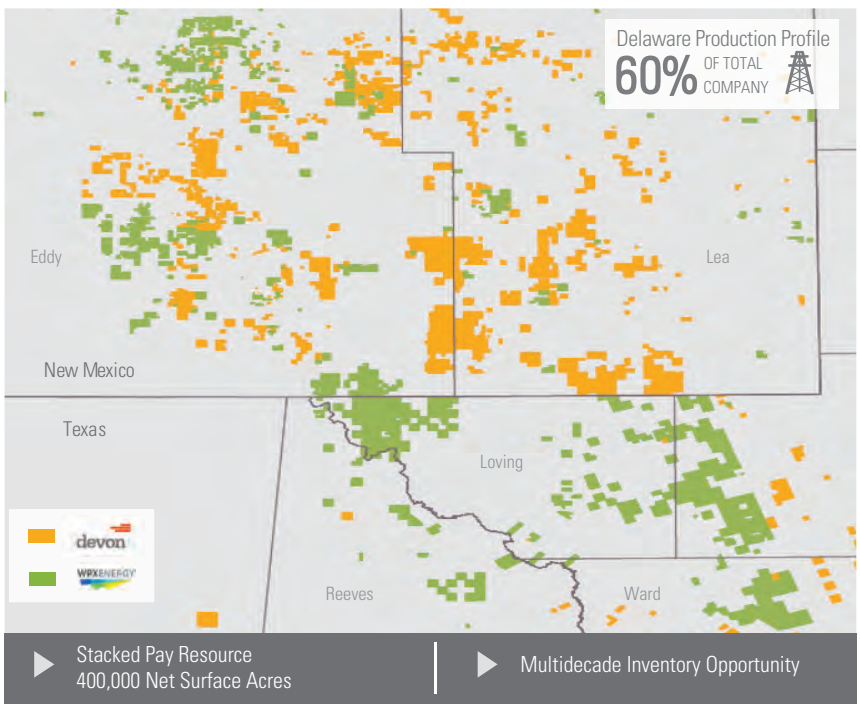
In addition to its position in the Permian's Delaware sub-basin, Devon's operations are focused in the Eagle Ford, Anadarko Basin and Powder River Basin. WPX also holds a large position in the Bakken and Three Forks plays within the Williston Basin.

"In our view, the merger would address DVN's risk to federal acreage into the election and creates a larger entity better able to navigate the current landscape," Gabriele Sorbara, equity research analyst with **Siebert Williams Shank & Co. LLC**, wrote in a Sept. 27 research note.

WPX holds roughly 30,000 net acres exposed to federal lands out of a total about 160,000 net acres in the Delaware Basin. Meanwhile, about 55% of Devon's Delaware Basin acreage and 60% of its Powder River Basin acreage is exposed to federal lands, according to Sorbara.

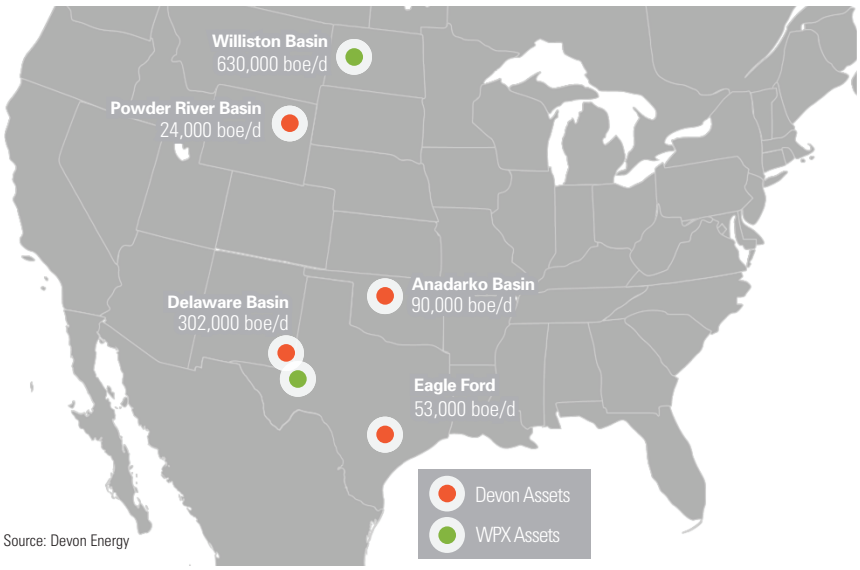
He expects the merger would be slightly dilutive to Devon's free cash flow profile while also increasing the company's oil mix with WPX's oilier asset base enhancing margins.

Combined Devon/WPX Delaware Basin Acreage



Source: Devon Energy

Combined Devon/WPX Assets



Source: Devon Energy

"While all the metrics are not directionally favorable, DVN is trading at a cheaper valuation and with the recent M&A chatter and deal speculation in the market, we believe a negative potential outcome was likely reflected in current depressed valuation," he wrote. "Specifically, DVN trades at half turn discount to peers on 2021 EV/EBITDA and is down 69.5% YTD (vs. peers, which are down 62.8% YTD)."

WPX Energy spent $2.75 billion to enter the Permian Basin in 2015 by acquiring **RKI Exploration & Production**. The company also added onto its Permian position in 2017 with the closing of a $775 million deal for **Panther Energy**.

Earlier this year, WPX grew its Delaware position with the $2.5 billion acquisition of Felix Energy II. In 2016, Devon closed the purchase of Felix Energy I's position in the STACK play within the Anadarko Basin. Both Felix Energy I and II were backed by **EnCap Investments LP**.

Upon completion of Devon and WPX's combination, Devon shareholders will own approximately 57% of the combined company and WPX shareholders will own about 43%. Funds managed by EnCap Investments own approximately 27% of the outstanding shares of WPX and have entered into a support agreement to vote in favor of the transaction.

Devon and WPX said the combination represents an enterprise value of about $12 billion.

J.P. Morgan Securities LLC is financial adviser to **Devon. Skadden, Arps, Slate, Meagher & Flom LLP** is legal adviser. **Citi** is WPX's financial adviser. **Kirkland & Ellis LLP** is its legal adviser. **Vinson & Elkins LLP** is legal adviser to EnCap.

—Emily Patsy

Callon Trims Eagle Ford, Permian Assets

CALLON PETROLEUM CO. agreed to $170 million in asset sales on Oct. 1 as the U.S. shale producer eyes paring down its debt.

The sale includes the monetization of approximately 3.5% of Callon's current daily production in both the Eagle Ford Shale and Permian Basin with a resulting average net revenue interest (8/8ths basis) of over 74% for both the company's existing producing wells, as well as its undeveloped location inventory.

The larger of the two monetizations was the sale of an overriding royalty interest in substantially all Callon-operated oil and gas leaseholds to a private investment vehicle managed by private-equity firm **Kimmeridge Energy** that generated gross cash proceeds of $140 million. Callon also issued $300 million of principal value second lien secured notes to Kimmeridge.

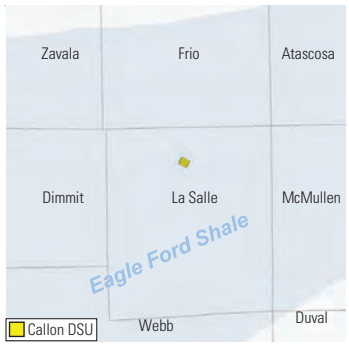
In a separate transaction, Callon said it had agreed to sell substantially all of its nonoperated assets for gross cash proceeds of $30 million to an undisclosed buyer. Current production from the assets, located in both the Permian Basin and Eagle Ford Shale, is approximately 1,600 boe/d (55% oil).

In addition to dealing with the market crash spurred by the coronavirus, Callon has still been digesting its multibillion-dollar acquisition of **Carrizo Oil & Gas**, which boosted its footprint in the Permian as well as added a position in the Eagle Ford Shale. The $2.7 billion all-stock transaction, which included the assumption of $1.96 billion net debt and preferred stock, closed last December.

"While we weren't the biggest fans of the [Carrizo] transaction, the deal has proven to be both a blessing and a curse as the Eagle Ford provides shorter-cycle opportunities to reallocate capital away from the Delaware, but the resulting debt wall may prove difficult to manage in this commodity price environment," analysts with **Tudor, Pickering, Holt & Co.** (TPH) wrote in a research note in March 2020.

According to the TPH note, Callon has $650 million bonds maturing in 2023. Beyond this, the company has $600 million due 2024, $250 million due 2025 and $400 million due 2026 along with about $1.3 billion drawn on the revolver maturing year-end 2024.

Callon Eagle Ford And Permian Asset Overview



Permian Basin Overview

- Core nonoperated working interest position across the Delaware and Midland basins
- Diversified base of production: 1,200 net boe/d (62% oil)[1] from 143 producing horizontal wells
- 2021 PDP Cash Flow: $6.5 million[2]
- PDP + DUC + Permit PV10: $28.1 million[2]
- Exposure to a substantial, de-risked inventory of undeveloped locations
- —Tier 1 Stacked Pay: 9 proven zones identified across both basins

Eagle Ford Overview

- Well-positioned nonoperated working interest located in the Eagle Ford—La Salle County, Texas
- Three units operated by Chesapeake Energy (100% HBP)
- Net production of 165 boe/d (91% oil)[1] from 11 producing horizontal wells
- 2021 PDP Cash Flow: $883,0002[2]
- PDP + DUC + Permit PV10: $3.3MM[2]

1) September 2020 projected daily production 2)Price Deck: July 6th, 2020 NYMEX Strip
Source: Callon Petroleum Co., TenOaks Energy Advisors

Joe Gatto, Callon's president and CEO, said the transactions on Oct. 1 represent an important step forward in improving the company's liquidity position, which he added is one of Callon's stated goals.

"Absolute debt reduction is also accelerated, complementing our free cash flow generation that has been bolstered by the significant synergies realized from the Carrizo acquisition," Gatto said in a statement in an Oct. 1 company release.

Total gross cash proceeds from the combined transactions will be roughly $465 million after original issue discount, according to the company release. In particular, the proceeds of the Kimmeridge transactions will be used to reduce borrowings on Callon's credit facility by nearly a third to approximately $1 billion.

"We will continue to pursue initiatives that improve our financial position and are encouraged by the expanding spectrum of actionable alternatives that have emerged as we execute on our strategic plan as a scaled operator in premier operating areas," Gatto continued.

Additionally, Callon said it had completed the fall borrowing base redetermination for its senior secured credit facility resulting in a reaffirmation of Callon's borrowing base at $1.7 billion. The borrowing base and elected commitment were subsequently reduced to $1.6 billion in consideration of the ORRI sale and total second lien notes capacity.

Callon estimates its pro forma liquidity after transaction expenses is $600 million, with the next regularly scheduled borrowing base redetermination in spring 2021.

The ORRI sale consists of a 2% (on an 8/8ths basis) ORRI, proportionately reduced to Callon's net revenue interest, in substantially all Callon-operated oil and gas leaseholds with an effective date of Oct. 1.

The sale of Callon's nonoperated working interest portfolio is expected to close in November. The company had retained **TenOaks Energy Advisors LLC** to market the package of Permian Basin and Eagle Ford assets in July.

Jefferies LLC was financial adviser to Callon for the issuance of the second lien notes and for the ORRI transaction. **RBC Capital Markets** was lead financial adviser for the ORRI transaction. **Kirkland & Ellis LLP** was legal adviser to Callon for the issuance of the second lien notes and for the ORRI transaction.

Barclays was exclusive financial adviser to Kimmeridge. A team from **Sidley Austin LLP** led by Irving Rotter acted as Kimmeridge's legal adviser.

—Emily Patsy

Approach Resources Hitches Saddle To New Buyer

HAVING THROWN its first stalking horse bidder, bankrupt Permian operator **Approach Resources Inc.** appears to be headed toward a sale again—albeit for less than two-thirds of the original sales price.

Affiliates of **Zarvona Energy LLC** entered an agreement to purchase essentially all of the assets of Fort Worth, Texas-based Approach Resources for $115.5 million, according to court documents. Approach Resources holds about 113,000 net acres in the southern Midland Basin as well as gas and water infrastructure.

Previously, Approach had agreed to sell its assets in what had been the largest first-quarter deal to an affiliate of **Alpine Energy Capital** for $192.5 million.

