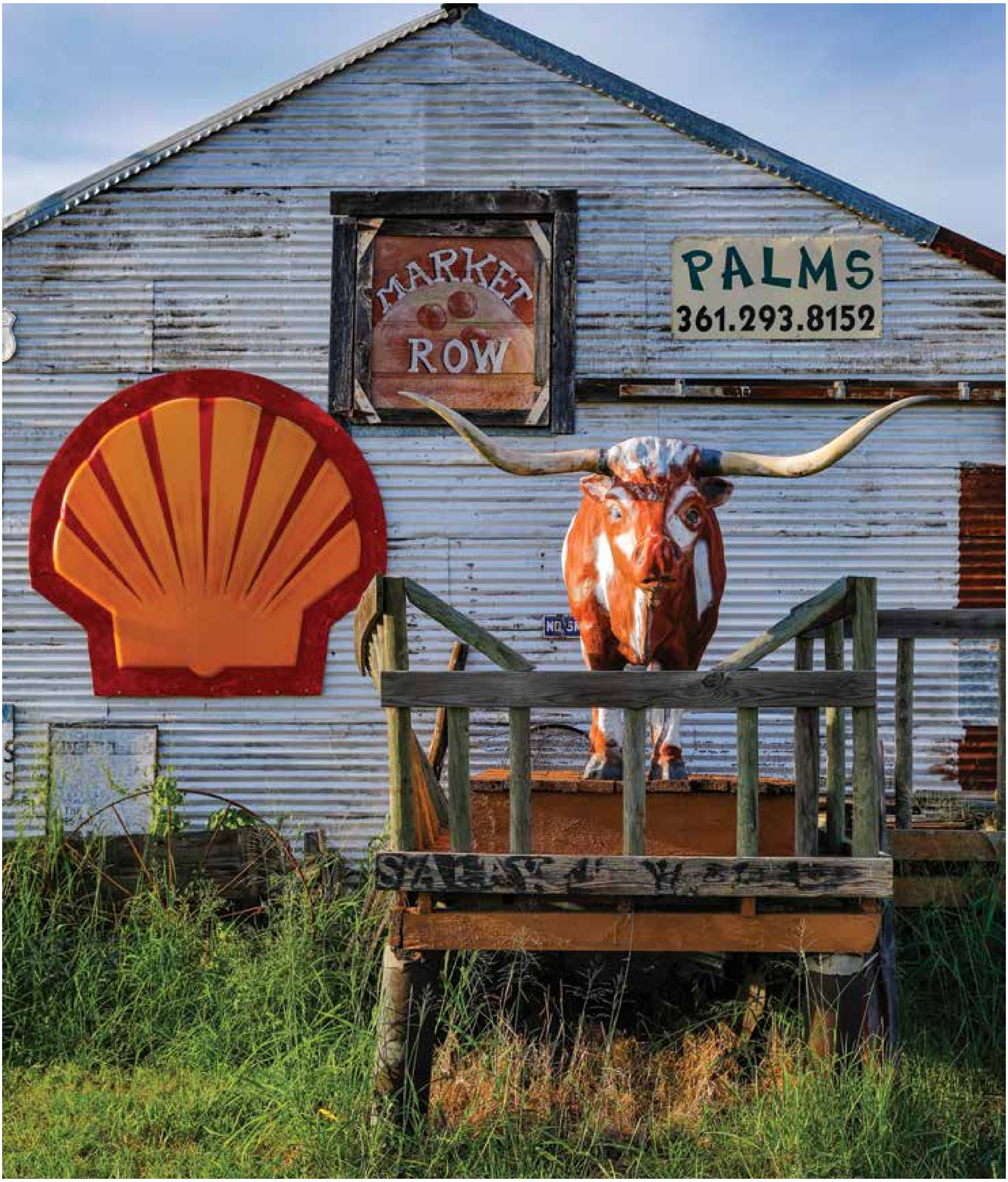
Oil and Gas Investor

SEPTEMBER 2019



Demands for returns-driven strategies flow down to private-equity-sponsored companies.

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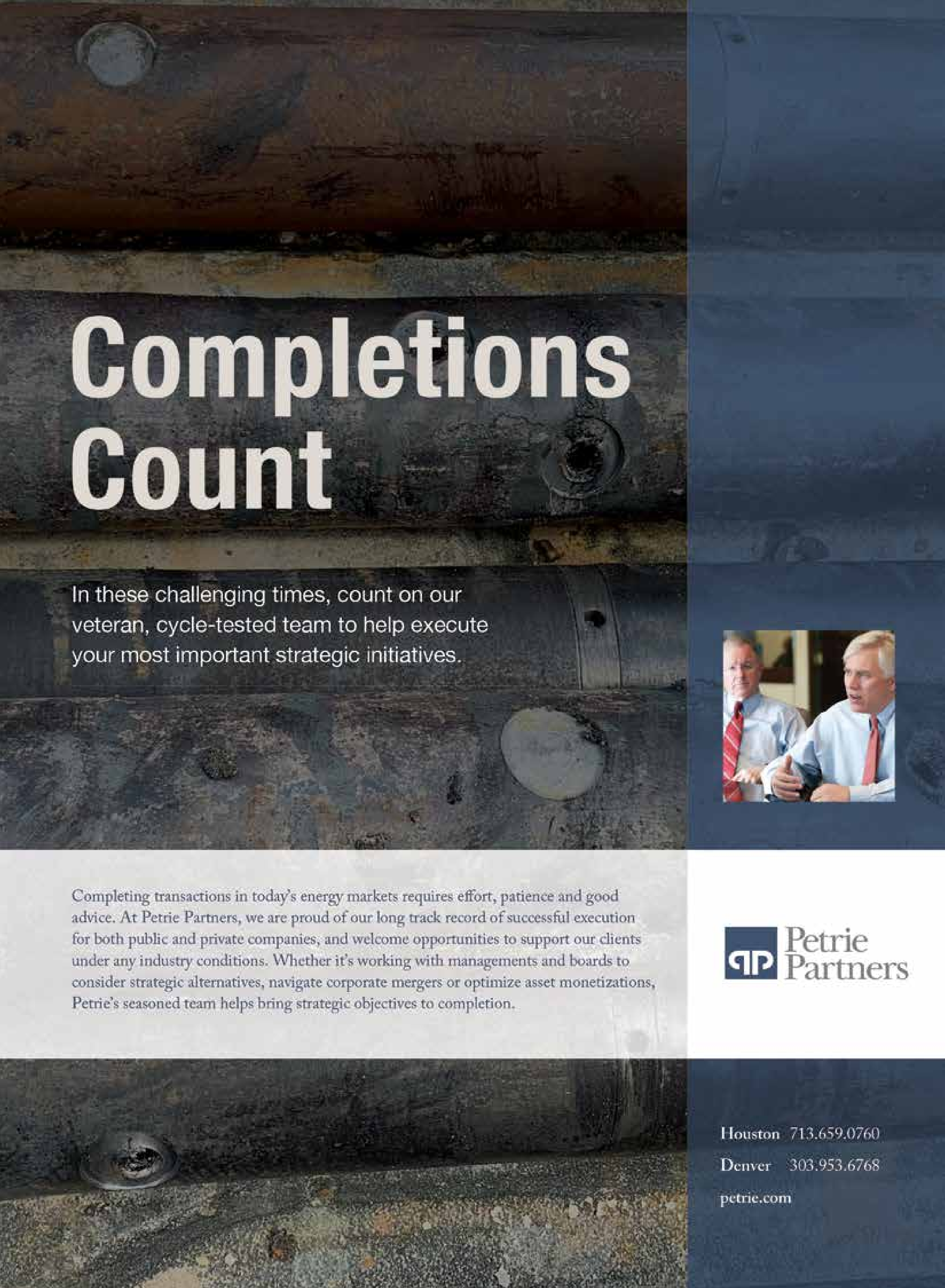

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COLUMNS

DEPARTMENTS

ABOUT THE COVER: Old signs and a longhorn steer adorn the outside of corrugated steel buildings lining Front St. in downtown Yoakum, Texas, in the heart of the Eagle Ford Shale. Photo by Tom Fox.

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LATEST CONTENT

EQT Sees Gains As New Leadership Makes Moves
The company plans to use the 'combo development' style as part of its efforts to drive down costs and improve efficiency.

Pioneer Takes Aim At High-Grading Prized Permian Basin Position
Pioneer Natural Resources recently divested a small slice of its acreage position in the Midland Basin, which CEO Scott Sheffield said will be the lone survivor of the U.S. shale boom.

Sanchez Energy Files For Chapter 11 Bankruptcy Protection
The independent E&P focused on the Eagle Ford joins a growing list of companies filing bankruptcy.

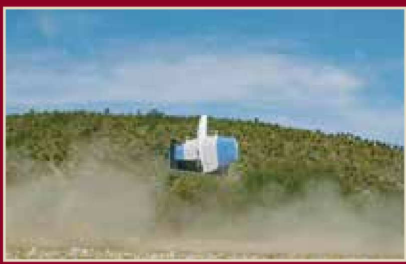
Diamondback Energy: 'Converting Rock Into Cash Flow'
The company reported falling well costs in the Permian Basin as production increased.

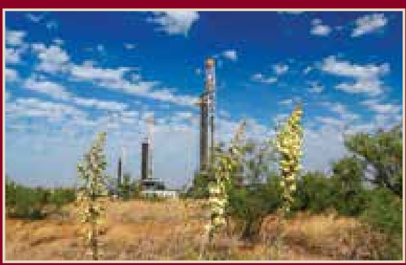
Basic Energy Services Establishes Permian Basin-Focused Water Subsidiary
Basic Energy Services is launching a new subsidiary that will move and dispose oilfield wastewater in the Permian Basin along with other basins.

Energy Prices Could Be Worse … And Probably Will Be
Fears of a global economic slowdown and continued storage increases have spooked traders.

ONLINE EXCLUSIVES

Drones Begin To Gain Ground In Oil, Gas Space
Long-range capabilities, blind management and new policies finally propel drones against industry doubts.





Are There Question Marks Over Permian Efficiency?
A recent report finds hydraulic fracturing activity in the Permian Basin was underreported by more than 20%. What does that mean for well efficiency?

Oilfield Service Providers See Stronger Offshore Activity Ahead
Improving rig counts and FIDs are boosting confidence in the offshore sector.

Videos

Private Operator Spotlight - Pursuing The Best
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What's Trending

1. Crude's Little Secrets
2. E&P Investment Banking: Aiming At Narrow Targets
3. Occidental CFO Talks Anadarko Saga, Rebuffs Sheffield Criticism
4. Liberty Oilfield Services Holds Off Deploying Newest Frack Fleet
5. Oil Falls On Lower Demand Outlook, U.S.-China Trade Dispute

Awards Program

Nominate top female industry executives for *Oil and Gas Investor*'s 25 Influential Women In Energy. Celebrate women who have risen to the top of their professions and achieved outstanding success in the oil and gas industry.

The deadline for nominations is **Oct. 1, 2019.**

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CONFIDENCE
EARNED.

THE GOAL TO GROW WITHIN FREE CASH FLOW

STEVE TOON,
EDITOR-IN-CHIEF

It's ironic, really, that in an age when E&Ps are promising coy investors that they will behave more grown up and spend within cash flow, that first-quarter 2019 proved the worst outspend in two years. That's according to the folk at Wood Mackenzie in a late-July report titled, "Is Tight Oil on the Verge of Sustained Free Cash Flow Generation?"

WoodMac reported that the outspend by tight oil independents reached $1.58 billion in the first quarter, the most since third-quarter 2017 when WTI averaged $48 per barrel, and compared with "just" $360 million of red ink year-over-year. But they had good reason, the analysts defended: E&Ps sought to take advantage of weakened service rates while oil was on an upswing.

"The increase in WTI at the start of the year presented a rare opportunity for companies to accelerate activity in the midst of relatively low service pricing." That outspend trend might play out again in second-quarter numbers too once they're all in. "U.S. independents may choose to continue to invest heavily in 2Q since the window to lock in lower costs is still open."

So WoodMac ponders out loud, "Will tight oil ever generate consistent free cash flow?" The prognosticators surmise "yes" despite the apparent seeming lack of capital discipline.

"The promise of massive cash flow from tight oil has always been just around the corner," the report said, "but what makes today different is the level of capital discipline exhibited across the industry, a much larger base of production generating cash flow, a depressed service pricing environment and an unwillingness of the public capital markets to fund tight oil."

By locking in lower costs in first quarter, this will boost returns and NPV. "The investment strategy should help support free-cash-flow generation in the second half of the year," the authors concluded, but added, "assuming investment is subsequently dialled back."

Well, that's the big question, isn't it?

Raymond James analyst John Freeman believes it will be so. In a July 29 research report, he noted operators planned for the front-loaded capex at the beginning of the year, with the intent to trim back as new production comes on. "We firmly believe that second-half spending will be reined in significantly," he said, "allowing the vast majority of our (covered) operators to spend within budget."

Freeman projected RayJay's coverage group will underspend free cash flow in 2020 by 5%, with budgets set to break even at $50 to $55 oil. And any outspend will come at a penalty to the company's shares.

"One thing that is certainly understood, by both operators and energy investors, is that any increase in spending in this environment will come at a high cost to a company's stock price. In this new environment, capital discipline and shareholder returns are at the forefront of management priorities," he said, "while production growth … is more of a secondary concern."

He noted that operators wryly ask, "Why grow when you get no credit for it?" and that "the market is ready to reward returns to shareholders."

But the growth-is-bad-pay-your-shareholder-first mantra might be foolhardy advice, per one contrarian analyst. David Heikkinen, namesake of Heikkinen Energy Advisors, said in a July 11 note that investors should be careful what they ask for. Looking at a basket of Permian E&P peers, he concluded, "We believe reduced growth expectations have played a key role in derating the peer group."

The bigger question, he said, is whether or not the sector is adding value, defined by generating returns above the cost of capital. "While the focus has been on increasing payout as a positive driver of valuation multiples, payout also negatively impacts growth, which is a large driver of net asset valuation and multiples."

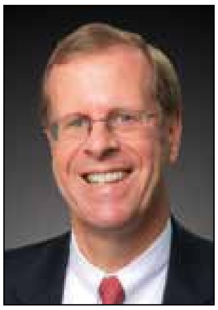
Operators that believe they are returning above their cost of capital but acquiesce to calls to increase shareholder payout while sacrificing growth are short sighted, he suggested. Their actions imply their returns are "inadequate to justify higher levels of reinvestment."

He urges, "If you, E&P operator or investor, are confident in your E&P company's ability to add value, then don't abandon growth just yet—that should be the job of those with the lowest returns."

Regardless of payout, "higher returns will drive higher growth, which drives a higher multiple," he argued. "As such, we believe focusing on returns via things that are controllable and durable (i.e. capturing quality resources at peer-leading capital costs, drilling and completing wells as cheaply and efficiently as possible, hammering on operating costs and managing leverage), will be the most lasting means to achieving and maintaining a premium through the cycle."

So maybe growth vs. returns isn't the dichotomy it's presented as by the investment community. Maybe you can have your growth and enjoy your returns too.

HOW LOW CAN VALUATIONS GO?



CHRIS SHEEHAN, CFA
SENIOR FINANCIAL ANALYST

One can only hope that some of the worst for energy is behind us, and that some of what is forecast to come doesn't materialize. The correlation between energy stocks and crude oil seems to be slipping, or possibly broken, even with a backdrop of potentially escalating geopolitical events. Stock valuations are down hard, but have they yet discounted a worst-case scenario?

In an early July report, J.P. Morgan noted that E&Ps remain disconnected from the commodity, with the XOP (S&P Oil & Gas Exploration & Production ETF) underperforming the prompt futures contract for West Texas Intermediate (WTI) by roughly 27%. E&P efforts to shift to a strategy of generating free cash flow (FCF) "have yet to translate into equity performance" and improved multiples.

With the SMID-cap E&P group trading at about a two multiple discount to its large-cap peers, the report raised the possibility of a "capitulation" by some SMID-caps to takeover moves. This would be despite the fact they had built asset bases at costs that were "significantly higher than where the market is currently discounting their equity values."

The report was issued after news of Occidental Petroleum's acquisition of Anadarko Petroleum, but before Callon Petroleum's bid for Carrizo Oil & Gas.

Market reaction to the all-stock Callon-Carrizo combination was ugly. While Carrizo was being acquired at an ostensible 25% premium to its prior day closing price, the premium soon melted away. In the five days following the announcement, Carrizo's stock was down 10%, while Callon's stock tumbled 23%.

Several research firms linked the negative stock reaction to Callon being viewed by some as a potential consolidatee.

Tudor, Pickering, Holt & Co. (TPH) estimated that, pro forma for the acquisition, Callon would have 11% production growth and generate $110 million of FCF at strip prices in 2020. It noted that "only a few select names offer a combination of double-digit production growth and meaningful FCF with less than 2 times net debt-to-EBITDA leverage."

At $4.80 per share, Callon's stock was trading at a mere 3.3 times enterprise value-to-EBITDA (EV-to-EBITDA), based on a 2020 price deck of $56 per barrel (bbl) for WTI and $2.56/Mcf for gas.

Only a little over a week earlier TPH had calculated fresh valuations using the above price deck. On average, large-cap E&Ps were trading at 5.4 times EV-to-2020 EBITDA, with 27% upside to net asset value (NAV) and a FCF yield of 6%, while SMID-caps traded at a lowly 4.1 times EV-to-2020 EBITDA, with 85% upside to NAV and a 1% FCF.

These would appear modest valuations, unless further pressure on crude prices lies ahead, as TPH says may occur. Even if U.S. producers slow production growth, the U.S. may alone meet 2020 global demand growth, which TPH projects at 1.5 MMbbl/d in a "generous recovery." Non-OPEC supply growth, including 1.6 MMbbl/d from the U.S., is put at 2.4 MMbbl/d in 2020.

In a mid-June report, Barclays took its WTI price forecast for 2020 down by $6/bbl to $62/bbl. In a nuanced commentary, it lowered global demand estimates by roughly 400,000 bbl/d and 500,000 bbl/d for 2019 and 2020, respectively. However, "concerns of a glut are overdone," it said, "and several underlying trends lead us to believe that the shale growth engine is slowing."

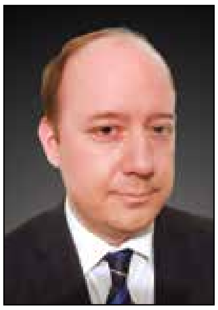
Positive factors supporting oil prices include new International Maritime Organization rules that come into effect on Jan. 1, 2020. It's unclear how much advance work has been done to cover incremental demand for distillates under the new rules, but what was once expected to be a jump in demand appears to have softened due to global trade frictions.

For the U.S., a positive has been its ability to ramp up exports and penetrate new overseas markets. Loadings by very large crude carriers reached a record 21 in June, and prior to Storm Barry estimates were for a robust 17 loadings in July. Since mid-June, exports have run near or above 3 MMbbl/d, barring Barry disruptions.

Although the U.S. has built export markets—and likely narrowed the Brent-WTI spread—has it simply spread the pain of slack oil markets elsewhere amid trade conflicts?

According to trade sources, it is Iran's exports into "bonded storage" in Chinese ports that could also weigh on global prices—and partly explain a near absence of oil price spikes. The Iranian barrels, sitting outside the world's largest oil importer, don't show up in import data and are technically not a breach of sanctions.

PERMIAN TREASURE MAPS



DARREN BARBEE,
SENIOR EDITOR

Welcome to the hit-or-miss A&D market: It's time to party like it's 2016.

The A&D market still has a large toolbox from which to crank deals, but more often it seems to be pulling out standard wrenches when a metric socket would be better suited.

These days, activist investors push for sales and settle for board seats; acquirers such as Occidental Petroleum Corp. get ultra-aggressive; and, to paraphrase Walt Whitman, some are noiseless, patient spiders waiting for a tug on the right thread.

Scott Sheffield, CEO of Pioneer Natural Resources Co., appears strikingly pragmatic about the turmoil. His take on Permian A&D is that some deal prices seem a bit high, but he'll take them if he can get them.

Pioneer said in the second quarter that it sold about 3,300 net Midland Basin acres in northern Martin County, Texas, for $66 million, or about $20,000 per acre.

"It's the first time we've seen a cash deal coming in from private equity over the last two years," Sheffield said.

Nevertheless, a more recent Occidental joint venture (JV) was encouraging, if slightly baffling, to Sheffield.

"Over the last two years, there hasn't been much done, except for the Oxy [Occidental Petroleum Inc.] transaction, which people have established acreage costs somewhere between $40,000 and $50,000 per acre," Sheffield said on an Aug. 7 earnings call.

In addition to buying Anadarko Petroleum Inc. for $55 billion, Sheffield also noted Occidental's JV with Colombia's Ecopetrol SA. The deal covers 97,000 net acres of Occidental's Midland Basin properties. The $1.5 billion transaction works out to about $31,500 per acre. Occidental will operate the Midland position, bringing along EOR techniques from the Delaware.

"We've seen this recent transaction for Ecopetrol doing a deal with Oxy at $31,500 per acre," Sheffield said. "In our treasure maps in the Midland Basin where [we're] the experts, only 15% of that acreage was in core [areas], 85% was noncore. So, it seems like a very, very high price for noncore acreage.

"We would sell noncore acreage all day long at $31,500 per acre," he said.

On Aug. 12, speaking at EnerCom's The Oil & Gas Conference in Denver, Occidental CFO Cedric Burgher weighed Sheffield's assessment after *Investor* asked whether the JV areas were mostly noncore.

"Do I agree with it? No," Burgher said. "Would I filter the input? Yes." Investors should look at well performance, he said. Without mentioning Pioneer by name, he added, "If you aren't making many good wells, you've got to be questioning, 'How good are they?' Look at the scorecards on by-well performance and how many great wells they can produce.

"Then look at the cost. Look at the proppant loading," he said. "If it takes a lot of proppant to load it up, you may be destroying value at the NPV [net present value]."

The JV and the asset unite quality assets and Occidental's operational prowess, Burgher added.

"We think it's a good asset, and we think we'll make some good wells," he said.

Another-quasi Permian company, QEP Resources Inc., saw its fortunes go south this year. In January, Elliott Management Corp. bought up QEP stock, arguing QEP was undervalued. The firm offered more than $2 billion to buy out the company.

In retrospect, QEP was either overvalued, or Elliott was speaking loudly but carrying a small stick.

On Jan. 7, Elliott publicized an $8.75 per-share deal to buy QEP—nearly 44% more than QEP's most recent trading day price of $6.08 per share. Share prices surged as high as $9. QEP reviewed different options, including potential divestitures or mergers. In August, after seven fruitless months, Elliott and QEP announced they would work together, with Elliott's $2 billion offer evaporating like an understudy's flop sweat. Upon reaching the détente, QEP's stock price was $4 per share. Time to cash in, investors.

With all the shouting done, QEP will continue as an independent company. In the second quarter, it delivered oil and cash flow per share beats vs. Wall Street, spent 12% less capital and lowered drilling expenses. Elliott, for setting off a string of firecrackers, will now have a say in selecting two new seats on QEP's board of directors. For a firm with not quite 5% of QEP's stock, that is an impressive deal.

And the patient sellers and buyers simply wait, as Pioneer has.

Sheffield said he wasn't sure exactly how much noncore Pioneer owns, "but we do have some pieces that, if we can't trade or block it up, we're going to sell."

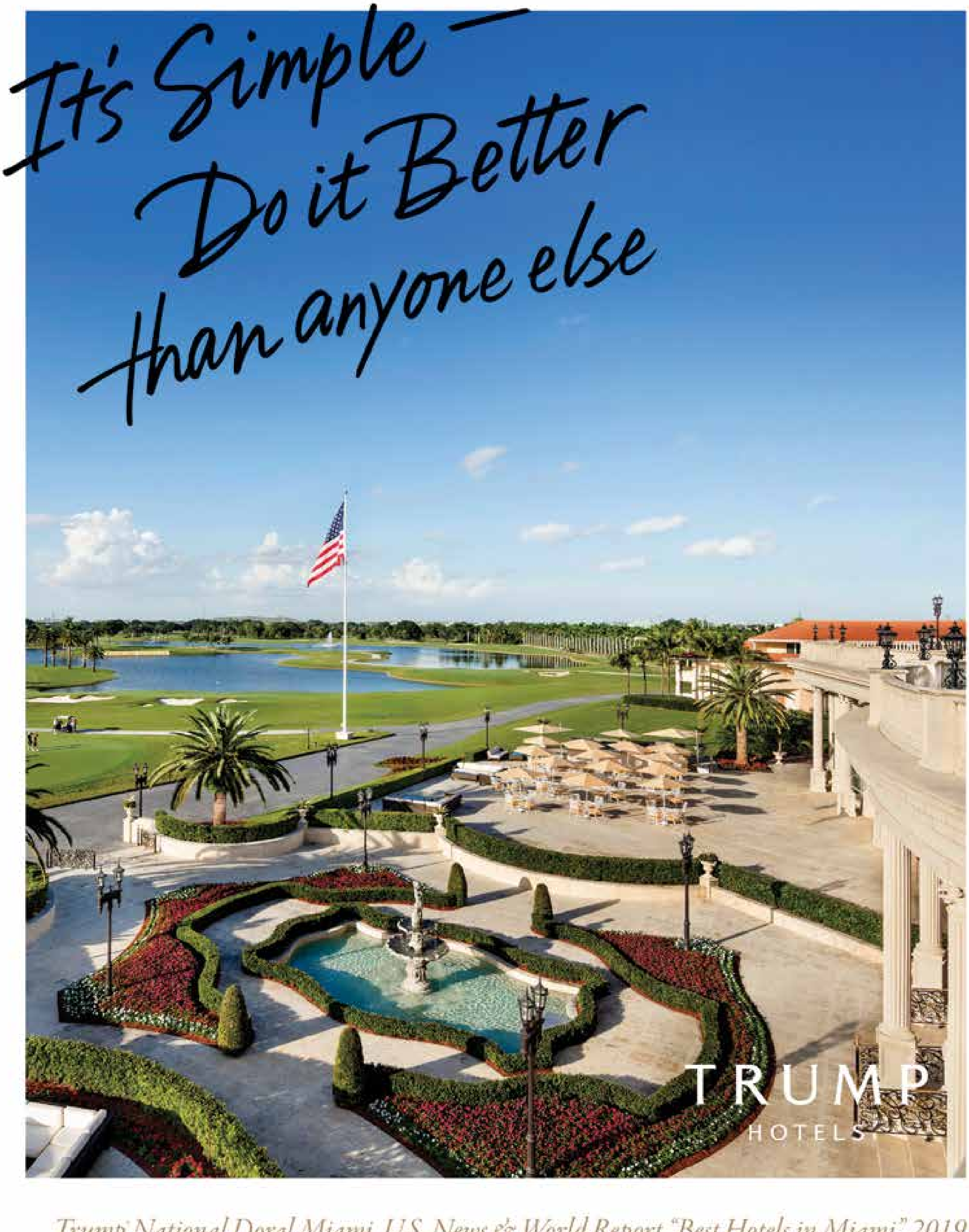
Sheffield added that he'd be just fine with a price "somewhere between that $20,000 and $30,000 per acre range."

EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2019				
PIOGA Fall Conference	Sept. 24-25	Seven Springs, Pa.	Seven Springs Mountain Resort	pioga.org
DUG Eagle Ford	**Sept. 24-26**	**San Antonio**	**Henry B. Gonzalez Conv. Center**	**dugeagleford.com**
A&D Strategies and Opportunities	**Oct. 22-23**	**Dallas**	**The Omni Dallas**	**adstrategies.com**
Executive Oil Conference	**Nov. 4-6**	**Midland, Texas**	**Midland County Horseshoe Pavilion**	**executiveoilconference.com**
IPAA Annual Meeting	Nov. 6-8	Washington, D.C.	Fairmount, Georgetown	ipaa.org
DUG Midcontinent	**Nov. 19-21**	**Oklahoma City**	**Cox Convention Center**	**dugmidcontinent.com**
Marcellus-Utica Midstream	**Dec. 3-5**	**Pittsburgh**	**David L. Lawrence Conv. Center**	**marcellusmidstream.com**
Privcap Game Change	Dec. 3-4	Houston	The Houstonian	energygamechange.com
2020				
Private Capital Conference	Jan. 23	Houston	JW Marriott Houston	ipaa.org
NAPE Summit	Feb. 3-7	Houston	George R. Brown Conv. Center	napeexpo.com
DUG Rockies	**Feb. 18-19**	**Denver**	**Colorado Convention Center**	**dugrockies.com**
Energy Capital Conference	**Mar. 2**	**Dallas**	**Fairmont Hotel**	**energycapitalconference.com**
Women in Energy Luncheon	**Mar. 4**	**Houston**	**Hilton Americas-Houston**	**womeninenergylunch.com**
EnerCom Dallas	Mar. 4-5	Dallas	Tower Club	enercomdallas.com
CERAWeek by IHS Markit	Mar. 9-13	Houston	Hilton Americas-Houston	ceraweek.com
DUG Permian	**April 6-8**	**Fort Worth, Texas**	**Fort Worth Convention Center**	**dugpermian.com**
OGIS New York	April 20-22	New York	TBA	ipaa.org
Offshore Technology Conference	May 4-7	Houston	NRG Park	2020.otcnet.org
DUG Haynesville	**May 19-20**	**Shreveport, La.**	**Shreveport Convention Center**	**dughaynesville.com**
Midstream Texas	**June 2-3**	**Midland, Texas**	**Midland County Horseshoe Pavilion**	**midstreamtexas.com**
AAPG Annual Conv. & Exhibition	June 7-10	Houston	George R. Brown Conv. Center	ace.aapg.org/2020
DUG East	**June 16-18**	**Pittsburgh**	**David L. Lawrence Conv. Center**	**dugeast.com**
Monthly				
ADAM-Dallas/Fort Worth	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.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	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.com
ADAM-Permian	Bi-monthly	Midland, Texas	Midland Petroleum Club	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.com
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Houston Petroleum Club	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	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 Brandy Fidler, bfidler@hartenergy.com.
For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com.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Despite record quarter, energy M&A outlook remains hazy

After a slump in the first quarter, M&A activity in the energy sector reached a record high during the second quarter, according to a recent PwC report.

"After an exceptionally quiet first quarter, the oil and gas M&A market roared back to life in the second, racking the biggest second-quarter deal numbers since PwC started tracking transactions in 2002," said Kyle West, a director of deals for PwC, during a July 25 webcast discussing the report.

Whether the third quarter will mirror either prior quarter depends on the outcome of a number of factors such as U.S. monetary policy, tensions in the Strait of Hormuz and weather. Additionally, any significant volatility in cash flow driven by a "sustained decline in commodity prices or an improved sentiment from higher prices is likely to drive more deal activity," West added, noting focus is expected to remain on capital discipline and operating within cash flow.

In the second quarter, PwC counted 44 energy deals totaling roughly $118.7 billion. Out of those, the firm noted three megadeals—a transaction worth over $5 billion—representing a total of $89.2 billion. Just two deals in the second quarter alone totaled $75 billion—the massive acquisition of Anadarko Petroleum Corp. by Occidental Petroleum Corp. and the private takeover of Buckeye Partners LP.

"We think [the Anadarko takeover is] a game-changer not only due to its size but also because of the scale it brings to the sector," said Andy Robinson, a director of deals at PwC specializing in providing financial diligence to corporate and private-equity clients.

The number of deals and their valuations in the energy industry rose in the second quarter. There were a record number of them—an increase of 13 deals, or by 50%, which generated another $9 billion in value consisting of $6 billion from the upstream sector and $3 billion from the oilfield service industry.

The deal value during the past 12 months is "considerably higher" and a substantial improvement compared to June 2018, according to Robinson. "This is a story of megadeals," he said.

The majority of second-quarter transactions were in the upstream sector, driven by Occidental's Anadarko acquisition which represented the bulk of the quarter's deal value.

Upstream assets are largely being acquired by strategic buyers who are dominating the market and now consist of 80% of the acquisitions. Strategic companies are now focusing their attention on improving returns, and more companies will turn to private capital or form joint ventures to fund new projects, Robinson said. "This was becoming more prevalent in the second quarter," he said.

The number of deals in the oilfield service sector fell flat, although there was a $1 billion difference due to an increase in the average price that was offset by a slightly lower deal volume, Robinson said.

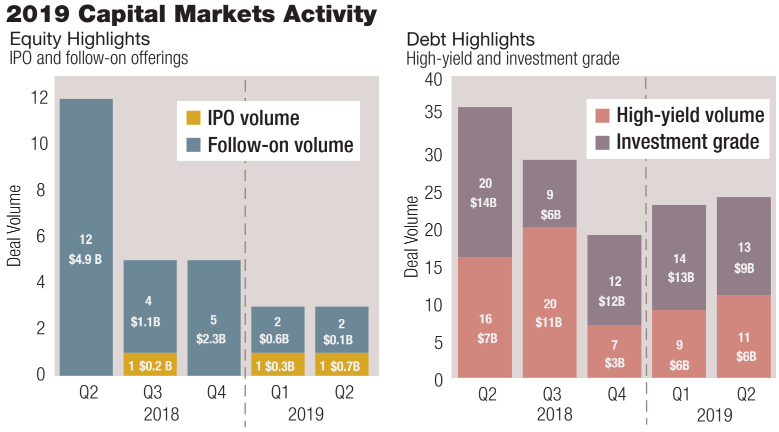
The sector's largest transaction during the quarter was the combination of C&J Energy Services Inc. and Keane Group Inc. in an all-stock merger worth about $745.7 million. The transaction, expected to close in the fourth quarter, is set to create one of the largest completion services company with an anticipated $4.2 billion in revenue.

During the past few years, the oilfield service sector chose to pay for deals with 100% cash, but now the sector has shifted to more stock to stock deals, plus some cash. This trend is likely to continue, Robinson said.

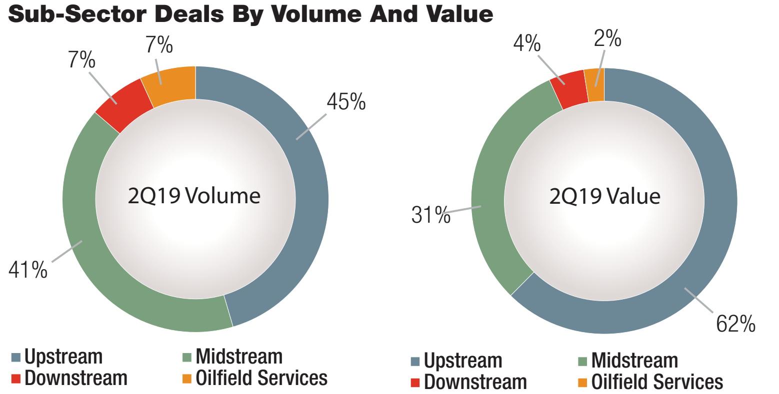
Shale deals regained momentum during the second quarter, with 17 upstream transactions averaging $5.1 billion for each deal.

The Permian Basin remained the most active basin with 12 deals. The remaining five deals were split evenly between the Eagle Ford, Bakken, Marcellus and Haynesville regions. The largest of the shale deals occurred in the Haynesville with Comstock Resources Inc.'s $ 2.1 billion acquisition of Covey Park Energy.

2019 Capital Markets Activity



Sub-Sector Deals By Volume And Value



Source: PwC

While the Gulf of Mexico (GoM) still experienced M&A activity during the second quarter, compared to the previous quarter it was relatively quiet with a slight uptick, Robinson said.

Three deals in the GoM totaling $2.5 billion occurred during the second quarter.

Determining whether the offshore sector is poised for recovery is also challenging and will depend on whether stability in oil prices continue or if there is more volatility, Robinson said. The reason the existing players are buying companies is to consolidate and generate scale.

—Ellen Chang

Industry's three threats: OFS survival, digitization and public sentiment

The oil and gas industry is facing many challenges, but perhaps none more than the struggling oilfield service sector, a leading oil and gas analyst said on July 18.

"Oilfield service has not benefited from this upturn at all," said John England, partner in Deloitte's oil, gas and chemicals practice, at Shale magazine's State of Energy luncheon. "In fact, as the industry has become more efficient, that's actually hurt their margins."

Consolidation is necessary, England said, for the sector to regain pricing power. "The space screams for consolidation," he said.

Other challenges the industry must grapple with include a negative public image and a necessary, but so far somewhat awkward, embrace of big data.

"Our society has become very data-centric," said Jason Reed, vice president for oil and gas products at Drillinginfo Inc. "Unfortunately, I think that energy has lagged behind. We're finally catching up, slowly but surely."

Digitization of energy is absolutely critical, he said, because the upstream needs optimization to be successful, and that requires robust, sound and trustworthy data.

"What's the shape of the decline curve?" Reed asked. Being able to predict outcomes allows a producer to optimize engineering designs to develop better wells and get more product per unit with less cost.

"You can't do that without really, really rich data and really sophisticated tools to help you better predict what the next steps will be in that optimization curve," he said.

But if the industry is slowly figuring out how to use data, it by and large remains at a loss in its efforts to convey its message effectively to the public. In this arena, reliance on data is a mistake.

"It's no longer sufficient for us as an industry to say we need to build this because supply needs to get from here to here," said Allen Fore, vice president for public affairs at Kinder Morgan, who has abandoned corporate talking points in favor of a direct approach to dealing with the public. "Maybe that worked a few years ago, 10 years ago. It doesn't work anymore."

Fore is focused on telling a compelling story for each of the company's projects. He said he begins with a micro perspective—how it will impact a landowner's property—and takes it to the macro perspective—the role that pipelines play in American energy independence, job creation and revenue generation for education and public safety.

"If we can explain why we're doing it and how we're doing it, folks will understand," he said.

But he urged industry members to get out of their echo chamber and comfort zones, and bring their message to forums where people oppose what the oil and gas industry represents. It's not easy, and it's not always pleasant.

For example, Fore participated in a town hall in New Hampshire that was called to inform citizens about a Kinder Morgan natural gas pipeline project. The region is desperate for natural gas, and the project helps to alleviate tightness in the market.

However, the first speaker during the Q&A portion did not see it that way.

"This local person said, 'How can you justify murdering my children?' and then walked off," Fore said. "And the whole place went crazy with cheers."

The experience taught Fore that he needed to be forceful and direct in telling the industry's story, because the story of providing energy for society to function as it does is a good one.

"We've got to use traditional and nontraditional platforms to do it," he said. "We're getting the heck beat out of us on social media."

Which is why telling the story in the halls of government of Austin or Washington isn't enough. Mainstream America, Fore said, is populated with people more inclined to support the industry.

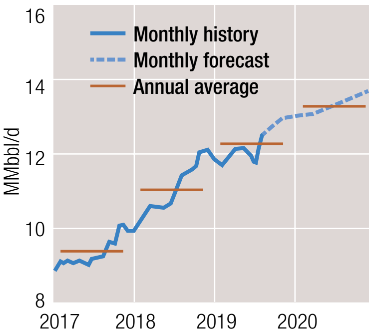
"This is a long game," he said, "and we've got to be better at it."

—Joe Markman

EIA: Permian pipe problems, oil price diffs to ease soon

Despite record-breaking U.S. oil production that seems to rise each month, things may be looking up for oil prices, especially as transportation capacity to the coast from the prolific Permian Basin

U.S. Crude Oil Production



Source: EIA Short-Term Energy Outlook, August 2019

ramps up, according to the latest "Short-Term Energy Outlook" (STEO), a status report issued by the Energy Information Administration (EIA) each month.

The EIA said in its July STEO report that it expects West Texas Intermediate (WTI) crude oil prices will average $5.50 per barrel (bbl) less than Brent prices in the fourth quarter of 2019 and in 2020, thus narrowing from the $6.60/bbl spread seen during July.

The narrowing price difference reflects The EIA's assumption that oil pipeline constraints from the Permian Basin to refineries and export terminals on the U.S. Gulf Coast will ease in the coming months, the report said.

Looking to the future, the EIA forecast the Brent-WTI spread to average $4/bbl in 2020. This updated differential forecast "reflects the agency's revised assumptions about the marginal cost of moving crude oil via pipeline from Cushing, Okla., to the coast."

The EIA also said it expects a relatively balanced global oil market, although some experts worry about slowing oil demand in the wake of the trade war between the U.S. and China.

The agency forecasts Brent spot prices will average $64/bbl in the second half of 2019 and $65/bbl in 2020. They were about $64/bbl in July, which was $10/bbl lower than July 2018. The EIA also forecasts that global oil inventories will increase by a slight 0.1 million barrels per day (MMbbl/d) in 2019 and 0.3 MMbbl/d in 2020.

The EIA estimated that U.S. crude oil production averaged 11.7 MMbbl/d in July, down slightly due to shut-ins in the Gulf of Mexico for severe weather from Hurricane Barry. For the full year, however, it estimated U.S. production will end up averaging about 12.3 MMbbl/d and rising to 13.3 MMbbl/d in 2020—both of which would be record annual levels.

The pace of growth in U.S. oil output is slowing down, according to the EIA. It said it expects monthly growth in Lower 48 onshore production to slow during the rest of the forecast period, averaging 50,000 bbl/d per month from fourth-quarter 2019 through year-end 2020.

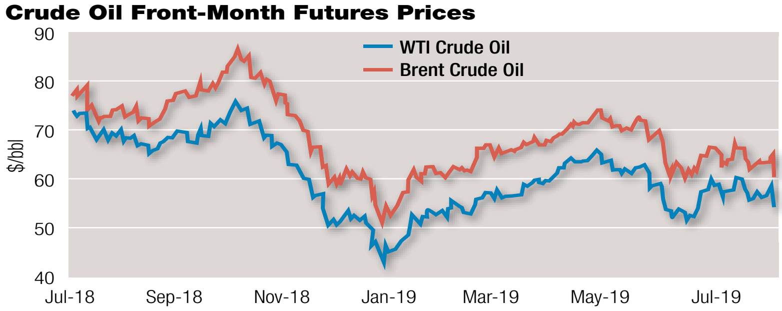
This pace, while still impressive, would be down by almost half from an average of 110,000 bbl/d per month seen from August 2018 through July 2019.

As for natural gas, the EIA's models indicate that rising prices will be necessary in the coming quarters to bring U.S. supply into balance with rising domestic and export demand in 2020.

The EIA forecasts that U.S. dry gas production will average 91 billion cubic feet per day (Bcf/d) in 2019, up 7.6 Bcf/d from last year. The EIA report said the agency expects monthly average gas production to increase in late 2019, but then decline slightly during first-quarter 2020 "as the lagged effect of low prices in the second half of 2019 reduces gas-directed drilling. However, the EIA forecasts that growth will resume in the second quarter of 2020, and natural gas production in 2020 will average 92.5 Bcf/d."

—Leslie Haines

Crude Oil Front-Month Futures Prices



Source: EIA Short-Term Energy Outlook, August 2019

Texas upstream oil industry hits the brakes

The upstream sector in Texas is undergoing a mild state of contraction based on data through June, according to Karr Ingham, a petroleum economist for the Texas Alliance of Energy Producers.

The decline can be "unnerving" for both producers and the state of Texas, which relies on the energy industry to help fund a portion of roads, schools and emergency services from the state and local taxes and state royalties paid by oil and gas companies, Ingham said during a midyear update of the Wichita Falls, Texas-based trade group's "Texas Petro Index" at the Petroleum Club of Houston on July 31.