The Alpine deal, however, was terminated on March 26 based on "inaccurate factual allegations and was legally ineffective," according to Approach Resources' regulatory filings with the Securities and Exchange Commission. Alpine demanded more than $20 million in settlement fees, which Approach Resources said were paid in July.

At one time, Approach's leasehold spanned 149,000 gross acres. The company said in 2018 it had 1,350 potential horizontal drilling locations across three Wolfcamp benches.

Approach Resources' assets are largely located in the Wolfcamp Shale in Crockett and Schleicher counties, Texas. The company's production for the nine months ended September 2019 totaled 9,700 boe/d, a 15% decrease over the same period in 2018. Production at the time consisted of 23% oil, 36% NGL and 41% gas.

In late 2018, Approach began to struggle with maintaining operations when pipeline constraints forced natural gas prices at the Waha hub in the Permian Basin to tumble to their lowest on record. As a result, the company began deferring most of its drilling and completions activity beginning in third-quarter 2018.

In May 2018, the company estimated its enterprise value at $637 million. Six months later, Approach Resources and its affiliates entered bankruptcy with nearly $3.7 billion in debt. As part of the voluntary Chapter 11 filing in the U.S. Bankruptcy Court for the Southern District of Texas (Houston Division), Approach began exploring strategic alternatives.

Approach has continued to operate through bankruptcy with debt-or-in-possession financing.

Approach Resources engaged **Perella Weinberg Partners LP** to act as its investment banker in connection with the Chapter 11 case, including to advise the company in its exploration of these strategic alternatives. The company was also assisted by **Alvarez & Marsal North America LLC** as financial adviser and **Thompson & Knight LLP** as legal advisers.

—Darren Barbee

Blackstone Sells $7 Billion Stake In Cheniere

BLACKSTONE CLOSED on Sept. 24 closed the sale of its stake in **Cheniere Energy Partners LP** valued at $7 billion, representing the culmination of the firm's involvement with the Houston-based LNG producer.

In 2012, **Blackstone Energy Partners** and its affiliates invested $1.5 billion in Cheniere Energy Partners to build the first two liquefaction trains at the Sabine Pass LNG facility in Louisiana—the first LNG export facility in the Lower 48.

"Blackstone's early equity commitment to Cheniere enabled the timely construction of Sabine Pass, the first LNG export facility in the Lower 48 states and one of the largest construction projects in the U.S.," David Foley, global head of Blackstone Energy Partners, said in a Sept. 24 news release.

Blackstone sold the approximately 42% stake in Cheniere Energy Partners to **Brookfield Infrastructure** and funds managed by **Blackstone Infrastructure Partners**.

Cheniere CEO Jack Fusco said in a released statement, "We still have much to accomplish at Cheniere, and I look forward to working alongside Blackstone Infrastructure Partners and Brookfield Infrastructure Management to achieve our shared goals."

CHENIERE ENERGY PARTNERS LP

Cheniere's Sabine Pass terminal in Louisiana sent out its first cargo in February 2016. The company also opened its $15 billion Corpus Christi LNG export facility in November 2018.

The company anticipates that Train 3 at its Corpus Christi LNG facility will begin operations in 2021 and Train 6 at the Sabine Pass LNG facility in 2022. An additional expansion at the Corpus Christi LNG facility is also in the works, according to the company's website.

Recently, **Abu Dhabi Investment Authority**—the United Arab Emirates' biggest sovereign wealth fund—disclosed a 5.05% stake in Cheniere Energy, according to a filing with the U.S. Securities and Exchange Commission.

Reuters on Sept. 16 reported the value of the stake at around $615 million, based on Cheniere's last traded price.

Jefferies LLC and **Morgan Stanley** were financial advisers to Blackstone Energy Partners. **Latham & Watkins** was its legal adviser. **Rothschild & Co.** was financial adviser to Blackstone Infrastructure Partners, while **Simpson Thacher & Bartlett** served as its legal adviser.

—Emily Patsy

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TRANSACTION HIGHLIGHTS

APPALACHIA

■ **EQT Corp.**, the largest U.S. natural gas producer by volume, has placed a bid on **Chevron Corp.**'s Appalachia gas properties and a pipeline stake, people familiar with the matter said.

EQT offered $750 million for the properties, one of the people familiar with the matter said.

Chevron last year said it was considering a sale of the properties and took an $8.17 billion charge to earnings to write down their value and an unrelated U.S. offshore project. Most of the impairment charge was for the gas properties.

Chevron is marketing about 800,000 acres in the Marcellus and Utica shale basins of Pennsylvania and neighboring states and a 31% nonoperating interest in **Laurel Mountain Midstream**, which has intrastate and gathering lines servicing the Marcellus shale area.

Bids for the properties were received on Aug. 12 and are being evaluated, Chevron said in response to inquiries. It declined to comment on the bids.

There is no guarantee the talks will lead to a sale to EQT or another company.

COLOMBIA

■ Debt-laden **Occidental Petroleum Corp.** said on Oct. 1 it agreed to sell its onshore assets in Colombia to private-equity firm **Carlyle Group Inc.** for $825 million.

The international energy company, based in Houston, said it is continuing to advance other asset sales as it tries to find cash to pay off debt amid a crude price crash. It has so far announced over $2 billion worth of divestitures this year.

The Colombia assets sale, expected to close in the fourth quarter, includes the company's operations and working interests in the Llanos Norte, Middle Magdalena and Putumayo Basins.

The company has operated in the Andean country alongside Colombia's majority state-owned **Ecopetrol** for more than 40 years. The two companies also have a joint venture in the Permian Basin in the U.S.

Occidental said it will retain a presence in the South American country through its offshore exploration blocks.

SERVICE & SUPPLY

■ **Calfrac Well Services Ltd.** investor **Wilks Brothers LLC** on Oct. 5 raised its hostile bid for the oilfield services company to as much as 25 Canadian cents per share from a prior 18 Canadian cents.

Calfrac last month rejected the prior offer and said it was sweetening its recapitalization plan to reduce debt, at a time when its market value has shrunk to about C$22.5 million since the crash in fuel demand caused by the COVID-19 pandemic.

Calfrac declined to comment on the offer. Its shares rose 3 cents to 18.5 cents in morning trading.

Wilks Brothers, led by oil billionaires Dan and Farris Wilks, has been acquiring stakes in hard-hit services firms in the United States and has been trying to buy Calfrac's U.S. business since July. The company owns nearly 20% of Calfrac.

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EASTERN US

1 ***DAC Energy & Drilling*** has added a fourth wildcat to its Menard County., Ill., drilling program. According to IHS Markit, the #5-1 Dart has a planned depth of 1,400 ft, and it will be in Section 3-19n-7w. The test is targeting Spechts Ferry (Lower Decorah), a nonproducing formation. The ventures are likely targeting Trenton, with the intent of drilling deep enough to completely penetrate Trenton. Only 30 wells have been drilled in the county, with the last venture in 2017. Offsetting DAC's proposed #5-1 Dart is #1 Dart Oil in Section 3-19n-7w. Permitted to 1,400 ft, the wildcat was junked and abandoned at 180 ft by ***Hicks Well Drilling***. Production in this part of Illinois comes from Morgan County's Prentice Field, about 20 miles to the southwest. Opened in 1953, recovery comes from pays in the Pennsylvanian. DAC Energy's headquarters are in Alma, W. Va.

2 A shallow exploratory test in southwestern Montgomery County, Ill., is planned by Paducah, Ky.-based ***Ronald D. Eggemeyer***. The venture, #1 Rose Simburger, will be in Section 33-8n-5w, and it has a planned depth of 750 ft. The Illinois Basin venture is targeting oil pays in Spoon (Pennsylvanian). One previous wildcat was drilled in Section 33 to the west-northwest at #1 J.B. Williams Estate, which was drilled in 1959 to 1,815 ft in Devonian. About 2 miles to the northwest of the planned well is Mount Olive Field. Mount Olive Field was opened in 1942, and production is from Pennsylvanian. Two Spoon oil wells in the field were drilled in 2014—#12 Taylor Hardt in Section 29-8n-5w pumped 1 bbl of crude and 10 bbl of water daily from a zone at 588-625 ft, and #13 Taylor Hardt in Section 29 pumped 2 bbl of crude per day from a zone at 592-602 ft.

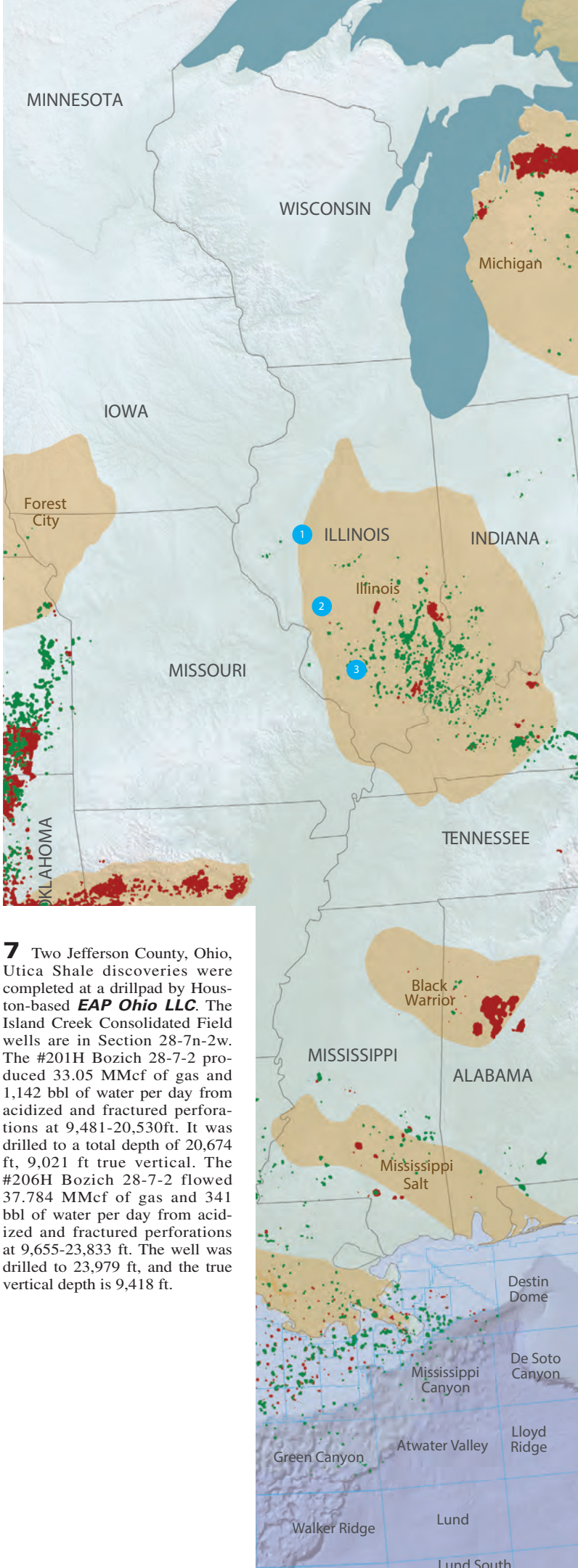
3 IHS Markit reported that Harrisville, Ill.-based ***KWR Ventures LLC*** has scheduled three 1,550-ft exploratory tests in Perry County, Ill., that will be targeting St. Genevieve oil pay. KWR's new locations are the company's first planned tests in the county. The #1-20 Opps will be in Section 20-5s-1w, #1-29 Opps will be in Section 29-5s-1w and #1 Tamaroa South Pier will be in Section 21-5s-1w. A nearby wildcat was drilled in 1978, at #1 W.C. McBride in Section 21, to 4,314 ft. A few oil wells in Tamaroa South Field are about 3 miles north of KWR's scheduled ventures, with the bulk of the field's wells another mile to the north. Opened in 1957, the Perry County reservoir yields crude from the Cypress Sand at around 1,100 ft.