Current crude oil prices are not "high enough to stimulate additional growth," said Ingham, the creator of the index which tallies various exploration and production indicators such as crude oil and natural gas prices and markets, the statewide rig count, drilling permits, industry employment and crude oil and natural gas production.

Texas continues to increase production even though the rate has "slowed a little," he said. The volume of crude oil production in the state rose by 15.1% monthly and 19% year-to-date. In June, Texas oil production surpassed 5 MMbbl/d primarily driven by the Permian Basin, which is located in the western part of the state as well as southeastern New Mexico.

Ingham said Texas' daily oil production stands at 42% of total production in the U.S. with the Permian Basin, in particular, comprising 25% of the country's production.

Meanwhile, investors have become impatient and are seeking greater profit margins from producers across the country. The pressure on the industry is being felt in the Permian Basin, according to Bernard Weinstein, associate director of the Maguire Energy Institute at Southern Methodist University's Cox School of Business in Dallas.

"Activity has slowed markedly in the Permian over the past few months as investors press E&P companies to focus on the bottom line rather than increases in output," Weinstein said. "At the same time the demand for oil and derived products is slowing because of various trade wars and a European economy on the verge of recession."

The Texas Petro Index peaked at 213.3 in October 2018 and has since lost 2.9% of its value. The index dipped in six of the past eight months, including four straight monthly declines, Ingham said.

Several economic indicators have declined through June compared to a year ago. The monthly average of the rig count dipped by 12.5% although the year-to-date average only fell by 0.1%. Monthly drilling permits fell by 18.6 as well as crude oil well completions, which declined by 30.9% monthly and 12.8% year-to-date. Still, the number of energy jobs, which Ingham said are some of the highest paying jobs in Texas, have risen slightly by 4.8% in June compared to a year ago.

Since March 2015, production in Texas has remained in an upward trend when volume reached 3.6 MMbbl/d except for a decline to 3.1 MMbbl/d, of 13.7% or total volume, in September of 2016. Production has rebounded and reached 5.09 MMbbl/d in June.

Looking ahead, Ingham said the total volume of crude oil production in Texas will be higher in 2019 compared to 2018 even though natural gas production in the Permian is putting a damper on development in the basin.

While the volume of crude oil production in Texas has risen, global oil prices have fallen drastically by 19.5% on a monthly average and 13% by year-to-date.

According to Ingham's forecast, crude oil prices will likely remain sluggish for the remainder of 2019 and early 2020 because of the continued uncertainty surrounding potential trade disputes. The rest of the year will likely mirror the first half of 2019, he continued, as neither supply nor production volumes will change in either direction.

Crude oil prices are not likely to reach the $60 to $70/bbl range since there is not enough energy demand, he added.

—Ellen Chang

Analysts give E&P sector 'stable' outlook for now

The next 12 to 18 months could bring a slowdown in capital efficiency gains, little to no growth in earnings, robust but slower production growth and flat free cash flow growth for the E&P sector, according to Moody's Investors Service.

More consolidation—a positive for the industry—could also be ahead as companies—mainly U.S. shale players—try to hit production targets and fulfill promises to shareholders.

But the "stable" outlook Moody's gave the global E&P sector could turn negative if already unstable oil prices fall lower than expected and companies' EBITDA dip by 5% or more.

"A stable outlook for the global E&P industry reflects our expectations that the industry will generate little to no earnings growth through 2020," Sajjad Alam, Moody's vice president and senior analyst, said in a statement. "Volatile oil prices and weak natural gas prices, shareholder demands, a slowing global economy and persistent supply growth all pose risks to earnings, although hedges, volume growth, narrower basis differentials and other factors will offer partial relief."

But don't expect E&Ps to see much more improvement on the capital efficiency front through 2020.

In the past, lower development costs came courtesy of oversupplied oilfield service providers' willingness to negotiate lower prices along with emphasis on short-cycle projects and targets set on prime drilling locations, Moody's said.

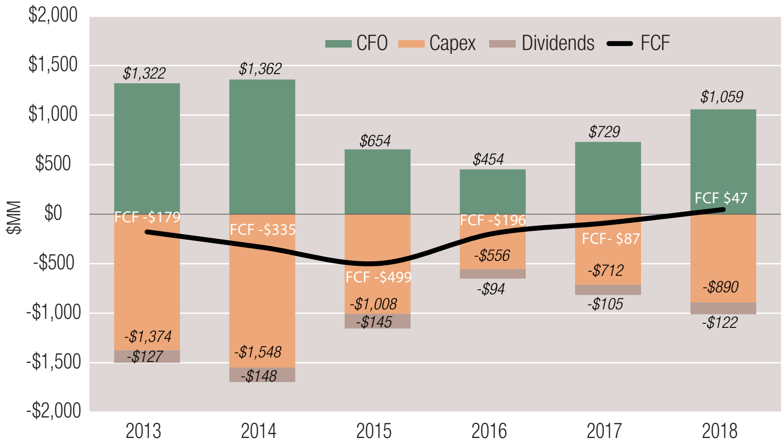
However, signs of change are already evident. Analysts turned to the U.S. as an example.

"Selling, general and administrative costs are still rising in a tight U.S. labor market, with unemployment at six-decade lows as of mid-2019. The cost of oil country tubular goods has also risen with the 25% tariff that the U.S. imposed on imported steel in April 2018. And recent M&A deal multiples suggest acreage costs are generally rising," Moody's said in the outlook.

But all costs are not expected to go up. In the Permian Basin, Moody's anticipates lower sand, drilling and completion, transportation and midstream costs—at least for 2019.

"E&P companies will need WTI price of at least $60/bbl to maintain

E&P Free Cash Flow



Source: Moody's Financial Metrics; company financial statements

decent capital efficiency," according to the outlook.

Moody's pointed out a surge in crude price volatility present since late 2018, driven mainly by concerns about supply outpacing demand. Global demand could grow slower than previously thought.

"The world's largest energy-consuming nations are grappling with decelerating economic activity and increasing trade barriers," Moody's said. "Additionally, lower breakeven costs, more industrial-scale development, and increasing takeaway capacity in the prolific Permian shale basin of western Texas and southeastern New Mexico will only encourage production growth in the U.S., pressuring prices. Any easing of sanctions against Iran would also drag prices lower."

Despite weaker prices, oil and natural gas volumes are forecast to continue rising as operational and drilling efficiency gains contribute to lower breakeven costs. Onshore U.S., this has come as the rig count has fallen—down 11% by mid-2019 from its November 2018 peak, according to Moody's.

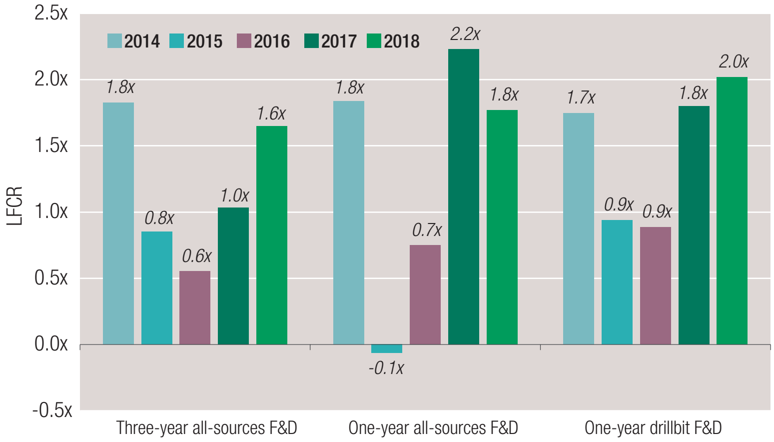
The EIA forecasts oil production could jump by about 1.4 MMbbl/d this year and by 1.1 MMbbl/d next year. Most of the growth will be from the Permian.

"Assuming no sustained drop in crude prices, we anticipate robust production growth to continue—especially as midstream operators add roughly 2.2 MMbbl/d of crude takeaway capacity in the Permian by early 2020, along with 2.0 Bcf/d of natural gas takeaway capacity," Moody's said.

Depressed prices aren't expected to halt U.S. gas production growth either. It's expected to rise by 8 Bcf/d in 2019, led by Appalachia's Marcellus and Utica shales, the Permian Basin and the Haynesville Shale.

But analysts warned growth will be slower amid investors' demands for producers to operate within

E&P Capital Efficiency Improvement Levels



Source: Moody's Financial Metrics; company financial statements

cash flow. Several E&P companies have already indicated plans to spend less this year.

"We expect that aggregate capital spending for the E&P sector will fall by high single-digit percentages in 2019 (excluding investments from the integrated or national oil companies), and will not rebound much in 2020 without higher prices or greater price stabilization," Moody's said. "The capital flight from long-cycle projects to short-cycle projects will remain very much alive as producers try to retain financial flexibility and maintain capital market access."

In addition, consolidation could set companies on a "path to achieve cost reductions and generate sustainable free cash flow at times of low commodity prices, helping companies maintain access to capital markets," Moody's said.

The firm noted E&P consolidation favors low-cost shale producers.

Analysts see M&A activity continuing through next year, mainly large public companies taking strategic steps.

"While the number of E&P deals has been decreasing since 2016, the size of E&P deals generally increased in 2018-19," Moody's said. "Strong companies with lower costs of capital can afford to pay a premium and still create value for their shareholders."

—Velda Addison

Midstream investing remains robust despite drop in A&D

For the first time since first-quarter 2018, U.S. midstream sector deal activity took a backseat to upstream in the second quarter of this year.

But Joe Dunleavy, U.S. EU&M deals leader at PwC, said midstream investing and deals are still active. He added the upstream jump in the second quarter hinged primarily on one megadeal—Occidental's acquisition of Anadarko.

In fact, two other megadeals in the second quarter were in the midstream sector: Marathon Petroleum Corp.'s midstream consolidation and IFM Investors' acquisition of Buckeye Partners LP. In total, upstream A&D totaled $74 billion for second-quarter 2019 compared to the $36.5 billion spread out over 18 midstream deals.

"It's a sector that is filled with investors, and it's a sector that I expect to be popular, notwithstanding this quarter. It fell below the upstream in terms of transactions but it's not like it fell off the map," Dunleavy said. "We had 14 midstream deals in the first quarter of 2019, and we had 18 in the second quarter. If you look at the upstream, in the first quarter of 2019 there were nine upstream deals and there happened to be 20 in the second quarter."

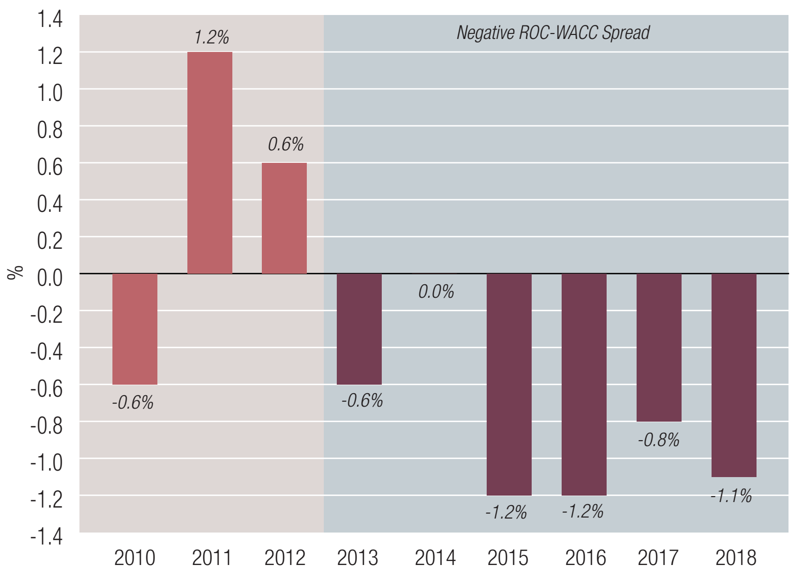
But Dunleavy did acknowledge that midstream deals are down because investors are cautious when it comes to the activity in the sector. Upstream production remains high, but having enough infrastructure to move that production to market continues to be a concern for investors.

PwC's second-quarter 2019 deals report said U.S. midstream companies have struggled to return to pre-downturn valuations and deliver value to shareholders above the cost of capital during the past six years, despite consistent production volume growth and margin recovery.

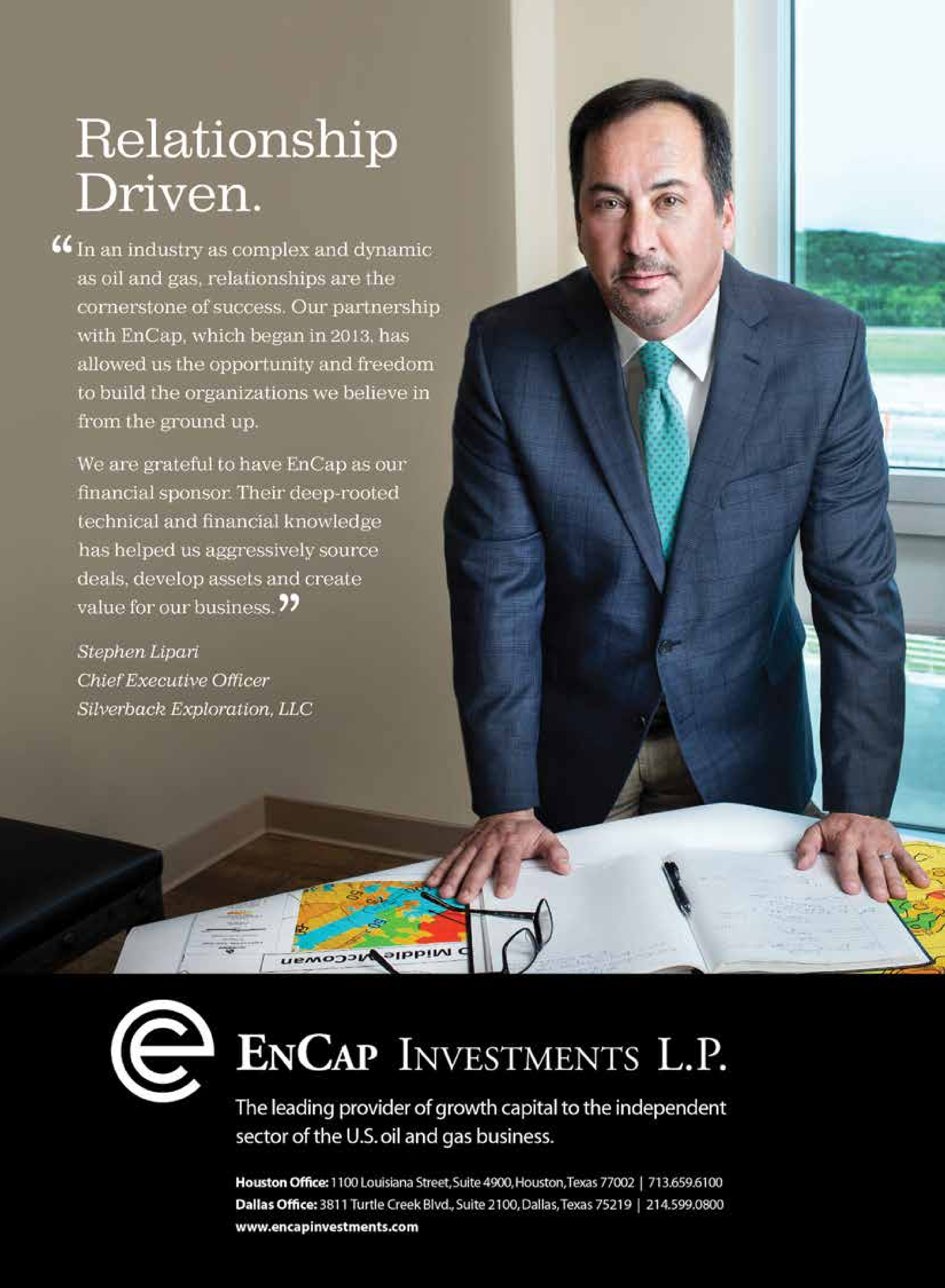
The report indicates a disconnect between investor expectations and performance has been driven by fundamental changes in the industry landscape. The sector has seen issues such as increased contract risk due to E&P bankruptcies, a shift in investor mix and financing landscape and increased time and complexity of regulatory approvals, which affects how, or if, deals get done.

"I think they are cautious," Dunleavy said of midstream investors. "There is a concern about the sector as a whole. The midstream

U.S. Midstream Companies ROC-WACC Spread



Source: PwC analysis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has its challenges, but having said all of that you can stand back and say, 'Where are we from a midstream infrastructure perspective? There is infrastructure that is still needed.'"

The expectation is the U.S. is becoming more of an exporter of crude oil, which means more production from major shale plays like the Permian Basin will make its way to the Gulf Coast. Dunleavy said this should also mean an uptick in building and spending in key export cities like Corpus Christi, Texas.

"The buildup we are seeing with pipelines in the Permian … When you build all of those pipelines to take the product out of the Permian, it's got to go somewhere so you move the infrastructure and midstream build to where product is going," he said.

Dunleavy added he sees an increase in investing and deals in the midstream space.

"You have other basins in the country where maybe the production is down but historically we have still had a need for pipelines," he said. "So going north to the Bakken or throughout the country, there is still a need for pipeline infrastructure and midstream infrastructure. The market right now is seeing a downturn, but the long term I think it's a viable area for M&A."

The outlook is for midstream M&A to remain active as exports ramp up, according to PwC.

"If the projections are right and we are a net exporter you are going to need the midstream infrastructure to get product to the coast to be able to be exported," Dunleavy said. "So you are going to see continued activity."

In the coming quarters, Dunleavy said he wouldn't be surprised if the midstream sector moves ahead of upstream in deals. But he added midstream companies will have to change how they do business going forward, moving away from the supply approach.

"In doing your due diligence now you have to look at that production profile, you have to look at the contract," Dunleavy said. "The companies that consider M&A will expect a change in how buyers are looking at midstream assets before they acquire them."

—Terrance Harris

Bakken EURs 'reign supreme' despite Permian popularity

Oil and gas operators in the Bakken remain resilient despite losing their "coolness factor" to the Permian Basin, a recent report from Seaport Global Securities LLC said.

"Bakken well productivity still reigns supreme based on our data shown today," Seaport analysts Mike Kelly and Patrick Sun wrote in the report published July 11.

In the report, Kelly and Sun analyzed 2018 EURs for Bakken operators while also gauging trends in oil EURs from between 2016 and 2018 to determine which players have made gains and which have held steady or sustained losses in well productivity.

According to their analysis, the Bakken operators with the three highest oil EURs in 2018 included:

- Marathon Oil Corp. at 1.101 MMbbl of oil;
- WPX Energy Inc. at 1.092 MMbbl of oil; and
- Continental Resources Inc. with 918,000 bbl of oil.

Adjusted for lateral length, the highest 2018 EURs in the Bakken were turned in by WPX at 115,000 bbl of oil per 1,000 feet. Behind WPX was Marathon at 107,000 bbl of oil per 1,000 feet and EOG Resources Inc. at 105,000 bbl of oil per 1,000 feet.

When the Seaport analysts compared the Bakken EUR stats to those of operators in Permian sub-basins—the Midland and Delaware—Bakken EURs came out on top.

When unadjusted for lateral lengths, Bakken operators averaged 823,000 bbl of oil EURs, which lands them at 21% and 57% better than their Midland and Delaware cousins, respectively.

Adjusted for lateral lengths, the Bakken EURs are still 15% higher than the Midland wells but 5% lower than the Delaware Basin. The analysts said lateral lengths for Delaware wells are increasing but are currently still an average of 43% shorter than Bakken laterals.

Still, the analysts noted that the average Bakken name today trades at 4.2 times 2019 estimated EBITDA. In comparison, Permian Basin E&P companies garner 5.4 times estimated EBITDA.

Marathon and EOG also topped the most improved Bakken oil EUR in 2018 vs. 2017 with both improving by 37%. Seaport's data show WPX's oil EURs in the Bakken improved 28% last year.

Others showing notable gains in Bakken oil EURs, according to the Seaport report, were Continental Resources (up about 18%) and Hess Corp. (up about 25%).

The Seaport analysts noted results in the report should be viewed with the understanding that the state data can be flawed and the EUR estimates were calculated by Drillinginfo, which uses an Arps model that could include some "shoddy" production data.

The analysts also said the state data "doesn't take into account downtime for shut-ins, relies upon an algorithm to allocate production between wells on multiwell pads, has inconsistencies with lateral lengths, and doesn't adjust for different flowback approaches."

—Susan Klann

Bakken Oil EUR Comparison

Stock Ticker	Avg. Oil Eur (MBBL)	Avg. Total EUR (BOE)	Well Count	Avg. Lateral Length (Ft.)
AXAS	719	1,086	13	9,417
CLR	918	1,193	167	10,097
EOG	637	789	27	9,372
HES	812	1,052	103	9,925
MRO	1,101	1,430	90	10,191
OAS	677	963	95	9,669
WLL	625	895	126	9,520
WPX	1,092	1,302	62	9,508
Average:	823	1,089	—	9,712

Source: Seaport Global Securities LLC July 11, 2019, Bakken EUR Analysis

New Mexico oil industry unconcerned about regulation obstacles

As production of oil and gas in New Mexico reached record highs in 2018 and the state's administration changed hands, energy executives were concerned that regulations would be tightened on natural gas flaring, permitting and methane gas emissions.

New Mexico's Gov. Michelle Lujan Grisham and state land commissioner Stephanie Garcia Richard, both Democrats, were elected in November 2018.

The transition to a Democratic administration from a Republican one has not affected oil and gas drilling, said Ryan Flynn, executive director of the New Mexico Oil & Gas Association (NMOGA), a trade association group that represents nearly 1,000 upstream, midstream and downstream operators, in a conference call hosted by SunTrust Robinson Humphrey on July 24.

Lujan Grisham is a career politician who is a native of New Mexico and understands the importance of the energy industry to the state's economy, he said. She previously served as the representative for the state's first congressional district from 2013 to 2018. From 2004 to 2007, Lujan Grisham served as secretary of health of New Mexico and as a Bernalillo County Commissioner from 2010 to 2012.

"She [Lujan Grisham] has been really good to work with," he said. "She has no personal opposition or strong feelings for or against the industry. She has seen the state prosper as a result of the industry and suffer when prices were down."

Oil production in New Mexico boomed in 2018 and rose by 46% from 2017, reaching 249 MMbbl, said the EIA.

Natural gas production followed suit and reached a 10-year record of about 1.4 MMcf for 2018 marketed production.

The record production rates resulted in the energy industry contributing $2.2 billion to state coffers, including $822 million in funding for public schools and nearly $241 million for the state's universities, colleges and other higher education institutions in fiscal-year 2018.

The massive increases in oil and natural gas taxes and revenue are benefitting the state's lower and higher education entities. The surge in production resulted in an additional $1.2 billion in revenue for the budget year that began in July.

New Mexico has become "increasingly dependent" on the energy industry and the revenue that it generates, Flynn said. The state faces pressure from environmental organizations and special interest groups who are active in New Mexico and are pouring money into the state to fund efforts to limit production.

"We are clear-eyed about the political dynamics," he said.

Since New Mexico lacks a diversified economy, the state has "doubled down on the industry," Flynn said.

Although there are state legislators who make negative comments about the industry, he characterized them as outliers. "We have strong relationships across the board [with legislators]," he said.

One issue that has cropped up is Garcia Richard's proposal to raise the state's royalty rate from 18.5% to 25% to be equivalent to the rate in Texas. The proposal did not make it out of committee, but Flynn said the land commissioner will likely keep pushing for the increase.

There is not currently a strong appetite from the governor or legislature to pursue an increase "since there is so much revenue being generated from the industry," he said.

"Things are going well and there is no appetite for a tax or royalty increase," Flynn said.

The issue will get more attention in the future and will be an issue that NMOGA will have to engage in for the long term, he said.

Comparing the state's royalty rate to Texas is an oversimplification, he said, because the Lone Star State does not contain any federal land and does not have to deal with the federal Bureau of Land Management, which administers public land.

The issue is nuanced because it is easier to work on oil and gas projects in Texas than in New Mexico.

"We want to keep our royalty rate to be competitive, and we don't want to drive business from the New Mexico side to Texas," Flynn said.

While the industry was nervous about Garcia Richard serving as land commissioner, the "operations have remained stable" since she took office, he said. The state will see action on royalty rates, but no changes are expected in the next year or two, Flynn said.

Gas flaring remains the largest issue from a regulatory perspective. NMOGA's methane group is working closely with Lujan Grisham's office. The goal is to decrease emissions, but choose an approach that does not curb production, he said.

This issue will be a priority for the next year as environmental groups "become political proxies with lots of fighting," Flynn said.

The state is seeking operational flexibility while innovating and plans to avoid the mistakes that were made in Colorado where reductions were achieved that were "harmful" to the industry, he said.

"This will be the hot topic for the next 12 months," Flynn said. "I don't see this as an issue is going to be detrimental to us."

—Ellen Chang

Frack sand supply reductions needed to balance market

The demand for frack sand is expected to grow at a slower rate this year as E&Ps make progress in stabilizing the amount of proppant used to complete wells in U.S. shale plays, though recipes are still being optimized.

This, according to analysts at Westwood Global Energy Group, follows a period in which frack sand supplies rose by 116% on what the firm described as overstated market demand by industry analysts between 2017 and 2018, contributing to an overbuild of mines. To balance the market, the firm believes between an estimated 30- to 50 million tons needs to be removed during the next 12 to 18 months.

"The industry must now face the consequences of 'sunshine pumping' and market exuberance that occurred in 2017 and 2018," Todd Bush, head of unconventionals for Westwood Global Energy Group, said in a statement. "Balance needs to be restored to the market with frack sand supply reductions."

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Association for Corporate Growth (ACG) is the premier global networking organization for professionals involved in corporate growth, mergers and acquisitions, equity capital, strategic alliances and other aspects of corporate development.

The recently released report was delivered as some E&Ps slow down spending and drilling and completions activity as larger players like ExxonMobil Corp. and Chevron Corp. step up activity.

Overall, forecasts are pointing to slower production growth from U.S. shale players as focus shifts more to shareholder returns, cash-flow growth and paying down debt instead of higher output.

Lowering costs and exercising financial discipline also remain at the forefront of agendas amid continued commodity price volatility.

"Under a macroeconomic scenario with $50 to $60 per barrel West Texas Intermediate crude oil, Westwood estimates the frack sand market to grow 10% in 2019 and 12% in 2020," the report said. "Even with a temporary slowdown in activity in 2019, we anticipate 5,100 completions in 2019 compared to 5,300 in 2018, a 4% decline in activity."

This year, frack demand is expected to increase by about 10% to 95 million tons.

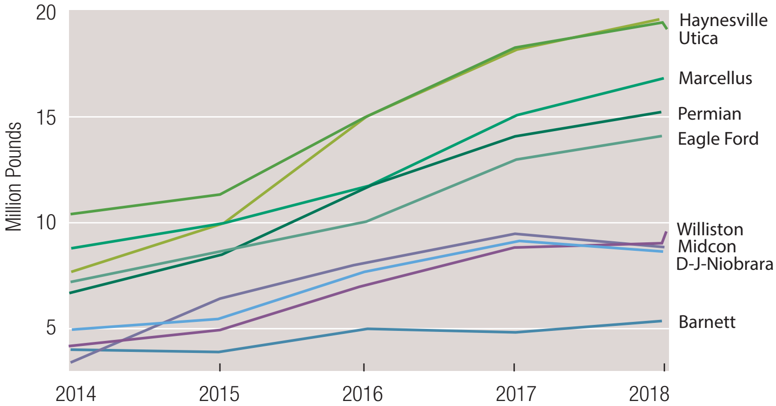
The percentage of year-over-year demand growth is less than the 30% the industry experienced in 2018 when the frack sand market grew to 86 million tons and far below the 82% seen in 2017 when proppant amounts soared from 36 million tons to 66 million tons, the report said.

Using on average 13 million pounds, or 7,000 tons, of sand per well completion last year, the Permian Basin dominated demand at 42%.

But companies are packing more sand into Utica and Haynesville wells, which each utilize about 18 million pounds of frack sand, according to the report.

Completion intensity metrics are starting to plateau, however, even decreasing in some U.S. basins, Westwood said.

Proppant Per Well Per Basin



Source: Energent

Frack sand supply could jump to nearly 143 million tons, assuming 70% utilization of facilities, though they are capable of producing more, in 2019.

"The growth in frack sand supply from Q217 through Q318 placed substantial pricing pressure on frack sand. As new entrants and industry leaders brought new mines online during this time, an oversupplied frack sand market became more and more evident," the report said. "Frack sand companies are now in a position where many companies must lower production, abandon mine operations, or restructure their business in order to last through this cycle."

Analysts expect to see the frack sand supply and demand imbalance—particularly for finer grain sand due to in-basin sand usage—throughout this year and into 2020.

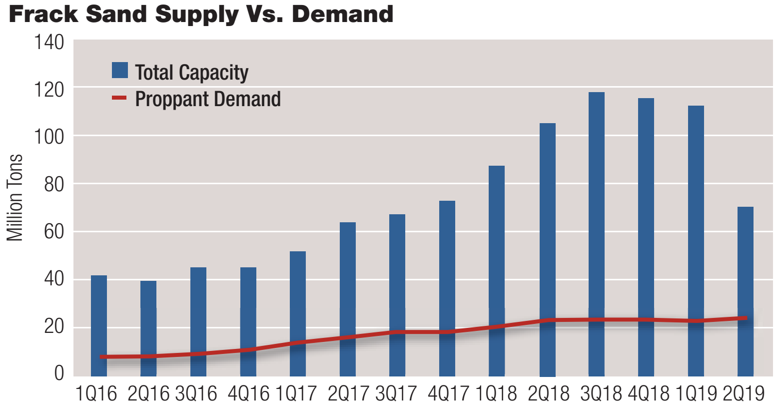
As a result, "Pricing will fluctuate as sand mines pull frack sand supply from the market," Westwood said in the report. "Over the next 12 to 18 months, we expect 30- to 50 million tons of frack sand to come off the market."

Meanwhile, frack sand miners are seeing more business from the oil and gas sector. In July, for example, U.S. Silica Holdings said it sold 3.9 million tons of sand to oil and gas companies in the second quarter. That was 13% more than the same quarter a year earlier as its West Texas capacity increased.

But it wasn't enough to result in a higher net income, which fell to $6.2 million from $17.2 million a year ago. Reuters reported U.S. Silica, which aims to expand its use in oil field and non-oil field industries, expects volumes in its oil and gas unit to rise by about 10% sequentially in the third quarter and projects annual capex of about $125 million.

—Velda Addison

Frack Sand Supply Vs. Demand



Source: Energent

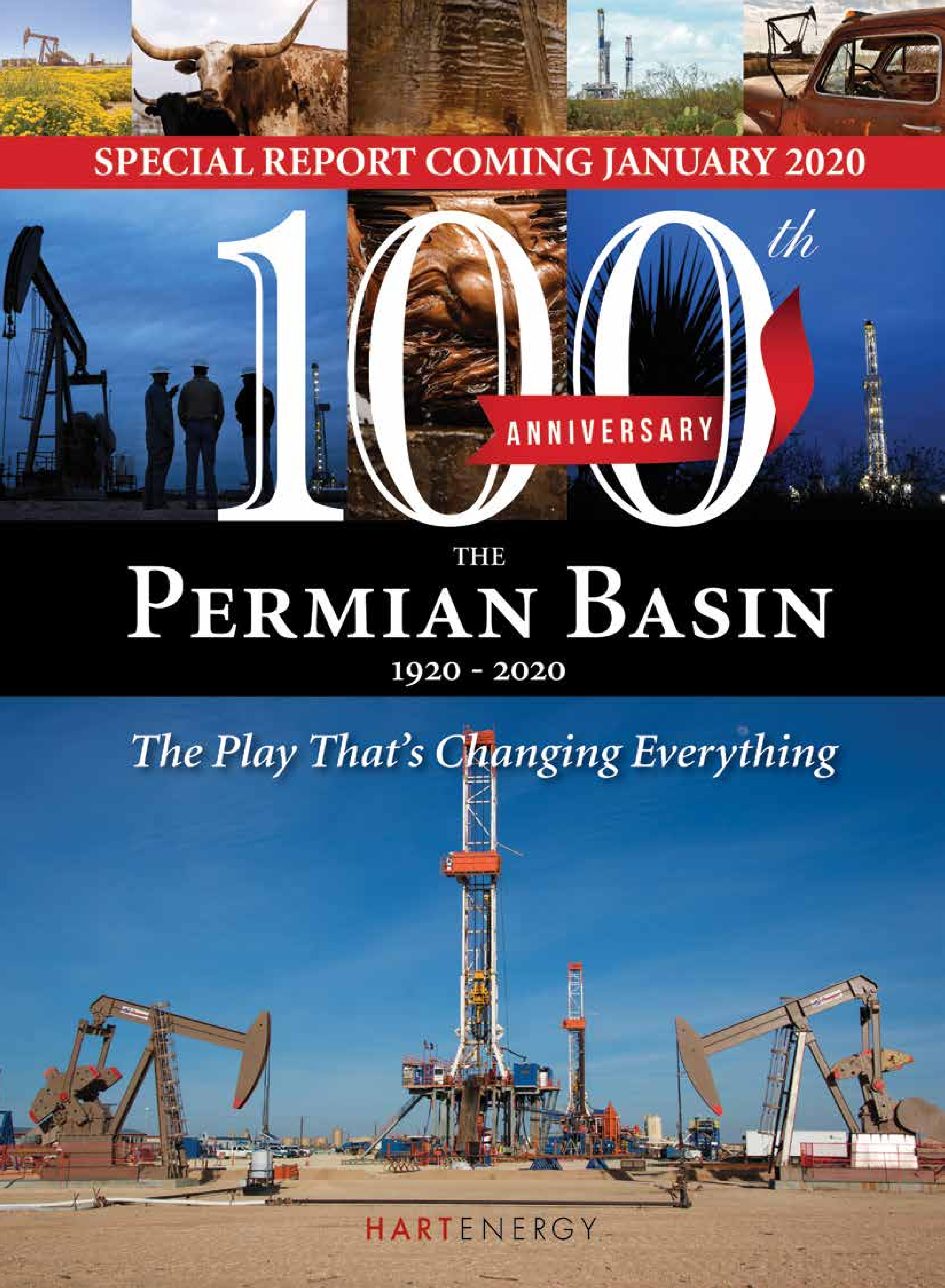
Drillinginfo: Takeaway relief on the way in Permian

The Permian Basin continues to be the most prolific oil field in the U.S. and, without much surprise, the lack of infrastructure to get more of the production to market has left the basin congested.

But with bigger pipeline projects set to come online later this year and into 2021, the latest Drillinginfo report, "Permian to Gulf Coast Midstream," presents a rosier outlook for long-haul takeaway capacity for crude oil, gas and NGL coming out of West Texas.

That will be a huge relief after the Permian has suffered from lack of adequate takeaway capacity in 2018 and 2019, which sometimes pressured Midland differentials to large discounts vs. Cushing. Now with new long-haul capacity being added in the coming months, Midland differentials are likely to gain support.

"Yes, we will have enough takeaway capacity, and yes it is going


SPECIAL REPORT COMING JANUARY 2020
100th
ANNIVERSARY
THE
PERMIAN BASIN
1920 - 2020
The Play That's Changing Everything
HARTENERGY

1920

An Invitation to

Celebrate This

February 1920

W. H. Abrams #1: the first commercial discovery of oil in the Permian was in Mitchell County, Texas. It began production in June, 1920 with 20 barrels per day, and marked the opening of Westbrook Field.

— Source: The Petroleum Museum, and Midland Reporter-Telegram, June 2009

100th ANNIVERSARY

COMING 2020

THE
PERMIAN BASIN
1920 - 2020

The Permian Basin is like none other. It has played a major role in U.S. oil production for 100 years. Now it's contributing to exports—and it's not done yet. "The Permian" promises to sustain production for many years to come. In April 2019, U.S. oil production topped 12 million barrels a day for the first time—and Permian Basin production contributed 4.2 million barrels of that volume. What's more, experts now forecast Permian crude output will grow another 50% by 2025.

Hart Energy is commemorating the 100th anniversary of the world's most remarkable oil basin with a special, coffee-table book by the editors of *Oil and Gas Investor* and *E&P* magazines. This special commemorative book will showcase the basin's proud past, its current activity and its extraordinary significance to U. S. energy production and independence. It is sure to delight the most seasoned professional and intrigue young engineers, geologists, entrepreneurs and investors who are leading the industry in the 21st century.

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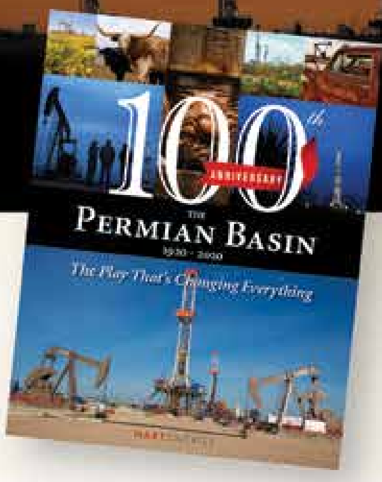
Remarkable Play



2020

January 2020

Hart Energy publishes a Centennial special issue to celebrate The Permian Basin's 100th Anniversary.

Featured Chapters:

From the Office of*...

U.S. President Donald Trump, **Secretary of Energy** Rick Perry, **Texas Governor** Greg Abbott, **New Mexico Governor** Michelle Lujan Grisham, former **Secretary of Commerce** and **Permian Strategic Partnership Chairman** Donald Evans, former **President** George W. Bush, **Midland Mayor** Jerry Morales and **Odessa Mayor** David Turner (*Requested)

Chapter 1 – History 1920 – 2020

The incredible ride through the booms and busts of oil and gas development in the Permian Basin has spanned a century. It's a story of constant change and innovation that has been essential to America's prosperity.

Chapter 2 – Drilling Activity

Current activity trends across the Northwest Shelf, Delaware Basin, Midland Basin and Central Basin Platform are captured, including rig deployment, major reservoir targets, early to full-field development plans, and oilfield service technology and logistics challenges.

Chapter 3 – Giving Back

Social responsibility, sustainability, environmental protection and strong corporate governance are crucial values that companies are embracing to address development issues and create lasting relationships between the industry and the region's residents.

Chapter 4 – Will To Succeed

The giants of the Permian Basin are those individuals who persevered through adversity, who disrupted tradition with new ideas, and who pioneered many innovations that have changed the worldwide industry.

Chapter 5 – Serving Up Technology

Operators and service providers are working together to rapidly evolve new and ever more effective technologies that aid in the discovery, production and transportation of Permian Basin oil and gas.

Chapter 6 – The Infrastructure Take-Away

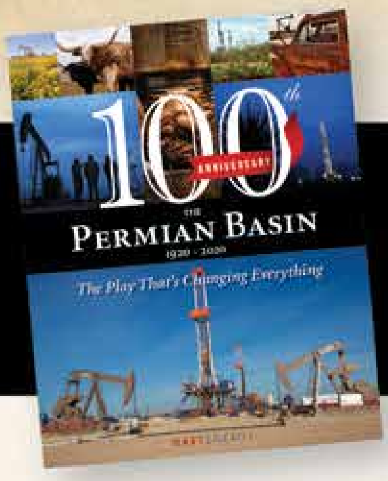
The midstream sector is working flat out to connect the Permian Basin's bountiful oil and gas production to domestic and international markets.

Chapter 7 – Capital Investment

Local lenders, friends and families often provided the seed money for early Permian Basin explorers. Now Wall Street and private equity are all-in on this amazing play.

Chapter 8 – The Future

The future is bright for economic development and job growth across the Permian Basin communities. The industry is working hard on workforce development and community projects, and Texas and New Mexico will unequivocally lead the way in America's energy independence story for decades to come.



The Permian Basin has given us so much to be grateful for, so let's do our part to accurately educate those who will lead our industry into the next 100 years.

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to happen very soon," said Drillinginfo analyst Jesse Mercer, who was a former crude oil treating strategist with Phillips 66 Co. "We will see some relief in the second half of 2019 and 2020."

Long-haul takeaway capacity from the Permian is on the rise. Energy DataLink provides data on oil and gas pipelines in the region.

In the report, Drillinginfo said one of the greatest reasons for optimism is the sizeable projects that are set to come online. Between now and the end of the year, there are three pipelines coming which include Plains All-American Pipeline's Cactus II—set to start commercial service in August—and Phillips 66's Gray Oak.

These three pipelines combined will be able to move an additional nearly 2 MMbbl/d of production from the Permian to market.

"That is more than offsetting the increase in production over that time period," Mercer said. "Capacity on those three pipelines alone is more or less enough to offset all of 2020 production growth from beginning to year end."

The Permian started the year with crude oil production at 3.9 MMbbl/d in January, and in June, the estimate was 3.4 MMbbl/d. By the end of the year, it will be about 4.9 MMbbl/d. The outbound capacity combined with local refining is only about 4.2 MMbbl/d.

While the Permian is oil-focused, the continued increase in NGL production and gas to a lesser degree has made the bottlenecks worst in recent years as midstream infrastructure has struggled to keep up. The continued growth of NGL production and gas has made the need for more infrastructure even more pressing.

If the infrastructure isn't in place to take the three hydrocarbons away then the only other option is to flare them, and there are limits to flaring.

"It's been a pretty big game changer in NGL production and with crude being the main target there; NGL and gas are byproducts, but you have to get them out," said Drillinginfo analyst Ashton Dirks, who focuses primarily on natural gas and NGL economics and fundamentals. "It is incentivizing more infrastructure as more wells get drilled, oil has to go somewhere and the gas has to go somewhere and the NGL has to go somewhere. With people focusing so much on crude down there that is what is really incentivizing NGL infrastructure development."

With more production leaving the area and much of it headed to the coast to be exported, there will be increased pressure on the infrastructure in the Gulf Coast as more volume is taken away from Cushing, according to the report. More export capacity will be required, which means there will be an acute need for new export facilities capable of fully loading very large crude carriers.

That has created a race to the finish with several onshore and at least seven offshore projects currently in the proposal or development stages.

—Terrance Harris

Analysis shows well interference's role in Scoop/Stack productivity

More wells drilled per section plus more proppant doesn't necessarily equal greater productivity.

At least that was the case for an operator targeting the Mississippian in a normal-pressured window of the Stack play in Oklahoma's Kingfisher County.

"The operator increased [its] well spacing from six to eight wells per section. At the same time, [it] increased proppant intensity about 40%," Sarp Ozkan, a senior oil and gas market analyst and manager of upstream and crude market efforts for Drillinginfo, said on a webinar. "However, that resulted in about a 30% loss in productivity. … An aggressive development plan of increasing frack intensity and downspacing at the same time can greatly impact productivity to the negative side."

The case study focused on the first six months of oil production, using Drillinginfo's spacing dataset, which has spacing metrics on neighbor, parent, child and co-completed wells as well as well density, EURs, production and completion data related to spacing among other data.

Analysis also pointed to a "noticeable degradation" in the productivity of child wells, compared to parent wells. The former had "roughly half of the productivity of those wells drilled in 2015 to 2016," compared to 2017 to 2018, Ozkan said.