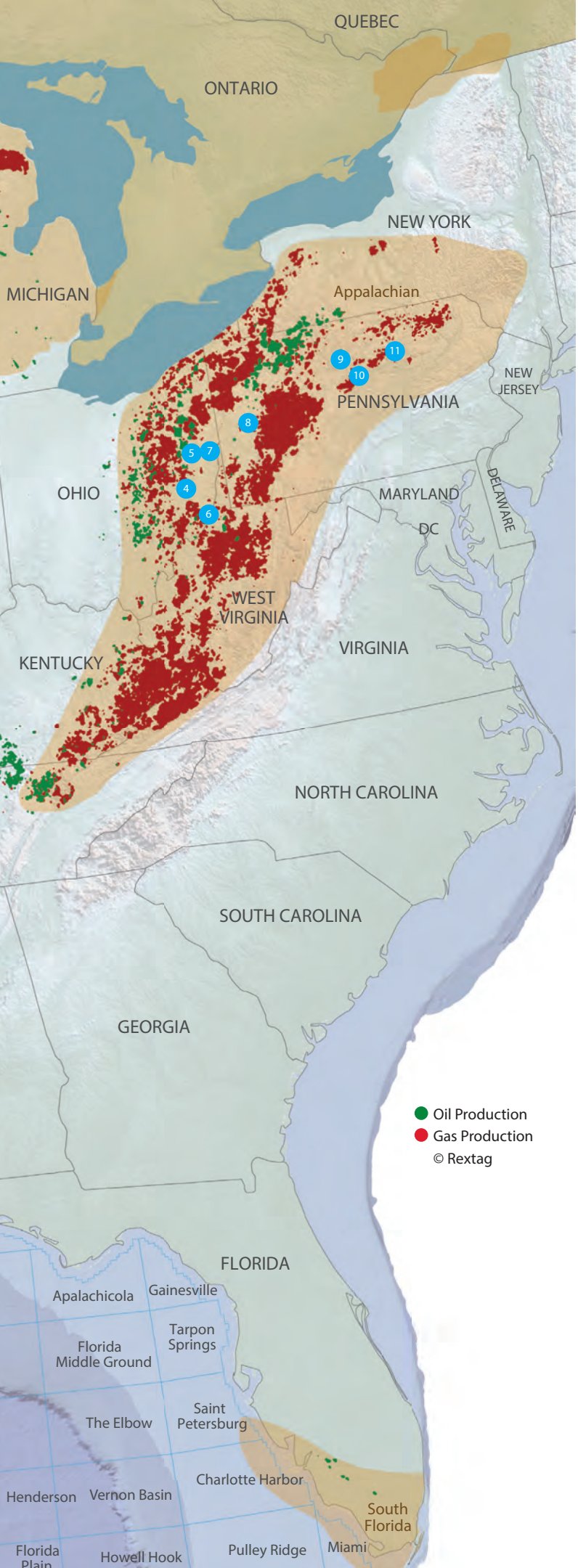
4 An ***Ascent Resources*** Utica Shale discovery was tested flowing 32.845 MMcf of gas and 139 bbl of water per day. The Belmont County, Ohio, well, #4H Bannock Unn BL, was drilled in Section 6-8n-5w. The Harrisville Consolidated Field completion reached 21,877 ft (9,170 ft true vertical). It was acidized and fractured, and production is from a perforated zone between 9,232 ft and 21,767 ft. Ascent is based in Oklahoma City.

5 A Harrison County, Ohio, Utica Shale discovery was announced by Oklahoma City-based ***Chesapeake Operating Inc***. The #5H McBride 20-11-4 initially flowed 36.506 MMcf of gas and 717 bbl of water per day. The well was drilled in Section 20-11n-4w in Kilgore Consolidated Field to 21,732 ft, with a true vertical depth of 8,359 ft. Production is from fractured perforations at 8,953-21,581 ft.

6 A Marcellus Shale completion was reported in Monroe County, Ohio, by ***Eclipse Resources*** at #8HM Bolen B-M. The Hannibal Field well initially flowed 523 bbl of oil, 7.21 MMcf of gas and 917 bbl of water per day after acidizing and fracturing. The venture is in Section 5-2n-4w and was drilled to a total depth of 22,246 ft, with a true vertical depth of 6,597 ft. Production is from a perforated zone at 7,052-22,081 ft. Eclipse Resources is based in Zanesville, Ohio.

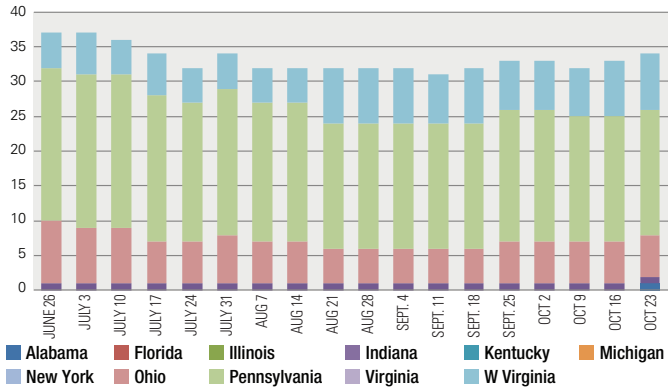
7 Two Jefferson County, Ohio, Utica Shale discoveries were completed at a drillpad by Houston-based ***EAP Ohio LLC***. The Island Creek Consolidated Field wells are in Section 28-7n-2w. The #201H Bozich 28-7-2 produced 33.05 MMcf of gas and 1,142 bbl of water per day from acidized and fractured perforations at 9,481-20,530ft. It was drilled to a total depth of 20,674 ft, 9,021 ft true vertical. The #206H Bozich 28-7-2 flowed 37.784 MMcf of gas and 341 bbl of water per day from acidized and fractured perforations at 9,655-23,833 ft. The well was drilled to 23,979 ft, and the true vertical depth is 9,418 ft.





Eastern US Rig Count

June 26, 2020-Oct. 23, 2020



Source: Baker Hughes Co.

8 Two Butler County, Pa., Marcellus Shale completions were announced by ***Penn Energy Resources***. The #5H PER W44 is in Winfield West Field and produced 4.44 MMcf of gas per day with a shut-in casing pressure of 1,361 psi. It was drilled to 14,721 ft with a true vertical depth of 6,704 ft. It is in Section 7, Worthington 7.5 Quad, Winfield Township, and production is from fractured perforations at 7,865-14,535 ft. The offsetting #2H PER W44 flowed 8.16 MMcf of gas per day after fracturing with a shut-in casing pressure of 1,286 psi. Drilled to 13,894 (6,589 ft true vertical), production is from a perforated zone between 7,250 ft and 13,600 ft. Penn Energy is based in Pittsburgh.

9 Results from four Tioga County, Pa., Marcellus Shale wells were announced by Spring, Texas-based ***Southwestern Production Co***. The wells were drilled from a drillpad in Section 4, Liberty 7.5 Quad, Liberty Township, in a new, unnamed field. The #1H Connolly B was drilled to 15,170 ft (7,059 ft true vertical) and flowed 21.55 MMcf of gas per day from perforations at 7,774-15,082 ft. The shut-in tubing pressure was 2,977 psi. The #2H Connolly B was drilled to 14,732 ft (7,058 ft true vertical) and produced 20.62 MMcf of gas per day from perforations at 7,244-14,658 ft. The shut-in casing pressure was 3,231 psi. The #3H Connolly B was drilled to 14,378 ft (7,027 ft true vertical) and flowed 21.02 MMcf of gas per day with a shut-in casing pressure of 3,136 psi. The #7H Connolly B was drilled to 14,519 ft (7,028 ft true vertical) and flowed 22.56 MMcf of gas per day from perforations at 7,474-14,442 ft. The shut-in casing pressure was 3,151 psi.

10 Two Lycoming County, Pa., Marcellus Shale discoveries were announced by ***ARD Operating LLC***. The wells were drilled from a Gamble Field pad in Section 6, Bodines 7.5 Quad, Cascade Township. The #7H-B David C Duncan was drilled to 18,585 ft, and the true vertical depth is 8,211 ft. It flowed 16.058 MMcf of gas per day from fractured perforations at 8,010-18,411 ft, with a shut-in casing pressure of 4,440 psi. The offsetting #9H-B Duncan David C was drilled to 19,865 ft, 6,527 ft true vertical, and produced 17.418 MMcf of gas per day from a fractured, perforated zone at 8,182-19,754 ft, with a shut-in casing pressure of 2,018 psi. ARD's headquarters are in Houston.

11 ***Chesapeake Operating Inc.*** completed three Mehoopany Field-Marcellus Shale discoveries from a pad in Section 1, Meshoppen 7.5 Quad, Meshoppen Township in Wyoming County, Pa. The #6H Hunter was drilled to 17,730, 7,697 ft true vertical, and initially flowed 46.507 MMcf of gas per day with a shut-in casing pressure of 3,397 psi. Production is from perforations at 7,898-17,712 ft. The #23HC Hunter was drilled to 19,280 ft, 7,150 ft true vertical, and produced 45.49 MMcf of gas per day with a shut-in casing pressure of 3,378 psi from perforations at 8,209-19,243 ft. The #5H Hunter was drilled to 14,839 ft, 7,639 ft true vertical, and was tested flowing 47.46 MMcf of gas with a shut-in casing pressure of 3,472 psi. Production is from a perforated zone between 7,623 ft and 14,824 ft. Chesapeake's headquarters are in Oklahoma City.

GULF COAST

1 ***CML Exploration*** has completed a multilateral oil well in Maverick County (RRC Dist. 1), Texas, about 5 miles east of the U.S./Mexico border. According to IHS Markit, the reentry, #501 CR, flowed at a daily rate of 130 bbl of 44° API crude and 370,000 cu ft of gas through five commingled, openhole Austin Chalk and Buda zones. The Pearsall Field venture was completed in laterals of 2,400-15,495 ft; 2,800-12,265 ft; 2,827-9,132 ft; 3,838-6,882 ft; and 3,393-11,645 ft. The well was drilled on a 95,250-acre Maverick Basin lease in Section 117, Block 6, I&GN RR Co Survey, A-159. CML's headquarters are in Austin.

2 ***Ageron Energy***, based in San Antonio, has completed three horizontal Eagle Ford oil wells from a drillpad in the Frio County (RRC Dist. 1), Texas, portion of Briscoe Ranch Field. The #1H Cyndi Unit initially flowed 840 bbl of 30.9° API crude and 117,000 cu ft of gas per day from fracture-treated perforations at 7,070-18,670 ft. Tested on an 11/64-inch choke, the flowing tubing pressure was 1,925 psi and flowing casing pressure was 850 psi. It was drilled to 18,794 ft (6,549 ft true vertical). The offsetting #2H Cyndi Unit flowed 984 bbl of 30.9° crude, 240,000 cu ft of gas and 240 bbl of water per day from a fracture-treated zone at 9,087-18,720 ft. It was drilled to 18,840 ft (6,444 ft true vertical). The #3H Cyndi Unit produced 984 bbl of crude, 266,000 cu ft of gas and 384 bbl of water from a fractured zone at 7,328-18,228 ft. The total depth is 18,344 ft, and the true vertical depth is 6,414 ft. The wells were drilled from offsetting surface locations in Ramona Urrugas Survey, A-645. The parallel horizontal laterals bottomed about 2.5 miles to the east-southeast. The #1H Cyndi Unit and #2H Cyndi Unit bottomed beneath the BS&F Survey, A-119, while #3H Cyndi Unit bottomed in BS&F Survey, A-1008.

3 Two La Salle County (RRC Dist. 1), Texas, Eagle Ford gas wells were completed by ***Lewis Petroleum Properties*** in Hawkville East Field. Both wells were drilled at a pad in Section 697, HE&WT RR CO Survey, A-883. The #24H Appling was drilled to the northwest to 17,206 ft (10,265 true vertical) and initially flowed 10.079 MMcf of gas and 508 bbl of water per day. Production is from acidized and fractured perforations at 10,893-16,745 ft. Gauged on a 20/64-inch choke, the flowing tubing pressure was 5,335 psi, and the shut-in casing pressure was 5,654 psi. Production is from a perforated zone at 10,893-16,745 ft. About 20 ft to the west, #23H Appling, produced 10.05 MMcf of gas with 484 bbl of water per day from acidized and fractured perforations at 10,817-16,581 ft. The 17,206 ft well has a true vertical depth of 10,265 ft, and it is producing from an acidized and fracture-stimulated zone at 10,817-16,581 ft. Tested on a 20/64-inch choke, the flowing tubing pressure was 5,401 psi, and the shut-in casing pressure was 6,945 psi. Lewis is based in San Antonio.