The talk took place as the number of child wells, or infill wells, across U.S. shale plays, continues to grow. The surge has brought concerns about spacing and impact on other nearby wells—particularly parent wells that could experience declining pressure.

The unfavorable impact could affect overall production and revenue potential not only for upstream players, but also for those down the pipeline.

"Lower productivity wells hurt returns for operators. That in turn will impact activity especially in an environment today where Wall Street is laser-focused on free cash flow and returns to shareholders," Ozkan said.

"Even if these wells are still economic and activity remains strong, lower productivity also translates to less volume going through your system," he said, referring to midstream players. "This is the main reason why the parent-child issue and spacing issues are going to be a focal point for the midstream industry moving forward as well."

Ozkan pointed out growing concerns about "how aggressive downspacing programs have negatively impacted oil productivity" in the Scoop/Stack. A jump in average per well productivity seen in 2014-2015 carried into 2016; however, well productivity declined the following year and in 2018, he said.

"When we look at those wells drilled in 2018 and look at the productivity of child wells in relation to parent wells, we see that there is a 25% productivity decrease," Ozkan said.

Drillinginfo's analysis shows that the number of child wells drilled in 2018 is more than five times that of 2016.

When analyzing data, it's important to isolate core and noncore assets when trying to understand optimal downspacing and parent-child well interactions, he added.

Scoop/Stack operators have consistently spaced wells at an average of six to seven wells per section, according to Drillinginfo. Wells drilled outside the core in emerging areas have smaller pads with four or fewer wells, compared to between eight and 12 wells per section inside the core, Ozkan said.

About 40% of the Scoop/Stack wells fall into the emerging or noncore areas, he added.

"They may not have interference issues, but an operator may still be learning best practices in the area," Ozkan said, or the area could have worse rocks. "Those will be contributing to the type curve degradation."

The shift of drilling programs toward more child wells could also alter production forecasts.

The concerns aren't unique to the Scoop/Stack. Companies have been tackling such issues in shale plays across the U.S.

So, what are companies doing to address well interference and parent-child issues?

"The real measures that are taking place are trying to understand what the optimal spacing is and taking measures to make sure development programs do not try to overdrill different units," Ozkan said. "Additionally, we are hearing there is work, in the research phase, around mitigating frack interference and being able to make sure that when child wells are coming in that the fracks are fracking virgin rock vs. rock that has already been crushed."

To minimize the impact of parent-child well interference, some E&Ps shut in the parent well before fracking a child well nearby.

Some operators are utilizing a factory approach—tapping multiple layers of shale rock at one time. The approach has been called cube development by some, while others have given their development styles unique names.

QEP Resources Inc. uses "tank-style development" in the Permian Basin. In April, QEP said in a presentation that tank-style development is "leading to consistent, repeatable, high-return wells" and "parent/child issues [are] not a concern with tank-style.

Callon Petroleum, which moved to acquire Carrizo Oil & Gas for $3.2 billion, is also looking to optimize development and reduce parent-child issues through use of what it calls SimOps (simultaneous operations) mega-pad development.

"Switching to mega-pad development designs significantly reduces the proportion of children wells within a given DSU [drill spacing unit]," the company said in a presentation July 15.

Continental Resources Inc.'s Project SpringBoard stacked development in the Scoop play focuses on the Springer, Sycamore and Woodford reservoirs. The company reported production is growing ahead of schedule, prompting it to increase the project's growth target to 18,000 bbl/d in third-quarter 2019, from the initial 16,500-bbl/d target.

Encana Corp., which calls itself a pioneer in cube development, has also made progress with the method in the Permian Basin since 2016-2017 when its initial cube attempts produced more than its vintage wells of the same period but experienced steep declines.

Since then, evolving completion designs and optimized spacing have contributed to overall Permian production improvement for the company.

—Velda Addison

Report: Industry has made strides in cutting emissions

The oil and gas industry has succeeded in putting a dent in emissions of methane and volatile organic compounds (VOC), the Environmental Partnership said in a July report.

The group, administered by the American Petroleum Institute (API), reported that more than 56 million equipment components—valves, flanges and connectors—were inspected at about 80,000 sites in 2018. The leak occurrence rate was 0.16%, meaning that fewer than two leaks were discovered for every 1,000 components inspected.

"This industry is leading the way in ensuring that methane emissions go down," said Mike Sommers, API's president and CEO, during a conference call with reporters.

Methane emissions from U.S. natural gas operations have declined by 14% since 1990, despite an increase in gas production of more than 50% during that period, said Matthew Todd, the partnership's program director.

"Thanks to the growth in natural gas usage, U.S. greenhouse gas emissions from power generation have fallen by 25% since 2005, helping to bring America's total greenhouse gas emissions to near-25-year lows," Todd said.

The partnership has grown from an initial 26 companies when it formed in 2017 to 66 members that operate in all major U.S. basins. It focuses on three areas: leak detection and repair, reduction of high-bleed pneumatic controllers, and improving the manual liquids unloading process.

In 2018, members replaced, retrofitted or removed 3,000 high-bleed pneumatic controllers from service. The controllers are typically located at production and gathering facilities and use gas pressure to operate mechanical devices. They are a significant source of methane and VOC emissions because they are so widely in use.

Solutions include conversion to continuous low-bleed controllers, intermittent-vent controllers, electrically operated controllers, use of compressed air instead of gas, or simply remove from service if that is feasible. The partnership seeks to replace all of the high-bleed devices within five years. So far, 38 of the participating companies no longer use high-bleed pneumatic controllers.

The partnership is a voluntary program designed to encourage members of the oil and gas industry, especially smaller companies, to engage in emission reduction beyond the minimum mandated by state and federal regulations. Not all of the smaller operators have the resources to achieve this on their own, so the partnership assists but without setting unrealistic goals.

"We believe that setting reduction minimum or maximum emission goals could potentially inhibit recruitment," Todd said. "It could add significant burdens for companies to participate and ultimately distract from some of the broader goals of the learning, collaborating and taking action to improve the industry's environmental performance."

But even without an estimate of the total emission reduction accomplished by partnership participants in 2018, the group is confident that it has succeeded in achieving cuts. Todd cited U.S. Environmental Protection Agency data that pointed to a 40% emissions reduction through finding and repairing leaks; and a 60% reduction when high-bleed pneumatic controllers are replace.

—Joseph Markman

THE PE-BACKED E&P, v.2019

Public E&P investors are insisting that operators produce returns, so private-equity-backed E&Ps wanting to sell to a public E&P are working to do the same. One said, "It all rolls downhill."

ARTICLE BY
NISSA DARBONNE

PHOTOGRAPHY BY
TOM FOX

Overleaf, as clouds dissipate from an early-morning storm, Liberty Oilfield Services Inc. employee Raul Sanchez is reflected in the rainwater on Teal Natural Resources LLC's Boening #3H and #4H site in the Eagle Ford near Yoakum in DeWitt County, Texas. Facing page, mature and ready-to-harvest corn lines Teal's Boening pad site in late July.

Private-equity-backed E&Ps are harvesting returns for investors, but—these days—not the old-fashioned way. Traditionally, the return has been via selling the portfolio—full of PUDs and plenty of PDP to demonstrate the acreage has good rock, ripe for tapping.

The buyer, usually a public E&P looking for more future-well inventory—that is, PUDs and, with some extra attention, some of those probables—on HBP leasehold with producing cash flow, would pick it up. The sale—usually within three or five or, pre-shale boom, up to seven years—was the harvest of private investors' initial investment plus more than 30%.

In the heated Permian, before shareholders shut down further public E&Ps' acquisitions of more leasehold, one PE-backed leaseholder flipped in fewer than 24 months; even with the capital-gains-tax hit, the sale met the return threshold.

Without public E&Ps wanting more inventory right now, what's a PE-backed E&P with a build-and-flip model to do? Many are proceeding to harvest upside for themselves, at least, via producing the reserves, instead. They're drilling those PUDs.

This changes the business model and thus everything, really.

'Lucky'

Ward Polzin joined Enerplus Corp. as U.S. country manager in 2006 after the Calgary-based producer took an interest in the then-nascent Bakken play. Later, as a managing director for Tudor, Pickering, Holt & Co., assignments included advising CNOOC Ltd. in shale joint ventures with Chesapeake Energy Corp.

In 2013, Polzin formed Centennial Resource Development Corp. with backing from NGP Energy Capital Management and focused on the Delaware Basin. The aim at the time was to IPO. Before the offering reached the pricing calendar, however, retired EOG Resources Inc. chairman and CEO Mark Papa picked up the portfolio as the platform asset for his special purpose acquisition company (SPAC).

Polzin reentered as an operator with NGP-backed Camino Natural Resources LLC in 2017, focused on the Midcontinent. Again, the plan was to build a sizable E&P to IPO. And that's "lucky for us," said Polzin, CEO.

"Eventually, the public companies will want to buy us for our free cash flow, or we will become public ourselves," said Ward Polzin, CEO at Camino Natural Resources LLC.

While the IPO part might not be in the near future—the public-equity market is demonstrating little interest in even existing E&P stocks—the resulting model of a sizable E&P suits the current commodity-price climate, he said.

"When we started in 2017, before we owned any acreage, our goal was to operate on a larger scale and possibly take that public someday, if that made sense, as opposed to being a small company that wasn't going to do that—one that was built to create some acreage and flip it."

In the last year, PE-backed E&Ps that were formed to build and flip to public E&Ps have encountered no takers. "All of us in the pri-

Facing page, C&J Energy Services Inc. employee Shane Dennis prepares the frack gun to complete Teal's Boening #4H during a zipper frack of it and Boening #3H.

vate-equity world want to sell. We [at Camino] are not unique to that."

Camino will eventually do that one way or another, he said. "But we thought, even back then, that bigger was going to give us a better shot at that. So we started off with that attitude."

Camino's 115,000 net acres are about 50% in the Scoop play in the southern Anadarko Basin and about 50% in the Merge play immediately north. It's producing about 38,000 barrels of oil equivalent per day (boe/d) now, making it the largest PE-backed producer in the area. It's had three rigs at work the past 18 months, "so we've had a lot of growth."

In the past—circa 2000, before shale was a thing—a couple of the rules of thumb PE-backed producers used were that it's time to sell when internal HR and more than one office-building floor would be needed for the staff.

In this day, Denver-based Camino has grown to 65 employees. The team began with some former Centennial staff and some former Denver-based Vantage Energy LLC employees. PE-backed Vantage built and flipped in the Appalachian Basin, selling in 2016 to Rice Energy Inc., which is now a part of EQT Corp.

The Vantage team members "had the same DNA we had," Polzin said, "meaning 'build, run multiple rigs and put all of our eggs in one basket in terms of the play.'"

'Staying power'

With a "lower for longer" business model, Camino is relying on economies of scale, "needing to be on the bigger side to be big enough to be able to run multiple rigs and multiple frack crews, so we get some volume pricing."

It is sourcing sand directly from local mines and has long-term contracts for completions. Three rigs are under continuous contract.

"If we weren't of scale, we wouldn't be able to do that and, then, we wouldn't have a lower operating cost. That's how we're addressing it: with scale, where the rubber meets the road. Scale allows you to get better pricing, but it gives you some flexibility too in where to drill.

"We can move the rigs around to what's working best at any given time."

Camino is focusing on "the things that we think give us longer staying power," said Polzin.

That means drilling the PUDs. "To a certain extent, we are harvesting that upside for ourselves by basically creating cash flow quicker than we might have otherwise."

Polzin sees the shale era in its middle innings today. "I don't know if it's the fourth and the fifth, but, in the first three innings, [PE-sponsored producers] were building inventory and a public company would buy that inventory because it needed it."

Now, public E&Ps aren't getting paid in share valuation for their surplus inventory; "therefore, they're not paying us for it. So you're not seeing much A&D."

Public E&Ps are being told, instead, to be cash-flow positive; so, now, PE-backed E&Ps are working toward that too. "Eventually, the public companies will want to buy us for our free cash flow, or we will become public ourselves," he said.

Another option is to return the cash flow to the PE investors. That means "we need to drill more of those PUDs now, turn them into cash flow and start dividending back to investors."

In the past, "you almost never dividended back to your [PE] investor. You sold and that's when everyone got their money. Now it's 'How can we get our investors their money piecemeal in dividends?' and the only way to do that is to drill some of your future now."

As private E&Ps are looking to create returns via producing reserves, the drilling program is different too. In the past, the goal was to prove all the acreage, putting in at least one well per section.

"Now, we need to pull back a little bit, and those drilling those PUDs are stepping out less and proving more. You're really more intensively drilling what you already have as opposed to broadening it."

'On paper'

The capital structure is different too. "It doesn't necessarily mean you have more debt. I think, on one hand, you have to be a little bit more conservative."

PE-backed E&Ps might have less debt, actually—on an absolute basis, such as in comparison with production. As the current situation is new to the PE model, "since you plan to be here longer, you have to make sure you have a debt facility and you are using it appropriately.

"Most companies need to be careful. You can't bet the farm, so to speak."

To build based on debt while thinking "'I will sell in two years,' I don't think that works anymore. I would think more people would have debt facilities, but I would think they're using them more conservatively on average than they have in the past."

Camino formed its initial leasehold in four acquisitions, consolidating about 95,000 net acres that were producing about 10,000 boe/d. It leased another 20,000 acres and traded 30,000 of the initial footprint for a different 30,000 "in a hundred small deals" in the past year and a half.

Meanwhile, the growth in production—from 10,000 boe/d to 38,000—has come entirely through the drillbit. In its Scoop leasehold, where the Woodford is deeper than in the Merge and the Stack play—"the wells are bigger. It costs more, but, obviously, you get bigger EURs and bigger production rates."

The production growth has come "really just from the quality of the wells." The Scoop comes with more natural gas—about 50% gas—as it's deeper, thus more cooked. "As you get deeper, you get bigger wells, of course, and more gas in your boe. It's not worth as much [as the liquids], but the incremental volumes equate to good returns."

Could there be private-private consolidation? "Yes, on paper," Polzin said. "But I think one can argue both sides of the fence that 'Well, private to private is easier to do than public to public.'

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"But I can also see why you could argue just the opposite." He expects some private-private, but "I don't think there will be a ton more because one of the problems is neither side has liquidity, still. You're merging two private companies into one, which is better because it's bigger."

But it's not a liquidity event. "At least in a [sale to a] public there is a liquidity event. Maybe it's just stock, but you can at least sell it."

Nevertheless, "I think you will see more private to private. Right now, all these have occurred just within the same [PE] family. Once you step out of [the family], I think it's a lot harder—but not impossible.

"I think they're so complicated they will be one-off events. But there will be some."

'Eat the meat'

In the Eagle Ford, NGP- and Pearl Energy Investments LP-backed Teal Natural Resources LLC is three years into its timeline. It has roughly 25,000 net acres, producing some 6,500 boe/d, about 66% oil. It kicked off a one-rig program in January with a six-well commitment. It has transitioned now to keeping the rig at work continuously.

"Coming out of December into the new year, we thought we could see where the commodity market was going to shake out and also see where our well performance was going and show the repeatability of the stacked/staggered program we started last year," said Erik Holt, chief commercial officer.

What will the next two years be like? "Two years ago, you were thinking 'Delineate the acreage and drill wells.'" The aim was to "save enough of our inventory for the next buyer. That has completely changed."

Now, the tack is "that, rather than keeping meat on the bones for the next owner, we need to be eating the meat. Where we have the best opportunities to drill great wells, we're going to drill those wells and eat the meat rather than save it for the next owner."

It's anyone's guess where the market will be in two years, "but we feel confident we'll be in a good position. We have a healthy amount of great inventory. We've had great results on some of our more recent wells, and we know we can control our destiny by drilling those locations and bringing that value forward through the drillbit."

In terms of capital structure, "now you want to make sure you're not just looking at execution risk. You're also looking at balance-sheet risk—preserving the health of your balance sheet."

Past PE-sponsored E&Ps started with buying undeveloped acreage with sponsor capital and used additional sponsor capital to appraise the acreage with delineation drilling. Teal acquired HBP properties that provided a PDP base, thus cash flow and collateral for a credit facility.

"The equity we've deployed to help fund our development program during the past two years is only a fraction of the total equity we've called," Holt said. "Everything we've been doing to date has roughly just been off cash flow and also our RBL."

Today, rather than expecting returns through a sale, PE sponsors are looking for the returns promised to their investors via the drillbit—positive cash flow to "start bringing some of that money home" with distributions.

"So, at a certain point, you do have to walk the tightrope. Do we want balance-sheet health or leverage up—either through some sort of second-lien facility or some sort of credit facility or a Drillco that allows you to preserve your balance sheet but also accelerate your development where you're getting cash?"

"One way we know we can control our destiny and have meaningful returns is by ramping up development," said Erik Holt, chief commercial officer at Teal Natural Resources LLC.

A pair of water lines leads to Teal's Boening #3H and #4H pad while being fracked, as trucks carrying boxes of frack sand line the gravel road. Facing page, Liberty Oilfield Services "Apache" crew workers check connections between fracking stages on Teal's Boening #3H and #4H.

"The typical business model for companies like ours is to consolidate a position, prove the economics and ultimately sell the asset to a company with a lower cost of capital," said Skye Callantine, president and CEO at Felix Energy II LLC.

It's what the equity sponsors want where sale isn't possible. "One way we know we can control our destiny and have meaningful returns is by ramping up development."

Say this goes on beyond Year Five, would Teal simply continue to drill and produce its leasehold until there's just no place to put another well?

"If things stay stagnant the next five-plus years, we're going to do everything we can to accelerate our production where we can pay off that equity at a rate of return we targeted for our investors."

Small fish or big fish?

In this world, deals that will get done are where buyers see credit-accretive or, at least, cash-flow-neutral assets—if not cash-flow positive. "When you look at public E&Ps' earnings, no one is trumpeting type-curve projections or IP rates. What we're seeing is 'How quick can we get to free cash flow? What can we do to improve total shareholder returns?'"

At Teal, the business is being built as one that would be—to a buyer—cash-flow accretive, improving EBITDA and the debt ratio. "And that's where I think you can see some activity in the M&A market."

And the sellers, since they're likely to get stock rather than cash, have to use "a different calculus." Depending on who the public buyer is, the equity component of the purchase might not be a good deal? "Right."

Rather, Teal is looking at buying. "If the market is saying now is not the time to be sellers, now is maybe the time to be aggressive and be buyers.

"You ask yourself 'What fish are you in the pond?' and I think this market is really making people identify whether they want to stay in the shallow end or jump in the deep end and become a much bigger company.

"It's been a psychological shift. In this market, scale is rewarded, and we're going to be looking to add scale with the right opportunities."

Teal's leasehold is in Lavaca, Karnes, Live Oak, Atascosa and DeWitt counties, Texas. In addition to Eagle Ford, it has Austin Chalk and Buda potential. For now, it's focusing on demonstrating the dual-bench potential of the Eagle Ford.

"We definitely have potential for Austin Chalk, but we really want to focus on the Eagle Ford."

Is there potential for a greater return by harvesting rather than flipping? "The way we look at it is that, as long as we do what we can control and we do that well, the opportunity to grow or monetize is always going to be a lot more abundant."

No matter the market, "what truly dictates great opportunities is being able to execute what you can control and do it well. Sometimes the opportunities will be more obvious in a more stagnant market."

Deepening the bench

Operating in the Delaware Basin, EnCap Investments LP-backed Felix Energy II LLC is also in Year Three. Will it exit before or in Year Five? "Very good question," said Skye Callantine, president and CEO.

"The market has changed much. We are preparing, on the asset side, for however long it takes. My guess is it will take at least a couple of years," he said.

A runner travels under the gateway to downtown Yoakum, Texas, at sunset in late July near Teal's Boening pad site. On the Lavaca-DeWitt county line, the city was built on an 1835 land grant and was a gathering place for cattle along the Chisholm Trail.

Shiner, Texas, just north of Yoakum, hosts Half-Moon Holidays, an annual festival that includes live music and a 5K fun run, pageant, parade and BBQ cook-off. The lead sponsor is the city's homegrown Shiner Beers. Since 1909, every drop of Shiner Beer has been brewed at the K. Spoetzel Brewery in Shiner.

The previous Felix proved 80,000 net acres for Stack, selling it in 2016 to Devon Energy Corp. In the Delaware today, it has seven rigs at work on its 60,000 net acres. Current production is some 50,000 boe/d.

At Felix II, the business model is different from that of Felix I. "The typical business model for companies like ours is to consolidate a position, prove the economics and ultimately sell the asset to a company with a lower cost of capital."

Today, "our strategy is to increase the value of the enterprise and convert more of the inventory to cash flow."

That requires more people—a lot more people. "That's been a material change— the additional personnel it takes to sustain a large capital program to drill more and more inventory." The capital it's needed—to drill all of those locations—has also increased. "Those are probably two of the biggest changes: more people and more capital."

The skillset within the team is more specialized than in a prove-and-flip model. "We might have had one guy who managed drilling, completion and production. Now we have multiple specialists in every discipline."

In the past, a typical PE-backed E&P would build takeaway to the lease line, so to speak—essentially, gathering infrastructure. In Felix II, management has formed Felix Midstream and Felix Water, separate companies that share space in Felix's Denver headquarters and have the same ownership.

In the water business, about 30% of revenues come from third-party sales. When getting started, Felix expected the midstream- and water-business potential would represent untapped upside for the buyer.

"We definitely identified the opportunity, but our intent early on was to sell that opportunity with the rest of the assets.

"All we are doing now is executing on the plan we designed and built for a buyer. So we're doing the development. We just decided to go ahead and fund it ourselves and operate it—both the upstream and midstream," said Callantine.

This new world is more capital intense. "We've grown our production 100 times in three years, so, to have that type of production growth, you need to invest beyond your cash flow.

"So we've been deficit-spending every year the last three years."

The capital program has been efficient and well economics are strong. "So we've been able to get cheap debt to fund that growth. With our relatively large cash flow, we likely won't be doing deficit spending much longer. We will be cash-flow neutral at the current activity level or cash-flow positive at reduced activity."

Minding the G&A

Achieving neutral—then, positive—cash flow has been difficult for public E&Ps. "That's one of the reasons why our industry is not doing so well today," said Callantine.

At Felix, "we have a far better cost structure than most public companies our size. Our G&A [general and administrative expense] is a multiple lower than most. More importantly, the team and culture we have built generate an incredible amount of value with fewer people."

Felix's spend on G&A is approximately 3% of its capital budget. "At our level of activity in both upstream and midstream, I expect we are one of the most efficient companies in our industry. I'm very proud of what our team has accomplished in what is turning out to be a very difficult time in our industry."

One public E&P's investor reported in July that it believes the producer is losing money every time it drills another well and called on it to cease drilling.

Among PE-backed operators, meanwhile, Felix's G&A profile may or may not be typical of all. "I think it is how you define our peer group. Most companies like us have [already] sold. There aren't many large-scale private operators left in the space."

He counts maybe a couple in the Delaware and maybe a couple in the Midland Basin. "The ones with quality assets definitely have a material advantage in cost structure, including G&A, real estate, planes, executive compensation, debt service, etc."

With challenges come opportunities. In this timeline of the industry, "having a stable investment program where you have a stable rig count allows us to get better service pricing, better equipment. It allows us to get more efficient."

The availability of services is likely the greatest opportunity. "There was a time 18 months ago, if you needed people, there were no people or equipment available. Now you can get pretty good people and equipment and at a good price."

It's a buyer's market in the Delaware, Callantine said, however, "we're not looking to grow through acreage. There is an opportunity for some, but it's not an opportunity we're interested in right now."

Also in the Delaware, NGP- and Pearl-backed Colgate Energy LLC was formed in 2015. James Walter, co-CEO, said Colgate has been funding development from cash flow and its credit facility since January 2018. "So our development cost of capital is in the mid-single digits."

It has two rigs at work and expects to add a third in the fourth quarter. "Most of our leasehold is HBP at this point, so we have a lot of flexibility in our drill schedule," Walter said.

He sees this market resulting in a "better business that should allow Colgate and our investors to realize a greater return than we would have received in a stronger market. The tradeoff is that the investment hold is longer, and it takes a lot of hard work to get there."

'Cruel' situation

At Camino in the Anadarko Basin, Polzin said the opportunity derived from the current industry environment is "definitely the consolidation part, meaning there are smaller companies that are private that just weren't built to be here a long time and to operate long term.

"They may not have the drilling team or the operations team. We have that."

Camino has seen more opportunities to purchase smaller companies. "That's the good news." Being big, "we've seen that opportuni-

The K. Spoetzel Brewery ships more than 6 million cases of beer to states throughout the U.S. each year. The company reports at its homepage, "We think our founder, Kosmos Spoetzl, would be pretty proud."

ty to buy. You can trade acreage that's 30 miles away from another piece of acreage. You have more options, which ultimately leads to more operated, longer laterals, which has been the goal of everything," he said.

Another opportunity—and it's not necessarily one for Camino's model, he said—is for non-operators. "In the tough timeframe we live in today, [an operator] would rather spend capital dollars on operated acreage than nonop. Because of this, we see a lot of nonop. That creates a lot of opportunity for the nonop players.

"We're seeing that more often in our acreage and in the Midcontinent overall."

Where to from here for the industry? With $55 to $60 oil, "it feels like it's $45 because of the trough we're in in [asset] valuations."

The upstream M&A industry works—or doesn't work—depending on public E&P investors' and potential investors' valuation of these stocks. "They're really at all-time-low multiples.

"Given that upstream public companies are poorly valued, the private guys will be poorly valued. It all rolls downhill."

The difference between $50 oil and $60 oil is enormous. "Our industry at $50 oil cannot provide what the public investor is asking, which is 'I want you to grow your production and within cash flow and I want you to pay a dividend and I want you to buy back some stock.'"

It can work at $50 but, for the industry overall, it really works at $60. "The past couple of years, we've been bounded by this $50, $60 world, which kind of puts you on the edge.

"It doesn't mean we're going bankrupt as an industry by any stretch. But can we deliver everything that's asked from us at this price deck?" The strip in the mid-$50s is, "to me, a very cruel kind of situation where we can't deliver everything the market wants. And we have to figure it out, right?"

It means slowing growth. "[Industry] is still growing in production, but we're not growing quite as fast as we were six months ago."

Is a $60 world enough for shareholders to let public E&Ps start buying again? "I don't think so. I don't think it's enough." It would have to be $60 for a while—at least a year. "And we really have to not buy until that happens."

That doesn't count for mergers of equals like the Callon Petroleum Co. and Carrizo Oil & Gas Inc. deal announced in July. "That's not buying; that's MOEs [merger of equals], which are great. We need more of those; long term, that makes a ton of sense."

More time is needed for other M&A, "which is terrible for our company and many others." A couple of good quarters won't count, "which is too bad. We need a couple of years."

At Felix, Callantine said the current A&D stalemate is "probably healthy. Some of the things I say may be a little controversial, but clearly our industry is struggling right now, which is why companies like us continue to exist.

"And I think it will play out over the next couple years—what needs to be corrected to attract investor interest again."

A bee looks for pollen in a bush outside the K. Spoetzl Brewery in late summer. Known as the peacock flower, Mexican bird of paradise and many names, this bush prefers a climate where frost is rare.

Capital discipline is No. 1. "As an industry, we've used cheap capital to drive down margins to unacceptable levels and lost many investors on the way. I'm confident the same people that drove the energy revolution in the U.S. will figure out how to make our industry more attractive to investors over time."

In Felix's neighborhood, he is impressed with many public E&Ps, including Diamondback Energy Inc., Concho Resources Inc. and WPX Energy Inc. "All have excellent management and good assets. They have everything going for them; very forthright people who are smart and know how to run a good business." □

MAKING IT IN THE MIDDLE

Midcontinent producers find success via asset optimization, drilling efficiency.

The Midcontinent holds potential for those willing to work for it. Oklahoma produced a state record 18.5 million barrels of oil in April, an increase of nearly 400,000 barrels compared to March. Despite a decline in active rigs, both crude oil and natural gas production in the region continue to climb.

Legacy companies like Continental Resources Inc. have enhanced well performance while operating fewer rigs thanks to advances in rig efficiency and drilling technique. The company's "Project Springboard," which has improved cycle times and well productivity, prompted a 9% production increase with 25% fewer rigs.

This move toward more production with less operating overhead could not have come at a better time. Tighter financial resources and higher median breakeven costs have spurred a jump in M&A activity in the region, and those with the means to reinvent their drilling strategies will reap the benefits down the line. "The play is resetting expectations around what it is capable of," said 2019 **DUG *Midcontinent*** speaker Shak Ahmed of RS Energy, "and while this won't be painless, it will be better in the long term."

2018 Event Metrics

1,220 Attendees
39 Speakers
53 Sponsors
105 Exhibitors

Drilling strategies play a pivotal role

The Midcontinent—along with every other U.S. shale play—has struggled to overcome challenges from parent-child well interference. As child wells see as much as a 25% decline in productivity, producers are working to minimize over-drilling and optimize well spacing. For some, this means turning to cube development (tapping multiple layers at once). For others, the answer is shutting in the parent well before completion for the infill wells even begins.

The DUG* Midcontinent *Conference & Exhibition attracts over 1,200 industry professionals representing top producers, from E&P and service companies.

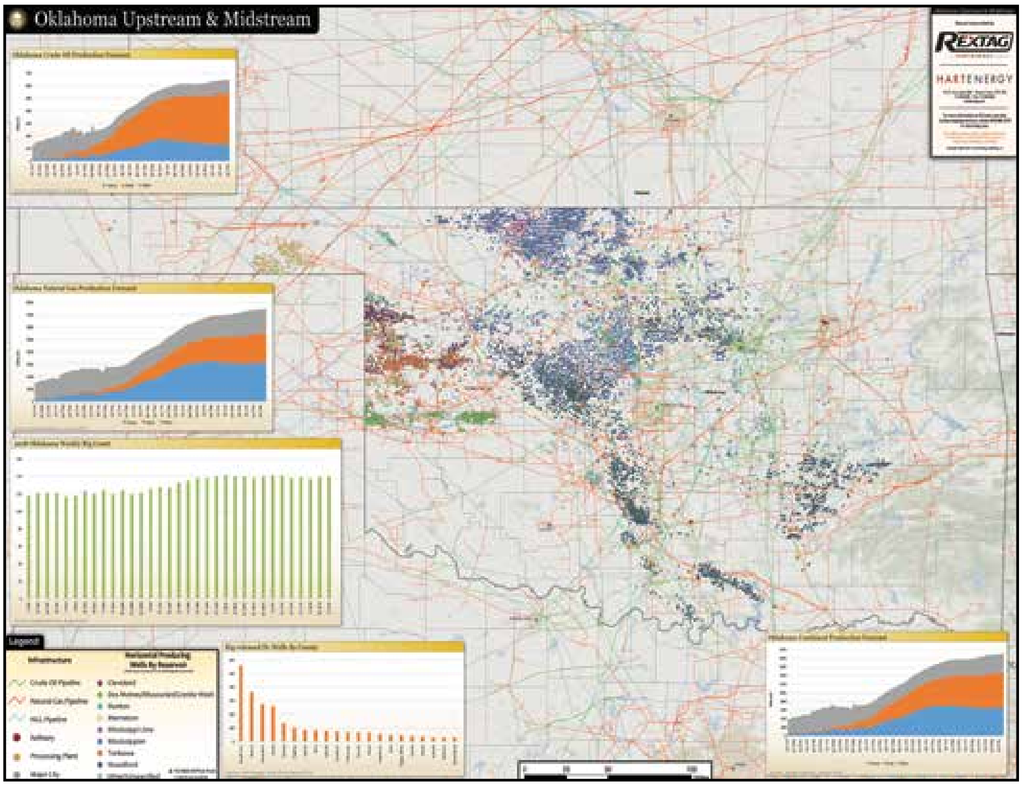
Testing new strategies is imperative to maintaining production and avoiding interference issues. For example, Chaparral Energy Inc.'s partial spacing test at the end of 2018 resulted in zero interference between infill wells, while also maintaining the parent wells' pre-infill production rate. "Instead of trying to reach out and touch someone with the frack job, we're trying to create a more complex near-wellbore fracture," said Chaparral's senior vice president of operations.

Actionable intel from active producers

Hart Energy's 2019 **DUG *Midcontinent* Conference & Exhibition** promises to deliver an insightful examination into these topics and others November 19-21, 2019, at the Cox Convention Center in Oklahoma City.

Conference attendees will receive the latest intelligence directly from the field. A roster with over 20 speakers includes leading executives from top Midcontinent producers, engineering experts, financiers and analysts. This year's agenda will address everything from M&A and capital sourcing, to proven recipes for superior well completions, Midcontinent mineral rights and midstream infrastructure.

Sessions will cover the Scoop, Stack, Score and Merge plays, with producers and operators alike sharing successes and advice for getting the most value out of Midcontinent assets.



Attendees eager to gain new insights into full-field development strategies are encouraged to register separately for the half-day forum on November 20, 2019. New to this year's conference, this forum will examine how hydrocarbon recovery methods, proppant markets and parent-child well interactions influence full-field optimization.

Strategies for success from the best and brightest

With so much to address, the 2019 **DUG *Midcontinent*** speaker slate offers a bit of something for everyone.

The conference kicks off with an opening keynote from Harold Hamm, founder, chairman and CEO of **Continental Resources**. Attendees will also get the chance to hear spotlight presentations from the executive vice president of **Roan Resources** and the president and CEO of **Calyx Energy**.

Earl Reynolds, CEO of **Chaparral Energy** and Drew Deaton, CEO of **Red Wolf Natural Resources** will take the stage for operator spotlights highlighting their companies' plans for some of their Midcontinent acreage. The well-rounded program includes technical panelists from **FourPoint Energy**, **RS Energy Group**, **Baker Hughes** and **Schlumberger**.

Midstream infrastructure on the way

The surge in associated gas production has Midcontinent producers hunting for pipeline capacity. Reaching a record high of nearly 4.5 Bcf/d, midstream operators are scrambling to modify and expand existing systems to provide relief. Fortunately, a bevy of new midstream infrastructure projects will soon come on-line.

With multiple projects underway, over 600 miles of new pipeline is being constructed in Oklahoma and some could be completed as early as this year. The new developments will add over 6 million barrels of storage and 1.44 Bcf/d of takeaway capacity, giving Midcontinent producers better access to Gulf Coast markets.

The best way to stay informed about what the future holds is simple: Be in the room for this year's **DUG *Midcontinent* Conference & Exhibition**. To view the agenda and register, visit **DUGMicontinent.com**. □

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APPALACHIAN BLEND

In a basin full of bigs, the combination of Eclipse Resources and Blue Ridge Mountain Resources to form Montage Resources creates a compelling gas and liquids growth story despite commodity headwinds. The question: Will Wall Street notice?

INTERVIEW BY STEVE TOON

Both companies faced financial challenges. Eclipse Resources Corp., a Wall Street star when it IPOed in 2014, made headlines with its successful drilling of super laterals in the Utica Shale, exceeding 19,000 feet last year. Yet it struggled from a persistent depressed share price—having fallen by 94% in the four years after going public—as public markets abandoned the oil and gas space, and particularly gassy names. As the stock continued to plunge, earlier this year the New York Stock Exchange put the company on notice of delisting.

Blue Ridge Mountain Resources Inc. was the resurrection of Magnum Hunter Resources Corp., another Marcellus/Utica operator that emerged from bankruptcy in January 2017 with new management and a new name. John Reinhart, coming out of Appalachian start-up Ascent Resources, took over the CEO role. During the next two years he would sell off Bakken assets and others to core up as a Utica and Marcellus pure player and further knock down debt.

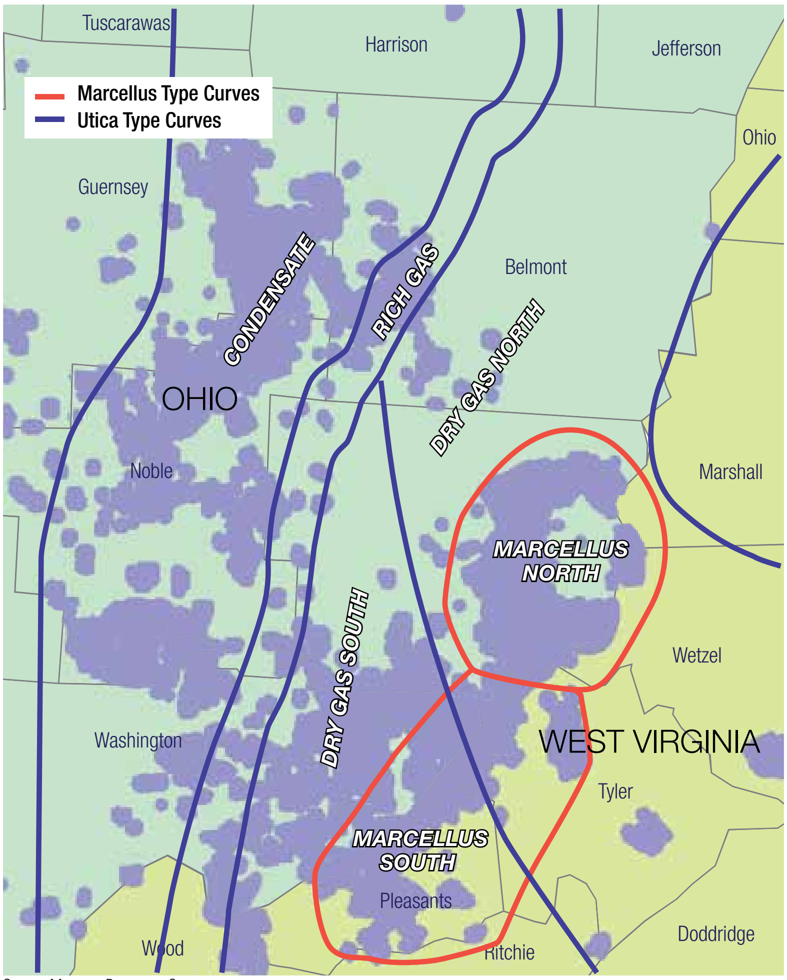
The two companies found their match where their acreage touched in Ohio. Eclipse and Blue Ridge closed their combination in February, forming Montage Resources Corp. The majority of the surviving management team came from Blue Ridge, with Reinhart as CEO. Making the integration easier, five out of six of Montage's new management team worked together previously at Chesapeake Energy Corp. in its Appalachia division.

Montage now holds some 220,000 net acres prospective for the Utica and Marcellus shales in Ohio, West Virginia and north-central Pennsylvania with production of approximately 535 million cubic feet per day. Its new mission: balance cash-flow generation with consistent growth while focused on efficiencies. While perceived by many as a natural gas-focused company, some 40% of Montage's revenues are derived from liquids production. Notably, its blended debt-to-EBITDA is 1.7 times, well below its peer group average of 2.1 times, giving it ample margin on the balance sheet.

Reinhart, a mechanical engineer from West Virginia University, began his career at Schlumberger Ltd., and worked as vice president of operations for Chesapeake's East Division, COO for Ascent Resources LLC and CEO of Blue Ridge Mountain Resources before assuming leadership of Montage. He was also a sergeant in the Army, serving in Operation Just

With a career rooted in Appalachia, Montage Resources CEO John Reinhart is eager to show that the small-cap producer is poised to be as good as—and better—than larger peers.

Montage Resources Acreage Overview



Source: Montage Resources Corp.

Cause in Panama and Operation Desert Storm in Iraq. Investor *spoke with him regarding his plans for Montage.*

Investor What motivated the merger with Eclipse?

Reinhart Our two companies sat side by side, so our acreage position was very contiguous. Production in the basin has grown over the past 10 years, and we saw a lot of synergies between the companies from the asset perspective, but also with the team; a lot of us had worked together in prior lives.

And knowing that scale does matter. That motivated both of us. Ben [Hulburt, former Eclipse CEO] and I just started having a conversation and said, "Hey, these two companies are pretty good companies. We have great staff and great assets. Let's see if we can do something a little special here."

Investor What is the Focus Five strategy?

Reinhart It's having disciplined growth and protecting the balance sheet. It's making sure that your hedge portfolio protects the downside on the cash. It's making sure that you're not overcommitted on any kind of volume commitments or long haul pipe. It's making sure that you can toggle between gas and condensate and maximize profitability.

In this low commodity cycle, we're all very sensitive to generating cash flow and keeping the business healthy. We have all come from a history of various companies that had some levels of distress and are very sensitive on making sure that we keep the company healthy with plenty of liquidity and a good leverage ratio. If that means growing 5% instead of 15%, that's what you do to protect that balance sheet. And when we come out of this cycle, we want to be strategically placed to have a lot of options that may be attractive inorganically for the company.

Investor Even following the merger, Montage is still a small-cap company, and public market investors have indicated they prefer larger-scale companies. Why do you then prioritize free-cash-flow neutrality over a more aggressive production growth model?

Reinhart We understand we have to grow. Growth is extremely important to us now. We're growing this year at 23%, so that's a pretty chunky growth profile as we continue to navigate these low commodity cycles. We have the ability to drill some wells right now in very high-quality rock very efficiently.

But it's not so much a focus on free cash flow, so to speak. It's more about a focus on keeping a prudent balance sheet and a healthy company. That means being mindful of your cash inflows and outflows. So whether that growth is 5%, 10% or 20%, we are going to be mindful to toggle that level of growth to be sure that we protect the company and keep it healthy. No one can predict commodity prices.

I personally believe that as we navigate the next few years, the landscape is going to look a lot different in Appalachia. There are companies that won't be here, and a lot of private companies are looking for an exit. So keeping the company in a healthy position while effecting growth we feel puts us in a much better position as we navigate this environment right now to come out of this with some opportunities that perhaps some other people may not have because of their leverage or commitments that they're saddled with. If you start stressing the balance sheet, your options to do things strategically, whenever it does recover, are very hamstrung.

Investor Are additional mergers or acquisitions part of your growth strategy?

Reinhart We're very focused on the fundamentals of the business and growth through the drillbit. Having said that, I think it's not a stretch to see a company of our size with a clean balance sheet, liquidity and attractive leverage ratios, if an opportunity comes up, to look at how that impacts the company. To the point that those materialize and are accretive I would say—absolutely—we're going to take a strong look at that. We stay plugged in and we are very open to accretive opportunities to grow scale at a much more accelerated pace.

Investor Natural gas and NGL prices have swooned since the merger. How are you adapting to weaker commodity prices this year?

Reinhart It's a wonderful thing to have half your assets in areas very high in condensate with NGL exposure as well as natural gas. For us it's about what the commodity prices are allowing us for growth from a cash-flow perspective. We look at it as more of an allocation, and you can do that if you don't have a lot of commitments driving your business. We don't have a lot of HBP issues, or MVCs [minimum volume commitments] or FTs [firm transportation agreements]. We sell in basin at a premium to people who are long on unutilized firm transportation.

One of the big benefits of the merger is our combined asset base contains about a 50% mix of condensate and a 50% mix of dry gas, so that was very attractive. The combined asset base of the company is 70% to 75% held long term, either HBP or long-term leases, which gives us some flexibility. It allows us to make decisions based on true economics.