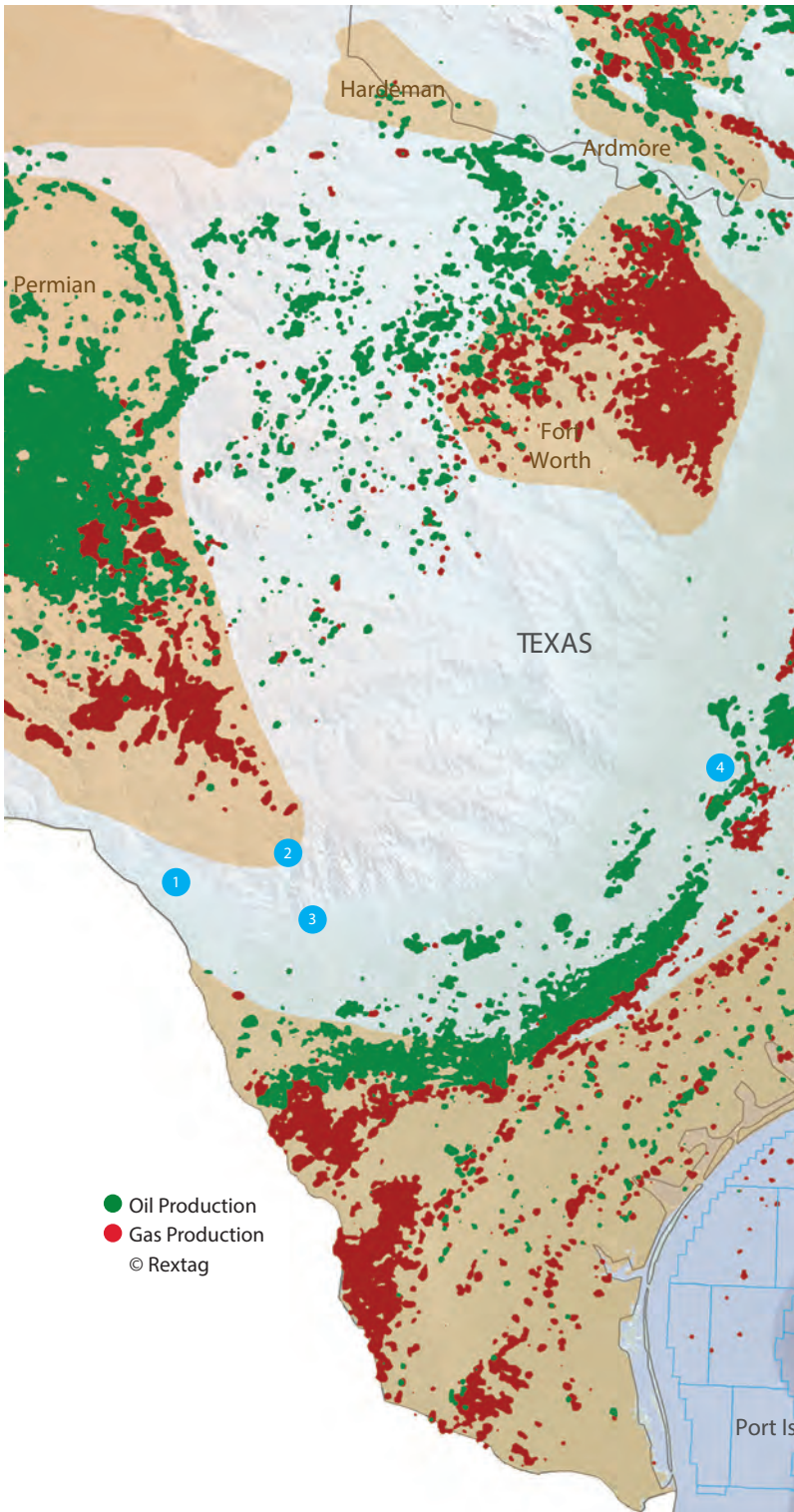
4 In Lee County, Texas (RRC Dist. 3), Texas, Houston-based ***Magnolia Oil & Gas Operating*** completed an Austin Chalk producer. Located in Boatwright Friend Survey, A-4, #2H Lehmann Heirs Ol Unit flowed 1,242 bbl of 43° API oil, 1.052 MMcf of gas and 933 bbl of water per day. The Giddings Field well was drilled to 14,389, and the true vertical depth is 9,602 ft. Production is from a perforated zone between 9,720 ft and 14,235 ft.

5 ***Shell Oil Co.*** has permitted a development test in Silvertip Field, one of the Lower Tertiary reservoirs in the company's Perdido project. According to IHS Markit, #6SA OCS G19409 will be drilled in the northwestern portion of Alaminos Canyon Block 859, with a planned bottomhole to the north beneath Block 815. Area water depth is 9,600 ft. The Perdido area is made up of several Lower Tertiary wells in Great White (Block 857), Tobago (Block 859) and Silvertip (Block 815) fields. Houston-based Shell's wells produce through perforations at 14,000-18,900 ft.

6 According to IHS Markit, ***Shell Oil Co.*** has scheduled a Lower Tertiary development test in the company's producing Silvertip Field. The #2 OCS G19409) will be in the southwestern portion of Alaminos Canyon Block 815. Water depth in the area is 9,600 ft. Shell has completed three wells at #1SA, #2SA and #5SA OCS G19409. The wells yield crude between 14,213 ft and 18,404 ft in Lower Tertiary. Nearby is Shell's 2018 Whale discovery.

7 ***GEP Haynesville LLC*** completed another Haynesville Shale producer in the Bayou San Miguel Field portion of Sabine Parish, La. The #001-Alt Olympia Minerals 26-23HC is in Section 26-9n-12w. It was drilled to 21,088 ft, with a true vertical depth of 12,763 ft. It flowed 39.845 MMcf of gas and 464 bbl of water per day from a perforated zone at 12,894-20,875 ft. Tested on a 33/64-inch choke, the flowing casing pressure was 8,438 psi. GEP's headquarters are in The Woodlands, Texas.

8 Four Haynesville Shale producers were announced by ***Indigo Minerals*** from a Natchitoches Parish, La., drillpad in San Miguel Creek Field. The wells were drilled from offsetting surface locations in Section 7-9n-10w and bottomed within one-half mile to the south in Section 18. The #1 RKS CRK 7&18-9-10HC flowed 23.923 MMcf



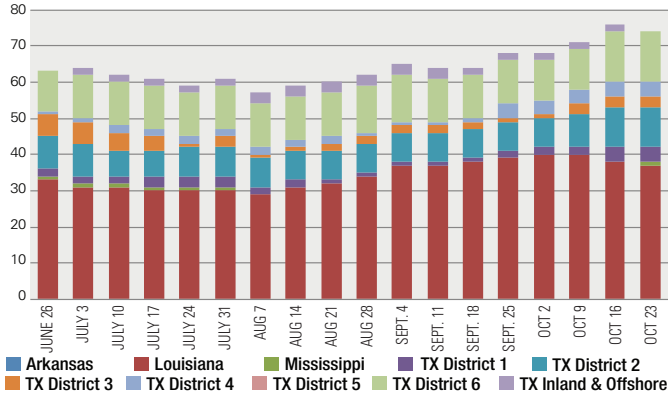
of gas and 140 bbl of water per day from perforations at 13,962-20,045 ft. Tested on a 22/64-inch choke, the flowing casing pressure was 9,962 psi. It was drilled to 20,168 ft (13,781 ft true vertical). The #2-Alt, 3-Alt and 4 Alt RKS CRK 7&18-9-10HC were completed at depths of around 14,000-21,000 ft. Those wells flowed at respective daily rates of 21.2 MMcf of gas, 16.1 MMcf of gas and 16.1 MMcf of gas. Indigo's headquarters are in Houston.

9 A Miocene producer was announced by ***Beacon Offshore Energy*** in Mississippi Canyon Block 794. The Houston-based company's #0SS001S1B OCS G34909 ST01BP00 flowed 6,912 bbl of 31° API oil, 7.049 MMcf of gas and 16 bbl of water per day from Miocene perforations at 20,386-20,514 ft. It was drilled to 24,193 ft, and the true vertical depth was 23,928 ft. Tested on a 38/64-inch choke, the flowing tubing pressure was 9,970 psi.

10 ***Shell Oil Co.*** has scheduled a development test in the Mars/Ursa Field in Mississippi Canyon Block 809. The #11P OCS G12166 is in the northwestern portion of the block with a planned bottomhole to the north in Mississippi Canyon Block 765. Area water depth is about 3,600 ft. Most of the production in the area comes from the Pliocene and Upper Miocene at 15,600-29,000 ft.

Gulf Coast Rig Count

June 26, 2020-Oct. 23, 2020

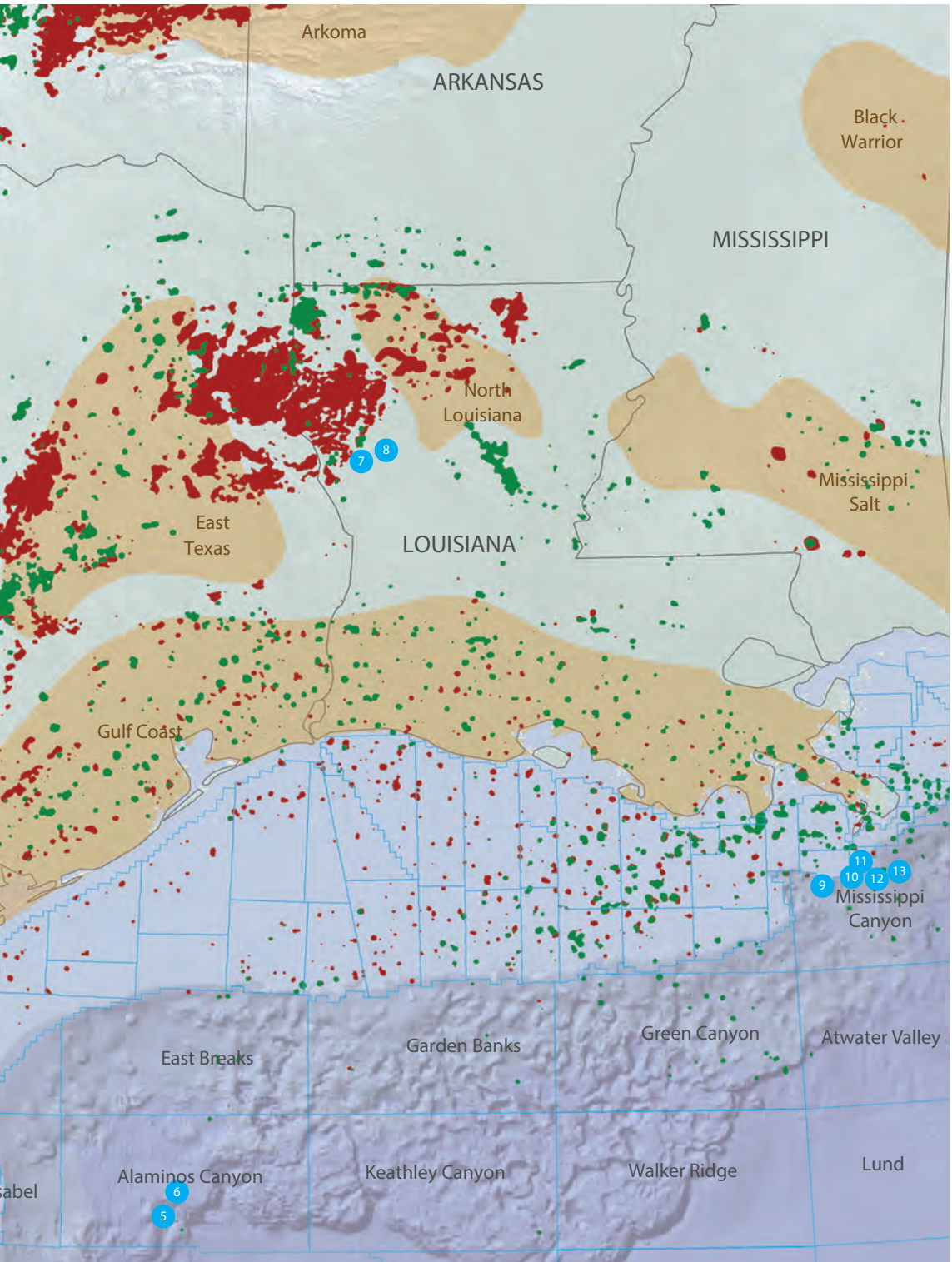


Source: Baker Hughes Co.