Is gas in the Utica attractive right now? Yes. You're talking 40% returns. Is condensate more returns driven? Yes. The Marcellus in Ohio, that's certainly where we focus a third of our capital this year—that provides even better returns. We manage commodities by looking at the strip, we look at the cash-flow outputs, and we just toggle between the Marcellus and Utica dry gas and condensate windows. And that's what we go drill.

Investor What is your primary goal in your operational plan this year?

Reinhart We're focused on cycle time improvements, removing dead time in the operation.

From an Eclipse standpoint, last year vs. this year, we've reduced our cycle times by over 30% year-over-year. That gets us down into that 150-day spread between spending capital and turning revenue. That means you can turn your cash faster, you can grow and be more prudent and get to cash-flow neutral, cash-flow positive, at a much quicker pace than what you would do if you were to stretch those cycle times out.

We mobilize rigs on a 24-hour basis now vs. 12. We've been very pleased with our Marcellus cycle times on the drilling side. We just finished a pad where we averaged nine days a well on a three- to four-well Marcellus pad last month.

Why is that important? If you can shave down two or three days per hole and you can skid over a rig on a pad in about eight to 10 hours, those days add up and you're adding wells toward the end of the year that you would normally otherwise not have.

Every day you shave off a drilling rig is $100,000 to $125,000 a day. Every day you shave off on your frack cycle times is $40,000 a day you save. So we work pretty hard at taking advantage of being active when some operators aren't as active.

On the pricing side, which is cyclical in nature, right now we're looking at utilizing our activity that we have planned to lock in prices over the next 12 months and take advantage of this very attractive environment from a service capacity side. We've been able to do that on the completion side and on the drilling side, and we'll continue to push.

Montage Snapshot

Corporate HQ	Irving, TX
Ticker (NYSE)	MR
Plays	Marcellus/Utica
Net acreage	218,000
Production	535 MMcf/d
Proved 1P Reserves	2.7 Tcfe
Net locations	700
2019 Capex	$357MM

"Where there's chaos and a lot of noise, I generally run to that where most people probably shy away from it. Where there's distress, I fundamentally do believe there's opportunity."

Investor Pre-merger, Eclipse made news in the past two years for its super-extended laterals. Why have you decided to decrease average lateral lengths?

Reinhart This strategy is formed around a return on capital. We want to make sure that, from a financial standpoint, it accretes value to the company. That may sound pretty common sense, but that's not always what you find with some of these bigger companies.

This team historically had drilled super-long laterals, which were technological accomplishments. But we're now focusing that execution prowess on being more efficient and reducing cycle times, increasing cash turns and making more money. So the lateral lengths were a pretty big shift.

We shifted from drilling 14,000- to 20,000-foot laterals down to 10,000- to 12,000-foot lateral lengths, which by the way are still some of the longest laterals. Practically, that dramatically reduces your cycle time of drilling, completion and turning these wells online.

If you drill five 20,000-foot laterals, that's probably $85- to $95 million you're floating. Your cycle time on that is going to be almost a year. I would rather drill three to four 12,000-foot laterals, spend half the money and make my cycle time about 150 to 160 days. You can imagine what that does to a small company's cash turns and balance sheet. It changes the production profile, changes your cash-flow profile, and you're getting revenues sooner.

Also, as you get back into this 10,000- to 12,000-foot lateral range, it really de-risks the development plan's operational exposure. The longer you go out, there's always more exposure to wellbore instability, potential issues and capital overruns. The shorter laterals also minimize your production and reserve concentrations in one lateral, which is very beneficial looking at the long-term outlook and having assurance of a low-risk production profile.

Investor Does shortening the lateral impact the productivity or the results of the well?

Reinhart It certainly doesn't impact it negatively. Eclipse had historically looked at a metric of dollars per foot of lateral. They took the approach that these longer laterals minimized their cost per foot. Naturally, if you drill a longer lateral, you spend more money and you want more production out of that to make

PHOTO COURTESY MONTAGE RESOURCES CORP.

A Montage Resources' well site in southeastern Ohio.

a decent return. Eclipse was aggressively opening up their production on these long laterals.

We produce the wells similar to other established operators, with restricted choke practices for pressure drawdown management. Generally speaking, our Utica dry gas wells are choked back at a 22- to 26 million cubic feet a day range. These prolific wells will produce at those rates for eight to 15 months depending on the lateral lengths. Almost without exception, in many plays where the choke is restricted, it actually improves the overall EUR. And it certainly de-risks any potential damage and productivity as well.

However, if you followed that pressure management choke on a 20,000-foot lateral, your returns would be substantially hindered because of the slower claw back of the increased sunk capital.

Investor How do you think about your development plan going forward?

Reinhart That's another big part of the strategy shift. These pads were built for stacked pay and for six to 12 to sometimes 14 wells per pad. But we didn't want to drill out six or seven wells per pad, initially.

By taking an approach where we now initially drill three to four wells on the pad, that shrinks cycle times significantly from the point where you're spending cash and making money. We mobilize and we go drill the next and we go drill the next. At some point in the future we're constructing these pads whereby we don't have to shut in those volumes, so we actually come back at a later date and we can continue to drill.

Investor Are you concerned about parent-child well issues?

Reinhart We really want to stay out of the parent-child relationships and issues that some of these companies are seeing by not executing on a more full development plan.

Think about a pad, you have let's say three southeast wells and three northwest wells. We like to drill out the southeast wells so you don't get into any kind of development

> “This team historically had drilled super-long laterals, which were technological accomplishments. But we’re now focusing that execution prowess on being more efficient and reducing cycle times, increasing cash turns and making more money.”

issues in the future, then move onto the next pad and drill out the southeast wells. At some point you come back and drill your northwest wells. This way you don’t have downtime and you don’t have parent-child issues. You fully develop your offset wells as you move.

We do these in tranches where we mow down the southeast wells and then come back and do the northwest wells. It’s not exposing us to parent-child issues where we’re drilling offset laterals in a row, and we’re constructing these pads whereby we don’t have to shut in those volumes in the future.

But the important part is our return on capital is dramatically improved because we’re spending money and collecting revenue in a much shorter cycle time, which moves the needle for return on capital.

Investor Why did you drop one of your two rigs this summer?

Reinhart We were looking at a growth rate of 23%, and we continue to outperform production expectations. Do we want to take a more cautious approach with regards to spending $30 million more in drilling right now? Commodities are low. We don’t need the extra growth right now. Let’s have the option at the end of the year to pick up based on what commodity prices are doing in Q4.

Investor Where will your drilling plan and capex be focused on through year-end and into 2020?

Reinhart We shifted drilling into core areas. Because of how the commodity prices have moved over the year we’ve shifted toward more condensate development. About 50% of our development this year is in the condensate window of the Marcellus and Utica, which has preferential returns right now vs. the dry gas area. Think half liquids, half gas for probably at least the first three quarters of 2020.

Investor Blue Ridge Mountain had its challenges at that time you took the CEO role, having just come out of bankruptcy. And it was your first turn at CEO. What did you see in the opportunity in that moment?

Reinhart You know, I’m an old Army guy, and where there’s chaos and a lot of noise, I generally run to that where most people probably shy away from it. Where there’s distress, I fundamentally do believe there’s opportunity. So when I looked at this opportunity, I saw a company that had really good Marcellus and Utica assets, but they did not have the execution, the staff, the liquidity, the corporate structure or the strategy to be able to exploit some of the high-quality assets that they owned.

So the assets brought me here. Also, I was ready to take on a leadership role of a company. But let there be no mistake: There was a lot of work to do to sell off noncore businesses, to get the strategy very focused, to staff with people who had the experience and the operational prowess.

Investor You spent a lot of years at Chesapeake and started up its Appalachia division. As Chesapeake discovered the Utica Shale, did you discover the Utica as part of that divisional start-up?

Reinhart A guy named Matt Weinreich, a young geologist for Chesapeake, is the guy who pitched it to Aubrey [McClendon, Chesapeake CEO at the time]. I was in the room. There were a lot of Knox penetrations up there, and they always had gas shows from this pesky zone called the Utica. And I remember in the meeting, we said, “Well let’s go drill one.” And we drilled the Buell well in Harrison County, and that was an outstanding well. It changed the tide of what we were doing.

It was pretty fascinating to watch a play be discovered and then subsequently go out and drill it. I don’t know how many people get to see that in their career, but it was pretty amazing to be a part of it.

Investor What is your vision for Montage over the next five years?

Reinhart It’s just to grow a prudent, attractive, value-driven company and continue to grow it as the market dictates, while also being mindful that there are going to be some inorganic opportunities. And the companies that keep a healthy balance sheet are going to be the ones that can have a pretty good shot at transacting on something.

Investor What is your most memorable experience while serving in the Army, and what did you learn from it?

Reinhart It was Dec. 19, 1989. I was on my second deployment to Panama. That particular date was my birthday and when the actual Panama invasion happened. I was part of that.

We were at a joint Panamanian/U.S. Army base and there were Special Forces from the Panamanian division on that base. We were tasked to secure the front gate and to stop the supporting troops from exiting as the invasion started. We got into a firefight as troops were trying to leave and we ran out of ammunition—we weren’t fully geared up because we didn’t want to tip them off.

We had secured two Panamanian gate guards with cuffs, and they got caught in the crossfire. In the middle of the firefight, as we ran out of ammo, my buddy and I pulled those guys back under cover. I was awarded an Army Commendation Medal with “V” device for valor in combat. It’s the lowest valor in combat medal awarded, but I was extremely proud of it.

What I learned from it is I don’t like bullets flying at me. And I learned that there’s probably another career option for me down the road vs. doing that. □

DEAL DOLDRUMS LEAD TO LOW-KEY LENDING

Faced with a slowdown in transactions, commercial banks await a catalyst to bolster market confidence.

ARTICLE BY
CHRIS SHEEHAN, CFA

It's hard to be effusive about energy if you're in commercial banking and—as has happened in the first half of the year—the economic terrain faces consistent headwinds. Public capital markets have been largely closed for energy, and easy exits have disappeared for private-equity-backed portfolio companies. Uncertainty hangs in the air, and the flow of transactions for banks to fund is down markedly.

Of course, existing lending commitments by bank syndicates continue in place with producers. Many of these were renegotiated and extended in the last couple of years, and so they're not facing a "maturity wall" in the loan market, said one banking source. But

In the A&D market, there is "a lot of dialog that goes on, but transactions have been a little more selective than they have been in the past."

—Phil Ballard, Citi

twice-yearly borrowing base redeterminations are based on volumes and price, as is the norm, and the spring redetermination season saw a slump in most natural gas prices.

There are some bright spots in terms of new lending opportunities. A couple of E&Ps have launched IPOs, spinning off assets in the midstream and mineral sectors. Moves to monetize midstream assets have included water infrastructure, helping highlight an underappreciated asset or, in some cases, offering an alternative way to shed noncore E&P assets in a weak A&D market.

But conditions have changed in what once was a fairly cohesive financial ecosystem between public-equity markets, private-equity (PE) investors and commercial banks. Public-equity investors have, as one commercial banker puts it, "boycotted" energy companies that outspend cash flow and come to equity and/or debt markets for funding that in the past opened up opportunities for new credit lines.

Gears 'not moving smoothly'

The interaction of energy markets "hasn't ground to a halt, but the gears are not moving smoothly," said one industry observer. With public-equity markets largely closed, PE sponsors are stepping back from earlier times when "there was always an endgame and a reasonable valuation. To make an investment, you have to have confidence that you know you have an exit. That is what's lacking now."

With diminished prospects of monetizing an investment, the earlier "virtuous cycle" of being able to recycle proceeds to PE investors has "slowed down dramatically," the observer said. "And when the acquisition and divestiture market is slower, and thus there are fewer new transactions coming to market, there are fewer opportunities to syndicate transactions in the commercial banking sector.

"It's an issue of transaction volume. There is deal activity, but it's a lower number of new transactions."

Todd Mogil, managing director overseeing all energy corporate banking in North America for Citi, described the recent capital market environment for the upstream sector as "challenging." Recent activity year-to-date has been "pretty low," with an IPO calendar that was "almost nonexistent." And "quality really matters" in terms of accessing and pricing issues in the high-yield market, he added.

"But whether the market is roaring or challenging, we're consistently looking for opportunities," said Mogil. "We're committed to the space; we've got lots of capital committed to the space. We try to be consistent in terms of our strategy, not piling in when things are good and then pulling out when things turn bad. We try to be consistent throughout all markets."

For favored customers, some of the recent slackness in lending may be showing up in credit terms.

"Bank capital is going to be there for good credits, for good structures and for good stories," said Mogil. "Some of the pricing power, especially for the stronger credits, has shifted back to the borrower. Banks are willing to trade pricing concessions for structural enhancements. We're starting to see pricing levels get back to where they were pre-downturn."

In terms of a catalyst for a pickup in lending activity, Mogil pointed to the need for improved investor sentiment driven by more consistent performance.

"Investors are broadly looking for more consistent performance. Recent underperformance, on both the equity and high-yield sides, has caused investors to demand higher returns or simply look to other places where they can put their money and get consistent returns. There has to be improved performance for generalists to rotate back in, or valuations need to reach a point where people have to pay attention."

Phil Ballard, managing director in charge of reserve-based lending (RBL) at Citi, said there have been some indications of a pickup in activity, but "the better part of this year so far has been slow." In key areas—the PE sector launching new portfolio companies and the A&D market— "a lot of that dialog goes on, but transactions have been a little more selective than they have been in the past."

"It's really all forms of capital that seem to have retrenched a bit," he continued. "The private-equity side and the public equity and debt markets are relatively dormant right now."

What available capital tends to flow into the hands of the larger-cap companies that "can show they have scale and continue to grow their production without outspending their cash flow," according to Ballard. In addition to being able to better manage capex amid uncertain commodity prices, he noted, the larger names often have greater leverage in negotiating oilfield service and marketing contracts.

Taking less risk

Despite the slow market conditions, Citi and most other banks "are still actively looking to add assets to their book, assuming they are well-structured conforming transactions," said Ballard. However, they are likely to be "a little more selective and cautious about getting into more challenging situations. The banks just aren't taking as much risk as they were five years ago."

In the latest RBL redetermination season in the spring, approaching 50% of producers had borrowing bases reaffirmed, with the balance of Citi clients seeing their borrowing bases split roughly equally between increases and decreases, said Ballard. The price deck used by banks in general is relatively flat. For Citi, the

Upstream companies with a midstream business embedded in their ownership structure have spun out midstream assets via an IPO or sale to a third party given the valuation differential between E&P and midstream sectors, said managing director Mike Lister, who leads J.P. Morgan's Corporate Client Banking practice within the commercial banking division.

STEADY ON COURSE

While it may not seem obvious to discuss commercial banking trends with a private-equity (PE) sponsor, *Oil and Gas Investor* was reminded of an observation by Quantum Energy Partners some 18 months ago. The Houston-based PE sponsor said if one aggregated the purchasing power across all its portfolio companies, its "credit facilities are probably larger than most large-cap public E&P companies."

With that perspective in mind, *Investor* visited with Quantum managing director Tom Field, who said, "Quantum's collective portfolio companies were now operating close to 30 rigs, making our firm one of the most active drillers in the U.S. If viewed as a single entity, the Quantum-backed portfolio companies would be the equivalent of a large independent oil and gas company.

"We deal with multiple banks, and the banks that we deal with are very active," said Field. "We have billions of dollars of capital drawn in what I would call 'regular way' RBL credit facilities. We are constantly in the market. For instance, we just upsized or closed three credit facilities in the last few weeks. In addition to upstream platforms, we have several midstream and mineral platforms, most of which utilize credit facilities."

Field emphasized, "How important it is to us that our banks have a deep understanding of the oil and gas industry. We view the banks as true partners in helping build and grow our portfolio companies."

An example is pad development, involving anywhere from about two to 20 wells drilled on a pad, said Field.

Tom Field, managing director at Quantum Energy Partners

"On a multiwell pad, we may start spending capital to build the pad and then drill and complete the wells in excess of a year before we bring the pad online and see cash flows," he said. "That's somewhat new for the banks, too. So we put our heads together with some of our key banking partners to figure out a construct that recognizes that dynamic and allows for a prudent amount of leverage."

With close to 30 rigs being run by its portfolio companies, Quantum's "organic" level of activity has been as high as it's ever been, according to Field, referring to the ongoing development of its existing portfolio companies' asset positions.

"Given the current state of the A&D market, plus the general desire of acquirers to buy assets that are approaching, if not already, cash-flow neutral or positive, we're generally taking our asset positions further along the development continuum, which may mean a longer hold period," said Field. A hold period of three to five years previously may now be four to seven years, for example, he added.

"Our banks are playing a very important role for us as our borrowing bases grow, and we continue to deploy capital from the RBLs, as well as from cash flow, to continue developing our assets," he said.

How comfortable is Quantum and its banking partners that the assets will find an eventual market?

"At a high level, it comes down to your conviction in the undeveloped inventory that you have," said Field. "If you have a high degree of confidence that you're going to achieve attractive rates of return with your wells, putting capital behind that program makes a lot of sense. And you need even more conviction if you're pad developing, because then it involves a larger amount of capital being invested before a group of wells come online."

Field acknowledged that recent market sentiment may have shifted somewhat so it is "less focused on having decades of inventory and more focused on high-returning inventory and cash flow." However, he said there will always be a market for very high-quality inventory with a low breakeven that can generate cash and repeatable, attractive rates of return.

"We work with our management teams to construct an asset base that any acquirer is going to say, 'That's going to the front of our queue for development,'" said Field. "We think there is always a market for an asset whose profile allows it to jump to the top of a buyer's undeveloped inventory stack from a returns standpoint."

In selecting assets to develop, Quantum is indifferent as to commodity, according to Field.

"We don't see a difference in terms of a willingness to develop oil-weighted assets rather than gas-oriented assets," he said. "Banks have their price decks for both commodities. They run the price decks and do the analysis for the conforming borrowing bases. And we get credit for hedging. Both our oil-weighted and gas-weighted companies' reserves are growing substantially."

Feedback from certain banks has been that they were becoming "more selective," said Field. "Our banks are telling us they're increasing exposure to what they deem to be high-quality companies and high-quality private-equity sponsors, while reducing their exposure to those they deem otherwise." For Quantum, pricing grids are largely unchanged recently, with spreads over LIBOR "generally at 225 to 275 basis points, depending on borrowing base utilization."

prompt Nymex month is set at $51 per barrel, rising over seven years to $53.

Not surprisingly, those actively drilling for liquids in the Permian Basin tended to make up the greatest portion of those with increases in borrowing bases. Haynesville Shale operators, benefiting from strong drilling results and premium natural gas prices due to its location, also tended to see increases. For natural gas-oriented E&Ps, those able to grow reserves enough to offset a drop in value due to lower gas prices were able to maintain borrowing bases.

Stable and higher oil prices

What would help spark a wider and more intense level of activity in the energy lending space?

"What we need to see is stability in oil prices at a higher level," said Ballard. "Also, we would welcome some positive news from the industry that it can maintain and grow its production without outspending cash flow. The criticism of institutional investors is that companies are growing, but not adding value. They want to see real signs that the industry is adding value."

Similarly, J.P. Morgan managing director Mike Lister emphasized, "We bank the industry, come high or low prices. We expect the cyclicality. As a firm, we've covered the oil and gas industry for over 50 years. We like to think it's about client selection, picking the right management teams and being there for them through the ups and downs in the cycle."

Based in Dallas, Lister leads J.P. Morgan's corporate client banking practice within the commercial banking division as it relates to clients outside the major global integrated producers. The client base is made up predominantly of domestic noninvestment-grade E&Ps that employ a reserve-based loan structure, but also includes companies in the midstream and oilfield service segments.

"We have a large and active client base across all three verticals," said Lister. "We have thoughtfully expanded our loan commitments in each vertical over the past three years. From a syndication standpoint, we still see loan demand for well-structured transactions for E&Ps that have demonstrated their ability to operate efficiently at lower commodity prices. J.P. Morgan and the market as a whole remain focused on keeping E&Ps within the normal lending metrics of asset coverage and cash flow."

Midstream stability

Given the critical nature that midstream infrastructure plays in moving oil, gas and NGL from the wellhead to the end consumer (e.g. utilities, the petchem sector, refineries or even offshore markets), the midstream sector has offered more stability in terms of the flow of credit opportunities, according to Lister. "In many cases, it's like a tolling arrangement. There's risk as you build out systems, but once you're operating gathering and processing assets in a basin, you typically have contractual minimum volume commitments or acreage dedications, so it's easier to project future cash flow."

Moreover, "valuations have held more firmly," he said. "That's why you've seen some of the public and private players in the upstream sector, who have built out a midstream business embedded in their ownership structure, spin out the midstream assets via an IPO or sell to a third party given the valuation differential between E&P and midstream assets. And it's a scale game, so you're also likely to find larger infrastructure funds or PE funds willing to put more capital to work on the midstream front."

Bryan Chapman, market president of energy lending with IberiaBank Corp., noted widespread industry awareness of "the issues and changed dynamics due to what is pretty much a boycott of public capital markets" for those E&Ps seeking funding beyond internally generated cash flow. In addition, "the A&D activity has tapered off," he noted.

With public-equity markets generally "not being supportive of growth strategies," producers are under pressure to "live within cash flow and return some of that cash to investors," said Chapman. "And, of course, they want you to do that without over-leveraging the company, because then you'll trade at a steep discount. It's a tough challenge, and companies are having to make that transition."

A silver lining

However, the fewer financial instruments available to producers may offer something of a silver lining to commercial bankers, according to Chapman.

"If companies, particularly those backed by private equity, are having to transition into prosecuting a development program and building up production that is able to support a borrowing base, there will be more companies having to grow production," he said. "And with fewer assets being monetized, that can create a pretty attractive environment for energy loans from a commercial bank."

Chapman referenced reports that some private-equity sponsors were withdrawing commitments to portfolio companies that had yet to make an acquisition "because they're trying to preserve that liquidity to invest in companies that are more mature in their development, since they're likely going to have to support those portfolio companies over a longer period."

In addition, by "rolling up" management teams operating in a single basin to create scale, sponsors can create "a better profile of a company able to prosecute a drilling program and increase its PDP [proved developed producing]" properties. "Whenever markets come back, the companies that are buying are probably going to want a much higher PDP component than they've had in the past," he observed.

"A lot of PE sponsors are consolidating their portfolio companies to create 'basin champions' that have a better chance of doing an IPO or 'merger of equals' when capital market conditions change," he added.

Bryan Chapman, market president of energy lending with IberiaBank Corp., cited "changed dynamics due to what is pretty much a boycott of public capital markets" for those E&Ps seeking funding beyond internally generated cash flow.

Liquidity management priority

Historically, banking relationships have "always been very, very important from a liquidity management perspective," recalled Chapman.

Traditionally, he said, E&Ps would "make an acquisition, maybe issue some equity, perhaps issue some high yield to partially fund the acquisition, and then pay down their revolver. Then, as they ran a drilling program, outspending cash flow, they'd start drawing on the revolver. And once they were at half to two-thirds drawn against the revolver, they would term it out in the high-yield market."

However, against the current backdrop, which is "not as growth-oriented, not as acquisition-oriented," such a series of transactions will likely no longer apply, according to Chapman. "The current environment requires people to think differently. CFOs are very much focused on liquidity management and refinancing risk in light of current market conditions.

"If you're a company, whether public or private, and you have some unsecured term debt that's maturing over the next two to three years, you may have to suddenly switch your focus to: 'How am I going to address that re-financing risk? Do I need to underspend my cash flow and use that to pay down my credit facility, so I have enough dry powder to take out a maturing high-yield issue if necessary?'"

"The expectation of both the bankers and the producers is that one year before maturity they will refinance this credit and roll the principal and extend the maturity," said Buddy Clark, co-chair of Haynes and Boone LLP's energy group.

As an example, he said, if a company issued debt a couple of years ago—and because of weakness in oil and gas prices the debt is trading at a discount to par—the market is signaling to the issuer that it will have to offer a higher coupon if it wants to refinance the debt. In turn, the issuer would have to carry a larger interest burden, he noted, contributing to a higher cost of capital.

"The one thing that the banks are not going to do is to extend the maturity date of a revolver beyond the maturity of a large subordinated debt repayment obligation," warned Chapman. "The banks are in the first lien position. They want to be the first debt to mature in the capital structure."

Where has IberiaBank made major inroads in growing its loan portfolio in a market beset by cross-currents?

"The midstream sector has been a big draw that wasn't there four or five years ago," said Chapman. The midstream sector made up roughly 15% of the energy portfolio at the end of 2014 vs. 85% for the upstream sector. Since then the midstream sector has "more than doubled" to about one-third of the IberiaBank energy portfolio vs. some two-thirds for the upstream sector.

'Nobody to flip it to'

Buddy Clark, co-chair of Haynes and Boone LLP's energy group, joked that commercial banking in energy has gone from being "boring and great" in 2018 to "too boring" this year.

"Deals are slow. Access to public markets is really slow, and that's the engine that drives transactions when people are buying and selling properties. Without the deals, there's not the need for a lot of financing," he said. "But the major energy banks are open for business and looking for deals."

Haynes and Boone conducts a twice-yearly survey of borrowing base redeterminations. The latest, conducted in February, showed that the greatest segment of respondents—among both borrowers and lenders—expected borrowing bases to stay constant. The second-largest segment, tilted toward lenders, expected a decline in borrowing bases of between zero and 10%.

While the formula for RBL loans is basically unchanged, "the banks are more selective," said Clark. "The banks have to a degree become more conservative on their calculations for borrowing bases for proven reserves. In particular, they're giving little to any credit for undeveloped reserves, because the market's not giving any credit for it. I think the advance rates for PDP reserves are fairly consistent."

In some cases, producers may have little urgency to take on a larger credit facility, even if their borrowing bases would make them eligible, according to Clark.

"For those E&Ps adding PDP reserves, the banks are going to increase the borrowing because it is essentially formulaic," he noted. "But what we're seeing is that borrowers that don't need access to additional capital are not asking for their borrowing bases to be increased, because they pay an unused fee on the amount they don't have drawn down."

> "You don't want to wait to refinance within one year of maturity, because it then goes into current obligations and can really ruin your financial ratios."
>
> —Buddy Clark, Haynes and Boone LLP

In addition, the gridlock in the A&D market may also hold back E&Ps from pushing for a revised facility.

"There's no point going to a bank to get funding to drill more wells on your property if your goal is to buy and flip, and there's nobody to flip it to," he observed. "Even E&Ps with a lot of locations are not necessarily accessing capital to build reserves until they can see an exit. With current market sentiment, adding reserves on its own through incremental debt is no way to increase share values for E&Ps."

This is by no means to understate the importance of banking relationships to both borrower and lender.

"These revolvers are usually now five-year maturities, and the only thing that gets repaid prior to maturity is the interest," he said. "The expectation of both the bankers and the producers is that one year before maturity they will refinance this credit and roll the principal and extend the maturity. Both the banker's and the producer's idea is often that they'll continue to grow the credit until somebody merges with the producer and pays it off.

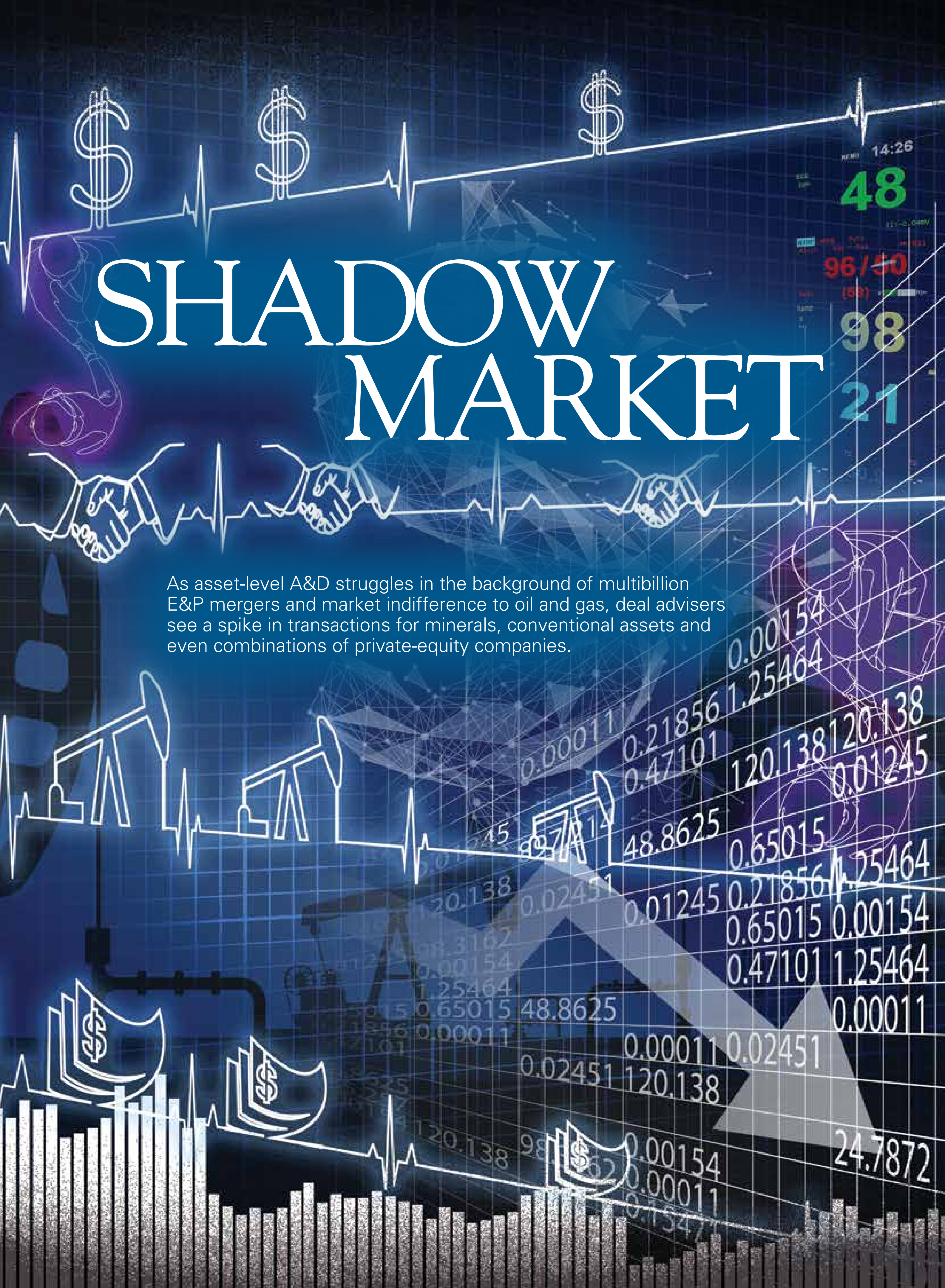
"You don't want to wait to refinance within one year of maturity, because it then goes into current obligations and can really ruin your financial ratios," according to Clark. "Often these credit facilities get amended with every acquisition or substantial sale of assets. So that's usually the goal: to keep that maturity out there at least one year. And still further out will make CFOs more comfortable."

Clark holds out hopes for better days in the A&D market for commercial bankers. The question is when. Clark wrote a book on the history of oil and gas lending in 2016 titled, "Oil Capital: The History of American Oil, Wildcatters, Independents and Their Bankers." The industry has "seen this rodeo many times over," he said.

The steep selloff in crude prices in the fourth quarter of last year "gave everybody another dose of reality. We're not going back to the go-go days any time soon," he said. "It's difficult. We're in that portion of the cycle where there's not a great emphasis on exploration or on acquisitions. But the industry repeats itself. I'll guarantee you it will come back. The question is when." □

SHADOW MARKET

As asset-level A&D struggles in the background of multibillion E&P mergers and market indifference to oil and gas, deal advisers see a spike in transactions for minerals, conventional assets and even combinations of private-equity companies.



ARTICLE BY
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ILLUSTRATION BY
ROBERT D. AVILA

The bright side of first-half 2019 A&D activity is that it's difficult to see how it could get worse any time soon.

First-quarter transactions "screeched to a halt" in the first quarter, with the lowest quarterly deal value recorded in a decade, according to Raymond James' analysis. A bounce back in deal values in the second quarter rested heavily on the shoulders of Occidental Petroleum Corp.'s merger with Anadarko Petroleum Corp. in a deal valued between $57 billion and $64 billion.

Around the edges of the supernova merger burned a pale corona of asset deals. In the Bakken, Permian, Eagle Ford, Marcellus and Haynesville, PwC counted just nine upstream shale deals in second-quarter 2019.

In a July report, PwC said a new reality is settling over contemporary oil production.

"Investors and lenders are no longer writing checks to companies that can't show positive cash flow. Eager to black ink, corporate dealmakers are looking to drive scale efficiencies."

Any lingering doubts about an off-kilter start to 2019 have been confirmed by numbers indicating the sector is sailing in shallow waters. The asset-level A&D environment is soft, though it still has epicenters of relatively strong or at least functional markets, said Art Krasny, managing director and head of A&D at Wells Fargo Securities.

As of late July, A&D asset transactions totaled roughly $13 billion. At its current pace, A&D values in 2019 may eventually tick up to perhaps $25 billion for the year, plus or minus $5 billion—at least a 30% decline compared to 2018, he said.

That's a shadow of a market that already showed weakness in 2017 and 2018.

"It's been a market that's seen a tremendous compression of activity, of volumes, of downward pressure on valuations," he said.

In the current market, mineral and royalty deals are gaining strength, private-equity firms are contemplating mergers and some buyers are looking for safe and less costly conventional assets.

Meagher Energy Advisors has seen success with low-decline, conventional asset deals, said Matthew E. Meagher, president and partner of the firm.

Partly, the turn back toward conventional assets comes at a time when public and private financing remains not just closed off but indifferent to upstream companies.

"I just don't know if buyers really have the capital to develop unconventional, horizontal-type assets," Meagher said.

Buyers, typically backed by private-equity funds, are making investments in conventional assets while they wait for better pricing and better times.

"A lot of people are just looking for conventional—its cash flow," he said.

In the first half of the year, bright spots have been fleeting, though electrifying. Comstock Resources Inc. closed on a cash and stock acquisition of Haynesville operator Covey Park Energy LLC in a $2.2 billion merger.

Apache Corp. sold off its Oklahoma positions in the western Anadarko Basin and Scoop and Stack plays to two private-equity-backed E&Ps for more than $600 million. And on July 29, Osaka Gas Co. Ltd. agreed to buy Houston-based independent Sabine Oil & Gas Holdings Inc., which Osaka said would make it the first Japanese firm to purchase a U.S.-based shale company. Sabine's East Texas operations sold for about $700 million and followed Osaka taking a 35% position in the company last year for about $145 million.

But A&D value in the second quarter largely rode the coattails of Occidental's massive deal with Anadarko. Of the $68.2 billion value from second-quarter deals tallied by PwC in its July report, just 6% of the total was from other transactions.

Dwindling interest by investors appears to have dampened enthusiasm among companies that would typically make transactions.

"On the psychological side, there is a great deal of pessimism out there," Meagher said. "So, a lot of people, they're not doing anything. They're not buying. They're not selling. They've just stopped their activity."

Meagher said he's not sure the reticence in the deal market is necessarily associated with oil prices.

"It's just more of an attitude, and we've been here before, where you think the rug is moving out from underneath you, and you just want to stop."

Forsaken

For the past few years, Wall Street has put public companies on a starvation diet, cutting back on capital and punishing companies that engage in A&D activity.

All but the most financially healthy E&Ps are able to make deals, though companies such as Occidental still face pushback from activist investors such as Carl Icahn.

The continuing drain of capital has started to affect private-equity-backed companies, which are blocked from the exits they would prefer—IPOs or buyouts.

Private-equity firms appear to have recognized that the market is here to stay, Krasny said. In a new twist, those firms are considering their own mergers among their portfolio of companies.

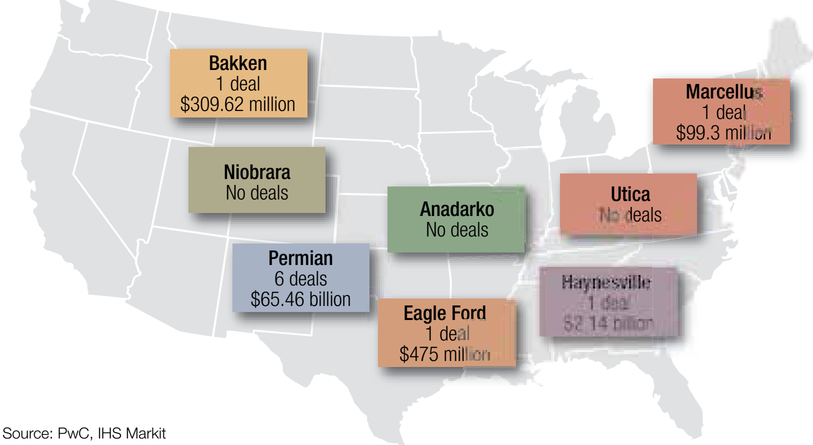
As little as nine months ago, private equity was willing to wait until a window in the market opened up.

"A year ago, PE-sponsored teams were expecting the A&D market to improve on a strengthening commodity tape," Krasny said. "In fact, several asset divestitures launched in the fall of last year on the basis of such expectations."

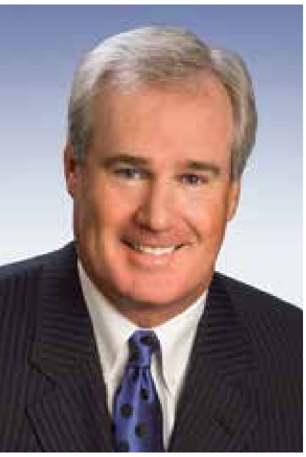
While conditions for E&Ps improved in 2018, the fourth-quarter collapse of crude oil prices "and the market meltdown that followed produced several failed sales and forced other sellers to withdraw asset offerings."

A&D activity is on pace for perhaps $30 billion in deal value in 2019 , and the market is a shadow of its former self while the energy sector has "lost its 'must own' status," said Art Krasny, managing director and head of A&D for Wells Fargo Securities.

2Q19 Upstream Shale Deals



Source: PwC, IHS Markit



Meagher Energy Advisors has seen success with low-decline, conventional asset deals, said Matthew E. Meagher, president and partner of the firm.

The reaction among private-equity firms has been a swift change in behavior. They're no longer waiting for the market to change but expect market conditions to remain the same—or even worsen, Krasny said.

"We see M&A momentum spreading into the private equity space," he said.

Like public companies, private equity is seeking consolidation to cut costs, gain scale, and tap into G&A and operational synergies, he said.

"We have already seen such consolidation taking place between portfolio companies of individual private equity firms and expect the pace to accelerate."

The steady drain of capital has also dulled the appetites of would-be buyers.

Meagher said less capital has pared back the number of offers made for assets and undeveloped acreage. However, quality assets still attract buyers with capital.

"Many of these buyers are family businesses, not private equity," he said. "But [there are] definitely fewer players."

Public companies continue to be victims not just of commodity prices beyond their control but of their own success. The industry has been ingenious in solving the equations needed to produce more oil for less money. But it's been hammered by subtraction as fewer energy stocks are in investors' portfolios, Krasny said.

The strength of U.S. producers has re-fashioned the oil and gas space as a lackluster and an unexciting place to put money. E&P stocks have retrenched in the face of historical losses and volatility.

"The energy sector has contracted as a percentage of the overall market from about 16% of the S&P in 2008 to about 5% in 2018," Krasny said. "The industry has lost its 'must own' status from a generalist investor standpoint."

As investors pulled out of the space, public E&Ps saw billions of market capitalization erased, Krasny said.

The confluence of those and other factors is also reflected in a cracked mirror view of the industry as ultra-resilient, in part because U.S. companies weathered the downturn. The result is that even major world events that would have caused spikes in oil prices in the past now barely cause oil prices to flicker. Rising tensions between the U.S. and Iran and continued hostility in the Strait of Hormuz have done little to affect oil prices.

"We changed the dynamic of the global market where the market has stopped responding to the geopolitical signals the way it was responding previously," Krasny said. "If you are an investor looking to invest in the commodity upside, their thesis has been muted by this dynamic."

'Shale 3.0'

One emerging thesis is that E&Ps are further transitioning, just as they metamorphized to their current state—Shale 2.0—by abandoning growth at all costs for restraint.

The current focus on drilling within cash flow and returning capital to investors may give way to what Krasny refers to as Shale 3.0.

In this stage, the industry will begin to self-regulate, managing production in response to commodity prices while also attempting to govern the supply of the commodity itself.

A&D and M&A are also working along different paths. While A&D rides on the current of the market, M&A is seen as an engine to build scale and efficiencies. In this realm, commodity type follows at a distant second.

"Scale matters," Krasny said. "When you look at different attributes and try to understand what drives [company] performance and underpins it," the difference is in the depth and breadth of operations and assets.

Companies with larger and more diverse portfolios and more mature portfolios are able to deliver on the Shale 2.0 promise of staying within cash flow and returning cash to investors—while also growing a cost-effective business.

The move toward Shale 3.0 is reflected in oil majors and large independents that are focused on securing running room in the Lower 48.

One way that's played out is in M&A among public companies. Since 2017, 11 deals worth about $104 billion in aggregate value have transacted in the public-to-public M&A market, Krasny said.

"As majors and large independents continue to ramp activity in the Lower 48, the race to secure adequate well inventory, particularly in the Permian Basin, will create a powerful catalyst as not all players in this group have sufficient inventory life."

Large E&Ps want to acquire needle-moving targets.

"Following Occidental's acquisition of Anadarko, industry and basin consolidation remains an important theme, he said.

Middle and smaller companies, at the same time, are already under pressure to consolidate. Those companies face different challenges than larger companies.

The declining nature of upstream assets' production means only a limited number of small- to mid-cap companies "are truly capable of delivering growth within cash flows," Krasny said.

Larger E&Ps' advantage: lower decline rates and expansive legacy assets.

"This structural fault in the [small- to mid-cap] strata should lead to consolidation and M&A activity within this group," he said.

Pressure among companies, either by activist shareholders or indirectly, has been a factor in deal flow.

Carrizo Oil & Gas Inc., for example, came under pressure in May from investor Lion Point Master LP, which acquired a 5.1% stake in the company. Lion Point saw Carrizo as an undervalued investment opportunity and advocated a merger or sale to increase its value.

On July 15, Callon Petroleum Co. said it would acquire Carrizo in an all-stock deal worth $3.2 billion. The deal builds scale for Callon, which will add Eagle Ford Shale acreage to its current Permian-focused company. Pro-forma production will average about 100,000 barrels of oil equivalent per day.

Carrizo's asset base will add about 76,500 net acres in the Eagle Ford and 46,000 net acres in the Delaware Basin.

Chesapeake Energy Corp.'s $4 billion purchase in February of oil-weighted WildHorse Resource Development Corp. highlights the market's interest in scale and diversity that will drive consolidation, dealmakers said.

While M&A has been active, the A&D market ebbs and flows with the broader market.

In addition to sluggish demand, the A&D space has been affected by reassessment of the value of reserves and economic models that underpin cash flows and asset values. The optimism that spurred land grabs—based on "unbounded parent well type curves" and aggressive spacing assumptions—has faded, he said.

As the industry started to master well control and advanced its knowledge of reservoir performance and other factors, those assumptions have been pared back.

Recently, industry pundits have started to talk about the need to move beyond Shale 2.0 and "voluntarily cut production to assist in stabilizing global oil markets in order to attract investor dollars," Krasny said.

"While the nascent signs of a Shale 3.0 mentality are just beginning to emerge, E&Ps are showing determination to prioritize free-cash-flow generation vs. growth," he said.

Holding pattern

In a clouded market, transaction advisers say they are staying remarkably busy.

"We are slightly down from years prior, but not that far," Meagher said. "We're pretty selective on the engagements we take."

The firm's due diligence—and frank conversations with sellers about their value expectations—have allowed Meagher to close about 90% of the packages it's offered.

"Basically, everything we've had on the market has sold," he said.

In part, ground lost in upstream deals has been made up through a rise in mineral and royalty transactions. Meagher said such transactions have mushroomed to roughly a third of the company's business—a far larger percentage than in past years.

"We've always done minerals and royalties. That's just part of the game," Meagher said. "But I would say this is probably double what we've done in the past. But that space is one of the only spaces with capital."

Assets without capital structures, such as nonops, are more difficult to work with.

"Pricing is stalling there," he said.

Meagher said activity has been strongest in Texas, Oklahoma and, to a certain extent, Wyoming.

Colorado's political climate has dampened action around the state.

"The activity here in Colorado has really dropped" due to a massive legislative restructuring of industry regulations signed by the governor in April, he said.

Vital for Colorado, a coalition of state business leaders focused on energy policy, said in August that oil and gas well permitting is down dramatically compared to 2018. The state's oil and gas regulator, the Colorado Oil and Gas Conservation Commission, is in the process of transforming from an agency "fostering" industry to "regulating" it.

That leaves would-be sellers ready to make deals but hoping to outlast the current market.

To stabilize, the market needs commodity price levels that don't simply recover in episodic fashion, as they did in 2018, but show sustained strength, Krasny said.

Krasny said Wells Fargo has also stayed busy despite negative sentiment. Such markets sometimes invite opportunities to make deals.

Potential sellers face either continuing along an unsustainable path for their business or selling at a less than optimal value, Meagher said.

"Sometimes the right answer is to sell. And we're seeing companies making those decisions," he said. "We're seeing sponsors making those decisions quicker than they have in the past. Because it's clear the market so far has not been improving."

Some oil and gas transactions are also insulated from broader market woes. Minerals are particularly strong, as evidenced by Brigham Minerals Inc.'s surprisingly strong $260 million IPO in April.

Minerals continue to have more appeal, particularly because of the contrast they offer of cash flow and less risk, than the industry they overlay.

However, the location of mineral assets remains a key factor. Permian mineral interests, for instance, still command a premium.

"That asset class is exposed to the logic of the upside, which is driven by the industry's ability to drive and continue growth of production," Krasny said. "Because of that, it's going to be highly dependent on the zip code."

And the market also offers bargain basement opportunity for financially healthy companies.

As the industry makes a tectonic shift, the right kind of capital provider can make investments that do extremely well, he said, "because the valuations are at rock-bottom for some of these assets."

"I think unless a company in this market has to sell a gas property, because gas prices are pretty depressed right now, they're not going to," said Mike O'Leary Hunton, co-head of Hunton Andrews Kurth LLP's corporate team.

But natural gas assets remain gripped by faltering prices and diminishing private-equity patience.

A private matter

On the 42nd floor offices of Hunton Andrews Kurth LLP in downtown Houston, the firm that represented Sabine offered little good news for momentum in the natural gas arena.

Sabine's sale came after the company's exit from a bankruptcy in which control resides in creditors, many of whom purchased Sabine's debt for pennies on the dollar, said Mike O'Leary, co-head of the firm's corporate team.

"I think unless a company in this market has to sell a gas property, because gas prices are pretty depressed right now, they're not going to," O'Leary said.

The potential for deals resides in companies that have no other choice, either because they're willing to part with assets at a sharp discount to pay down debt or are forced to seek bankruptcy protection.

"Otherwise, I think people just sit on the sidelines," he said. "This is not a really active time in the M&A market outside of those areas, or maybe you have an Osaka that wants to hedge their position."

Phil Haines, who was part of the firm's Sabine team, said natural gas deals seem stuck in neutral over concerns that future associated gas production in the Permian Basin and elsewhere in the U.S. will keep prices down for the foreseeable future.

"I think a lot of the interest has been overseas because you can play the differential from continent to continent or you've got some other needs where you have to supply LNG," he said.

But O'Leary said that previous Asian investment, which withered into billions of dollars in asset impairments, leaves additional future investment in doubt.

"Whether their hands are so burned from that that they won't come back in, I don't know. But we do some work with some of those Chinese national companies, and we haven't heard any big movement yet," O'Leary said.

Courtney Butler, co-lead of the firm's capital markets practice group, said companies are attempting to run sell-side processes but there aren't buyers because of the wide gulf between buyer's and seller's price points.

"We haven't heard any of those deals getting past initial discussions," she said.

Even one of the world's largest integrated energy companies, which announced an intention to dispose of its Lower 48 oil and gas properties, is taking time to sell its gassier assets, O'Leary said.

"I think they're still playing it, given what's happened to prices since they announced" a sales process, he said. "The market is just not real strong."

Private-equity firms are seeing a similar struggle and are considering potential combinations. The attorneys said that rumblings among private-equity firms are that there's an unwillingness to extend some funds beyond their current expirations.

"If we're looking at a downcycle that is going to be the next 18 to 24 months, some of these funds don't have that long to wait," Butler said. "So there could be forced sales."

Deals may turn within the next 12 to 18 months because firms want to raise new funds.

"They've got to liquidate," she said.

With depressed prices, wary lenders and apathetic investors, traditional exits are difficult, O'Leary said. As Krasny noted, firms are considering combinations, though those are also difficult to navigate.

"With so much concern about lower-levering portfolio companies, unless the PE firms are willing to put new equity into a buyer to [raise funds for a cash payout], you're probably not looking at a full cash payout so PE firms can get a full exit," O'Leary said. "It's just a very difficult time right now." ☐

U.S. E&P ACQUISITIONS & DIVESTITURES

Deals closed from Jan. 1-June 30, 2019. Deals closed in second-half 2018 were listed in the March 2019 issue. All deals, updated in real time, are now available at HartEnergy.com/ad-transactions.

Deal No.	Estimated Value ($MM)	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Month Deal Closed	Comments
1	7,700	Encana Corp.	Newfield Exploration Co.	2	Acquired The Woodlands, TX-based Newfield in an all-stock transaction and the assumption of $2.2B net debt; includes positions in the Anadarko Basin (Stack/Scoop), Arkoma Basin, Uinta Basin and Williston Basin.
2	3,977	Chesapeake Energy Corp.	WildHorse Resource Development Corp.	2	Acquired Houston-based WildHorse in a cash-and-stock merger; includes roughly 420,000 net acre position in the Eagle Ford Shale and Austin Chalk Formation in S TX with 47,000 boe/d of production (88% liquids/73% oil).
3	1,625	Murphy Oil Corp.	LLOG Exploration Co. LLC; LLOG Bluewater LLC	6	Acquired deepwater U.S. GoM assets comprising 26 GoM blocks in the Mississippi Canyon and Green Canyon areas with 38,000 boe/d of current net production; includes up to $250MM of contingency payments.
4	1,600	Cimarex Energy Co.	Resolute Energy Corp.	3	Acquired Denver-based Resolute which controls 21,100 net acres (89% HBP) within the Delaware Basin in Reeves County, TX, with an average 79% WI (97% operated) and average production of about 34,752 boe/d during 3Q 2018.

Deal No.	Estimated Value ($MM)	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Month Deal Closed	Comments
5	735	Aethon Energy III; Ontario Teachers' Pension Plan; RedBird Capital Partners LLC	QEP Resources Inc.	1	Bought QEP's Haynesville/Cotton Valley business comprised of about 49,700 net acres including 137 gross operated producing wells in NW LA with production averaging 49,500 boe/d (100% dry gas) during 3Q 2018; includes midstream operations.
6	475	Ensign Natural Resources LLC; Warburg Pincus LLC; Kayne Anderson Capital Advisors LP	Pioneer Natural Resources Co.	5	Bought Pioneer's Eagle Ford Shale assets comprising roughly 59,000 net acres in S TX with 14,000 boe/d of average net production during 4Q 2018; comprised of $25MM at closing and $450MM contingent payments.
7	400	Diversified Gas & Oil Plc	HG Energy LLC; HG Energy II Appalachia LLC	4	Acquired certain Appalachia assets including 107 unconventional, producing gas wells with combined net production of over 20,000 boe/d across PA and WV.
8	345	Montage Resources Corp.; Eclipse Resources Corp.	Blue Ridge Mountain Resources Inc.	2	Acquired Irving, TX-based Blue Ridge Mountain through merger; creates Montage Resources with about 227,000 net effective undeveloped core acres across the Appalachia Marcellus and Utica shales plus 500-560 MMcfe/d of pro forma production.
9	320	Sequitur Energy Resources LLC; Sequitur Permian LLC	Callon Petroleum Co.	6	Purchased Ranger operating position within the Midland Basin of the Permian comprising 85% WI in 9,850 net Wolfcamp acres averaging about 4,000 boe/d (52% oil) of production; purchase price includes contingency payments tied to oil prices of up to $60MM.
10	300	Ring Energy Inc.	Wishbone Energy Partners LLC; Quantum Energy Partners	4	Purchased Wishbone's North Central Basin Platform assets in the Permian comprising 49,754 gross (37,206 net) acres of mostly contiguous leasehold located primarily in SW Yoakum County, TX, and E Lea County, NM, with an average net production of 6,000 boe/d.
11	245	Red Wolf Natural Resources LLC; Pearl Energy Investments	Apache Corp.	5	Purchased roughly 56,000 net acres and associated production in OK's Scoop, Stack and Merge shale plays as well as the broader Anadarko Basin; includes infrastructure and midstream agreements.
12	235	Undisclosed	California Resources Corp.	5	Acquired 50% of CRC WI and operatorship in certain zones in Lost Hills Field in CA's San Joaquin Basin; includes 200-well development program to be drilled through 2023.
13	191	Stronghold Energy II Holdings LLC; Warburg Pincus LLC	Devon Energy Corp.	2	Purchased Devon's Central Basin Platform assets located in the Permian Basin, which had 4,000 boe/d (about 45% oil) of production in 3Q 2018.
14	176	Alliance Resource Partners LP	AllDale Minerals LP; AllDale Minerals II LP	1	Purchased remaining partnership interests in AllDale; includes control of 42,000 net royalty acres in the core of the Anadarko, Permian, Williston and Appalachian basins.
15	171.6	Kimbell Royalty Partners LP	EnCap Investments LP; Phillips Energy Partners LLC	3	Bought certain oil and gas royalty assets in a 100% equity transaction; includes 12,200 net royalty acres and 1,600 boe/d of production with more than half of production from the Eagle Ford Shale, Permian Basin, Haynesville Shale and Powder River Basin. (Fortis Minerals LLC acted as manager of the Phillips assets prior to sale.)
16	165	Development Capital Management LLC; Ares Management Corp.	Undisclosed	6	Formed JV as a working interest owner to fund up to $165MM worth of drilling and development in the Permian's Wolfcamp Shale.
17	132	Tall City Exploration III LLC	Noble Energy Inc.	2	Acquired roughly 13,000 net acres in Reeves County, TX, within the Permian Basin.
18	126.9	Viper Energy Partners LP	Undisclosed	6	Acquired 1,028 net royalty acres, primarily in the Permian Basin, through 74 separate acquisitions that closed in 1H 2019; added 73 gross horizontal producing wells with an average royalty interest of 3.2%.
19	100	Viking Energy Group Inc.	Multiple sellers	1	Acquired oil and gas wells in Texas and Louisiana producing 2,469 boe/d.
20	100	WPX Energy Inc.	Undisclosed	2	Bought 14,000 surface acres in WPX's core Stateline development area within the Delaware Basin.
21	68	Foundation Energy Management LLC	Riviera Resources Inc.	1	Bought interest in properties located in the Arkoma Basin in OK including about 37,000 net acres, 100% HBP, with 24 MMcfe/d of net production during 3Q 2018.
22	60	Scout Energy Partners	Mid-Con Energy Partners LP	4	Acquired substantially all of Mid-Con Energy's TX properties within the Permian Basin's Eastern Shelf across Coke, Coleman, Fisher, Haskell, Jones, Nolan, Runnels, Stonewall and Taylor counties.
23	55	Glendale Energy Ventures LLC; TPG Sixth Street Partners	Undisclosed	6	Bought nonoperated interests in drilling pads located in OK's Stack play.
24	51.7	Undisclosed	Harvest Oil & Gas Corp.; Magnolia Oil & Gas Corp.	2	Purchased all of the stock Harvest holds in Eagle Ford producer and Houston-based Magnolia Oil & Gas comprised of roughly 4.2 million shares.

Deals shown are those closed during first-half 2019, involving U.S.-based assets or companies only, and having values of approx. $20MM or more. Deals are ranked in descending estimated dollar value, when available, and then alphabetically when no value was made public or when the deal was significant but valued at less than $20MM. Deals shown as pending may have since closed. The next E&P A&D list, covering July 1-Dec. 31, 2019, will appear in the March 2020 issue. Details on all deal-making, updated in real time, are available at HartEnergy.com/ad-transactions.

Deal No.	Estimated Value ($MM)	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Month Deal Closed	Comments
26	44	Dorchester Minerals LP	Undisclosed	3	Purchased producing and nonproducing mineral, royalty and net profit interests from multiple parties across 14 states in the U.S. including positions in the Bakken of ND and interests in multiple EOR units in the Permian Basin.
27	42.8	Undisclosed	Harvest Oil & Gas Corp.	4	Bought all of Harvest's interests in the San Juan Basin in NM and CO with average production of 23,7 MMcfe/d and 163.2 Bcfe (65% natgas, 30% NGL, 5% oil) estimated proved reserves.
28	41.3	Brigham Minerals Inc.	Undisclosed	5	Acquired 2,700 net royalty acres in OK and TX (standardized to a 1/8th royalty interest) during 1Q 2019 with 90% of the capital deployed to the Permian Basin (51%) and Scoop/Stack (39%).
29	34	Undisclosed	Range Resources Corp.	6	Purchased certain nonproducing acreage in NW Armstrong County, PA, within the Appalachian Basin that included about 20,000 acres.
30	31	Undisclosed	Riviera Resources Inc.	5	Bought certain nonoperated properties within the Hugoton B sin in KS including 2,300 nonop wells with proved developed reserves of about 74 Bcfe.
31	29.6	Talos Energy Inc.	Samson Energy Co. LLC; Samson Offshore Mapleleaf LLC	1	Acquired 9.6% nonop WI in the Gunflint producing asset in the U.S. GoM Mississippi Canyon core area.
32	27.5	Mid-Con Energy Partners LP	Scout Energy Partners; Scout Energy Partners IV-A LP	4	Bought producing OK properties in Caddo, Grady and Osage counties including 10 mature waterflood units with net PDP reserves of 6.2 MMboe (96% oil) and a PDP decline rate of less than 5%.
33	22.4	Undisclosed	Extraction Oil & Gas Inc.	3	Bought about 5,000 net acres in Weld County, CO, within the D-J Basin.
34	22	Undisclosed	Rosehill Resources Inc.	4	Bought Permian Basin assets in Lea County, NM; about 880 net acres.
35	20	Undisclosed	MCM Energy Partners LLC	1	Purchased Midland Basin leasehold within the Permian in W TX.
36		Alpha Energy Inc.	Premier Gas Co. LLC	3	Purchased OK oil and gas assets in Rogers County that consist of about 3,429 acres of proven developed and nondeveloped leases containing 126 wells, saltwater injection wells and well production equipment.
37		BCE-Mach LLC; Mach Resources LLC; Bayou City Energy Management LLC	Undisclosed	5	Purchased producing Mississippi Lime properties primarily in Barber and Harper counties, KS.
38		BlackGold Capital Management LP	Undisclosed	3	Bought a portfolio of ORRI in the Utica Shale of OH.
39		Callon Petroleum Co.	Undisclosed	4	Acquired two incremental long-lateral DSUs (167 net acres) within the Midland Basin of the Permian in Howard County, TX, in exchange for low WI properties in Midland County, TX.
40		Contango Oil & Gas Co.	Undisclosed	3	Purchased an additional 4,200 gross (1,700 net) operated acres and 4,000 gross (200 net) nonoperated acres in Pecos County, TX, adjacent to its current southern Delaware Basin position in the Permian.
41		Eni SpA	Caelus Energy LLC; Caelus Natural Resources Alaska LLC	1	Bought remaining 70% WI plus operatorship in the Oooguruk oil field located in the Beaufort Sea offshore AK's North Slope.
42		Foothills Exploration Inc.	American Shale Energy LLC	3	Acquired undeveloped oil and gas leases in Fremont County, WY, within the Wind River Basin; includes 16,387 acres of predominantly continuous acreage.
43		Inpex Corp.	GulfTex Energy LLC	3	Acquired multiple development and production assets in the Eagle Ford Shale in S TX marking Inpex's entry into U.S. tight oil development; includes project covering 13,000 acres primarily located in Karnes County with net production of 7,600 boe/d.
44		LLOG Exploration Co. LLC; LLOG Exploration Offshore LLC	Repsol SA	4	Formed JV to develop deepwater U.S. GoM assets covering Keathley Canyon blocks; includes asset exchange of WI in Leon and Moccasin discoveries.
45		Maverick Natural Resources LLC	Undisclosed	4	Purchased remaining 50% nonoperated WI producing properties in Overton Field in E TX including about 7,600 net acres and 2,700 net boe/d (28% liquids); Maverick currently operates the field.
46		Otto Energy Ltd.	Talos Energy Inc.	3	Formed JV by purchasing 16.67% WI in the Green Canyon 21 lease in the U.S. GoM; plans to pay 22.22% of the cost of the drilling of the Bulleit appraisal well.
47		Paloma Partners IV LLC; EnCap Investments LP	Travis Peak Resources LLC; TPR Mid-Continent LLC	2	Purchased Travis Peak's 44,635 net acres in Grady, Canadian and McLain counties, OK, and about 174 producing wells.
48		Peregrine Energy Partners	Undisclosed	3	Purchased producing and nonproducing oil and gas royalties in Santa Rosa County, FL, operated by Breitburn Energy.

Deal No.	Estimated Value ($MM)	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Month Deal Closed	Comments
49		Peregrine Energy Partners	Summit Natural Resources LLC	3	Bought producing and nonproducing oil and gas royalties across the Appalachian and Black Warrior basins.
50		Pin Oak Energy Partners LLC	Royal Dutch Shell Plc; SWEPI LP	4	Acquired roughly 43,000 acres prospective for Utica Shale development in NW PA in Mercer, Crawford and Venango counties; majority of acreage is HBP.
51		Pin Oak Energy Partners LLC	Undisclosed	3	Bought certain producing Marcellus and conventional assets in Elk County, PA, within the Appalachian Basin; transaction includes a 12-mile midstream gathering system and agreement to develop over 20,000 net acres, also in Elk County, prospective for both the Marcellus and Utica.
52		Pin Oak Energy Partners LLC	Protégé Energy III LLC; EnCap Investments LP	4	Bought nearly 10,000 net acres in Appalachia's Utica Shale across Washington and Noble counties, OH, and Wood County, WV, plus the producing Caywood A 1H Utica well, the Big Red pad location, 60 sq miles of proprietary 3-D seismic and a 4-mile gathering line.
53		Prime Rock Resources LLC; Lime Rock Partners	New Dawn Energy LLC	6	Formed JV to jointly develop about 120,000 net acres contributed by each company in central LA targeting the Austin Chalk covering Allen, Avoyelles, Beauregard, Rapides and Vernon parishes, primarily in the legacy Masters Creek Field.
54		Spur Energy Partners LLC; KKR & Co. Inc.	Percussion Petroleum LLC; Carnelian Energy Capital Management LP	6	Acquired Permian Northwest Shelf assets within the core of the Yeso Formation in Eddy and Lea counties, NM, comprising 22,000 net acres and interests in roughly 380 gross producing wells plus associate water and midstream assets; produced 9,200 net boe/d (85% liquids) during 1Q 2019.
55		Talos Energy Inc.	ExxonMobil Corp.	3	Acquired 100% interest in the Antrim Project in Green Canyon Block 364 in the U.S. GoM.
56		Undisclosed	Samson Resources II LLC	5	Purchased a portion of Samson's position in Converse County, WY, in exchange for cash plus 15,000 net acres bolt-on to an acreage position in Johnson County, WY, within the Powder River Basin; includes all depths below the Fort Union Formation.
57		Undisclosed	WPX Energy Inc.	2	Purchased noncore Nine Mile Draw E&P assets in southern Reeves County, Texas, within the Delaware Basin of the Permian.
58		Viper Capital Partners LLC	Undisclosed	2	Purchased drilling rights to 1,923 acres in Hendershot Ogden Berea Sand Oil Field in Wood County, WV, within the Appalachian Basin.
PENDING DEALS (AS OF JULY 1, 2019)					
59	55,000	Occidental Petroleum Corp.	Anadarko Petroleum Corp.		To acquire The Woodlands, TX-based independent producer with a portfolio of international assets including 600,000 gross acres in the Permian's Delaware Basin; stock-and-cash transaction includes assumption of debt. *This deal closed in August.*
60	2,200	Comstock Resources Inc.	Covey Park Energy LLC; Denham Capital Management LP		To acquire the Dallas-based privately held independent backed by Denham Capital with properties in the Haynesville and Bossier shale plays of N LA and E TX; includes assumption of debt and retirement of preferred units. *This deal closed in July.*
61	965	Equinor ASA	Royal Dutch Shell Plc; Shell Offshore Inc.		To acquire, through an exercise of preferential rights, an additional 22.45% interest in the Caesar Tonga deepwater U.S. GoM field within the Green Canyon area; boosts Equinor's interest to 46% from 23.55%. *This deal closed in July.*
62	512	Amplify Energy Corp.	Midstates Petroleum Co. Inc.		To acquire Midstates through a merger; combined company portfolio includes CA, E TX/N LA, S TX's Eagle Ford and OK's Mississippian Lime.
63	450	Oil Search Ltd.	Armstrong Oil & Gas Inc.; GMT Exploration Co. LLC		To buy the companies remaining interest in the Pikka Unit and Horseshoe Block plus other AK North Slope exploration leases as an option to a previous transaction.
64	322	Undisclosed; Sabinal Energy LLC	Diamondback Energy Inc.		To purchase, in separate transactions, a package of 103,423 net acres in the Central Basin Platform, Eastern Shelf and the Northwest Shelf plus 6,589 net acres in the southern Midland Basin in Crockett and Reagan counties, TX; estimated full-year 2019 net production is about 6,500 boe/d from over 3,000 producing wells.
65	310.5	Northern Oil and Gas Inc.	Flywheel Energy LLC; Kayne Anderson Capital Advisors LP		To buy Williston Basin properties consisting of nonop interest in 86.9 net producing wells expected to produce 6,600 boe/d during 2H 2019; includes roughly 18,000 net acres (100% HBP). *This deal closed in July.*
66	200	W&T Offshore Inc.	ExxonMobil Corp.		To purchase interests in and operatorship of U.S. GoM properties and related onshore processing facilities in the Mobil Bay Area offshore AL; includes 19,800 boe/d (25% liquids) of production.
67	145	Alliance Resource Partners LP	Wing Resources LLC; Natural Gas Partners LP		To buy oil and gas mineral interests in the Permian Basin from Dallas-based Wing, which holds more than 200,000 gross acres with interest in over 4,000 wells in the Midland and Delaware basins.

Deal No.	Estimated Value ($MM)	Buyer/Surviving Entity	Seller/Acquired or Merged Entity	Month Deal Closed	Comments
68	44.5	Riverside Energy Michigan LLC	Riviera Resources Inc.		To acquire interest in MI properties consisting of 1,400 net wells with 193 Bcfe proved developed reserves and proved developed PV-10 value of $38MM. *This deal closed in July.*
69		Chisholm Oil and Gas LLC; Apollo Global Management LLC	Gastar Exploration LLC; Ares Management Corp.		To acquire Houston-based Gastar through a merger agreement; combined company to hold roughly 165,000 net acres in the OK Stack play, primarily in Kingfisher County, with net production of about 20,000 boe/d.
70		ConocoPhillips Co.; ConocoPhillips Alaska	Caelus Energy LLC; Caelus Natural Resources Alaska LLC		To acquire 100% of the Nuna discovery comprised of 11 tracts covering 21,000 acres within the AK North Slope region.
71		Lime Rock Resources	BP Plc; BP America Production Co.		To buy properties in the SWOOP area of Cleveland and McClain counties, OK.
72		Oil Search Ltd.	Repsol SA		To exchange certain AK North Slope assets in the Pikka Unit and the Horseshoe Block plus E of the Horseshoe area within the Nanushuk trend; includes $64.3MM payment to Oil Search.

INDEX: U.S. E&P ACQUISITIONS & DIVESTITURES

OFS INVESTMENT OPPORTUNITY

Private-equity firms are seeking new technology for oilfield service assets.

ARTICLE BY
TRAVIS E. POLING

Unlike venture capital, private equity is chasing companies with positive balance sheets and getting them to the next level. But some have found ways to get start-ups that aren't making money into their portfolio through less direct means.

Most of the investments are for acquiring cutting-edge technology that will improve the operations and efficiency of existing oilfield service companies or investing alongside venture capital arms of major firms such as Saudi Aramco and Schlumberger Ltd., said Brittany Sakowitz, a partner at Vinson & Elkins' M&A and private-equity practice.

Brittany Sakowitz, a partner at Vinson & Elkins, said there has been a spike in the number of private-equity funds buying into oilfield service companies in the U.S., particularly from international private-equity firms with a thirst for those providing services in the Permian Basin.

It has been especially true in the past five years that venture capital has been actively investing in technology companies in oilfield services or with applications for that industry, particularly because they do not require a large amount of start-up capital, and even relatively small seed investments can reap sizeable returns, she said. Private equity's interest in those same companies once they have a track record also can lead to a quicker payout for the venture investors.

There are a few exceptions such as RigUp, an Austin, Texas-based company that received early-stage venture capital in 2014. Later that year, the energy-industry online marketplace for independent contractors and labor received a renewal of investment from that fund alongside a rare private-equity buy-in from Quantum Energy Partners LP. In January, the private-equity firm, along with several others, invested again as part of a $60 million round of funding.

Sakowitz said there has been a spike in the number of private-equity funds buying into oilfield service companies in the U.S., particularly from international private-equity firms with a thirst for those providing services in the Permian Basin.

"Oilfield service investment and industry consolidation has been pretty steady the last few years," Sakowitz said. However, without stability in the oil and gas sector, private-equity firms and service companies are experiencing "a period of uncertainty on how to value companies, and that makes it hard to get deals done," she said.

That has sent much of venture capital and private equity into technology firms that can help oilfield service assets operate more efficiently or give a leg up on the competition.

A matter of resources

There's nothing flashy about the phrase "lower middle market," but that's where Houston-based Hastings Equity Partners finds energy service companies that meet that definition of being a lucrative investment opportunity.

"These companies deliver consistent growth, often overlooked because of their perceived lack of scale or management capability, but the lower middle market is dominated by unique companies that have significant upside, material opportunities for scale and experienced leadership that is looking for a partner," according to Hastings' official explanation of its strategy. "The constraints holding these companies back are often a matter of resources rather than capability, market or vision."

Since its founding in 2004, Hastings has made 60 acquisitions and has routinely made advantageous sales, often within three years.

"We come in and help grow a business and take it to the proverbial next level," said Tanner Moran, a managing director at Hastings, overseeing business development. "We partner with owners and companies in niches and verticals that help them grow their bandwidth. We're not a buyout shop that buys 100% of the business, sticks in a new CEO and we're off and running. We want to help existing businesses find efficiencies."

Finding the right deal isn't as easy as announcing there is a pot of money ready to invest in energy and industrial service firms. Moran attends trade shows, energy industry and investment conferences and anywhere owners of target companies will be.

"It takes years to develop a relationship with a target company that is strong enough to become an investment partnership. It's a constant series of follow up," Moran said. "Rarely when we call on a company are they ready to take on a partner or sell." When a company seeking an investment partner has

PHOTO COURTESY BUCKTHORN PARTNERS

TWMA, a portfolio company of Buckthorn Partners, developed the TCC RotoMill, a technology that separates drill cuttings for recycling and reuse.

The majority of our investments are in companies that performed well through downcycles, because we can't have a concentrated investment portfolio of cycle-exposed businesses, said Tanner Moran, a managing director at Hastings Equity Partners.

hired representation to make the match, the deal can happen more quickly, but it is often still a 12-month process from start to finish, he said.

Like most private-equity companies, Hastings is looking for energy service and equipment companies with three to five years of profitability under their belts, solid management that will stay onboard and an EBITDA of $4- to $20 million.

"It's important to us to acquire companies that have an established earnings history. If a business has several years of profitable operations, it allows us to become more comfortable that the company is battle tested. The majority of our investments are in companies that performed well through downcycles, because we can't have a concentrated investment portfolio of cycle-exposed businesses. We wouldn't have much of a future if we did," Moran said.

The company has made investments in some new companies, but Hastings' start-up investments in companies that have yet to turn a profit are usually done using a different strategy.

"Sometimes the concept of a start-up could join a portfolio we already have," Moran said. "The way we've approached start-ups and newer companies is to acquire them and immediately roll it into an established business in our portfolio to differentiate our investments."

In 2017, Hastings invested in Reach Wireline. Reach was formed by an experienced management team with a strategy to put the latest wireline technology into the field. The coated electric wireline gave operators the capabilities required to service longer laterals.

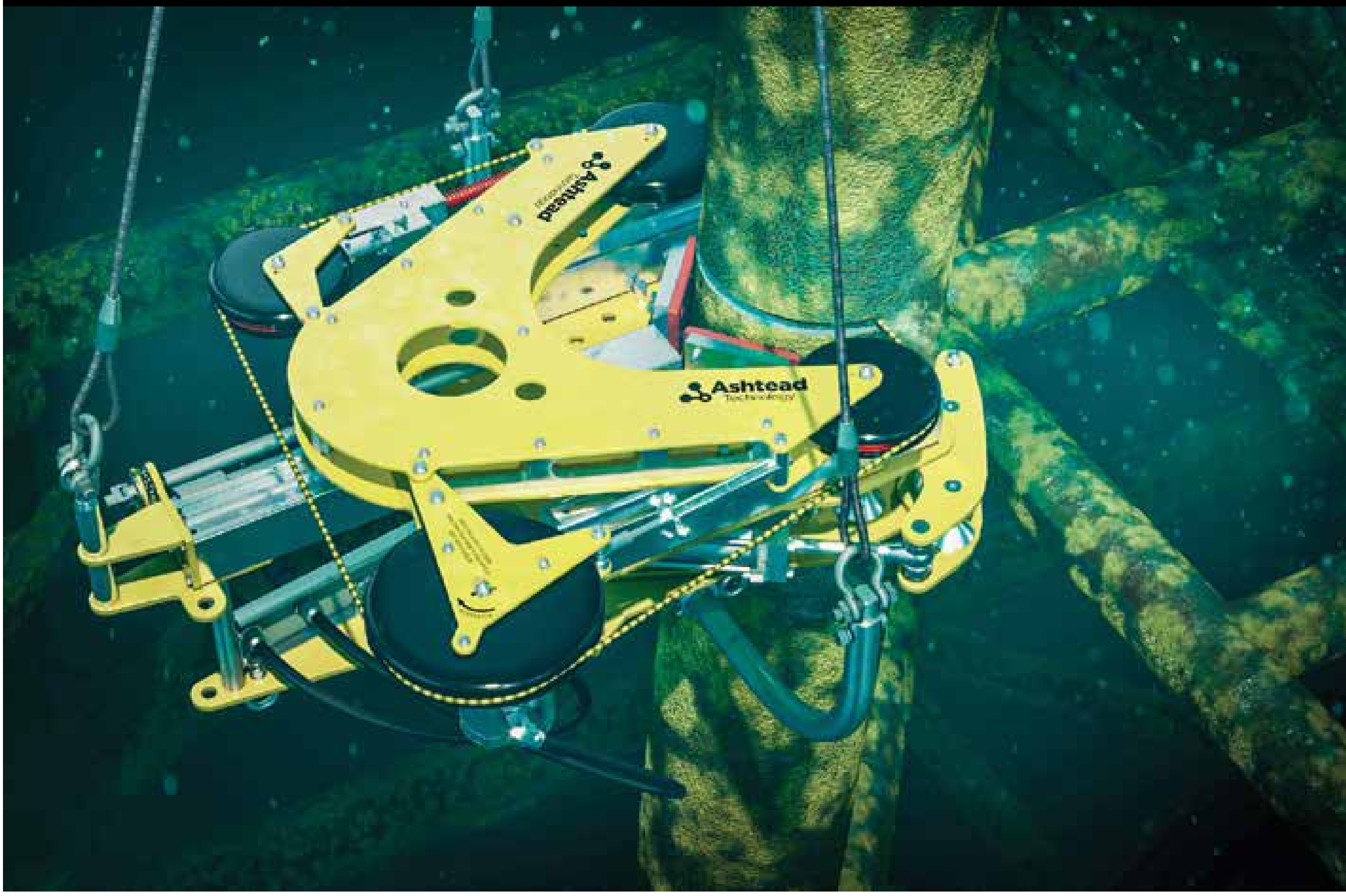
"Reach was a start-up, with a unique technology partner, and built the business from the ground up," Moran said. At the time "there were no coated cable platforms to buy. We purchased units, acquired the cable and built systems, but combined two existing wireline companies that had several years of operating history, equipment and personnel to rapidly expand the Reach platform."

Although much capital has been raised in the past five years, instability in the oil and gas market has made some of those funds hard to come by. "There is an incredible amount of capital raised and deployed in the sector, but there hasn't been much liquidity, so the investment community is slow to invest more capital. A priority for all is to create liquidity events for our investors," Moran said.

However, he thinks now is a great time for investing across the oil and gas service industry spectrum. With oil at $106 a barrel there was a lot of "poor market discipline" that led to paying too much for companies. Stability has improved, apart from a six-week downturn of 40% in the fourth quarter of 2018, he said.

Hastings' investments take advantage of efficiencies emerging in the service sector, but it still keeps an eye on what oil prices might mean for companies.

PHOTO COURTESY BUCKTHORN PARTNERS



Buckthorn-backed Ashtead Technology's Diamond Wire Saw, pictured above, is a remote-controlled subsea tool used to cut horizontal or vertical pipes, casings and structures.

"There is an upside and downside if oil hits those highs again." Moran said. Lower prices have driven efficiency through discipline and improvements in technology. "There is just as much profitability for operators and service companies with $60-a-barrel oil today as there was when it was $100 in some cases."

On one hand, if prices of the commodity go up, it "could create cost inflation across a lot of sectors." On the other hand, higher prices could help with liquidity by drawing institutional investors and others back in, a positive for private-equity and venture capital funds ready to exit.

Moran's advice for service companies looking for capital to expand is to "have an open dialogue. Talk to a friend who has done it with their company or contact a firm directly. Bringing on a partner is a wonderful way to reach a new level. It's an intense process, so learn all you can before starting."

Technologically different

Buckthorn Partners, based in London, views the oilfield service M&A market with an international eye. There are plenty of offshore and subsea service businesses in its portfolio, which occasionally buy start-ups or U.S.-based assets to help achieve their goals.

"We don't start at start-ups, but once we have a portfolio company established, then certainly we would give that company the opportunity to look at something and to invest in something small, and that was perhaps pre-profit that we thought we could commercialize within the portfolio business," said Nicholas Gee, partner at Buckthorn.

"I think the reality though is that we believe that technological differentiation is important to businesses, in a world where you've got essentially flat oil and gas prices, which are a proxy for the oilfield service flat activity," Gee said. "Post the crash in 2014 and 2015, activity, which is the major driver for oilfield services, has been definitely muted and slow to recover in almost all segments. Part of that muted recovery has naturally to do with oil and gas operating company activity. Also, it's because there is an awful lot of oilfield service capital chasing a reduced amount of business. A lot of that speaks to an overpopulated market, and the commodity end of that is competing very, very hard for what remaining revenues there are."

Because of that, technological differentiation is the key to survival in the service industry, especially in U.S. land-based oil and gas, "if you really want to play hard in that market. Otherwise it's really about whose capital can last longest," he said.

Gee said he has seen few private-equity investors in oilfield service-related technology internationally, "but over the past decade there has been a rise of corporate venturing from inside large companies such as Saudi Aramco and Chevron [Corp.], investing in

"I think the reality though is that we believe that technological differentiation is important to businesses, in a world where you've got essentially flat oil and gas prices, which are a proxy for the oilfield service flat activity," said Nicholas Gee, partner at Buckthorn Partners.

CAPITAL WITH EXPERIENCE

The story of Houston-based LiquidFrameworks' growth is told in the carpet and paint at the company's offices in Southwest Houston. As walls were removed with each growth spurt in the past decade, floor and wall colors tell the tale like tree rings.

As the tech start-up, assisting oilfield, industrial and environmental service companies, tops 100 employees, they are ready to move up to modern space on the 10th floor of the high rise, a move befitting a company that received nearly $100 million in private-equity funding from San Francisco's Luminate Capital at the end of 2018.

Its product, FieldFX, runs on tablets and laptops to enable the "quote to cash" process for efficiency and improved cash flow. "We have streamlined the day-to-day operations for field service professionals and have increased transparency across organizations by transforming previously paper- or Excel-based workflows," said LiquidFrameworks founder and CEO Travis Parigi.

FieldFX also works offline in the field and automatically uploads all data such as field tickets and workflow schedules when a connection is in range.

"I've been working in the oil and gas space for a while, and I saw the same problem with field ticketing over and over again," Parigi said.

He founded the company in 2005 with his own capital and pumped any money made back into the company and product development. "For seven years, we didn't make a dime. There were zeros across the board," Parigi said. He didn't pay himself for five years and funded development mostly from money that came from his consulting practice. "It was stressful to make payroll."

That all changed in 2012, when Houston Ventures came through for the start-up. Ultimately, the 15-year-old venture capital firm put $6 million into the company before it sold six years later to technology private-equity company Luminate Capital Partners.

LiquidFrameworks is currently hiring people to do implementation, software, development and sales with plans to be at more than 100 employees by 2020. The catalyst for the venture capital in 2012 was the need to move existing customers off a legacy process developed in Microsoft.net and to grow across all areas of the business.

LiquidFrameworks founder and CEO Travis Parigi founded the company in 2005 with his own capital and pumped any money made back into the company and product development.

In April 2018, the process of finding a new private-equity partner to scale everything up began. "I know a lot of people in oilfield service private equity in Houston, but we're really a software company that plays in the [oilfield service] space," Parigi said. That led them to investors in California that specialize in companies with subscription-based software.

"It's way more than the money. You're looking for capital that has some expertise attached to it," Parigi said. In this case, they gained a team with a deep expertise in enterprise software after fielding offers from several private-equity funds.

Parigi said he knows Luminate will eventually exercise its exit strategy and that his company will have a new financial partner. For now, he is taking advantage of the team's knowledge to fill any holes more quickly for customers and to possibly do acquisitions. "This private-equity round will facilitate much more growth," he said.

businesses that they think could be important to their business."

Other than new technologies, there are companies in Buckthorn's portfolio that differentiate themselves with other ways to remove cost from a process. For example, Buckthorn invested in Coretrax, a company that specializes in well-bore cleanup and well abandonment, in which there is an active market in the North Sea.

"Coretrax works very closely with its clients to see how it can reduce the cost and improve the effectiveness of the well-plugging process. That is a more customized approach. How can I maintain or improve the quality of the job while taking structural cost out of the operation? It's not about price," said Gee. The technology isn't new but improves functionality by saving time and improving effectiveness.

What does Buckthorn bring to the table besides money to the companies in its portfolio? A wealth of expertise in how to deploy that money in the best way is one example.

"We're not management, and that's an important distinction. For us, we work very closely with the management team, and we do play an active role at times in certain tasks.

"I think the first thing is that nobody knows the business like the management team," Gee said. The team at Buckthorn brings "the ability to have a conversation around what could be or what you want to do as a team. We act as a sounding board on an occasional basis and certainly at the outset in the period when we're looking to buy the business and get it set on its path.

"One of the things we bring is money. That's not particularly differentiating; a lot of people bring money. But if we want to invest to grow the business, then we need to be able to help the management team be explicit about where they want to go and how they can deploy capital effectively," Gee said.

The Buckthorn team also can help the company move into new geographies, especially when it or its personal network have contacts that can provide introductions or inside market knowledge, he said.

Another expertise Buckthorn brings to bear is M&A experience. "If the company hasn't done acquisitions before, but thinks there's a target that is a strategic fit with where they want to take the business, then we can absolutely roll our sleeves up and guide them through the detail of the M&A process, because it's not something that's done all the time," Gee said. □

CREATING A BETTER TYPE CURVE

Predicting well economics can be a matter of opinion when it comes to the method of estimating production. This engineer believes greater transparency would benefit users of type curves.

ARTICLE BY STEVE HENDRICKSON

Unconventional oil and gas reservoirs present challenging problems for reservoir engineers tasked with predicting the future performance of undrilled and recently completed wells. In conventional reservoirs, there are many analytical techniques that can be used, but unconventional reservoirs present too many complexities, variations and unknowns to apply these methods. In particular, the extent, geometry and conductivity of the fracture network are unknown, and perhaps impossible to model.

A common solution used by many engineers is to use production data from existing wells nearby as analogues for future wells to generate a type well profile (TWP), also known as a type curve. These type curves are an important bit of information that appears often in company presentations.

They are derived by selecting analogous wells, collecting their production history and key well information, and applying several mathematical adjustments to generate the prediction.

The adjustments include steps like estimating the future production of existing wells, normalizing the data to the first month of production, scaling the data to account for differences in lateral length or fracture design, and binning the data according to other parameters, such as formation or operator.

The scaled and normalized production can be used to generate average production forecasts for each of the bins.

Operators use TWPs to make investment decisions, prepare reserve estimates and to inform their investors about the expected economics of their undrilled wells. Many of them are disclosed to the public in investor presentations and public filings.

But although they are widely used, typically there is very little disclosure about how they are derived. There are no industry standards for the preparation of TWPs. Rather, they are created under many different circumstances, and engineers have personal opinions about the best way to prepare them. However, some of these opinions are certainly better than others.

A committee of the Society of Petroleum Evaluation Engineers is currently considering a solution through development of best practices for TWP generation. Ahead of that work, however, we at Ralph E. Davis Associates believe that improved disclosure about how a TWP was created would help users better understand the quality and reliability of the estimate. Disclosure would also provide more transparency to help users understand why different engineers in the same play and area generate different TWPs.

Recommendations for better TWPs

We recommend that TWPs presented to the public, to investors or to other consumers be accompanied by a voluntary disclosure that explains or addresses the following items. A sample disclosure is provided here as well.