11 ***LLOG Exploration*** announced results from a Mississippi Canyon Block 503 discovery. The #0SS006S0B OCS G27277 ST00BP00 was tested flowing 2,930 bbl of 29.4° API oil and 8.64 MMcf of gas per day from Upper Miocene perforations at 17,800-17,950 ft. Tested on an unreported choke size, the flowing tubing pressure was 7,919 psi. LLOG is based in Covington, La.

12 In Mississippi Canyon Block 812, ***Shell Oil Co.*** completed a Middle Miocene discovery at #0K003S3B OCS G34460 ST03BP00. The well was drilled to 29,739 ft, with a true vertical depth of 23,343 ft. It flowed 12,478 bbl of 33.5° API oil and 25.725 MMcf of gas per day. Tested on a 36/64-inch coke, the flowing tubing pressure was 9,897 psi, and production is from a perforated zone between 29,218 and 29,345 ft.

13 ***Chevron Corp.*** completed a Mississippi Canyon Block 696 venture at #1BF006S1B OCS G16641 ST01BP01. The well was drilled to a total depth of 25,077 ft, with a true vertical depth of 24,141 ft. It flowed 7,744 bbl of 30° API oil, with 268,000 cu ft of gas and 12 bbl of water per day from Middle Miocene at 24,439-24,930 ft. Gauged on a 74/64-inch choke, the flowing tubing pressure was 6,521 psi. Chevron's headquarters are in Houston.



MIDCONTINENT & PERMIAN BASIN

1 A Purple Sage Field-Wolfcamp completion in Eddy County, N.M., was announced by ***Oxy USA Inc***. Located in Section 17-24s-29e, the #037H Salt Flat CC 20-29 Federal Com produced at a daily flow rate of 5,202 bbl of oil, 11.096 cu ft of gas and 9,516 bbl of water. Drilled to 20,363 ft, the true vertical depth is 9,990 ft, and production is from acidized and fractured perforations at 10,209-20,185 ft. Tested on a 21/64-inch choke, the shut-in casing pressure was 1,421 psi. Houston-based Oxy USA is a subsidiary of ***Occidental Petroleum***.

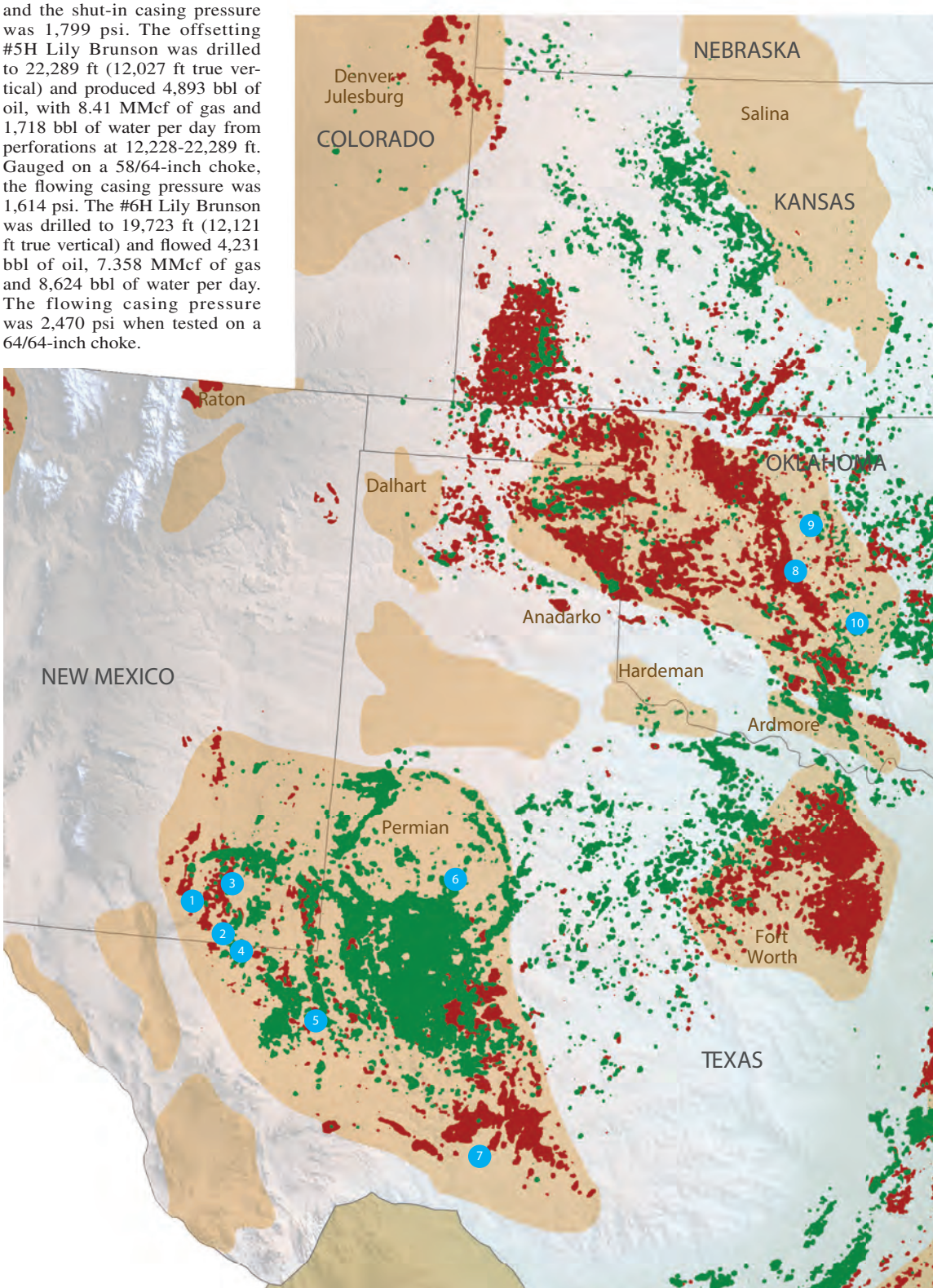
2 A Sandbar Field-Bone Spring discovery was announced by ***EOG Resources Inc.*** in Loving County (RRC Dist. 8), Texas. The #34H State Mercury E initially flowed 2,319 bbl of 46° API oil, with 11.377 MMcf of gas and 3,057 bbl of water per day. The 19,051-ft well has a true vertical depth of 8,885 ft and was drilled in Section 4, Block 54, T&P RR CO Survey, A-936. It was tested on a 76/64-inch choke, and the shut-in casing pressure was 895 psi. Production is from fractured perforations at 9,124-19,051 ft. EOG is based in Houston.

3 A Pronghorn Field completion by ***Matador Production Co.*** produced 2,247 bbl of oil, 3.026 MMcf of gas and 5,736 bbl of water per day from Bone Spring. The #121H Rodney Robinson Federal is in Lea County, N.M. Located in Section 6-23s-33e, the venture was drilled to 21,253 ft, and the true vertical depth is 11,123 ft. Tested on a 40/64-inch choke, the shut-in casing pressure was 2,050 psi. Production is from acidized and fractured perforations between 11,135 and 21,109 ft.

4 ***EOG Resources Inc.*** announced results from three Loving County (RRC Dist. 8), Texas, Wolfcamp completions. The Phantom Field wells are in Section 36, Block 76, PSL Survey, A882. The #4H Lily Brunson was drilled to 22,274 ft (12,041 ft true vertical) and flowed 3,775 bbl of oil, 6.849 MMcf of gas and 7,639 bbl of water daily from perforations at 12,362-22,250 ft. Tested on a 68/64-inch choke, the flowing tubing pressure was 1,796 psi, and the shut-in casing pressure was 1,799 psi. The offsetting #5H Lily Brunson was drilled to 22,289 ft (12,027 ft true vertical) and produced 4,893 bbl of oil, with 8.41 MMcf of gas and 1,718 bbl of water per day from perforations at 12,228-22,289 ft. Gauged on a 58/64-inch choke, the flowing casing pressure was 1,614 psi. The #6H Lily Brunson was drilled to 19,723 ft (12,121 ft true vertical) and flowed 4,231 bbl of oil, 7.358 MMcf of gas and 8,624 bbl of water per day. The flowing casing pressure was 2,470 psi when tested on a 64/64-inch choke.

5 In Pecos County (RRC Dist. 8), Texas, ***XTO Energy Inc.*** completed two Wolfbone Field wells. The ventures were drilled from a pad in Section 19, PSL Survey, A-5069. The #701H Baba Looey C2-30-19 WA1 was drilled to 18,988 (9,640 ft true vertical) and produced 420 bbl of 43° API oil, 2.332 MMcf of gas and 4,505 bbl of water per day from commingled Bone Spring and Wolfcamp perforations at 9,911-18,842 ft. Tested on an unreported choke size, the flowing tubing pressure was 418 psi, and the flowing casing pressure was 191 psi. Within 25 ft to the north, #502H Baba Looey C2-30-19 TB2 was drilled to a total depth of 18,792 ft, with a true vertical depth of 9,325 ft, and flowed 554 bbl of 43° API oil, with 1.752 MMcf of gas and 5,385 bbl of water per day from Bone Spring at 9,711-18,644 ft. Gauged on an unreported choke size, the flowing tubing pressure was 356 psi. Houston-based XTO is a subsidiary of ***Exxon Mobil***.

6 Two Howard County (RRC Dist. 8), Texas, Spraberry Field wells were announced by ***Birch Operations Inc***. The wells were drilled from a pad in Section 18, Block 33, T&P RR CO Survey, A-1090. The #7LS

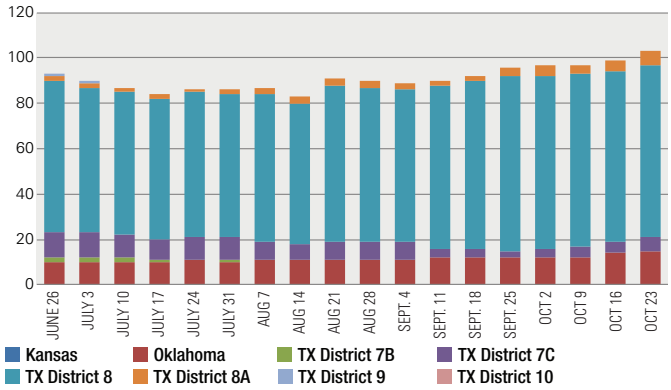


Traveler 18-30 G was drilled to 18,358 ft with a true vertical depth of 7,674 ft. It was tested flowing 533 bbl of 37° API oil, 376,000 cu ft of gas and 2,284 bbl of water daily from a perforated Spraberry zone at 8,052-18,245 ft. The #7WA Traveler 18-30 G was drilled to 18,844 ft, 8,016 ft true vertical. It produced 2,098 bbl of 36.8° API oil, 578,000 cu ft of gas and 260 bbl of water per day from a perforated Wolfcamp interval at 8,548-18,790 ft. Birch Operatons is based in Houston.