- *Selection of analogous wells* – A list of API numbers, a map or a description of the area that includes the analogous wells. If certain well types, operators, vintages, etc., were used to filter the list of wells, that should be disclosed. If the list of API numbers is not disclosed, the number of wells used should be disclosed for each TWP. The goal is to make it clear which wells were used and why.
- *Source of the production data* – Describe whether the data came from internal or public sources and cite the source. If lease-level data has been allocated to individual wells, this should be disclosed.
- *Frequency of the production data* – Describe whether daily or monthly production was used. Some public data is reported quarterly, so if the monthly data is calculated from quarterly values, that should be disclosed.
- *Months of production history used* – The disclosure should discuss how many months of production data was available and used in the TWP. One approach would be to provide the minimum, maximum and median number of producing months.
- *Scaling and binning* – How was the production data for each analogue well scaled

to account for variations in relevant variables (lateral length, for instance), and how were the analogues binned to generate the TWPs?

- *"Project the average" or "average the projections"?* – Petroleum engineers may average the analogue wells' production-month-normalized historical data and then project the average into the future, or, they may project the future performance of the analogues and then average the wells' combined history/projection data. If projections were used, what engineering methods were used to make them? Engineers that have access to detailed production and pressure history data will sometimes employ additional reservoir engineering techniques to project the analogue wells before aggregating them.
- *Form of TWP equation* – What form of production rate vs. time equation (Arps analysis, etc.) is used to represent the type well?
- *TWP parameters* – What are the relevant parameters of the resulting TWP? For example, initial rate, initial effective decline, b-factor, minimum decline, final rate, well life, expected ultimate recovery, etc.
- *Reliability measures* – Statistical measures should be presented that allow the user to understand the uncertainty and reliability of the TWP. These could include confidence intervals around the TWP or standard deviation as a function of time (absolute or a percentage of the expected value).

There are many approaches to creating TWPs, and they often rely on very limited data. We believe that their users should have enough information to understand how they were made, and which specific parameters were involved, so they can make informed investment decisions. A thorough disclosure of the data and methods used would be a good first step, as outlined here. □

Steve Hendrickson is president of Ralph E. Davis Associates, an Opportune LLP company. He has more than 30 years of experience in engineering, acquisitions and operations. Before joining Opportune, he was principal of Hendrickson Engineering LLC, a licensed petroleum engineering firm focused on reserves assessment and property valuation. He began his career at Shell Oil as an engineer in Permian Basin water floods and CO_2 floods, and he was an executive at several E&P companies, including El Paso Production Co. and Eagle Rock Energy Partners LP.

Sample Type Well Profile

Analog Wells and Production

- Horizontal wells completed to the Lower Bone Spring formations (2nd Bone Spring sand, 3rd Bone Spring carbonate, 3rd Bone Spring sand)
- Wells located in the western portion of the Delaware Basin where cumulative GOR >2,000 scf/bbl
- Single-well leases only
- Monthly production from Drillinginfo; no pressure data
- n = 500 wells at month 1; 165 at month 60; most wells landed in the 2nd Bone Spring sand

Results for 1-mile Lateral

- Form of equation—Arps with terminal exponential decline
- Initial oil rate, bbl/mo – 3,400
- Initial decline rate (secant), % - 89
- B-factor – 1.45
- Final oil rate, bbl/mo (assumed) – 30
- Terminal exponential decline, % - 8
- Oil EUR, mbo – 216
- Average standard deviation (1-60 months) – 65% of predicted rate

Note: Data and results shown are for illustration only
Source: Opportune LLP

Methodology

- Historical production only; no individual well forecasts
- No binning for well spacing, vintage or completion design
- Monthly production was length normalized (per 1,000 feet of gross perforated interval (GPI) per DI)
- Length-normalized monthly production was normalized to month of first production to determine initial rate and 60-month cumulative
- Monthly production was normalized to peak production month and peak oil rate to determine initial decline and b-factor
- Values above were used to generate final TWP parameters in Aries normalized to 1-mile nominal lateral (average GPI=4,280 ft)

2018 STATISTICS

1,023 ATTENDEES | **21** SPEAKERS | **95** SPONSORS | **116** EXHIBITORS

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Nov. 5-6
Conference & Exhibition
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PLUS Nov. 5
Pre-Conference Water Forum
1:00PM to 4:00PM
Education Building | Midland County Horseshoe Pavilion

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AND Nov. 5
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*Founder, **Henry Petroleum**; Founder, **Henry Resources***
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MIKE FORD
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Caza Oil & Gas LLC

DAVID BLEDSOE
President
Henry Resources

JAY GRAHAM
CEO
Spur Energy Partners

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EDITED BY
DARREN BARBEE

Callon, Carrizo Get Engaged In $3.2 Billion Merger

CALLON PETROLEUM Co. agreed on July 15 to acquire **Carrizo Oil & Gas Inc.** in an all-stock transaction valued at $3.2 billion, gaining oil-weighted positions in the Permian Basin and Eagle Ford Shale.

The companies, both based in Houston, said in a joint release that the combination will create a premier oil-weighted mid-cap with peer-leading capital efficiency and cash margins. Callon, currently a Permian pure play, is set to have over 100,000 barrels of oil equivalent per day (boe/d) of pro forma production and 200,000 net acres in the Permian and Eagle Ford through its combination with Carrizo.

"We believe that Callon is the ideal partner for Carrizo," S.P. "Chip" Johnson, president and CEO of Carrizo, said in a statement on July 15. "Through our combination, we bring together a strong foundation of Midland Basin and Eagle Ford Shale assets and overlay a substantial Delaware acreage position and value proposition that will be unlocked through an integrated plan of large-scale program development."

Carrizo had previously faced activist investor demands that included exploring a merger or sale.

In a regulatory filing from early May, **Lion Point Master LP** disclosed a 5.1% stake in the company and said it acquired Carrizo's shares because it is undervalued and represented an "attractive investment opportunity." The firm also contended that shareholder value would be enhanced if Carrizo were to pursue a potential merger or broader sales to other operators.

Carrizo's asset base will add about 76,500 net acres in the Eagle Ford and 46,000 net acres in the Delaware within the Permian Basin. The company's production, as of the second quarter, totaled 67,200 boe/d, 64% of which was oil.

As a result of the broader scale and scope, Callon is expecting an accelerated free-cash-flow generation and enhanced credit profile. Additionally, the companies have identified synergies from the combination generating a total of $850 million in net present value.

Estimating $35,000 per flowing boe, the $3.2 billion price tag of Callon's acquisition of Carrizo translates to a PDP value of about $2.35 billion, according to Mark Lear, equity analyst with **Jefferies LLC**. At that price, undeveloped acreage was valued at about $850 million.

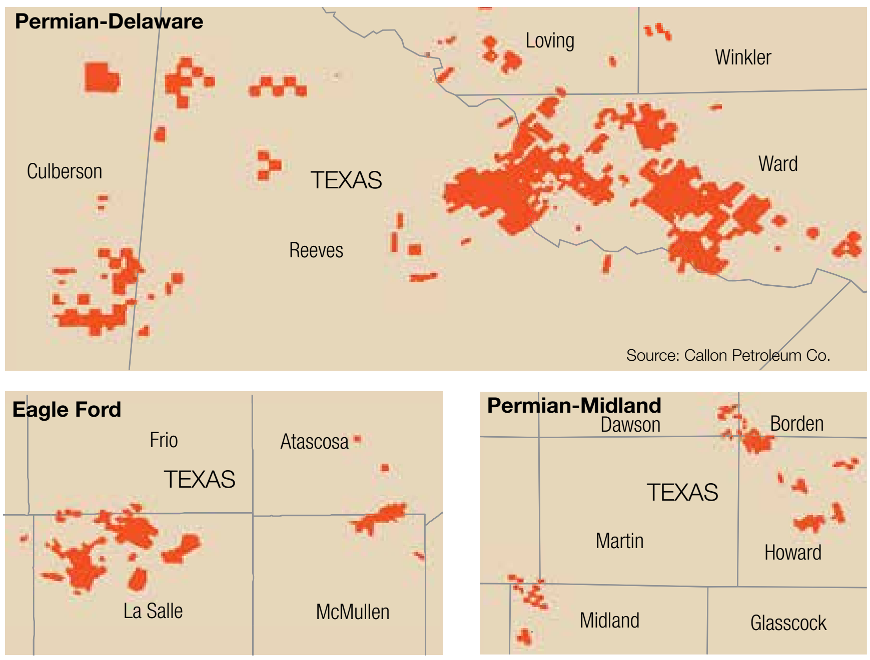
"Placing $2,000 per acre on the Eagle Ford (about $150 million), we estimate [Carrizo's] remaining Delaware (some of which stretches out on the Culberson/Reeves County line) sold for about $15,000 per acre, including all Delaware acreage," Lear wrote in a July 15 research note.

Analysts with **Capital One Securities Inc.** said the transaction values Carrizo at $13.12 per share, a 25% premium to the closing price of its stock on July 12.

The analysts also noted that the all-stock deal continues a theme of corporate M&A that accelerated last year as multiple E&Ps agreed to merge—topped by **Concho Resources Inc.**'s $9.5 billion acquisition of **RSP Permian**.

"We think the relative performance of [Callon's] stock in the coming days, weeks and months will be critical in determining whether or not more corporate deals get consummated in the space, especially among SMID-caps," Capital One analysts wrote in a July 15 research

Callon-Carrizo Pro Forma Asset Overview



note. "If the market rewards [Callon], given the expected $100- to $125 million of synergies and the accretion that the company anticipates, we think it will be more likely that other 'would-be acquires' will pursue consolidation."

Shares of Callon were trading at $5.38, down roughly 16% by mid-morning. Meanwhile, Carrizo was up 2% at $10.72.

Following the close of the transaction, Carrizo shareholders will own 46% of the combined company.

Under terms of the transaction agreement, Carrizo shareholders will receive a fixed exchange ratio of 2.05 Callon shares for each share of Carrizo common stock. The transaction value is comprised of $1.25 billion of equity plus the assumption of roughly $1.96 billion of net debt and preferred stock, according to Capital One.

The transaction, which requires approval from shareholders of both companies, is expected to close during fourth-quarter 2019.

Upon closing, a new board of directors will consist of 11 members, including Callon's eight current board members and three to be appointed from the Carrizo board. The combined company will be led by Callon's executive management team and will remain headquartered in Houston.

Joe Gatto, president and CEO of Callon, said in a statement on July 15: "Together with Carrizo, we will accelerate our free cash flow, capital efficiency and deleveraging goals through an optimized model of large-scale development across the portfolio. … With a deep inventory of high rate-of-return well locations in well-established areas and substantial upside opportunities for organic inventory delineation, we will be able [to] drive differentiated growth deploying our life-of-field development model for many years to come."

Callon-Carrizo Merger, Pro Forma

Net acres	200,000
Permian Basin acres	120,000
Eagle Ford Shale acres	80,000
Operated locations	2,500
First-quarter production (boe/d)	102,300
Percent oil production	71%
2020E rigs	9
LTM adjusted EBITDA	$1.2 billion

Source: Callon Petroleum Co.

Based on initial plans for capital allocation within the combined portfolio, Callon forecasts its free-cash-flow breakeven crude oil price to progress to under $50 West Texas Intermediate by 2021, according to a joint company press release.

Callon's pro forma acreage footprint includes about 2,500 total gross horizontal drilling locations. The company plans to expand large-scale development with "simultaneous operations" primarily in the Permian Basin. This will be balanced by shorter cycle and less capital-intensive projects in the Eagle Ford.

Combined, Callon is expecting a total of nine to 10 drilling rigs and three to four completion crews working during the course of 2020, predominantly in the Permian Basin.

J.P. Morgan LLC is exclusive financial adviser to Callon, and **Kirkland & Ellis LLP** is serving as its legal adviser. Additionally, **JPMorgan Chase Bank NA** and **BofA Merrill Lynch** provided underwritten financing to Callon to support the transaction. Carrizo's financial advisers are **RBC Capital Markets LLC** and **Lazard** with **Baker Botts LLP** serving as legal adviser.

Upon closing, the combined company is anticipated to have pro forma liquidity of more than $1 billion under a new underwritten credit facility combined with no near-term debt maturities.

—Emily Patsy

Osaka To Become First Japanese Shale Owner

OSAKA GAS CO. Ltd. agreed on July 29 to buy Houston-based independent **Sabine Oil & Gas Corp.** as the Japanese company looks to U.S. shale for growth.

The transaction, which still requires government approvals, will mark the first time a Japanese company has purchased a U.S.-based shale gas developer, Osaka Gas said in its release.

Sabine, a former publicly traded E&P which emerged as a private company after filing for bankruptcy in 2016, operates in the Haynesville and Cotton Valley shale plays in East Texas. According to a report by Reuters, the sale of Sabine is worth $610 million.

The acquisition of Sabine includes an acreage position in East Texas, which Osaka Gas had acquired a 35% interest in for about $144.5 million last year. Since acquiring its stake in Sabine's East Texas position, Osaka said, "The wells have been producing more than expected volumes, generating stable cash flow."

Sabine's position totals 175,000 net acres and about 1,200 wells in Harrison, Panola, Rusk and Upshur counties, Texas. Production from the acreage is 210 million cubic feet equivalent per day of shale gas, according to the company release.

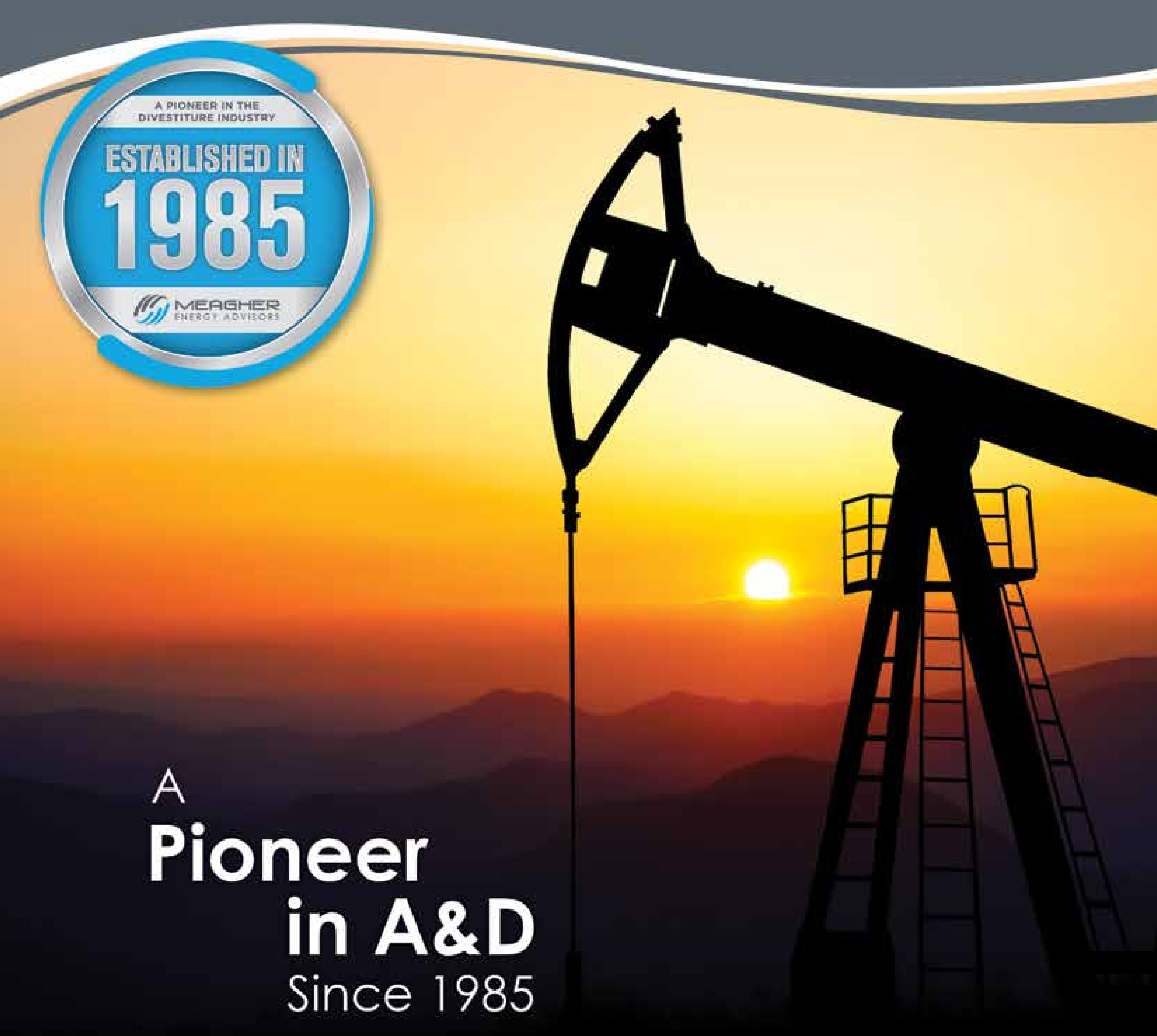
Osaka Gas said the acquisition will support its long-term goal to expand its global energy businesses "along the energy value chain from upstream to mid- and downstream business, including LNG trading."

In the U.S., Osaka Gas' core businesses comprise the Sabine shale gas project, **Freeport LNG** and independent power producer projects.

Under its long-term business strategy, Osaka Gas plans to boost its earnings from overseas to account for one-third of its total recurring profit in the business year to March 2031, up from 9% in the year ended March this year, according to the report by Reuters.

Vinson & Elkins LLP advised Osaka Gas on its acquisition of Sabine, led by partner Shay Kuperman with assistance from associates Josh Rocha and Tara Tegeleci. Meanwhile, **Hunton Andrews Kurth LLP** represented Sabine.

—Emily Patsy



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Occidental's $1.5 Billion JV Jumpstarts Midland Basin Development

OCCIDENTAL PETROLEUM Corp. is teaming up with Colombia's **Ecopetrol SA** to develop assets in the Permian's Midland Basin—where it currently has minimal activity—in a joint venture (JV) worth up to $1.5 billion.

Nearing completion of its takeover of rival **Anadarko Petroleum Corp.**, Occidental said July 31 alongside its second-quarter results that it had entered into definitive agreements with Ecopetrol to form the JV.

"As we move toward closing the acquisition of Anadarko and combining our two companies into an innovative and sustainable energy leader, we remain well-positioned to drive profitable growth and return excess cash to our shareholders," Occidental CEO Vicki Hollub said on July 31, adding that the Ecopetrol JV is a further example of the company's commitment to "enhancing our value proposition."

The JV covers 97,000 net acres of Occidental's Midland Basin properties and will allow the company to accelerate its development of the Permian sub-basin.

Occidental's acreage is located in the heart of Midland Basin in West Texas, including all of the company's holdings in Midland, Martin and Howard counties, according to an Aug. 1 research note by **Capital One Securities Inc.** analysts.

As part of the partnership, Ecopetrol will purchase a 49% interest in Occidental's current acreage Midland position for $750 million in cash at closing plus $750 million of carried capital. During the carry period, Ecopetrol will pay 75% of Occidental's share of capex. Meanwhile, Occidental will operate the JV, owning the remaining 51% interest, and retain all existing production.

Capital One estimated the JV transaction is worth about $31,500 per acre, which is higher than the firm's $22,000 per-acre valuation for Occidental's leasehold. Occidental holds about 200,000 Midland Basin acres. "The JV acreage is likely better quality on average compared to [Occidental's] entire [Midland Basin] position," Capital One analysts said.

Maynard Holt, CEO of **Tudor, Pickering, Holt & Co.** (TPH), which served as Occidental's exclusive financial adviser on the transaction, called the deal "a true win-win" in an emailed statement on July 31.

"In this unique transaction between existing long-time partners in Colombia, Occidental will benefit from cash proceeds today as well as funding for accelerated development on a core Midland Basin position," Holt said, adding that Ecopetrol will also benefit from lessons learned in the Permian.

"While Ecopetrol is able to gain exposure to the leading North American oil basin, with a great partner, and also advance its expertise in shale development," he continued.

Michael Whitney, an analyst from **Wood Mackenzie**'s corporate research team, added that he sees ventures similar to Occidental's partnership with Ecopetrol becoming more common as the Permian Basin matures.

"Strategies of this nature should become more commonplace in a world of stockpiled Permian inventory with drilling locations that wouldn't otherwise fit into development plans for upwards of a decade," Whitney said in an emailed statement on Aug. 1.

Shearman & Sterling LLP advised Ecopetrol in the deal. The companies are planning on closing the JV transaction around year-end.

Meanwhile, Occidental is expecting to close its combination with Anadarko Petroleum shortly after Anadarko's shareholder vote on Aug. 8, Hollub said during the company's earnings call.

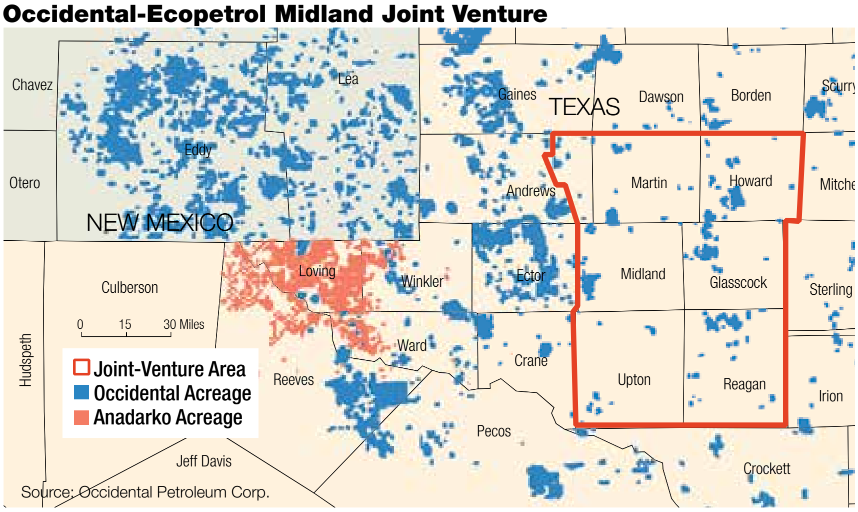
Occidental has already reached an agreement with **Total SA** to sell Anadarko's Africa assets to the French oil major for $8.8 billion. The company has also been rumored to be exploring the sale of **Western Midstream Partners LP**, the midstream MLP that Occidental will take over from Anadarko.

Hollub wouldn't comment on the fate of Western Midstream during Occidental's earnings call on Aug. 1. Though, she did add that Occidental has seen a lot of interest in the Anadarko assets.

"The reason we're so confident about our asset divestitures is we have a lot of incoming calls about various things, and so we'll be able to high grade what we want to do over time," she said.

—Emily Patsy

Occidental-Ecopetrol Midland Joint Venture



Scoop, Stack, Sell: Apache Exits Oklahoma Position

APACHE CORP. has exited its Oklahoma shale position in divestitures with two private-equity-backed E&Ps as the Permian Basin remains Apache's primary focus in the U.S.

Last week, the Houston-based oil and gas company said it completed the sale of noncore assets that reflected Apache's exit from the western Anadarko Basin and Scoop/Stack play. The divestitures were made through two separate transactions—one in May and the other in July—and comprised of $612 million in net proceeds.

Although Apache didn't disclose the buyers, on July 23**, Presidio Petroleum LLC** said it purchased the western Anadarko position—its first add-on acquisition since **Morgan Stanley Energy Partners**' initial investment in May 2018.

Oklahoma City-based **Red Wolf Natural Resources LLC** was the buyer of Apache's earlier divestiture that closed in May, according to a report by **BMO Capital Markets**.

In its first-quarter results release, Apache reported more than $300 million worth of asset sales that CEO John Christmann said were mostly located in the company's Scoop/Stack position. During the company's earnings call on May 2, Christmann explained that Apache's decision to exit the Scoop/Stack was driven by a strategy of what's going to attract capital in the long term.

"We did not see the Scoop/Stack as an area where we would be putting capital," he said, also noting that "if there's an opportunity for somebody else to own those and create value by purchasing those, then we're not afraid to do that."

On July 18, Apache said production from the divested assets averaged 33,000 boe/d in the first quarter of 2019, about 90% of which consisted of natural gas and NGL. The company anticipates reporting production of about 32,000 boe/d from the Midcontinent-Gulf Coast region for second-quarter 2019.

The acquisition from Apache marked Red Wolf's first transaction since forming in February with an equity commitment from Dallas-based **Pearl Energy Investments**. The company's purchase comprised of roughly 56,000 net acres and associated production in Oklahoma's Scoop, Stack and Merge plays as well as the broader Anadarko Basin, according to a May press release by Red Wolf.

BMO estimated the value of the Red Wolf transaction at $245 million.

Headquartered in Fort Worth, Texas, Presidio has assets located in the western Anadarko Basin of Texas, Oklahoma and Kansas. The company had previously acquired the western Anadarko position of **Midstates Petroleum Co. Inc**. for about $58 million last year.

Presidio's purchase from Apache included oil and natural gas producing properties in the western Anadarko Basin of Texas, Oklahoma and Kansas. Apache's field operations team will also join the Presidio team as part of the transaction, according to the company press release.

Sidley Austin LLP represented **Morgan Stanley Energy Partners** and its portfolio company Presidio in the acquisition from Apache. The law firm's deal team was led by partner Marc Rose. BMO acted as left lead arranger and administrative agent for Presidio on the transaction.

—Emily Patsy

California Resources Lands $500 Million JV

CALIFORNIA'S LARGEST OIL and gas producer could receive up to $500 million as part of a new JV to develop one of the most historically productive fields in the U.S.

California Resources Corp. (CRC) formed the JV with **Colony HB2 Energy**, an investment firm, which agreed to fund the development of CRC's flagship Elk Hills Field, the Los Angeles-based company said July 23 in a press release. Colony HB2 Energy is the energy investment management platform of **Colony Capital Inc.**, a Los Angeles-based firm with holdings in the healthcare, industrial and hospitality property sectors.

The partnership follows a strategy by CRC to pursue JVs that CFO Mark Smith told attendees of the Bank of America Merrill Lynch Energy Credit Conference in June would allow the company to fund exploration and development despite reducing its budget to stay within cash flow.

"Another key aspect of our strategy is the thoughtful use of relationships, particularly joint ventures," Smith said, according to a transcript of the presentation provided by CRC. "They allow us to accelerate our value and participate in the growth wedge, to de-risk our inventory."

CRC currently has ongoing JV partnerships with **Benefit Street Partners LLC**, **Ares Management LP** and **Macquarie Infrastructure and Real Assets**.

As part of a pre-approved development plan for Elk Hills Field, CRC will drill about 275 wells, of which Colony has agreed to fund 100%. Located within the San Joaquin Basin, 20 miles west of Bakersfield in Kern County, Calif., Elk Hills is the largest natural gas and NGL field in California, generating over half of the state's natural gas production, according to CRC's website.

Colony has initially committed to invest $320 million, which could be increased to $500 million. The capital will be invested over about three years to cover multiple development opportunities throughout Elk Hills Field.

"This is the largest joint-venture capital commitment to date for CRC, and the terms reflect the sizable project inventory we have established at Elk Hills," Todd Stevens, president and CEO of CRC, said in a July 23 news release. "This partnership also provides additional flexibility to aid in our deleveraging efforts through growing our production and cash flow."

In exchange for funding 100% of the development wells, Colony will earn a 90% working interest. CRC said its working interest will revert to 82.5% from the initial 10% upon Colony achieving an undisclosed, agreed-upon return.

Lastly, Colony will also receive warrants to purchase up to 1.25 million shares of CRC stock with a $40 strike price upon funding its capital obligations.

Tom Barrack, chairman and CEO of Colony Capital, noted that the CRC investment is a milestone event for Colony in the establishment and growth of the firm's new energy investment management platform.

Peter Eichler, managing director of Colony Capital, also added, "CRC's operational expertise, technical understanding and substantial infrastructure in the San Joaquin Basin are unparalleled, and we look forward to building upon decades of profitable investment by CRC in Elk Hills Field over the long term."

—Emily Patsy

Tom Ward Strikes Again In Western Anadarko Basin

MACH RESOURCES LLC, the independent oil and gas producer led by industry veteran Tom Ward, entered the western Anadarko Basin with two acquisitions on July 15.

The acquisitions represent the first transactions within a new partnership between the Oklahoma company and Houston-based private-equity firm **Bayou City Energy Management LLC** (BCE) named **BCE-Mach II LLC**. The pair previously formed BCE-Mach LLC in early 2018 to focus on the development of Mississippi Lime assets across Oklahoma and Kansas.

Ward said Mach's new partnership with BCE will allow the company to expand its strategy into the Anadarko Basin, starting with the two initial acquisitions comprised of producing properties in Western Oklahoma and the Texas Panhandle.

Throughout his career, Ward has formed and led several oil and gas companies including shale pioneer **Chesapeake Energy Corp.**, which he co-founded in 1989 alongside Aubrey K. McClendon. He also went on to start **SandRidge Energy Inc.** in 2006 and **Tapstone Energy LLC** in 2013.

Ward formed Mach Resources in January 2017 to pursue "high-return, low-cost" projects. BCE, led by Will McMullen and Mark Stoner, agreed to link up with Ward's Mach Resources in March 2018 to initially acquire, explore and develop oil and gas assets in Oklahoma and Kansas.

"Mach looks forward to continuing its partnership with BCE via BCE-Mach II with a focus on acquiring proven cash flow using low leverage as opposed to the industry standard of solely relying on growth at all costs through the drillbit," Ward said in a statement on July 15.

On July 15, BCE-Mach II agreed to acquire the western Anadarko properties in separate transactions with different unnamed sellers. The terms of the agreements, both expected to close in September, were not disclosed.

The first agreement included assets in Beckham, Custer, Dewey, Roger Mills and Washita counties, Okla., and Hemphill and Roberts counties, Texas. Meanwhile, the second agreement is comprised of properties across 32 counties in Oklahoma and seven counties in Texas.

Mach's first partnership with BCE will continue to own, operate and acquire properties in the Mississippi Lime, according to the company press release.

McMullen, BCE founder and managing partner, said he sees the role of the two BCE-Mach partnerships as a consolidator in the Midcontinent region.

Upon closing its initial western Anadarko acquisitions, the two BCE-Mach partnerships will have closed on five transactions spanning the Mississippi Lime, Stack, Merge, Scoop and western Anadarko Basin plays.

In total, McMullen said these assets represent 365,000 net acres, which are 98% HBP. Production is roughly 30,000 net boe/d, 49% liquids, he added.

"We believe that excellence in operations combined with an under-levered balance sheet and future sponsorship support will continue to drive our ability to be a regional consolidator," McMullen said in a statement on July 15. "And we look forward to achieving this end with Tom Ward's team."

—Emily Patsy

Kimmeridge Set To Dominate Delaware Basin Minerals

KIMMERIDGE ENERGY Management Co. LLC is on track to create the largest pure-play mineral and royalty company by net royalty acres in the Delaware Basin.

The private-equity firm entered agreements on July 18 to merge its mineral company with **Desert Royalty Co. LLC**, a Midland, Texas-based independent oil and gas company focusing on the acquisition and management of mineral and royalty properties for more than 25 years.

The combined company—to be known as **Desert Peak Minerals**—is expected to be positioned as a "logical consolidator" of Delaware Basin mineral and royalty assets, according to the firm's joint press release with Desert Royalty.

"The creation of a large mineral company with a singular focus on the Delaware Basin is the most interesting development I have observed in 33 years in the mineral business," Kyle Stallings, founder and CEO of Desert Royalty, said in a news release. "Desert Royalty is honored to have played a role in the conception of Desert Peak."

Desert Royalty has completed several thousand transactions since 1990, according to its website. The company currently owns and manages over 100,000 net royalty acres nationwide, over 30,000 of which are located in the Delaware Basin.

Though the financial details of the combination were not disclosed, Desert Peak's position will total over 70,000 net royalty acres on a 1/8th royalty-adjusted basis across eight counties in West Texas and southeast New Mexico. At closing, the companies expect production to average about 8,000 boe/d.

Kimmeridge itself was founded in 2012 by Ben Dell, Neil McMahon and Henry Makansi to focus on investments in unconventional oil and gas assets.

"Against the backdrop of a challenging environment for E&P, minerals provide a compelling mix of organic growth and free-cash-flow generation," Dell said in a July 18 statement. "Desert Peak will have our full support as they execute on their strategic growth plans."

Headquartered in Denver, Desert Peak will be led by CEO Chris Conoscenti and the Kimmeridge management team.

Conoscenti believes Desert Peak will benefit from its focus on the Delaware Basin.

"As is widely recognized, the Delaware Basin is the leading oil and gas producing region in the United States, combining the best rates of return for operators, established and expanding takeaway infrastructure and oilfield services capacity, and a favorable regulatory environment," he said in a statement.

The companies noted that the benefits of the Delaware Basin are evident by the 259 rigs currently running in the Permian sub-basin, which represents 27% of all rigs running onshore in the U.S.

Sidley Austin LLP was legal adviser to Kimmeridge for the transaction led by partner Jim Rice. **Tudor, Pickering, Holt & Co.** is Desert Royalty's exclusive financial adviser, and **Kirkland & Ellis LLP** is serving as the company's legal adviser.

Desert Royalty is currently in the process of deploying its sixth mineral fund and intends to raise a seventh mineral fund from its existing private investor base in 2020.

—Emily Patsy

Range Trims Appalachia Footprint With $634 Million In Sales

RANGE RESOURCES CORP. is selling a chunk of its prized Appalachia footprint as the oil and gas producer works to strengthen its business through asset sales.

In total, the Fort Worth, Texas-based company said July 19 that it had agreed to sell assets in three separate transactions for combined proceeds of about $634 million. Sale processes to monetize additional noncore assets remain underway, according to the Range press release.

Franco-Nevada Corp. was the buyer of overriding royalty interests (ORRI), according to law firm **Porter Hedges**, which is representing the company in its $300 million purchase of the assets. The identity of the remaining buyers hasn't been disclosed.

Proceeds from the asset sales will be used to reduce company debt. Range CEO Jeff Ventura expects the company's debt reduction over the past year will total $1 billion by the close of the transactions.

"Over the past year, Range will have generated asset sale proceeds that equate to approximately 75% of our current market cap through the divestment of assets with a net impact to annual cash flow of less than 4%," Ventura said in a statement on July 19.

Two of the asset sales comprised separate agreements for the sale of a 2% proportionately reduced ORRI in 350,000 net surface acres in southwest Appalachia for gross proceeds totaling $600 million. The remaining transaction was a $34 million sale of certain nonproducing acreage in Pennsylvania that Range closed in June.

The nonproducing acreage sale included about 20,000 acres in northwest Armstrong County, Pa.

The sale of the ORRI properties applies to existing and future Marcellus, Utica and Upper Devonian development on the subject leases and excludes shallower and deeper horizons. Range said net production from the properties in the first quarter was about 1.9 billion cubic feet equivalent per day (Bcfe/d). The company also projects annualized cash flow associated with ORRI to be roughly $48 million, based on first-half 2019 pricing.

The series of transactions follow a sale by Range in October 2018 of a 1% ORRI in its Washington County, Pa., leases for gross proceeds of $300 million. According to Ventura, the asset sales on July 19 once again highlight the significant intrinsic value of Range's assets

"Harvesting value from our asset base through these divestitures coupled with capital-efficient operations positions Range for future success through commodity price cycles," he added.

Combined proceeds from the asset sales is expected to reduce Range's total debt by 17%. The company also anticipates its annual interest expense to decline by roughly $30 million.

Range expects to close the ORRI transactions in July. The transactions have an effective date of March 1.

J.P. Morgan Securities LLC was financial adviser to Range on the overriding royalty sales**. Vinson & Elkins LLP** (V&E) provided the company with legal advice. The V&E corporate team was led by partner Bryan Loocke with senior associate Tan Lu and associate Josh Rocha. The Porter Hedges team, representing Franco-Nevada, was led by Jeremy Mouton and James Thompson.

—Emily Patsy

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TRANSACTION HIGHLIGHTS

LOWER 48, INTERNATIONAL

■ **Occidental Petroleum Corp.** completed its acquisition on Aug. 8 of rival **Anadarko Petroleum Corp.** after Anadarko shareholders voted overwhelmingly in support of the sale.

The companies had agreed to the transaction, valued at $55 billion (including debt), in May following a bidding war with **Chevron Corp.**

The acquisition of Anadarko adds a portfolio of international assets, including a prime position in the Permian Basin, to Occidental's footprint. Occidental CEO Vicki Hollub expects to deliver at least $3.5 billion annually in cost and capital spending synergies from the combination, she said in a company press release.

"With Anadarko's world-class asset portfolio now officially part of Occidental, we begin our work to integrate our two companies and unlock the significant value of this combination for shareholders," Hollub said.

Hollub has also lined up asset sales and financings, including a $13 billion debt offering on Aug. 6, to support Occidental's multibillion-dollar acquisition of Anadarko.

About 99% of Anadarko shareholders voted in favor of the deal. Occidental shareholders didn't vote due to a $10 billion financing agreement with Warren Buffett's **Berkshire Hathaway Inc.**—a move that has drawn the ire of activist investor Carl Icahn, who owns 4.4% of Occidental. Icahn has launched a proxy campaign to replace four Occidental directors.

HAYNESVILLE

■ **Comstock Resources Inc.** wrapped up its $2.2 billion cash and stock purchase of Haynesville operator **Covey Park Energy LLC** on July 16, creating a North Louisiana and East Texas position stretching across about 374,000 net acres.

The acquisition of the **Denham Capital**-backed company, supported by an investment from Dallas Cowboys owner Jerry Jones, creates a basin leader in the Haynesville Shale. As a result of the combination, Comstock's will average net production of about 1.1 Bcfe/d. The company also has assets in North Dakota.

Comstock funded the Covey Park acquisition through a combination of debt under a new $2.5 billion revolving credit facility and its investment from Jones.

Comstock's management team will continue to be led by M. Jay Allison as board chairman and CEO and Roland Burns as president and CFO. Covey Park co-CEO John Jacobi, along with Denham Capital managing partner Jordan Marye, will also join the Comstock board of directors.

BARNETT SHALE

■ **Harvest Oil & Gas Corp.** agreed on July 30 to exit the Barnett through a divestiture of its position in the North Texas shale play with sale proceeds earmarked for shareholder returns.

An undisclosed buyer agreed to buy the Barnett Shale assets from Harvest, a Houston-based company formerly tied to **EnerVest Ltd.**, for $72 million. The sale, which Harvest said includes "substantially all of its interests in the Barnett Shale," follows a series of divestitures made by the company since its successor emerged from bankruptcy last year.

According to an investor presentation from March, Harvest's Barnett Shale acreage covers 164,276 gross (40,658 net) acres across North Texas. The company's working interest in the position was roughly 28%, of which over 90% was nonoperated.

Harvest's Barnett Shale production for the first three months of 2019 averaged 55.6 MMcfe/d, the company said in its July 30 release.

ARKOMA BASIN

■ **Encana Corp.** is selling off its Arkoma Basin position as the Calgary, Alberta-based company continues to digest the slew of assets it acquired earlier this year from its multibillion-dollar deal for U.S. independent **Newfield Exploration Co.**

An undisclosed company agreed to buy the Arkoma assets, comprising roughly 140,000 net acres of leasehold in Oklahoma, Encana said in a July 8 release. Production from the assets is currently about 77 MMcfe/d, 98% of which is natural gas. **BMO Capital Markets** said **NextEra Energy Inc.** was the buyer.

Encana said it will receive $165 million in cash from the Arkoma exit, which is in line with estimates made by analysts with **Tudor, Pickering, Holt & Co.** (TPH) in a research note on July 8. The TPH analysts also noted that the Arkoma sale represents the second of Newfield's legacy assets to go.

GOM

■ Japan's **Inpex Corp.** entered a deal on July 26 to purchase U.S. Gulf of Mexico (GoM) assets from **Anadarko Petroleum Corp.**, which itself was acquired by **Occidental Petroleum Corp.** on Aug. 8.

The Tokyo-based company said its U.S. subsidiary reached an agreement with Anadarko to acquire a participating interest in Keathley Canyon and Walker Ridge blocks located roughly 236 miles off the coast of Louisiana. The terms of the transaction have not been disclosed.

Inpex already has plans to drill an exploration well at an early stage in partnership with the operator, Anadarko, subject to management approvals and further evaluation work, the Japanese E&P said.

In the sale to Inpex, Anadarko is divesting a 40% participating interest in Keathley Canyon blocks 921 and 965 and Walker Ridge blocks 881 and 925. As part of the agreement, Anadarko will retain operatorship with a 60% interest remaining in the blocks.

Inpex is Japan's largest E&P company. The company said it ranks as a mid-tier E&P player, just behind the world's oil majors.

VACA MUERTA

■ **ConocoPhillips Co.** is teaming up with German oil and gas producer **Wintershall Dea GmbH** in Argentina's massive Vaca Muerta Shale through a new joint venture.

On July 25, Wintershall Dea said the companies had signed a sales and purchase agreement to jointly develop certain blocks within the Vaca Muerta fairway in the central Argentine province of Neuquén. ConocoPhillips will acquire a 45% interest share in the Aguada Federal block and a 50% share in the nearby Bandurria Norte block. The terms of the transaction weren't disclosed.

Wintershall DEA, which formed earlier this year through the merger of Wintershall Holding GmbH and DEA Deutsche Erdoel AG, has been active for more than 20 years in the Argentinian province of Neuquén, where the blocks are located. Still, the company is hoping to glean knowledge from ConocoPhillips' unconventional oil and gas experience in U.S. shale through the new partnership, said Thilo Wieland, a member of Wintershall Dea board responsible for Latin America.


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KILLING THE GOOSE THAT LAYS THE GOLDEN EGG

RICHARD MASON
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Imagine a business where you could improve customer efficiency every quarter, produce demonstrable evidence of performance gains for the customer despite economic headwinds and enable customers to transition from capital outspend as far as the eye can see to a sustainable business that self-funds development—the standard capitalist business model.

Now imagine seeing demand for your services decrease—along with pricing. What kind of economic theory is that? Whatever you name the phenomenon, it is now the status quo for oilfield services, which have been instrumental in improving capital efficiency for E&Ps, winnowing down finding and operational costs, and reducing discreet costs for services that account for more than half the savings gains E&Ps have experienced in wellbore construction.

Engineers can draw up any plan in an E&P reservoir stimulation department. But wealth is not created in oil and gas until the crews on the drilling rigs and pressure pumping units show up at the well site to make it happen in the field.

The reward for the oilfield service sector to date? Nonparticipation in the financial gains that have accrued to their customers. In a sense, the E&P sector today is living off the depreciation for pressure pumping equipment and for land drilling rigs.

The current sector in the crosshairs for this unbalanced economic partnership is that of the well stimulation firms, judging by second-quarter 2019 earnings calls. This, of course, is not a first-time event in oil and gas. Consider the stunning decline in drilling days where more than a month has been shaved out of the equation in every shale basin during the past four years, even as laterals have increased in length. Those gains are still accruing in the mid-single digits percentage-wise across the oil patch.

So special kudos to the land drillers and their rigs with omni-directional walking systems, directional drilling improvements, work process automation and exceptional safety performance. It now requires less than half the rigs necessary back in 2014 to generate more oil and gas in the U.S. The equipment and the crews who operate it have kept E&Ps economically relevant during the commodity price collapse in the shale era.

The payout for drillers? Flat rig rates for super-spec drilling rigs—now below the 2014 peak for lesser technology rigs—and softening demand for drilling services. The horizontal rig count has declined year-to-date and is on track to drop 10% in 2019. Rare indeed is the E&P sector today, particularly in the publicly held sector, that is not releasing rigs in the second half of 2019.

Now the demand decline for services is spreading to the well stimulation sector with multiple E&Ps reducing frack crews, particularly in Appalachia and the Midcontinent, while promising double-digit production volume increases in a world dangerously close to systemic oversupply in oil, gas and NGL output. Think about this: military hostilities in the Strait of Hormuz, the collapse in Venezuelan oil production and routine disruption in Libya's rebel-torn oil sector. All of this is underway, and oil prices are declining.

The deteriorating economic environment for well stimulation firms is evolving despite an increase in stages completed per day and the ensuing increase in hours spent pumping per stage. Well completion cadence set new records in June, reaching 50 wells daily. Credit the bundling of wellsite services such as wireline and well stimulation, the cost-reducing move to dual fuel prime movers, and improvements in perforating technology.

The pressure pumpers have done yeoman's work in working themselves out of a job. Pressure pumpers are slowly stacking equipment and letting crews go as retained earnings per fleet fall. Frankly, stimulation providers find that it makes better economic sense to stack equipment than to allocate the $2- to $5 million annually in maintenance capex.

Meanwhile, investment in new technology, such as electric frack fleets, remains sporadic.

The performance improvements provided by the oilfield service sector are responsible for more than half of the well construction cost reductions that E&Ps identify on their desperate open-field run toward sustainable free cash flow.

Finding some way for oil services to participate equitably in performance improvements, even in a sere budgetary environment, will avoid the old idiom about killing the goose that lays the golden egg.

EASTERN U.S.

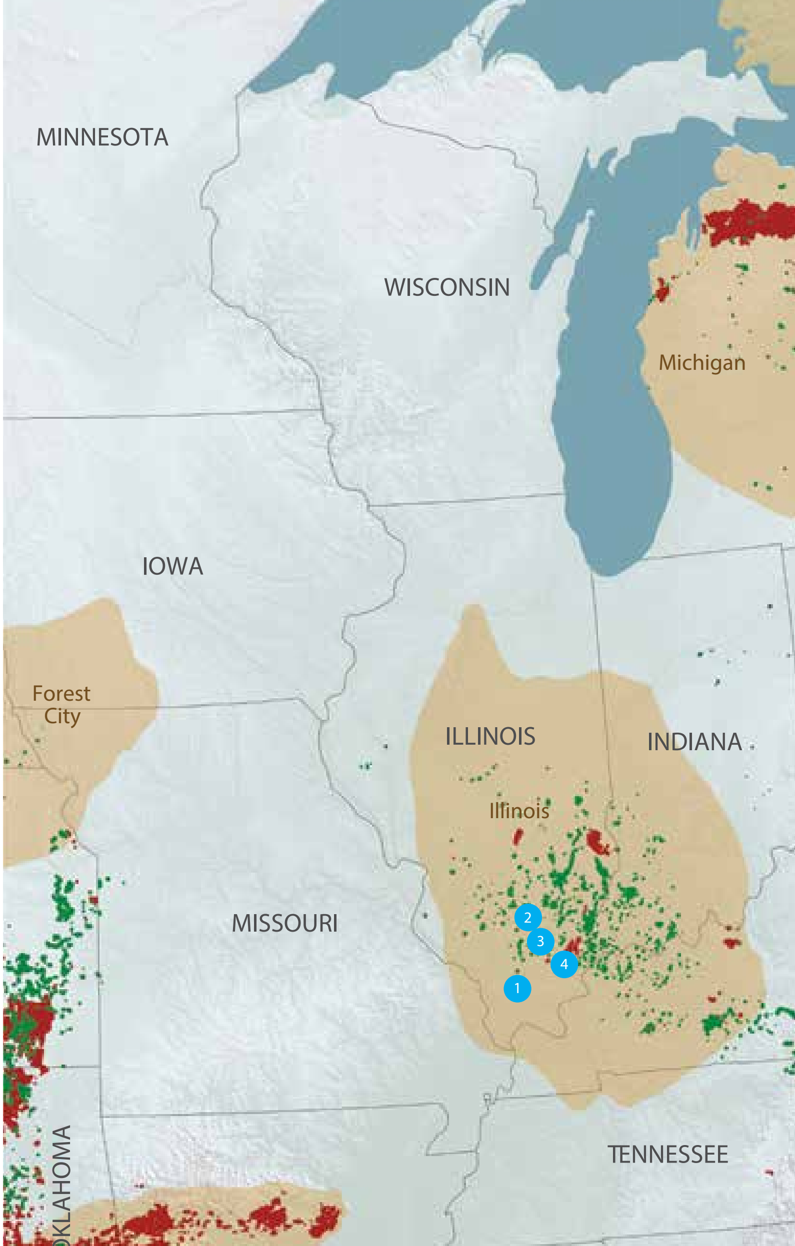
1 A deeper pool wildcat in Franklin County, Ill., has been staked by ***Pioneer Oil Co. Inc.*** The #1-34 Royalton has a planned depth of 6,200 ft and is in Section 34-7s-1e. The venture is targeting oil pays in Platteville, and a successful completion would open a new pool and extend Clifford Field about 1.5 miles to the northwest. Offsetting the new location to the southeast is a shallow 300-ft test that was drilled in 1989. Clifford Field is a three-well reservoir that opened in 1957. In 2016, ***Paragon Oil*** re-entered a 2,600-ft well that was originally abandoned in 2003 at #1-11 Illinois Minerals, which was tested pumping 7 bbl of crude and 2 bbl of water per day from Aux Vases at 2,431-44 ft. Pioneer's headquarters are in Lawrenceville, Ill.

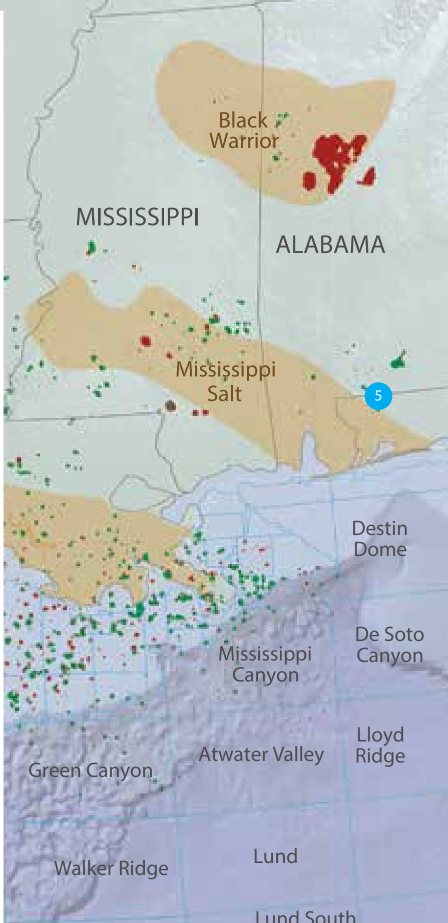
2 ***Resolve Exploration Corp.*** is planning to drill a deeper pool wildcat in Illinois' Coil West Field. The #1 Withrow will be in Section 38-1s-4e in Jefferson County. It has a planned depth of 4,200 ft and is targeting oil pays in Warsaw. According to IHS Markit, there has been no previous drilling in Section 36. The nearest drilling is within 1 mile to the northwest in Section 25 at #1-A Clyne M. Rapp. It was drilled in 1962 to a total depth of 3,051 ft in Valmeyer. Deeper drilling is 1 mile northeast of #1 Withrow at #1 Cesario in Wayne County. It was drilled in 2007 to 5,021 ft in Lower Devonian with some oil shows in Aux Vases at 2,871-90 ft. Oil production in Coil West Field started in 1942 with the deepest well producing crude from Salem Lime at around 3,250 ft. Resolve Exploration is based in Mount Vernon, Ill.

3 A Wayne County, Ill., deep exploratory test has been spud by ***Pioneer Oil Co. Inc.*** The #1-Alt Espey is in Section 7-3s-5e and is targeting oil pays in Platteville. The proposed depth is 6,800 ft. Nearby production is within one-half mile to the south in the same section at a 2011 oil discovery: #1 K&L Wilkerson pumped 17 bbl of oil per day from St. Louis at 3,321-25 ft. It was drilled to 3,645 ft and is in Markham City Field. Recovery through late 2016 totaled 1.028 Mbbl of crude. Three other tests were drilled in Section 7 more than 50 years ago, and those wildcats were abandoned at depths of around 3,200 ft.

4 ***Campbell Energy LLC*** plans to drill two 5,700-ft Backbone (Lower Devonian) exploratory tests in Saline County, Ill. The Carmi, Ill.-based company's #24-1 Tison Heirs will be in Section 24-7s-6e. Immediately to the east will be #1 Longbranch in Section 24. Nearby production is within 2 miles to the south in Raleigh Field, which yields crude from pays as deep as Salem. According to IHS Markit, ***KWR Ventures*** permitted two St. Louis ventures in 2018 about 1 mile to the southwest—#1-26 Massey and #1-26 Rhine Anderson are in Section 26-7s-6e and each was permitted to 3,350 ft.

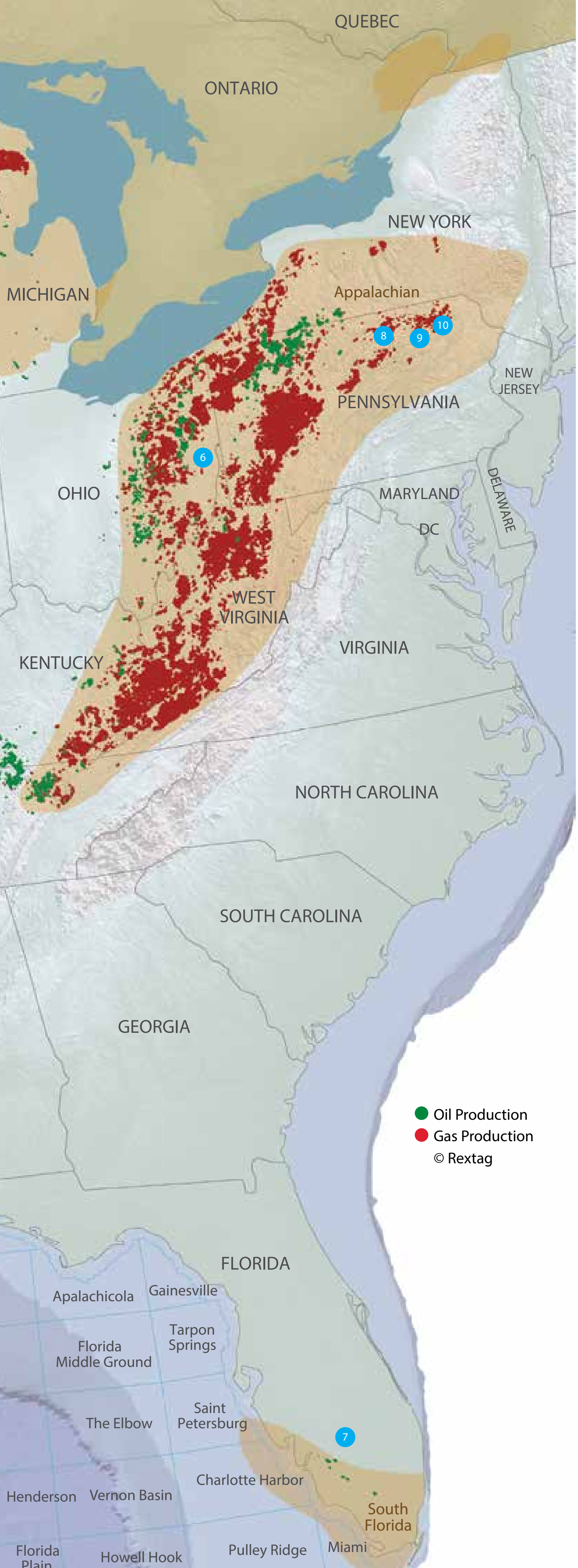
5 A Norphlet oil test has been added to ***Sklar Exploration Co.***'s drilling program in the Florida Panhandle. The Santa Rosa County venture, #1 Pitnic 16-3, will be directionally drilled from a site in Section 15-5n-29w and will bottom to the northwest in irregular Section 16. The planned depth is 15,631 ft (15,500 ft true vertical). About 2 miles northwest of its new location, the Shreveport, La.-based company directionally drilled #1 Bates 2-2 in Section 2 to an estimated depth of 15,500 ft. No additional details are available on the Norphlet venture. Nearby production is in Section 13 at Sklar's #1 Polk Estate 13-5. The discovery reopened Mount Carmel Field, and the well was tested pumping an unreported amount of crude from an undisclosed Norphlet zone.





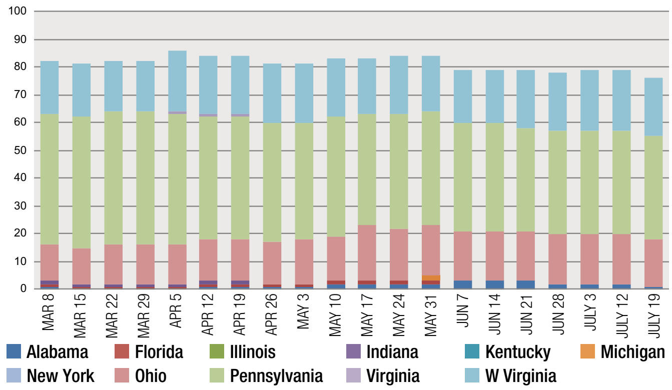
6 A Utica completion in Jefferson County, Ohio, by ***Ascent Resources LLC*** was tested flowing 21.506 MMcf of gas with 212 bbl of water per day. The #2H Nolan S CRC JF is on a 640-acre lease in Section 32-6n-2w and had a projected depth of 18,000 ft in Gould Consolidated Field. It was drilled to the southeast to 18,532 ft and production is from a fractured zone at 9,731-18,176 ft. Ascent's headquarters are in Oklahoma City.

7 ***Drawbridge Energy Co.***, based in Houston, has staked an 11,500-ft wildcat exploratory test in Florida's Hendry County. The #33-4 Indigo will be vertically drilled in Section 33-43s-32e, and it is targeting oil pays in Sunniland Lime. Nearby drilling is about 9 miles to the southwest at a well drilled in 1975 at #1 Tomoka 18-4. The well was drilled to 12,423 ft in Sunniland Lime. A similar distance to the northeast near Lake Okeechobee is a slightly deeper wildcat



Eastern U.S. Rig Count

Mar. 8, 2019-July 19, 2019



Data compiled from Baker Hughes

(13,424 ft) drilled in 1953 at #1 Tiedtke & Shroeder in Section 25-42s-33e.

8 Dallas-based ***Chief Oil & Gas Inc.*** completed four Marcellus wells in Bradford County, Pa. From a pad in Section 7 Leroy 7.5 Quad, Leroy Township, #1H SGL-12 K South Unit in Baileys Corner Field was tested flowing 20.2 MMcf of gas per day from perforations at 8,660-16,993 ft. It was drilled to 17,428 ft, 8,665 ft true vertical. The #2H SGL-12 K South was completed in an unnamed field with a 7,632-ft lateral and tested flowing 20.2 MMcf/d—additional completion information was not available. About 3 miles northwest of #1H SGL-12 K South Unit in Section 3, Shunk 7.5 Quad, Township, #12-SGL Hardy was completed in an unnamed field producing 14.6 MMcf/d from perforations at 9,056-17,212 ft. It was drilled to 17,366 ft, 8,780 ft true vertical. About 4 miles east of #1H SGL-12 K South Unit, in Section 2, Overton 7.5 Quad, Overton Township, #1H L Kingsley NW produced 19.238 MMcf per day from perforations at 9,036-20,183 ft. It was drilled to 17,366 ft, 8,780 ft true vertical.

9 ***Chesapeake Operating Inc.*** completed a Marcellus Shale producer in Wyoming County, Pa. The Oklahoma City-based company's #22 Slumber Valley was tested flowing 18.485 MMcf of gas from a fractured zone at 7,381-14,323 ft. The Mehoopany Field well was drilled to 14,452 ft with a true vertical depth of 7,302 ft and is in Section 3 Meshoppen 7.5 Quad, Meshoppen Township.

10 ***Cabot Oil & Gas Corp.*** completed six Marcellus Shale wells from a pad in Susquehanna County, Pa. The Lenox Field wells are in Section 8, Harford 7.5 Quad, Harford Township. The #1H Adams J was drilled to 19,294 ft, 7,354 ft true vertical, and flowed 31 MMcf of gas per day after 51-stage fracturing. Production is from perforations at 8,399-19,224 ft. The #2H Adams J. was drilled to 19,976 ft, 7,174 ft true vertical. It flowed 12 MMcf of gas per day after 58-stage fracturing. Production is from perforations at 8,877-19,886 ft. The #3H Adams J was drilled to 18,776 ft, 7,412 ft true vertical. It flowed 31 MMcf of gas per day after 50-stage fracturing. Production is from perforations at 8,901-18,706 ft. The #5H Adams J was drilled to 18,406 ft, 7,420 ft true vertical, and flowed 26.4 MMcf of gas per day after 51-stage fracturing. Production is from perforations at 8,233-18,333 ft. The #7H Adams J was drilled to 12,509 ft, 7,186 ft true vertical, and was tested flowing 16.7 MMcf of gas per day after 23-stage fracturing. Production is from perforations at 7,837-12,443 ft. The #8H Adams J was drilled to 13,617 ft, 7,203 ft true vertical, and produced 12.5 MMcf of gas per day after 30-stage fracturing. Production is from perforations at 7,723-13,551 ft. Cabot's headquarters are in Houston.

GULF COAST

1 ***Lonestar Resources*** announced results from four Eagle Ford completions that were drilled from a pad in the Hawkville Field portion of La Sale County (RRC Dist. 1), Texas. The pad is in WP Hardeman Survey, A-1182. According to the Fort Worth, Texas-based company, #4H Horned Frog MW produced 152 boe per day from a 9,771-ft lateral. The #5H Horned Frog NW flowed 153 bbl of oil equivalent from a 12,170-ft lateral. It was drilled to 22,675 ft, 9,502 ft true vertical. The #1AH Horned Frog F flowed 192 bbl of oil equivalent per day from a 12,146-ft lateral. It was drilled to 22,520 ft, 9,559 ft true vertical. The #1BH Horned Frog F flowed 214 bbl of oil equivalent per day from a 12,170-ft lateral. It was drilled to 19,649 ft, 9,297 ft true vertical.

2 ***Hawkwood Energy Operating LLC*** completed a Giddings Field-Eagle Ford well at #3H Brazos Farms I. The discovery is in Brazos County (RRC Dist. 3), Texas, in William Mathis Survey A-37. According to the Denver-based company, it flowed 803 bbl of oil equivalent per day. Production is from an 8,473-ft effective lateral. It was drilled to 17,093 ft, 7,861 ft true vertical. Gauged on a 22/64-in. choke, the flowing tubing pressure was 760 psi.

3 ***Covey Park Resources LLC*** has completed two Carthage Field wells in Harrison County (RRC Dist. 6), Texas. The wells are on a 1,404-acre East Texas lease in Bethany Rogers Survey, A-20, and bottomed about 2 miles to the northwest. According to IHS Markit, #5H Westmoreland-Lancaster was tested flowing 11.203 MMcf of gas and 1.166 Mbbl of water daily through acid- and fracture-treated perforations in Haynesville Shale at 11,610-20,496 ft. Gauged on a 21/64-in. choke, the flowing casing pressure was 4,916 psi, and the shut-in casing pressure was 5,381 psi. It was drilled to 20,623 ft, 11,294 ft true vertical. The offsetting #6H Westmoreland-Lancaster produced 11.547 MMcf of gas and 1.148 Mbbl of water from acid- and fracture-treated perforations at 11,389-20,426 ft. The well was drilled to 20,525 ft, 11,284 ft true vertical. Tested on a 29/64-in. choke, the flowing casing pressure was 5,469 psi. Covey Park's headquarters are in Dallas, Texas.

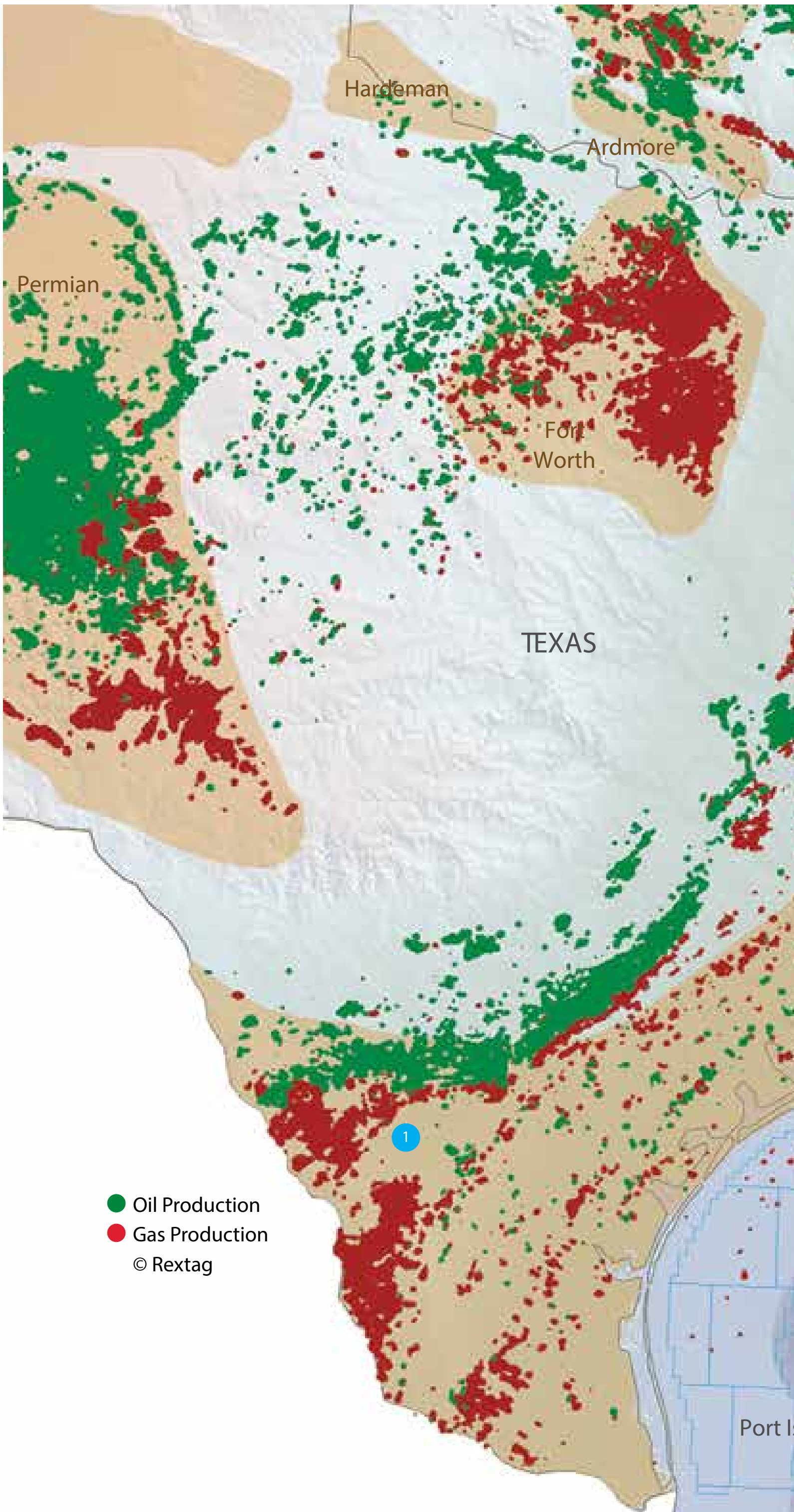
4 In Panola County (RRC Dist. 6), Texas, ***Rockcliff Energy LLC*** completed two Haynesville Shale wells from a Carthage Field pad in Alford Johnson Survey A-360. The Houston-based company's #3H Herndon HV Unit flowed 26.7 MMcf of gas per day during testing on a 28/64-in. choke with a flowing tubing pressure of 6,271 psi. It had a projected depth of 12,000 ft and production is from a 7,373-ft effective lateral. Additional completion information is not available. The #2H Herndon HV Unit produced 25.7 MMcf of gas per day during testing on a 29/64-in. choke with a flowing tubing pressure of 6,171 psi. The planned depth was 9,000 ft.

5 Two Red River-Bull Bayou Field-Haynesville producers were completed by ***Exco Resources Inc.*** from a drillpad in Section 12-13n-13w in DeSoto Parish, La. The #1-ALT Nabors 12-1 HC initially flowed 30.1 MMcf of gas per day. It was tested on a 33/64-in. choke with a flowing tubing pressure of 8,180 psi. It had a projected depth of 23,000 ft and a projected true vertical depth of 13,500 ft. The #2-ALT Nabors 12-1 HC flowed 22.2 MMcf of gas per day from a 9,316-ft lateral. It had a projected depth of 23,572 ft and a projected true vertical depth of 13,646 ft. It was tested on a 27/64-in. choke, and the flowing tubing pressure was 8,268 psi. Exco is based in Dallas.

6 In Red River Parish, La., ***Vine Oil & Gas*** announced results from two Jurassic A completions at a drillpad in Bracky Branch Field. The drillpad is in Section 15-13n-10w. The #3-ALT Martin Timber 10-3HC flowed 20 MMcf of gas per day during testing on a 20/64-in. choke. It was drilled to 20,665 ft, 12,501 ft true vertical. The #4-ALT Martin Timber 10-3HC was drilled to 20,430 ft, 12,429 ft true vertical, and tested on a 16/64-in. choke and also flowed 20 Mcf of gas per day. The average flowing tubing pressure for both wells was 8,555 psi.

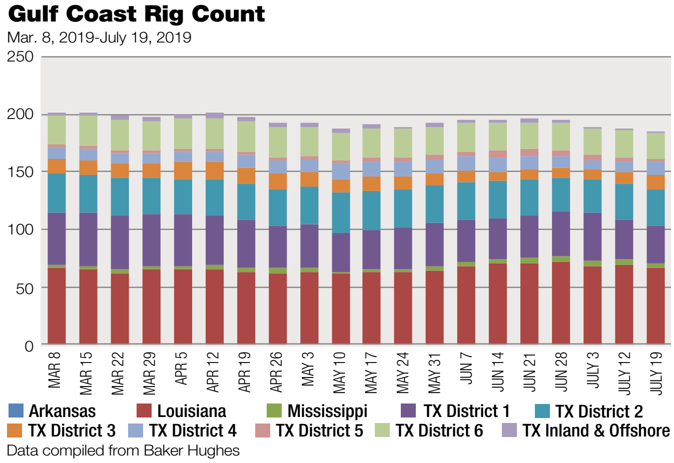
7 Houston-based ***ConocoPhillips Co.*** has completed a second Austin Chalk producer as part of the company's program in Louisiana. In West Feliciana Parish, #1 Hebert flowed 206 bbl of 37-degree-gravity crude, 134 Mcf of gas and 4.279 Mbbl of water daily from fracture-treated perforations at 14,086-19,320 ft. Gauged on a 27/64-in. choke, the flowing casing pressure was 1,871 psi, and the shut-in casing pressure was 3,729 psi. A vertical pilot hole was drilled to 14,120 ft, and the horizontal well was drilled to 19,461 ft (13,629 ft true vertical). It is in irregular Section 42-2s-1w and was drilled about 1 mile to the northeast. ConocoPhillips' discovery has opened Jackson Northwest Field.

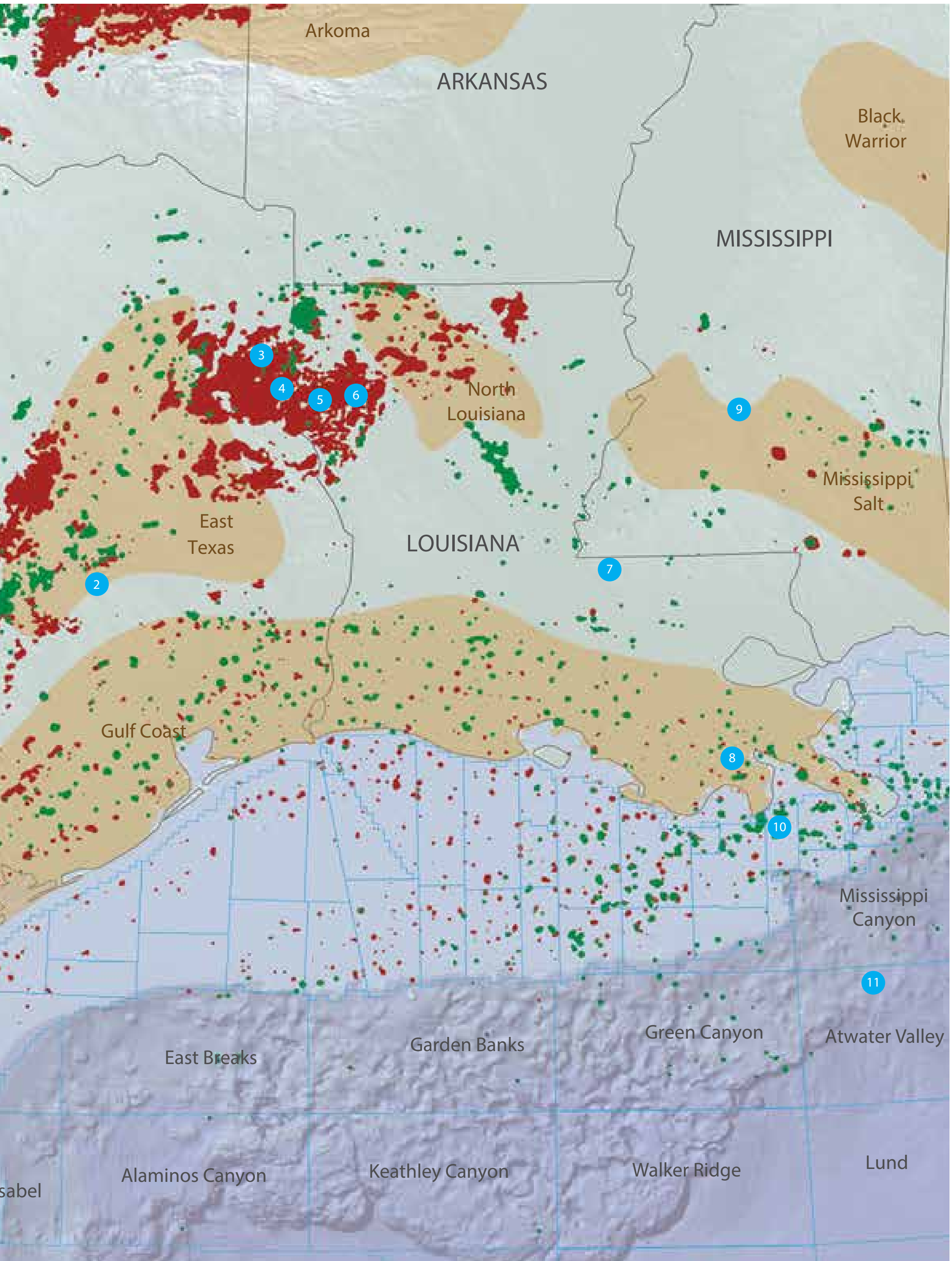
8 Lafayette, La.-based ***Mack Energy Co.*** has completed its



first three wells in South Louisiana's Bully Camp Field. In Lafourche Parish, #1 Exxon Mobil Fee was tested flowing 69 bbl of 39.4-degree-gravity crude and 71 Mcf of gas from Miocene (8800 Sand) at 10,068-96 ft. Tested on a 17/64-in. choke, the flowing tubing pressure was 350 psi. It was drilled to 10,587 ft (9,232 ft true vertical). The directional well was drilled to the southwest in Section 55-18s-21e and bottomed in Section 62. Also in Section 55, #1 Convexx Oil & Gas flowed 130 bbl of 36.5-degree-gravity oil and 350 Mcf of gas per day from a deeper Miocene (TP Sand) zone at 11,167-11,270 ft. Gauged on a 10/64-in. choke, the flowing tubing pressure was 780 psi. The directional well was drilled to 11,352 ft (11,285 ft true vertical). The offsetting #2 Convexx Oil & Gas produced 23 bbl of oil, and 10 Mcf of gas per day from Miocene (TP Sand) at 10,802-71 ft. It was drilled to 11,025 ft (11,004 ft true vertical). The flowing tubing pressure was 350 psi during testing on a 15/64-in. choke.

9 A Sparta Sand discovery by ***Sunland Production*** has reopened Wayside Field, an oil reservoir in Adams County, Miss. The #1 Sojourner was tested flowing 65 bbl of 25-degree-gravity crude per day through perforations at 4,202-08 ft. It was drilled to 4,860 ft and bottomed in irregular Section 12-5n-2w. Flowing tubing pressure was measured at 600 psi on a 7/64-in. choke. Wayside Field was opened in 1951. Sunland is based in Shreveport, La.





10 ***Talos Energy,*** based in Houston, has added a second test to the company's development program from an existing platform on Ewing Bank Block 305. The #22-A OCS G36365 will be drilled in the far eastern portion of the block. The venture is expected to bottom to the north in Grand Isle Block 82. A successful completion would be the first well drilled from the platform to bottom beneath Grand Isle Block 82. Water depth in the area is 270 ft.

11 A second exploratory test has been scheduled by ***Shell Oil Co.*** on the company's ultra-deepwater Aransas prospect. The #2 OCS G35431 will be in the northwestern portion of Atwater Valley Block 198. The first test, #1 OCS G35431, was permitted by the Houston-based company in early 2019 from an offsetting surface location. According to IHS Markit, the two-tract Aransas prospect is made up of Block 198 and adjacent Block 154 (OCS G35019) to the north. The prospect's exploration plan indicated that Shell could drill as many as eight tests on the two tracts. Water depth in the area is 4,900 ft.

MIDCONTINENT & PERMIAN BASIN

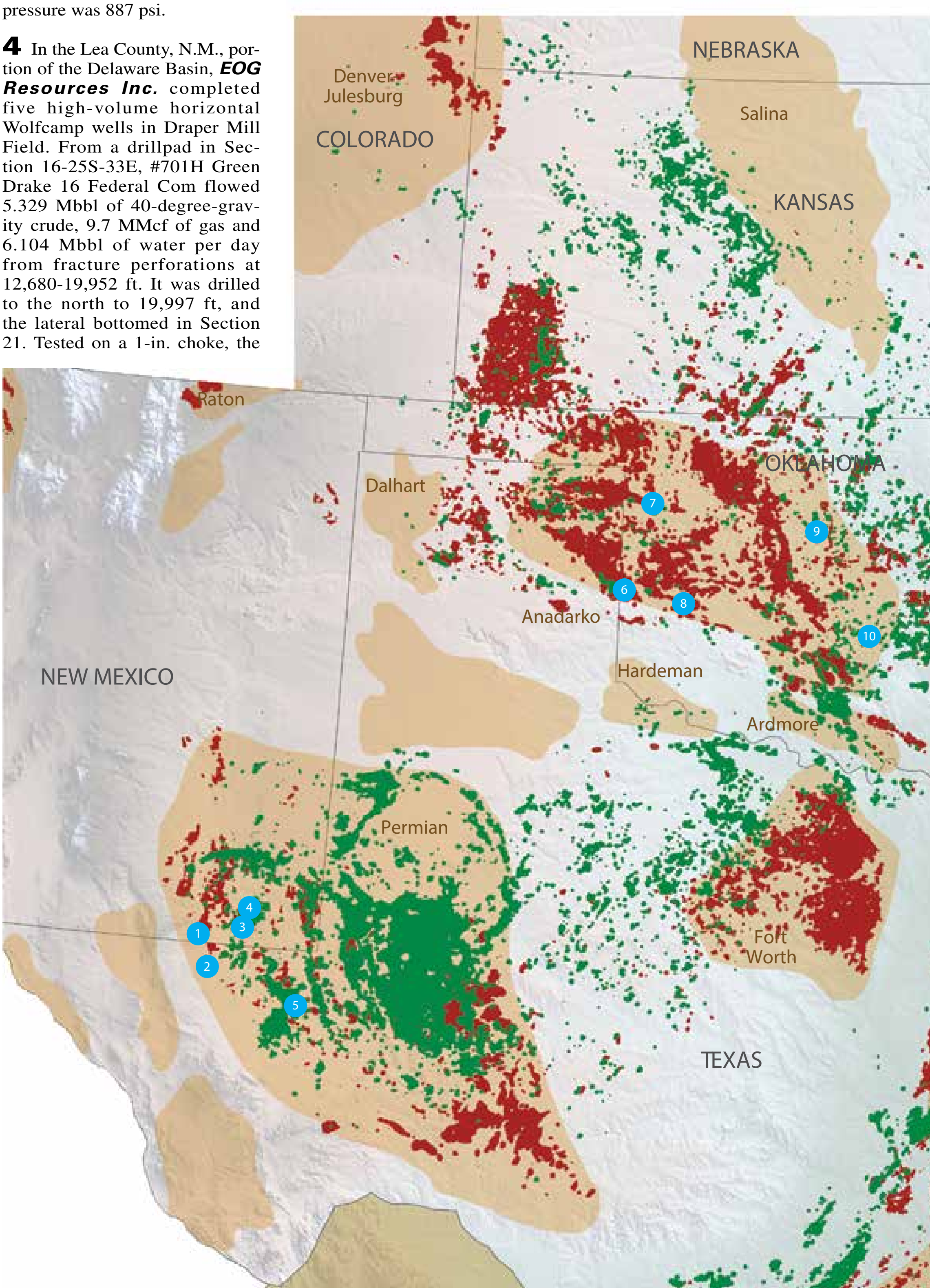
1 IHS Markit reported that Houston-based ***EOG Resources Inc.*** completed a two-section horizontal Wolfcamp well in the Eddy County, N.M., portion of the Delaware Basin. The #701H Stella Blue 30 Federal Com flowed 2.478 Mbbl of 44-degree-gravity crude, 14.43 MMcf of gas and 7.757 Mbbl of water per day. Production is from a fracture-stimulated interval at 11,500-21,067 ft. The Purple Sage Field well was drilled to 21,078 ft, 11,295 ft true vertical, and is in Section 30-26s-31e. The lateral bottomed about 2 miles to the north in Section 19. Gauged on a 1-in. choke, the shut-in tubing pressure was 2,513 psi.

2 ***Shell Oil Co.*** has completed two offsetting horizontal Wolfcamp wells in the Loving County (RRC Dis. 8), Texas, portion of Phantom Field. The completions were drilled from a pad in Section 34, Block 55 T2S, T&P RR Co Survey, A-1380. The #1H Link-VJ Ranch 55-2-27 LOV flowed 2.61 MMcf of gas, 766 bbl of 47.9-degree-gravity oil and 3.933 Mbbl of water daily from acid- and fracture-treated perforations at 11,646-21,881 ft. Gauged on a 32/64-in. choke, the flowing tubing pressure was 2,323 psi, and the shut-in tubing pressure was 3,176 psi. It was drilled to 22,075 ft, 11,126 ft true vertical, and bottomed 2 miles to the north in Section 22. The #1H VJ Ranch-Link 55-2-34 LOV produced 2.122 MMcf of gas, 575 bbl of 50-degree-gravity condensate and 2.259 Mbbl of water per day from perforations at 11,486-16,432 ft. Tested on a 1-in. choke, the flowing tubing pressure was 780 psi, and the shut-in tubing pressure was 3,416 psi. The lateral bottomed about 1 mile to the south at 16,625 ft (11,152 ft true vertical).

3 ***Chevron Corp.*** announced results from an Upper Wolfcamp discovery in Lea County, N.M. According to the Houston-based company, #010H SD EA 29 Federal Com P8 was tested flowing 3.67 Mbbl of oil, 2.792 MMcf of gas and 5.272 Mbbl of water per day. It is in Section 29-26s-33e in Red Hill Field. Production is from a 6,722-ft lateral. The well had a projected depth of 19,775 ft and a projected true vertical depth of 12,575 ft. Gauged on a 1.5-in. choke, the flowing tubing pressure was 887 psi.

4 In the Lea County, N.M., portion of the Delaware Basin, ***EOG Resources Inc.*** completed five high-volume horizontal Wolfcamp wells in Draper Mill Field. From a drillpad in Section 16-25S-33E, #701H Green Drake 16 Federal Com flowed 5.329 Mbbl of 40-degree-gravity crude, 9.7 MMcf of gas and 6.104 Mbbl of water per day from fracture perforations at 12,680-19,952 ft. It was drilled to the north to 19,997 ft, and the lateral bottomed in Section 21. Tested on a 1-in. choke, the flowing casing pressure was 262 psi. The parallel #702H Green Drake 16 Federal Com flowed 4.126 Mbbl of oil, 8.5 MMcf of gas and 6.611 Mbbl of water per day from 12,565-19,521 ft. The #703H Green Drake 16 Federal Com flowed 4.077 Mbbl of oil, 7.9 MMcf of gas and 8.42 Mbbl of water per day from 12,861-19,958 ft. Within one-half mile to the southeast are two more south-trending Green Drake 16 wells. The #704H Green Drake 16 Federal Com flowed 5.024 Mbbl of oil, 8.8 MMcf of gas and 8,102 bbl of water per day. Production is from perforations at 12,795-20,000 ft. The #705H Green Drake 16 Federal Com flowed 5.155 Mbbl of crude, 9.5 MMcf of gas and 7.650 Mbbl of water per day from perforations at 12,850-20,025 ft.

5 A Third Bone Spring well in Winkler County (RRC Dist. 8), Texas, was completed by ***Jagged Peak Energy LLC***. The discovery is in Section 30, Block 17, University Lands Survey, A-U4, in Winkler County, Texas, at #5HX UTL L J Beldin 1211-17. According to the company, it initially flowed 3.354 Mboe per day (89% oil). It had a projected depth of 15,000 ft and was tested on a 48/64-in. choke



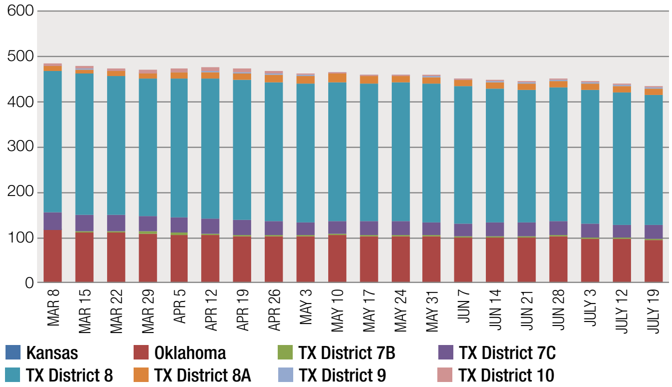
with a flowing tubing pressure of 1,632 psi. Additional information was not available from the Denver-based company.