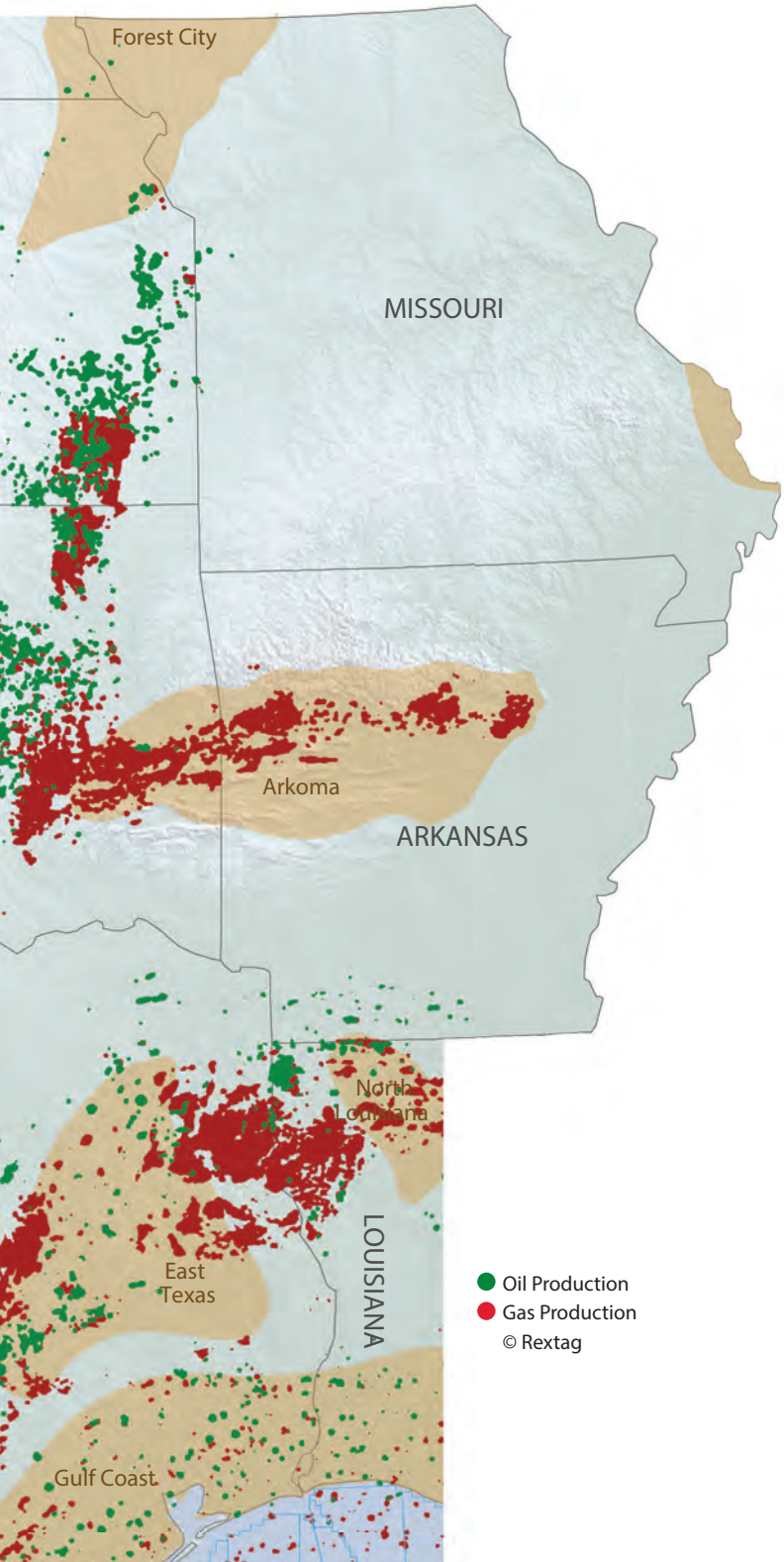
7 IHS Markit reported that ***Barron Petroleum*** completed a Val Verde Basin discovery in Val Verde County (RRC Dist. 1), Texas. Based on the results from two wells, the company estimates that the 13,000-acre project holds 417 Bcf equivalent (74.2 MMboe) in oil and gas reserves. Developed with the use of a 3D seismic survey, Barron has identified 67 high-graded Strawn locations on the acreage and could potentially develop Canyon at 9,000 ft and Ellenburger at 16,000 ft. The first wildcat, #1 Sahota Carson 20BU, hit approximately 70 ft of gas-bearing Strawn pay. It was fracture-stimulated and flowed up to 5 MMcf of gas per day. It was drilled to 12,650 ft in Section 12, Block C15, R.A. Ashley Survey, A-2575. About one-half mile to the east-southeast in the same section, #3 Sahota Carson 19BU was drilled and cased to 12,890 ft. According to IHS Markit, the well is currently holding for data. Nearby Strawn gas production is in Massie Field, about 6 miles northeast of Barron's program, and to the east-southeast in Massie West Field is a shallow Paluxy reservoir opened in 1959 that produces from perforations at 325-640 ft. Barron is based in Graham, Texas.

Midcontinent & Permian Basin Rig Count

June 26, 2020-Oct. 23, 2020



Source: Baker Hughes Co.



8 ***Citizen Energy III*** has completed an extended-lateral Woodford Shale well in Canadian County, Okla. The Anadarko Basin well, #1H-2-35 Honey Springs, initially flowed 1.11 MMcf of gas with 21 bbl of 54° condensate and 1,371 bbl of water per day. Acid- and fracture-stimulated perforations are at 12,872-22,994 ft. The Union City Field well was drilled to a 23,043 ft, and the proposed true vertical depth was 12,695 ft. It is in Section 11-11n-9w, and the horizontal leg bottomed 2 miles to the north in Section 35. Citizen Energy is based in Tulsa.

9 Two horizontal Mississippian producers have been reported by ***Paloma Operating Co.*** on an Anadarko Basin lease in Kingfisher County, Okla. The Okarche North Field wells were drilled in Section 31-16n-7w. The #2MHX Quidditch BIA 31-30-16n-17w flowed 824 bbl of 44°API oil, 1.712 MMcf of gas and 2,000 bbl of water per day from perforations at 8,602-18,590 ft. The flowing tubing pressure was gauged at 500 psi on a 50/64-inch choke. It was drilled to 18,710 ft, and the 2-mile lateral bottomed to the north-northeast in Section 30-16n-7w. Within 1 mile to the east, #3MHX Quidditch BIA 31-30-16n-17w initially flowed 1,128 bbl of 45°API crude, 2.43 MMcf of gas and 1,845 bbl of water daily from perforations at 8,729-18,791 ft. Tested on a 44/64-inch choke, the flowing tubing pressure was 751 psi. The lateral bottomed 2 miles to the north in Section 30, with a total depth of 18,910 ft and a true vertical depth of 8,198 ft. Paloma's headquarters are in Houston.

10 A horizontal Woodford oil well was completed in McClain County, Okla., by Oklahoma City-based ***Warwick-Bacchus LLC***. The #1WHX Calvert 0603-6-7 pumped 187 bbl of 40° crude, 138,000 cu ft of gas and 1,124 bbl of water per day from acid- and fracture-stimulated perforations at 10,376-20,994 ft. This is the first horizontal well drilled in Iron Chapel Field. It was drilled to 21,100 ft in Section 31-7n-3w. The horizontal leg bottomed within 2.5 miles to the south-southwest in Section 7 with a true vertical depth of 9,863 ft.

WESTERN US

1 ***EP Energy*** released information from two horizontal Uteland Buttes oil wells in the Duchesne County portion of the Uinta Basin. The Altamont Field wells were drilled from a pad in Section 23-3s-4w, and both offsetting wells bottomed about 2 miles to the west in Section 21. The #8-22-21-C4-3H EP Energy pumped 889 bbl of crude per day from an unreported depth after acidizing and fracturing. It was drilled to 19,610 ft (9,177 ft true vertical). The #8-22-21-C4-2H EP Energy flowed 130 bbl of crude, 137,000 cu ft of gas and 928 bbl of water per day after acidizing and fracture stimulation. The flowing casing pressure was 2,876 psi on a 12/64-inch choke. The horizontal oil well was drilled to an estimated total depth of 19,556 ft. It was permitted to a true vertical depth of 9,185 ft. EP's headquarters are in Houston.

2 ***DJR Energy LLC*** has completed a horizontal Gallup oil well in New Mexico's San Juan Basin. IHS Markit reported that #627H Nageezi Unit was tested on gas lift flowing 548 bbl of 42.2° API crude, 4.528 MMcf of gas and 361 bbl of water per day. The Nageezi Unit Field discovery was drilled to 14,500 ft from a pad in Section 30-24n-8w. Tested on a 24/64-inch choke, the flowing tubing pressure was 850 psi. Production is from a perforated zone at 6,259-14,443 ft. The horizontal leg bottomed at a true vertical depth of 5,363 ft within one-half mile to the northwest in Section 23-24n-9w. From the same pad, the parallel #628H Nageezi Unit has been fracture-stimulated at 6,049-10,220 ft, apparently in the Mancos/Gallup. Testing results have not yet been released. DJR is based in Denver.

3 A horizontal Gallup oil well in the San Juan Basin was completed by ***DJR Operating LLC*** in San Juan County, N.M. According to IHS Markit, #717H Betonnie Tsosie Wash Unit was tested for an initial daily potential of 330 bbl of 42.3° crude, 3,351 MMcf of gas and 592 bbl of water from perforations at 5,700-14,671 ft following a 30-stage fracturing. Flowing tubing pressure was 934 psi on a 34/64-inch choke. The Betonnie Tsosie Wash field well was drilled to a total depth of 14,744 ft from a surface location in Section 3-22n-8w. True vertical depth is 4,851 ft with the lateral bottoming nearly 2 miles to the northwest beneath section 33-23n-8w.

4 Denver-based ***PDC Energy*** announced results from three completions in Weld County, Colo. The DJ Field wells were drilled from a pad in Section 7-5n-66w. The #31C-11-L Bost Farm was drilled to 17,236 ft, and the true vertical depth is 7,145 ft. It produced 219 bbl of condensate, 543,000 cu ft of gas and 117 bbl of water per day from commingled perforations in Carlile at 7,463-8,102 ft; Codell at 8,102-17,049 ft; Fort Hays at 12,030-13,556; and Niobrara at 12,321-13,240 ft. Tested on a 16/64-inch choke, the flowing casing pressure was 2,178 psi. The #4C-11-L2 Bost Farm was drilled to a total depth of 17,195 ft, with a true vertical depth of 7,118 ft. It flowed 267 bbl of 52° API oil, 678,000 cu ft of gas and 113 bbl of water per day from commingled Codell (7,450-16,977 ft); Fort Hays (11,240-11,925 ft); Niobrara (11,520-11,749 ft) and Carlile (13,098-14,051 ft). Tested on a 16/64-inch choke, the flowing tubing pressure was 2,049 psi, and the flowing casing pressure was 2,354 psi. The #32n-11b-L Bost Farm was drilled to 17,668 ft, 6,908 ft true vertical. It was tested after 56-stage fracturing on a 16/64-inch choke flowing 691 bbl of oil, 1.078 MMcf of gas and 1,742 bbl of water per day from Niobrara at 7,495-17,480 ft. The flowing tubing pressure was 1,628 psi, and the flowing casing pressure was 1,896 psi.

5 ***Great Western Operating Co.*** announced results from a Wattenberg Field completion in Colorado's Weld County, The #11-019HN Schneider HD was drilled from a site in Section 7-4n-66w. It was drilled to a total depth of 18,296 ft, with a true vertical depth of 7,106 ft. It was tested flowing 366 bbl of oil, with 2.215 MMcf of gas and 717 bbl of water per day from Niobrara at 8,498-18,010 ft. Gauged on an 18/64-inch choke, the flowing tubing pressure was 2,285 psi, and the flowing casing pressure was 3,000 psi. Great Western's headquarters are in Denver.

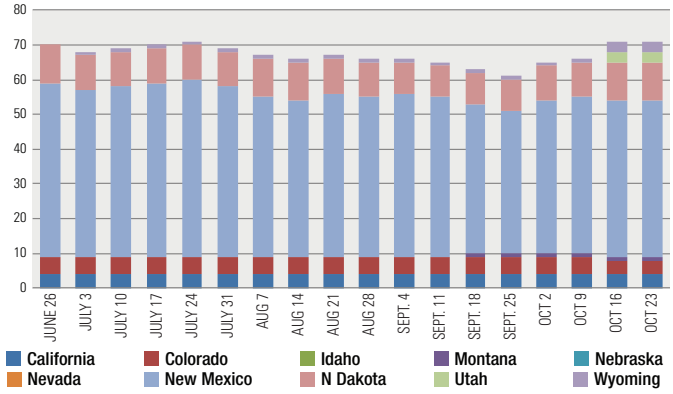
6 ***Burlington Resources Oil & Gas*** completed a Middle Bakken well and a Middle Three Forks well at a Dunn County, N.D., drillpad. The pad is in Section 26-147n-97w in Little Knife Field. The #44-36TFH Franklin was drilled to 21,747 ft, 11,393 ft true vertical. It initially flowed 230 bbl of 41° API oil, 276,000 cu ft and 5,717 bbl of water per day after 31-stage fracturing. Production is from Middle Three Forks perforations at 11,705-21,541 ft. Gauged on a 31/64-inch choke, the flowing tubing pressure was 1,715 psi. The #34-36MBH-2NH Franklin

was drilled to 21,835 ft (11,305 ft true vertical) and produced 278 bbl of 30.5° API oil and 504,000 cu ft of gas per day from Middle Bakken at 11,705-21,625 ft. It was tested on a 30/64-inch choke with a flowing tubing pressure of 2,488 psi. Burlington is a subsidiary of ***ConocoPhillips***.

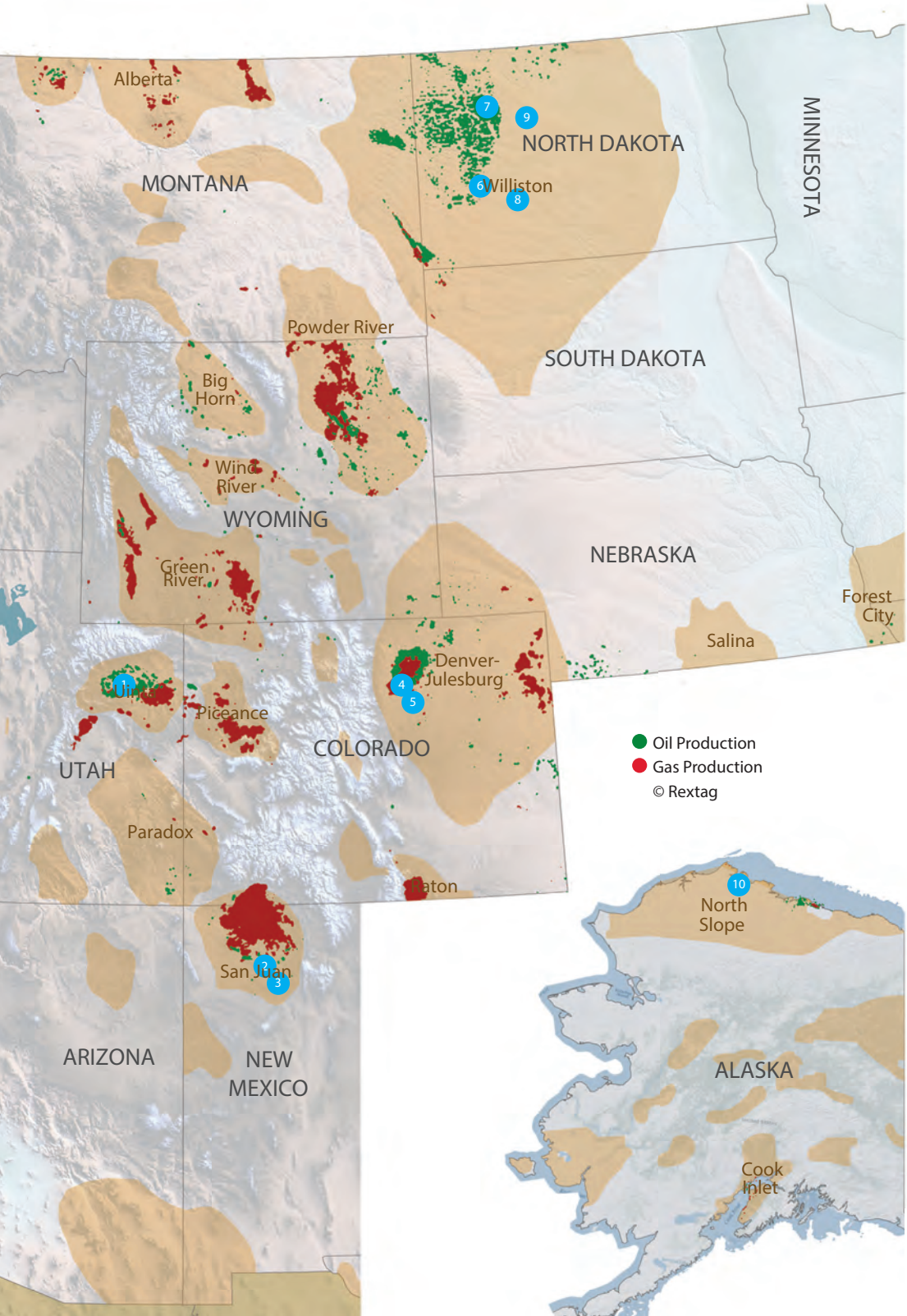
7 In McKenzie County, N.D., Oklahoma City-based ***Continental Resources Inc.*** completed a Middle Bakken and an Upper Three Forks well from a Elm Tree Field drillpad in Section 26-153n-94w. The #12-26H Bohmbach Federal was drilled to 19,185 ft (10,818 ft true vertical). It was tested flowing 1,751 bbl of 44.5° API oil, with 1.544 MMcf of gas and 1,149 bbl of water per day from Middle Bakken at 10,993-19,170 ft. Gauged on a 22/64-inch choke, the flowing casing pressure was 1,600 psi after 30-stage fracturing. The offsetting #13-26H1 Bohmbach Federal was drilled to a total depth of 19,260 ft, with a true vertical depth of 10,908 ft. It was tested after 39-stage fracturing flowing 925 bbl of 44.5° API oil, 1.416 MMcf of gas and 1,158 bbl of water daily. It was tested on a 22/64-inch choke with a flowing casing pressure of 1,600 psi. Production is from a fractured zone between 11,184 and 19,245 ft.

Western US Rig Count

June 26, 2020-Oct. 23, 2020



Source: Baker Hughes Co.



8 In North Dakota's Dunn County, ***Marathon Oil Co.*** completed a Bailey Field-Upper Three Forks well. The #24-12TFH Emil is in 12-146n-94w. It was drilled to a total depth of 21,461 ft and a true vertical depth of 10,760 ft and was tested after 45-stage fracturing. It initially flowed 4,726 bbl of 41° API oil, with 3.237 MMcf of gas and 5,079 bbl of water daily. The venture was tested on a 64/64-inch choke, and the flowing casing pressure was 1,120 psi. Production is from perforations at 11,247-21,328 ft.

9 A ***Marathon Oil Co.***-Middle Bakken discovery was reported in North Dakota's Mountrail County. The Reunion Bay Field well, #11-15H Frances USA, is in Section 10-151n-93w and was drilled to 21,185 ft with a true vertical depth of 10,660 ft. It initially flowed 5,455 bbl of 41° API oil, 5.654 MMcf of gas and 6,340 bbl of water per day. Gauged on a 64/64-inch choke, the flowing casing pressure was 1,245 psi, and production is from a perforated zone at 11,121-21,051 ft.

10 London-based ***BP*** recompleted a Prudhoe Bay Field well in Alaska that was originally drilled in 2014 at #06-22B Prudhoe Bay Unit. The well is in Section 2-10n-14e in Umiat Meridian. It was tested flowing 288 bbl of oil, 27.513 MMcf of gas and 1,051 bbl of water per day with a flowing tubing pressure of 903 psi. Production is from a Ivishak Shale perforated zone at 10,465-10,870 ft.

INTERNATIONAL HIGHLIGHTS

One of the world's earliest and largest oil producers, Venezuela, may soon be producing zero barrels of oil.

According to an analysis by IHS Markit, one of the founding members of the Organization of Petroleum Exporting Countries (OPEC) reported that the country's crude output is currently about 100,000 bbl/d to 200,000 bbl/d and falling. Production was approximately 650,000 bbl/d in the third quarter of 2019 and had been as high as 2 MMbbl/d as recently as 2017. The country is now the third smallest producer among OPEC's 13 members, just ahead of Equatorial Guinea and war-torn Libya.

An IHS Markit analyst said Venezuela's production fall is the product of decades of decline and decay. It has been exacerbated by the COVID-19-induced oil price collapse of 2020, U.S. sanctions, and limited domestic oil storage. Venezuela's demise as an oil producer will have little to no impact, according to the analyst, on global oil markets given the much larger shifts in world oil supply and repercussions of COVID-19.

With the size of the country's reserves, a restoration of production in the future is possible with a rebuilding of infrastructure under appropriate investment and security conditions and could return the country to the ranks of major oil producers.

—Larry Prado

1 *Trinidad*

Touchstone Exploration has announced final production test results from #1ST1-Cascadura well in Trinidad's Ortoire exploration block. Two sections were tested, an upper zone from 5,570-5,915 ft and a lower zone, 6,056 ft to 6,218 ft. The upper zone (Cruse and Herrera) had an absolute open flow rate of 390 MMcf of gas per day and averaged 5,472 bbl of oil equivalent per day (86% gas). The lower test (Herrera) flowed 92 MMcf per day with an average of 5,157 bbl of oil equivalent per day (87% gas). Both tests were limited by the capacity of surface test equipment. Calgary, Alberta-based operator Touchstone holds an 80% working interest, and partner ***Heritage Petroleum Company Ltd.*** holds a 20% working interest.

2 *Guyana*

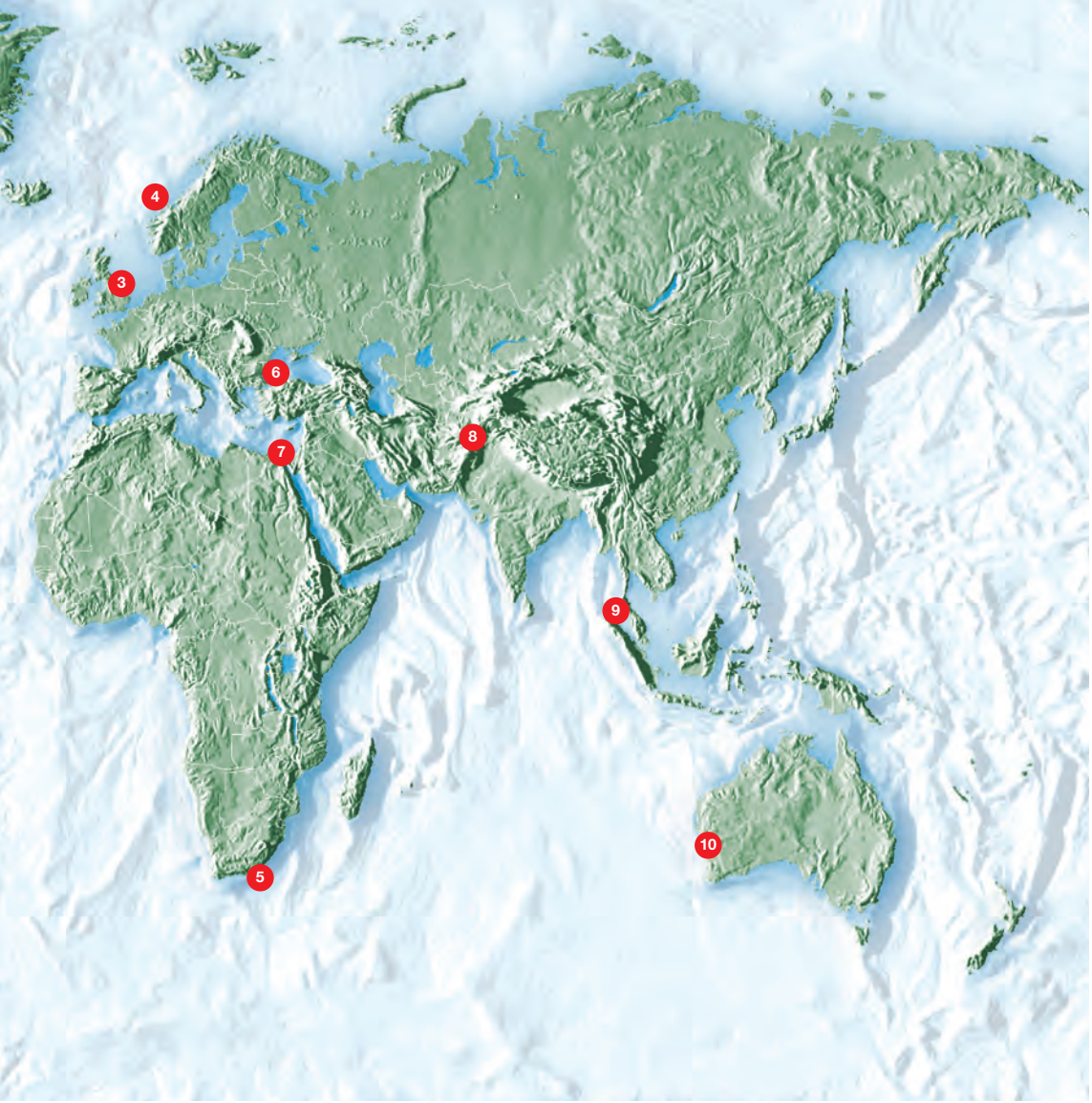
Exxon Mobil Corp. has mobilized a drillship to drill an exploratory test in offshore Guyana's Kaieteur Block. The venture, #1-Tanager, is targeting prospective resources of 256.2 MMbbl of oil. Current estimates for the site range from 135.6 MMbbl to 451.6 MMbbl of oil. The planned depth of 8,000 m will be targeting the stacked Maastrichtian to Turonian reservoir intervals in the southern part of the block. The #1-Tanager is the first well in a potential multiwell drilling campaign being operated by Exxon Mobil on the Kaieteur and Canje Blocks over the next six months to 12 months. This campaign will evaluate high impact, Upper Cretaceous prospects in the Liza play fairway with possible multiple stacked reservoir targets. Irving, Texas-based Exxon Mobil is the operator and holds 35% interest, along with partners ***Hess Corp.*** and ***Cataleya Energy***.

3 *U.K.*

Reabold Resources has spud an exploration well at the West Newton B site in East Yorkshire, U.K., in PEDL183. The test is follow-up to the discovery #2A-West Newton well in 2019. Surface casing at the new site will be set to approximately 80 m into Cretaceous Chalk. The planned depth of the new venture is approximately 2,000 m. According to the company, West Newton covers 176,000 acres and could represent the largest U.K. onshore oilfield discovery in decades with a significant liquid and gas development opportunity with two hydrocarbon discoveries. The findings will establish productive capability and any future drilling operations. Reabold Resources is the operator of PEDL183 and the West Newton site with 100% interest.

4 *Norway*

Neptune Energy has received a drilling permit for wildcat well #6406/12-G-1 H in Norway's production license PL 586. The well will be drilled after a drillship completes the drilling of observation well #6406/12-H-4 in production license PL 586. The area in this license consists of part of Block 6406. This is the seventh exploration well to be drilled in this license and is about 36 km southwest of Njord Field. Neptune Energy, based in London, is the operator with an ownership interest of 30%. The other licensees are ***Var Energi*** (45%), ***Suncor Energy*** (17.5%) and ***DNO Norge*** (7.5%).



5 *South Africa*

Total has spud an exploration well #1X-Luiperd on offshore South Africa's Block 11B/12B following the Brulpadda discovery. The exploratory will test the eastern area of the Paddavissie Fairway on Block 11B/12B to follow-up on the Brulpadda discovery of gas, condensate and light oil. A drillstem test is also planned. Block 11B/12B is located in the Outeniqua Basin and covers an area of approximately 19,000 sq km. The Paddavissie Fairway is in the southwest area of the block and includes the Brulpadda discovery, which confirmed the petroleum system. The Luiperd prospect is the second to be drilled in a series of five large submarine fan prospects with direct hydrocarbon indicators defined utilizing both 2D and 3D seismic data. The #1X-Luiperd is being drilled in 1,795 m of water and has a panned depth of 3,550 m subsea. According to Paris-based Total, the well will test the oil and gas potential in a mid-Cretaceous aged deep marine sequence where fan sandstone systems are developed within combined stratigraphic/structural closure. Total is the operator of the prospect and partners include ***Africa Energy*** and ***Qatar Petroleum***.

6 *Turkey*

Turkish Petroleum Corp. announced a deepwater gas discovery in the Turkish sector of the Black Sea. Well data and geophysical testing indicate that the estimated reserves are 11.3 Tcf of gas. The #1-Tuna was drilled in Sakarya Field in Block AR/TPO/KD/C26-C27-D26-D27. Area water depth is 2,115 m, and the well had a total depth of 4,525 m. It encountered more than 100 m of gas-bearing reservoir in Pliocene and Miocene sands. Turkish Petroleum, based in Ankara, plans to begin production and turning the gas into the national grid by 2023.

7 *Egypt*

Rome-based ***Eni*** announced a new gas discovery in the Abu Madi West Development Lease in the waters of the Nile Delta, offshore Egypt. The exploratory well, #1-Nidoco NW-1, hit 100 m of gas-bearing sands with 50 m in the Pliocene sands of Kafr-El-Sheik and 50 m in the Messinian age sandstone of Abu Madi. Both zones had good petrophysical properties. This is the first time Abu Madi was encountered in Nooros Field, and it extends gas potential to the north of the field. The preliminary evaluation indicates that the Great Nooros Area gas-in-place is estimated to be more than 4 Tcf. Area water depth is 16 m. Eni holds a 75% stake in the license of Abu Madi West development lease with ***BP*** holding the remaining 25%.

8 *Pakistan*

Oil & Gas Development Co. announced a gas and condensate discovery at exploration well #01-Togh Balal in the Kohat District of Khyber Pakhtunkhwa Province, Pakistan. The venture was drilled to a total depth of 2,172 m and was targeting Lockhart. During an openhole test, the well produced 9 MMcf of gas and 125 bbl of condensate per day. It was tested on a 32/64-inch choke, and the wellhead flowing pressure was 1,690 psi. The discovery is the second consecutive discovery in the Kohat Block. Oil & Gas Development, based in Mumbai, is the operator with 50% interest, with partners ***Mari Petroleum Company Ltd.*** (33.33%) and ***Saif Energy Ltd.*** (16.67%).

9 *Indonesia*

London-based ***Premier Oil*** has confirmed a large wet gas prospect in the southern Andaman Sea off northern Sumatra, Indonesia. The discovery is near the giant Arun LNG facility. According to the company, the primary focus is the Andaman II Block, where it has identified two clusters, Timpan and Sangar. An extensive 3D seismic acquisition program was conducted over the Andaman I, Andaman II, and South Andaman Blocks in 2019 and has reported highly encouraging initial results. The estimated prospective resource is approximately 6 Tcf of gas and 200 MMbbl of condensate in each of the Andaman blocks. Both prospects support planned field development and exploratory drilling is planned in 2022. Premier has a 40% operated interest in Andaman II in partnership with ***Mubadala Petroleum***, holding 30%, and ***BP***, with 30%. It has a 20% interest in the South Andaman Block, in which Mubadala holds the remaining 80% operated interest.

10 *Australia*

Strike Energy has secured a rig to drill #3 West Erregulla in Western Australia's EP469 Joint Venture. The planned spud date is in the third quarter of 2020. After completion, the rig will be moved to drill #4 West Erregulla and #5 West Erregulla. The two planned ventures are north of #2 West Erregulla, which was drilled to 5,017 m and encountered a 97-m gas column with a net pay of 41 m and porosities of up to 19%. Strike Energy, based in Thebarton, South Australia, is operator and holder of a 50% interest in a joint venture with ***Warrego Energy*** holding the remaining interest.

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Peridot Acquisition Corp.	NYSE: PDAC	Houston	$300 million	Closed IPO composed of 30 million units. The blank check company sponsored by an affiliate of **Carnelian Energy Capital Management LP** is targeting companies that focus on environmentally sound infrastructure, industrial applications and disruptive technologies that eliminate or mitigate greenhouse gas emissions and/or enhance resilience to climate change, a thematic that it refers to as mitigation and adaptation. Offering included an option for underwriters to purchase up to an additional 4.5 million units to cover over-allotments, if any. **UBS Securities LLC** and **Barclays Capital Inc.** were joint book-running managers. **Tudor, Pickering, Holt & Co. Securities LLC** was co-manager.

DEBT

Callon Petroleum Co.	NYSE: CPE	Houston	$300 million	Issued second lien secured notes due 2025 to **Kimmeridge Energy** at 98% of par. Proceeds will be used to reduce borrowings on the company's credit facility by nearly a third to approximately $1 billion. **Jefferies LLC** was financial adviser, and **Kirkland & Ellis LLP** was legal adviser.
CNX Resources Corp.	NYSE: CNX	Pittsburgh	$200 million	Closed its 7.250% senior notes due 2027 at 103.5% of par with an effective yield of 6.34%. Proceeds will be used to redeem all of its outstanding 2022 notes, eliminating any senior note maturities prior to 2026.
Kosmos Energy Ltd.	N/A	Dallas	$200 million	Restructured its previously announced Gulf of Mexico prepayment facility into a five-year $200 million term-loan facility secured against the company's U.S. Gulf of Mexico assets. The $50 million advanced under the prepayment agreement with **Trafigura Trading LLC** announced in June has been rolled into the new facility, structured by **CSG Investments Inc.** with the remaining $150 million provided by **Beal Bank USA**. The facility, which has an interest rate of approximately 6%, increases the company's borrowing capacity by $50 million from the initial prepayment agreement, extends the tenor to five years and includes an accordion feature allowing the facility to be expanded up to $300 million.

COMPANIES IN THIS ISSUE

This index refers to the pages of the story or news item in which the company is first mentioned. Advertisers are in boldface.

GOING LO-CARB

LESLIE HAINES, EXECUTIVE EDITOR-AT-LARGE

It's happening. No matter who sits in the Oval Office, no matter what kind of new state or federal policies emerge or what courts uphold, the great energy transition promises to be a long and contentious road. Some industry players are not sitting by gnashing their teeth as the world discusses reducing fossil fuel use. Instead, they are planning to go on a low-carb diet. No more potatoes, much more solar power.

Oil and gas will continue to be the backbone of energy use for some time to come, but decarbonization is fast becoming the buzzword of the 2020s, and it takes several forms, most significantly in the automobile world. To the dismay of people in Detroit or Stuttgart, or at the Toyota factory in Plano outside Dallas, California Gov. Gavin Newsom, who presides over the largest automobile market in the U.S., has declared no more new cars with traditional internal combustion engines will be sold in the state after 2035. Legacy cars already registered by that date can continue to clog the freeways. Still, it will take a superhuman effort to get millions of those old cars off the road over time and to convince consumers to change their buying preferences.

Mexico City, Paris, Madrid and Athens have announced similar bans and the U.K. has announced no new gasoline or diesel vehicles from 2030. Cars must be emissions-free. Zero is the new hero. If someone can figure out how to make an emissions-free internal combustion engine powered by a fossil fuel, that's Nobel Prize material. We're working on it: some 187 U.S. universities have research underway looking to develop new energy technologies, according to the American Energy Society, including in Austin and Houston.

Investors are working on it too. Here in the U.S., two special purpose acquisition companies (SPACs) debuted in October with decarbonization in mind, and both were headed by people very familiar with traditional oil and gas investing. Riverstone Holdings LLC, a longtime investor in oil and gas themes such as offshore Guff of Mexico, took public on Nasdaq a SPAC called Decarbonization Plus Acquisition Corp. with 20 million units (stock and warrants) valued at $10 per. Turns out the company has a 15-year franchise in low-carbon investing with some $5 billion deployed so far.

"We believe decarbonization will be a multidecade investment megatrend …," the company said in a statement. "Significant pools of capital are beginning to form, and investor interest will be redirected towards these critical and innovative initiatives well into the future," said Riverstone chairman Robert Tichio.

The point of the IPO is to "decarb" the energy, agriculture, industrial or transportation sectors by acquiring relevant companies. (The IPO's new CEO is Erik Anderson, who also happens to be the executive chairman of Topgolf Entertainment Group.) Will Riverstone offer innovative decarb companies a mulligan to offset the stumbling blocks they'll encounter along the way to a new kind of bottom line?

Also in October, the Rice brothers behind EQT Corp. took public Rice Acquisition Corp. on the New York Stock Exchange, a SPAC with 21.5 million units at $10 per. "The company's efforts to identify a prospective target business will not be limited to a particular industry, although it intends to focus its search … in the broadly defined energy transition or sustainability arena," a Rice statement said.

Investors will go where the money is, where they think they've spotted an emerging opportunity, and we know they are often intrigued by the next new thing. Getting in on the ground floor and all that.

But what is dramatic is how much the majors and integrateds vow to get involved in a low-carbon diet as well, in order to get to net zero emissions for their production—and for the end users of their products. Seven of the biggest oils have committed to net zero between 2040 and 2050. In September BP became the latest to outline its new strategy.

Under the plan, the company's hydrocarbon production will be flat to 2025, and by 2030 its volumes will supposedly be 40% below the 2019 level. Spending on low-carbon initiatives and renewables will soar. What a stunning goal, to change such a large and historic enterprise to this degree. It remains to be seen how much can actually be achieved.

"Until at least 2023, we will be evaluating BP like other integrateds," said Pavel Molchanov, an E&P and alternative energy analyst for Raymond James. "This will still be an oil stock for the foreseeable future, but we are fans of the energy transition strategy."

There are a few truths here: The world needs to figure out how to reduce pollution, it needs to figure out how to provide clean, affordable energy to everyone and it needs to preserve the traditional oil and gas industry so that it can continue to provide the energy we need. "For the record, our view is that oil demand has not yet peaked," Molchanov said.

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