6 ***FourPoint Energy LLC***, based in Denver, completed a high-volume Upper Granite Wash (Missouri) well in Roger Mills County, Okla. The Sweetwater Field well, #1HC Freezeout 17X8-11-26, is in Section 17-11n-26w and produced 2.165 Mbbl of 47-degree-gravity oil, 4.18 MMcf of gas and 916 bbl of water per day. Tested on a 30/64-in. choke, the flowing tubing pressure was 2,100 psi, and the shut-in tubing pressure was 1,875 psi. The completion was acidized and fractured between 11,800 and 19,539 ft. The 19,757-ft Sweetwater Field prospect was drilled northward about 1.5 miles with a true vertical depth of 11,452 ft. It bottomed in Section 7-11n-26w.

7 Amarillo-based ***ValPoint Operating LLC*** completed an Oswego producer that flowed 1.067 Mbbl of oil, 1.14 MMcf of gas and 1.978 Mbbl of water daily. The #1H Shrewder 26-23 is in Section 35-18n-23w in Ellis County, Okla. The venture was drilled north 2 miles across Section 26 and bottomed in Section 23-18n-23w. It was acidized and fractured, and production is from perforations at 10,179-20,346 ft. Tested on a 35/64-in. choke, the shut-in tubing pressure was 2,000 psi, and the flowing tubing pressure was 975 psi. It was drilled to 20,485 ft, 9,495 ft true vertical.

Midcontinent & Permian Basin Rig Count

Mar. 8, 2019-July 19, 2019

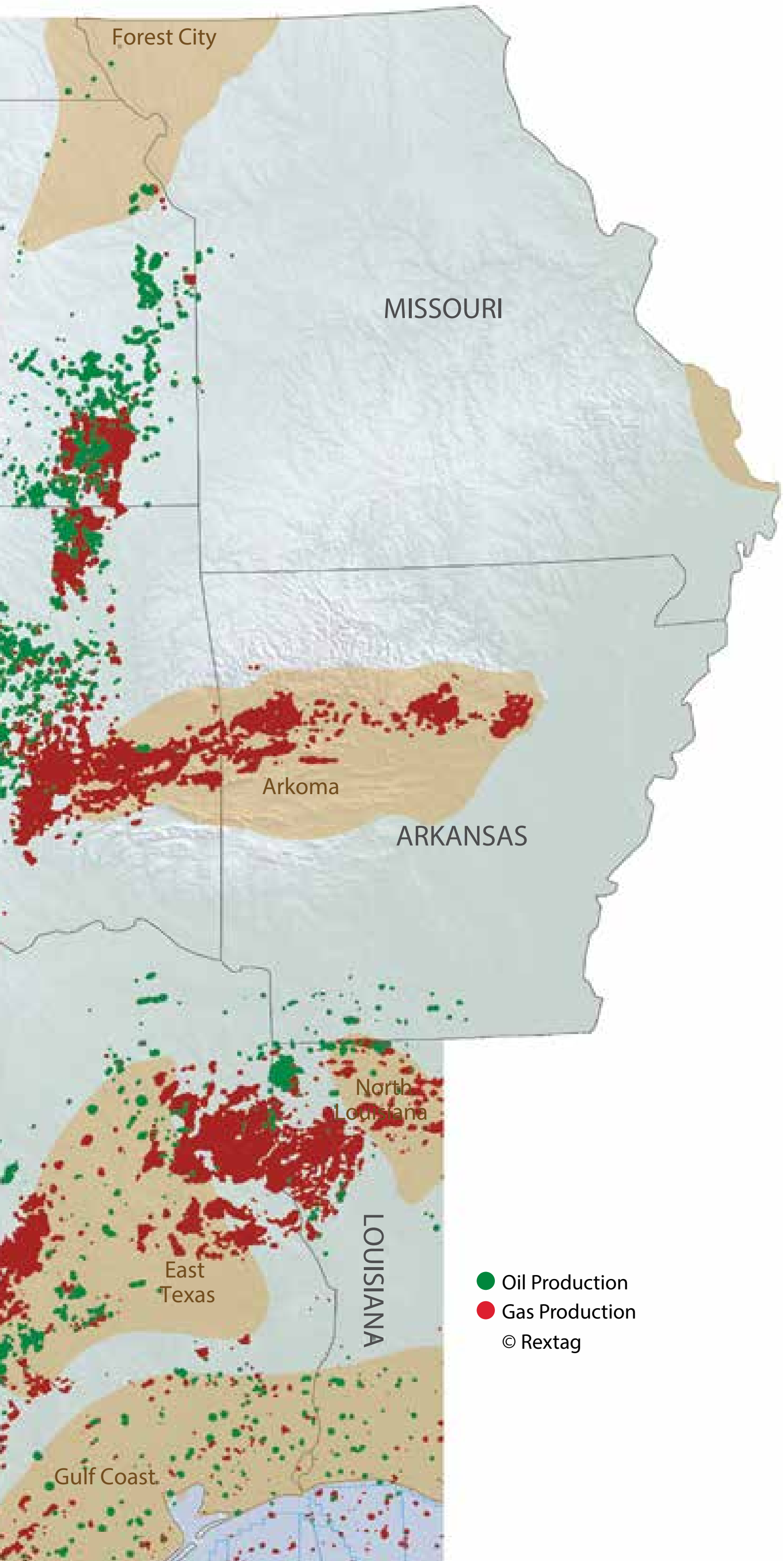


Data compiled from Baker Hughes

8 A Des Moines Granite Wash discovery by ***FourPoint Energy LLC*** initially flowed 15.7 MMcf of gas with 161 bbl of 50-degree-gravity condensate and 1.377 Mbbl of water daily. The Washita County, Okla., well, #2HC Sasseen 24-10-19, is in Section 24-10n-19w, and it was tested on a 27/64-in. choke following acidizing and fracturing at 13,175-17,301 ft. It was drilled to the north to 17,450 ft, 12,972 ft true vertical.

9 Houston-based ***Marathon Oil Corp.*** has completed two high-rate horizontal Meramec producers in the Stack play in Section 27-17n-10w in Blaine County, Okla. IHS Markit reported that #3-22-15MXH Olive June 1710 was tested on a 32/64-in. choke initially flowing 2.519 Mbbl of oil, 2.56 MMcf of gas and 372 bbl of water per day after acidizing and fracturing at 9,613-19,802 ft. The 19,926-ft Cooper Field well was drilled north about 2 miles across Section 22-17n-10w and bottomed in Section 15-17n-10w with a true vertical depth of 9,056 ft. Twenty ft east of the pad, #4-22-15MXH Olive June 1710 flowed 2.123 Mbbl of 46-degree-gravity oil, 2.43 MMcf of gas and 406 bbl of water per day. It was drilled in a parallel lateral and bottomed in Section 15-17n-10w at 20,097 ft, 8,976 ft true vertical. Tested on a 32/64-in. choke, production is from a fractured zone at 9,744 ft and 19,826 ft.

10 From a pad in Section 24-5n-6w, Grady County, Okla., ***Marathon Oil Corp.*** made three Woodford completions. According to IHS Markit, #3-25-36WXH Ellis 0506 was tested on a 40/64-in. choke flowing 16.2 MMcf of gas, 452 bbl of 56-degree-gravity condensate and 2.367 Mbbl of water daily. The 25,184-ft Chitwood Field prospect was drilled south about 2 miles across the section to a true vertical depth of 14,608 ft. It bottomed in Section 36-5n-6w and was perforated, acidized and fractured at 14,700-25,021 ft. About 40 ft west, #1-25-36WXH BP01 Ellis 0506 flowed 15.7 MMcf of gas, 447 bbl of condensate and 1.634 Mbbl of water per day. Drilled to 25,074 ft (15,106 ft true vertical) in a parallel lateral, it was tested on a 46/64-in. choke. Production is from acidized and fractured perforations between 16,017 and 24,898 ft. The #2-25-36WXH Ellis 0506 produced 15.8 MMcf of gas, 424 bbl of condensate and 1.567 Mbbl of water per day during testing on a 58/64-in. choke. Production is from a treated interval at 15,209-21,607 ft in a south lateral extending to 21,775 ft (14,819 ft true vertical).



WESTERN U.S.

1 A drilling permit has been granted for a Railroad Valley wildcat in Nye County, Nev. ***West Grant Canyon Development LLC***, based in Kaysville, Utah, plans to drill #1 Butterfield-Federal in Section 21-7n-56e, and it has a projected depth of 8,999 ft. No objectives were disclosed. Nearby production is about 2 miles to the southwest in Sans Spring Field, a three-well Tertiary accumulation discovered in 1993 that produces from the Garret Ranch volcanic tuff. The field opener, #5-14 CENEX Federal, is in Section 14-7n-56e. It was tested on a 19/64-in. choke flowing 1.253 Mbbl of 28-degree-gravity crude per day, with no water, from untreated perforations at 5,716-66 ft.

2 The first new well in 30 years in the Utah portion of Anschutz Ranch East Field on the Overthrust Belt was announced by ***Wesco Operating Inc.*** The #41-32 Moench is in Section 32 of partial township 4n-8e, Summit County, Utah. It initially flowed 177 bbl of oil, 2.657 MMcf of gas and 193 bbl of water per day. It was tested on a 20/64-in. choke in an undisclosed Jurassic Nugget Sand interval. The flowing tubing pressure was 1,100 psi. The discovery was drilled to a true vertical depth of 15,622 ft. Further details are not yet available.

3 In Sweetwater County, Wyo., ***Southland Royalty Co.*** completed a Lewis Sand venture that initially flowed 7.763 MMcf of gas, 772 bbl of oil/condensate and 1.032 Mbbl of water per day. The #I5 31-3H Chain Lakes is in Section 30-23n-93w and production is from a lateral extending from 11,396 ft southeastward to 17,006 ft. It bottomed in Section 31-23n-93w with a true vertical depth of 11,777 ft. It was tested on a 30/64-in. choke after 13-stage fracturing (plug-and-perf) between 12,323 and 16,858 ft. The casing pressure was 3,000 psi. Southland is based in Fort Worth, Texas.

4 ***Alta Vista Oil Co.*** has completed a horizontal exploratory test on the Sumatra Syncline in Rosebud County, Mont. The #1H Spider Monkey initially pumped 671 bbl of oil with 170 Mcf of gas and 881 bbl of water per day. The well is in Section 34-11n-32e, and it is producing from a lateral in Mississippian Heath Shale that was drilled to the northwest to 8,861 ft. The true vertical depth is 5,169 ft. It was tested after fracture stimulation and acid cleanup in an undisclosed number of stages between 5,240 and 8,782 ft. Alta Vista's headquarters are in Clearmont, Wyo.

5 ***Enduring Resources LLC*** has been granted drilling permits for two San Juan Basin exploratory tests in Sandoval County, N.M. According to IHS Markit, the ventures will be drilled from a pad in Section 30-22n-6w and will test the Gallup member of Mancos Shale. The #359H South Escavada Unit will be drilled to the northwest with a planned depth of 13,208 ft (4,961 ft true vertical) and will bottom in Section 13-22n-7w. The #360H South Escavada Unit will be drilled to the northwest to 15,712 ft (4,991 ft true vertical) and will also bottom in Section 13-22n-7w. Nearby production is at a ***WPX Energy Inc.*** short-radius horizontal Gallup discovery at #193H State 2207-36D in Section 36-22n-7w. It was tested in 2017 flowing 366 bbl of oil, 438 Mcf of gas and 404 bbl of water per day. Enduring's headquarters are in Denver.

6 Tulsa, Okla.-based ***Samson Resources Co.*** has completed a Powder River Basin exploratory test as a discovery in Frontier. The #31-1918-39-74FH Allemand Fed is in Section 30-39n-74w of Converse County, Wyo. It initially flowed 596 bbl of oil, 3.119 MMcf of gas and 951 bbl of water per day. Production is from a lateral drilled to the northeast to 22,950 ft at a bottomhole location in Section 18-39n-74w. The true vertical depth is 12,539 ft. It was tested on a 30/64-in. choke after 42-stage fracturing between 12,850 and 22,761 ft.

7 Houston-based ***EOG Resources Inc.*** announced results from a horizontal Mowry Shale discovery on the southern flank of the Powder River Basin. The #423-1720H Flatbow is in Section 17-42n-73w of Campbell County, Wyo. It initially flowed 623 bbl of 47.3-degree-gravity oil, 4.771 MMcf of gas and 3.14 Mbbl of water per day. Production is from a lateral in Mowry that was drilled to the south to 21,782 ft, 12,068 ft true vertical, and it bottomed in Section 20-42n-73w. It was tested on a 50/64-in. choke after 57-stage fracturing between 12,380 and 21,594 ft.

8 Oklahoma City-based ***Renos Land & Minerals Co.*** announced results from a wildcat completion in the Powder River Basin. The extended-reach venture, #35-72 8-5NH Spillman Draw Unit, flowed 1.638 Mbbl of oil, 1.285 MMcf of gas and 2.11 Mbbl of water per day from Niobrara. The well is in Section 8-35n-72w in Converse County, Wyo. Production is from a lateral drilled to the north to 22,480 ft, 12,188 ft true vertical. It bottomed in Section 32-36n-17w and was tested on a 24/64-in. choke after fracturing between 12,377 and 22,085 ft.

9 ***Chesapeake Operating Co.*** has completed a horizontal Turner producer that initially flowed 1.476 Mbbl of oil, 1.972 MMcf of gas and 1.728 Mbbl of water per day. The Powder River Basin discovery, #23H RRC

5-34-70 USA B TR, is in Section 5-34n-70w of Converse County, Wyo. Production is from a lateral drilled to the north to 21,688 ft, 11,560 ft true vertical, and it bottomed in Section 29-35n-70w. It was tested on a 26/64-in. choke following 39-stage fracturing between 12,475 and 21,574 ft. Chesapeake's headquarters are in Oklahoma City.

10 ***Ossidiana Operating LLC*** has staked 13 horizontal Niobrara/Codell wildcats at a drillpad in Goshen County, Wyo. The northern Denver-Julesburg Basin wildcats will be drilled in Section 17-20n-64w on the Denver-based company's High Noon lease with bottomhole locations are generally 2 miles to the south in Section 20-20n-64w. The true vertical depth of the Niobrara tests is planned at 8,193 ft, and the planned true vertical depth of the Codell ventures is about 8,431 ft.

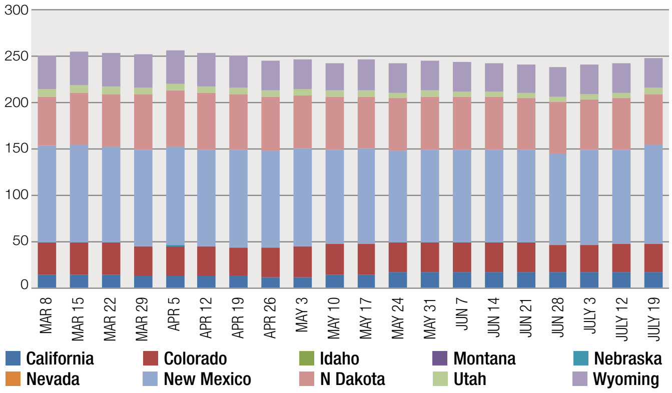
11 According to IHS Markit, ***Burlington Resources Oil & Gas Co LP*** completed an extended-reach horizontal Niobrara delineation test in Arapahoe County, Colo. The #4-65 29-30-3AH Rush is in Section 28-4s-65w, within the Aurora city limits. It produced 1.051 Mbbl of oil, 860 Mcf of gas and 637 bbl of water per day. Production is from a Niobrara lateral extending west-northwestward to 15,645 ft (7,981 ft true vertical) and bottomed in Section 30-4s-65w. It was tested on a 26/64-in. choke following 29-stage fracturing between 8,476 and 15,476 ft. Burlington is a subsidiary of ***ConocoPhillips***.

12 New York City-based ***Hess Corp.*** completed an Antelope Field well at the Dinwoodie pad in McKenzie County, N.D. The #153-94-2833H-8 AN-Dinwoodie was tested flowing 4.107 MMcf of gas, 3.541 Mbbl of 43.7-degree-gravity oil and 1.181 Mbbl of water per day. It was drilled to 20,765 ft, 10,276 true vertical and bottomed to the south. It was tested on a 44/64-in. choke and was completed after 35-stage fracturing (plug-and-perf).

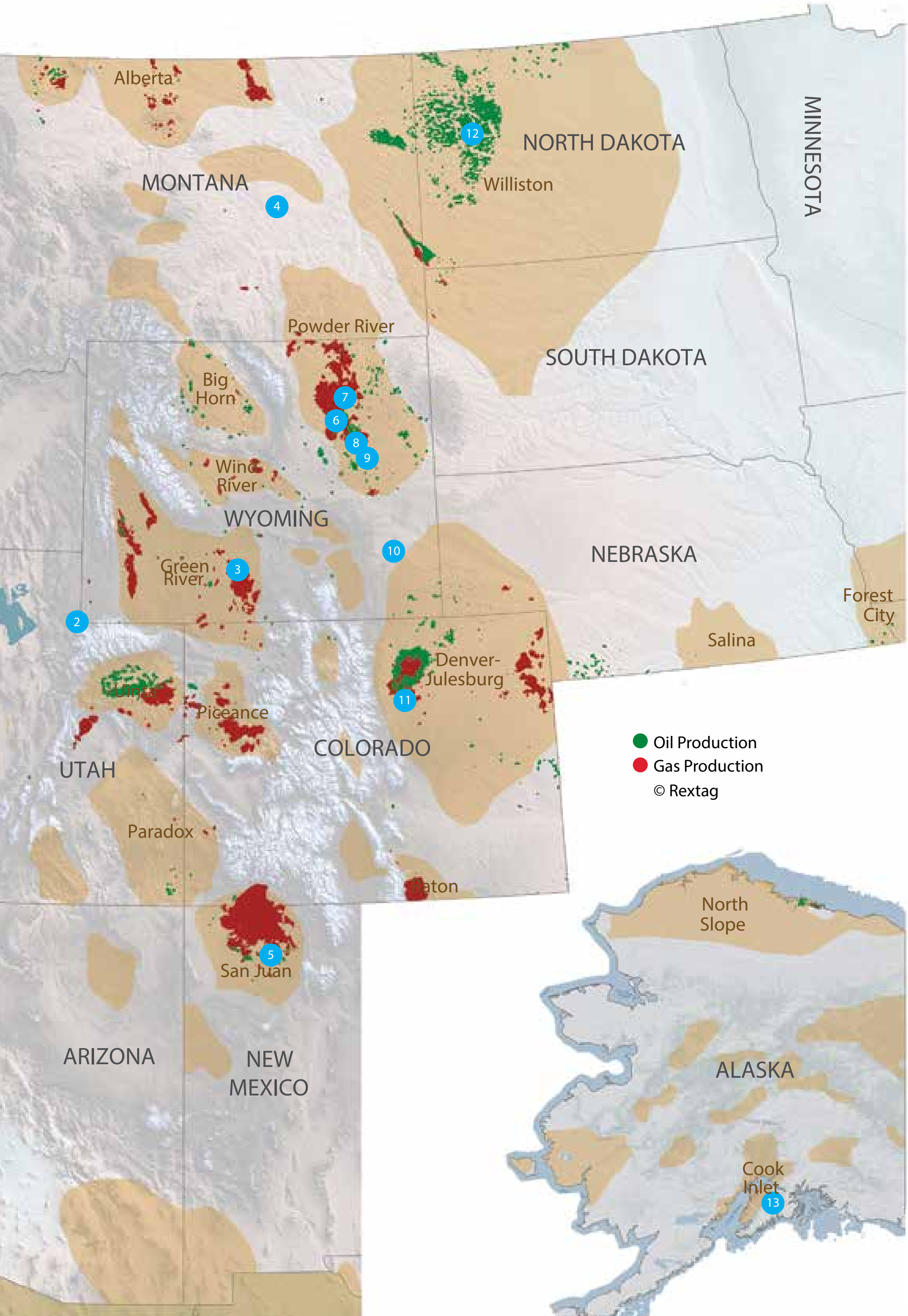
13 ***Hilcorp Energy Co.*** has submitted a plan for a new grassroots development well in the Cannery Loop Unit (CLU) on the Kenai Peninsula in Alaska. One well will be drilled from the existing CLU Pad 1, including the installation of well cellar and conductor. Drilling will occur from private surface lands through a private oil and gas mineral estate to reach a bottomhole location within a state oil and gas lease. The proposed well, #14 CLU, will be in Section 7-5n-11w in Seward Meridian, on the ADL 324602 lease. Hilcorp is based in Houston.

Western U.S. Rig Count

Mar. 8, 2019-July 19, 2019



Data compiled from Baker Hughes



INTERNATIONAL HIGHLIGHTS

In its July 2019 edition of the Short-Term Energy Outlook (STEO), the U.S. Energy Information Administration (EIA) forecasts that global liquid fuels consumption growth will be lower in 2019 and 2020.

Global liquids demand growth has decreased for six consecutive months, reflecting slower-than-expected economic growth in many of the world's largest oil-consuming countries, lower-than-expected oil consumption so far this year and higher crude oil prices.

One of the main drivers of the EIA's global oil consumption forecast is global GDP based on country-level forecasts. The EIA calculates an oil-weighted GDP by using relative magnitudes of oil consumption in each country. The administration revised the 2019 oil-weighted GDP growth rate from 2.9% in its January STEO to 2.2% in its July STEO. If realized, the 2.2% growth rate would be the lowest annual growth rate since 2009 and one of the main reasons for slower growth in global liquids consumption.

The EIA attributes lower-than-expected oil consumption for OECD countries. Consumption fell earlier this year due to relatively warm weather in Europe in February and March, which caused reduced heating oil consumption, slowing GDP growth, and a slowdown in Europe's manufacturing sector.

—Larry Prado

1 *Colombia*

Ecopetrol has reported a discovery on the Playon Block in Rio Negro (Santander) in the Middle Magdalena Basin in Colombia. The #2-ST Boranda encountered crude in Eocene Basal Sands. The well was drilled from the same platform as discovery well #1-Boranda about 1,200 m to the southeast. The well initially produced 960 bbl oil per day with a water cut of less than 2%. It was drilled to 4,246 m, and it confirmed the finding of 23-degree-gravity crude. Additional testing is planned. ***Parex*** is the operator of Payon Block and the Boranda wells with 50% interest in partnership with Bogota-based Ecopetrol holding the remaining 50%.

2 *Senegal*

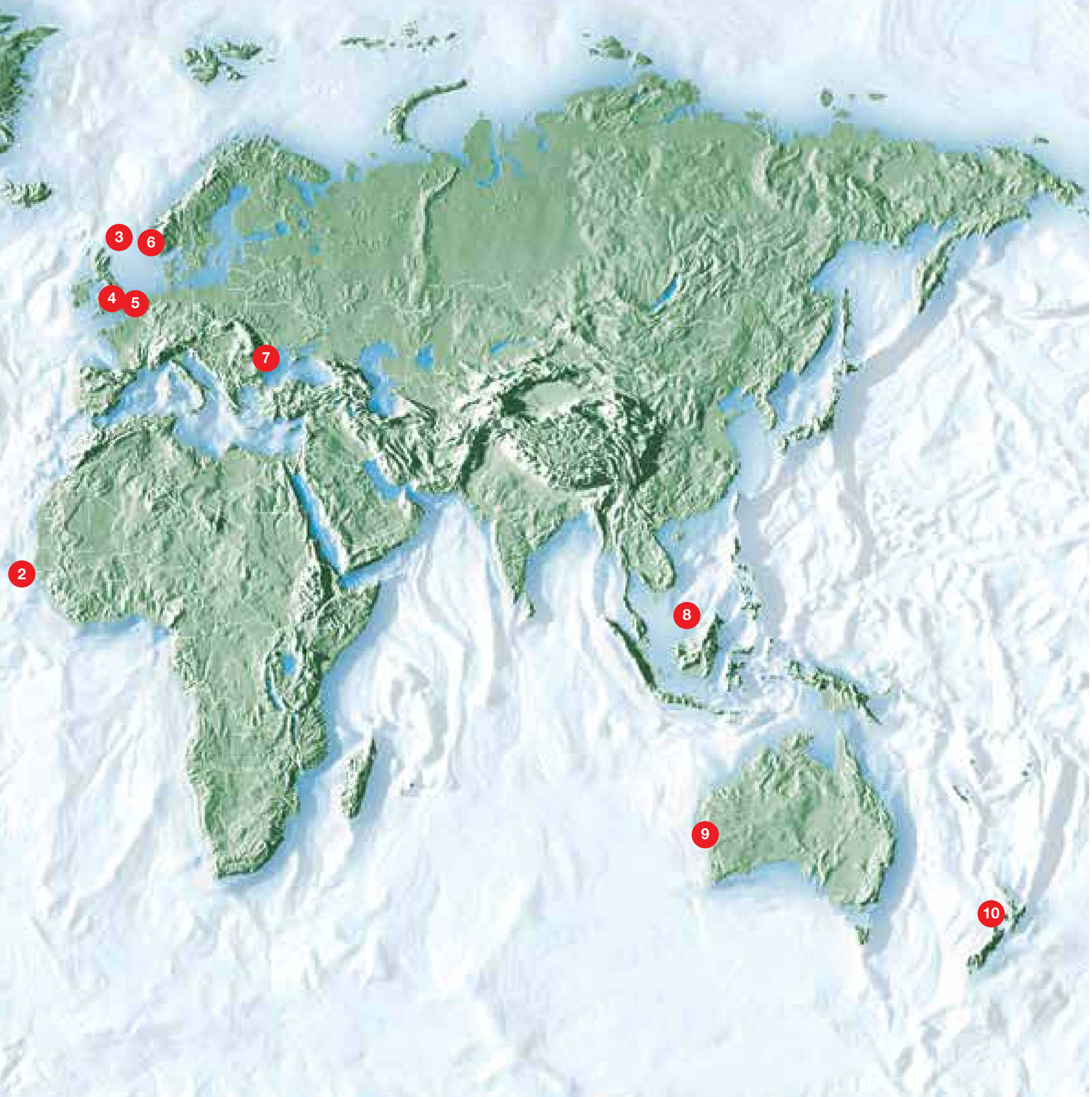
Kosmos Energy has reported a discovery in the eastern anticline in the Greater Tortue, encountering approximately 30 m of net gas pay in high-quality Albian reservoir. The offshore Senegal well, #1-GTA, was drilled to 4,884 m in 2,500 m of water. The Greater Tortue Ahmeyim Field Development is located in Block C-8 (Mauritania) and Saint-Louis Profond Block (Senegal). The drillship will be moved to drill appraisal well #2-Yakaar in the Senegal portion of the development area. ***BP Plc*** is the operator, and partners include Kosmos and ***Petrosen***.

3 *Norway*

Aker BP is nearing completion at exploration well #1-Liatarnet in offshore Norway license 442 in the NOAKA area. The well has proved oil with a gross resource estimate of 80-200 MMboe. Further data acquisition and analysis will be undertaken to determine the drainage strategy and recovery factor for the discovery. Oslo-based Aker BP is the operator and holds 90.26% interest in license 442, with partner ***LOTOS*** (9.74%). A more detailed technical description of well results will be released by the Norwegian Petroleum Directorate when the operation has been completed.

4 *U.K.*

Egdon Resources has confirmed the presence of hydrocarbons at exploration well #2-Biscathorpe in Lincolnshire, U.K. The well is in license PEDL253. According to the Hampshire, U.K.-based company, the well was drilled in the proven hydrocarbon fairway of the Humber Basin and was targeting a Carboniferous Westphalian Sandstone reservoir. Elevated gas readings were recorded in Westphalian over a 157-m Dinantian Limestone interval along with the presence of oil shows in both Westphalian and Dinantian cuttings samples. The well was suspended, and a sidetrack may be drilled after additional studies of existing 3-D seismic data and testing. Egdon Resources is the operator of PEDL253 with 35.8% interest in partnership with ***Montrose Industries Ltd.***, holding 22.2%, ***Union Jack Oil***, with 22%, and ***Humber Oil & Gas Ltd.***, with 20%.



5 *U.K.*

IGas announced core analysis results from exploration well #01-SR at Springs Road in North Nottinghamshire, U.K. The vertical well is in PEDL140 in the Gainsborough Trough Basin. Three zones were targeted—the Bowland Shale, Millstone Grit and Arundian Shale—with 429 m of hydrocarbon bearing shale in Bowland. About 147 m of core was recovered, and testing indicates a total organic compound of 2%-7%, 2%-9% porosity, low clay content and 24-131 MMcf of potential gas pay. It is the second well of an integrated exploration and appraisal program to define the Gainsborough Trough Basin. A previous well, #1-Tinker Lane, was drilled at the edge of the basin and encountered a shale interval before penetrating the targeted Dinantian Limestone. London-based IGas is the operator, and ***Total*** holds a 40% stake in license area PEDL140.

6 *Norway*

Oslo-based ***Lundin Petroleum*** made two oil discoveries at exploration wells #16/1-31S (Jorvik) and #16/1-31A (Tellus East). The discoveries are on the edge of Edvard Grieg Field in the Norwegian sector of the North Sea in PL338 on the Utsira High. The #16/1-31S (Jorvik) encountered oil in 30 m of conglomerate reservoir of Triassic age with thin, high-quality sandstone above. The well was tested at an anticipated flow rate of about 130 bbl per day in the conglomerate interval, and pressure measurements show that the area is in communication with Edvard Grieg Field. The #16/1-31A (Tellus East) encountered a gross oil column of 60 m in porous, weathered basement reservoir. Tellus is on the northern edge of the field. The combined gross resources of Jorvik and Tellus East are estimated to be between 4 and 37 MMboe. The rig will stay in the Utsira High area to drill several shallow gas pilot wells as part of the Solveig development project. Afterward, it will move to drill the Goddo exploration well, #16/5-8S, in PL815 to test the Rolvsnes-weathered basement oil discovery into the adjacent license where the combined area is estimated to contain gross potential resources of more than 250 MMboe. Lundin is the operator of PL338 with a 65% working interest in partnership with ***OMV Norge***, holding 20%, and ***Wintershall***, with 15%.

7 *Romania*

OMV plans to drill two offshore wells in the shallow waters of the Istria Block XVIII in the Romanian sector of the Black Sea. The two wells have planned depths of about 2,000 m, and area water depth is 50 m. The ventures will target additional production from the oil and associated gas in Lebada East Field, which was discovered in 1979. Oil and gas production in the Istria block is currently about 25 Mboe per day, and production is from five producing fields: Lebada East, Lebada Vest, Sinoe, Pescarus and Delta. OMV is based in Vienna.

8 *Malaysia*

A large gas field discovery in offshore Sarawak, Malaysia, was announced by ***PTT Exploration & Production***. The #1RDR2 Lang Lebah is in Block SK410B and hit 252 m of gas pay in the South China Sea. The well was drilled to 3,801 m and was targeting a Middle Miocene Cycle IV/V carbonate reservoir. It was tested at a completion-constrained rate flowing 41.3 MMcf of gas and 246 bbl of condensate per day during testing on a 40/64-in. choke. Although additional testing is planned, current estimates indicate the find at 2 Tcf. Bangkok-based PTT is the operator of the block and the discovery with 42.5% interest in partnership with ***Kuwait Foreign Petroleum Exploration Co.***, holding 42.5%, and ***Petronas***, with 15%.

9 *Australia*

In the Western Australia Block 469, Adelaide-based ***Strike Energy*** has reported hydrocarbon shows in Lesueur and Woodada formations at exploration well #2-West Erregulla in the North Perth Basin. According to the company, good hydrocarbons have been observed, and both formations had fair-to-good visual porosity and appear better than the offset well #1-West Erregulla. The hydrocarbon-bearing formations will be further evaluated with open-hole wireline logging. Strike plans to test the secondary conventional gas target of the well and the Basal Wagina Sandstone and will be targeting analogous Permian gas sands of a similar nature as the Waitsia gas discovery. The well has a planned depth of 5,200 m and will penetrate two additional independent reservoir targets including a conventional gas target in Basal Wagina sandstones and the primary gas sand sequence in the Kingia High Cliff. Strike Energy is the operator with 50% interest in EP469 and its wells in partnership with ***Warrego Energy***, with the remaining 50%.

10 *New Zealand*

Three development wells in the Tui area of offshore New Zealand have been planned by Kuala Lumpur, Malaysia-based ***Tamarind Resources*** in the offshore Taranaki Basin. The company expects to develop an additional 6-8 MMboe. Three sidetrack wells are planned, and the company is considering a possible fourth sidetrack well, depending on the results from the initial three wells. Tamarind owns 100% of Tui within the Taranaki Basin.

WILDHORSE RIDES AGAIN

Just as the summer doldrums seemed about to take hold, some surprisingly large and highly focused transactions emerged in the latter part of July.

WildFire Energy I LLC said it signed a "line of equity arrangement exceeding $1 billion" from funds affiliated with Warburg Pincus LLC and Kayne Private Energy Income Funds. WildFire said it intends to pursue acquire-and-exploit opportunities in the Lower 48, leveraging experience gained in acquiring and scaling assets at prior ventures, including Wildhorse, Memorial Resource Development Corp. and earlier endeavors.

The company will "develop sizeable upstream and midstream assets where the latest technology can unlock further value potential, and production optimization can improve cash flows," added WildFire president Steve Habachy, formerly the COO at WildHorse.

Meanwhile, California Resources (NYSE: CRC) and Colony Capital Inc. (NYSE: CLNY) said they had set up a strategic joint venture in which $350 million is committed through Colony's energy investment arm, Colony HB2 Energy, to develop CRC's flagship Elk Hills Field in the San Joaquin Basin. Total investment may increase to $500 million, subject to mutual agreement.

The investment provides for a pre-approved development plan to drill about 275 wells over three years at Elk Hills. Colony will also receive warrants to buy 1.25 million CRC shares at a $40 strike price upon funding its capital obligations.

In debt, Enterprise Products Operating LLC priced $2.5 billion of senior notes.

—Chris Sheehan, CFA

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount	Comments
WildFire Energy I LLC	N/A	Houston	US$1 billion	Announced it had signed a line of equity arrangement exceeding $1 billion from management, funds affiliated with **Warburg Pincus LLC** and the **Kayne Private Energy Income Funds**. The company's management will leverage its experience in acquiring, optimizing and scaling assets that has proven to be successful in prior ventures, including **WildHorse Resource Development Corp.**, **Memorial Resource Development Corp.** and their private company predecessors.
California Resources Corp.	NYSE: CRC	Los Angeles	US$320 million	California Resources and **Colony Capital Inc.**, through its energy investment management arm, **Colony HB2 Energy**, formed a strategic joint venture in which Colony has committed to fund $320 million for the development of CRC's flagship Elk Hills Field in the San Joaquin Basin. Subject to the mutual agreement of the parties, the total investment may be increased to $500 million.

DEBT

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Enterprise Products Partners	NYSE: EPD	Houston	US$2.5 billion	Announced that its operating subsidiary, **Enterprise Products Operating LLC**, priced a public offering of $2.5 billion aggregate principal amount of notes comprised of $1.25 billion principal amount of senior notes due July 31, 2029, and $1.25 billion principal amount of senior notes due Jan. 31, 2050. It expects to use the net proceeds of this offering for the repayment of debt, including the repayment of amounts outstanding under its commercial paper program and payment of $800 million principal amount of senior notes LL due October 2019 at their maturity, and for general company purposes, including for organic growth capex. Senior notes YY will be issued to the public at 99.955% of their principal amount and will have a fixed-rate interest coupon of 3.125%. Senior notes ZZ will be issued to the public at 99.792% of their principal amount and will have a fixed-rate interest coupon of 4.2%. Enterprise Products Partners will guarantee the senior notes through an unconditional guarantee on an unsecured and unsubordinated basis. Settlement of the offering was expected to occur on July 8, 2019.
Antero Midstream Corp.	NYSE: AM	Denver	US$650 million	Announced the pricing of the private placement by **Antero Midstream Partners LP**, an indirect wholly owned subsidiary of Antero Midstream, to eligible purchasers of $650 million in aggregate principal amount of 5.75% senior unsecured notes due 2028 at par. Antero Midstream estimates that proceeds of the offering will be approximately $643 million, after deducting the initial purchasers' discounts and estimated expenses, which Antero Midstream Partners intends to use to repay a portion of the outstanding borrowings under its credit facility.
Nine Point Energy LLC	N/A	Denver	US$320 million	Announced its entry into a $320 million term loan facility with **AB Private Credit Investors LLC** as administrative agent and lead-arranger. The purpose of the facility is to fund the continued growth of Nine Point's Williston Basin development program.

These deals and details on thousands more are available in real time in a searchable, sortable database at HartEnergy.com.

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.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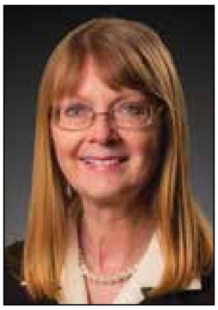
THE ROAD NOT TAKEN



LESLIE HAINES, EXECUTIVE EDITOR-AT-LARGE

It seems it is difficult to get away from energy controversies even while driving through the White Mountain National Forest in northern New Hampshire.

We were on our way to see the home of revered New England poet Robert Frost when we drove through a small, scenic village. There, we spied a public building whose sign on the front lawn read, "Northern Pass is dead! Yay!"

Northern Pass, a project of utility Eversource, was to be a 192-mile transmission line that would move electric power from Hydro-Quebec through New Hampshire to the New England grid.

It was needed, for residents there pay more for electricity than consumers in any other region except for Hawaii and Alaska. However, they opposed this project for years—it was first announced back in 2011. Through months of regulatory hearings and public meetings, Eversource changed the route, offered to put some of the transmission line underground, and vowed not to use eminent domain.

Despite these concessions, local opposition never died down.

Finally, in late July of this year, the N.H. Supreme Court put the final nail in the coffin when it ruled unanimously against the proposed power line, denying permits for construction. Eversource had to pull the plug.

This is outrageous, and sad. After all, this project would have brought clean, renewable power derived from water—not fossil fuels. But it shows you how adamant New Englanders are about preserving their environment and scenery, upon which tourism income depends. Opponents of Northern Pass also asked why their state should be the conduit for power that was mostly going to be used by consumers in Massachusetts and other states south of them.

Meanwhile, returning from the energy wars of New England, we found ourselves at the midpoint of 2019, which is turning out to be a challenging year. Oil prices have tumbled, natural gas and NGL prices are beyond terrible, and stock prices are taking a huge hit. Challenges abound for E&Ps, and investor sentiment continues to question the existence of any company with a market cap below $2 billion. Let's not even talk about the black hole into which most service companies have sunk.

We like what analyst Paul Sankey of Mizuho counseled at the time: "Stay in the race. This is a marathon, not a sprint. Companies are on the right road."

After a particularly bad drop in the stock market that dragged the price of oil and the energy stocks much lower on Aug. 5 (U.S.-China trade war tariffs), he wrote: "We have become a hard-bitten, shell-shocked surviving band of losers, and have seen worse days than yesterday for oil ... in the past week. It really is quite extraordinary.

"Our star E&P analyst, Vin Lovaglio, runs through last week results in his Target Depth note, highlighting Noble Energy, EOG Resources and Oxy as winners, not to mention Hess, which had a strong quarter. Again and again, we reiterate that these oils are grinding their way toward the right delivery of the right strategy."

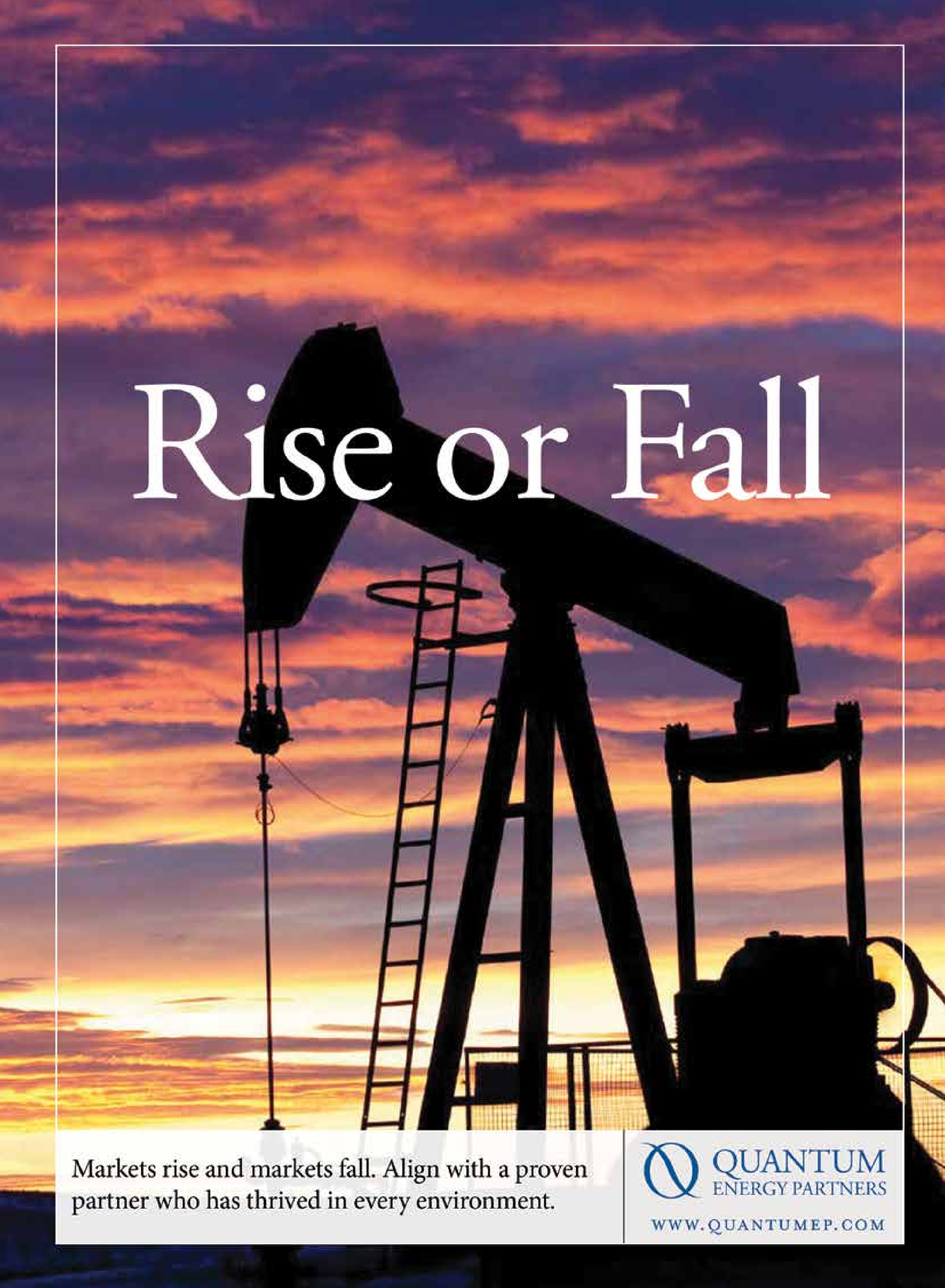
For equity recovery, the right road to take is abundantly clear: spend within cash flow (no matter that it is declining), yet still grow production slightly. Seek a better return on capital employed. Return something to shareholders. Under-promise and meet those expectations, if not over-deliver.

Experimentation has always been a necessary part of an E&P company's game plan. How else can the engineers nail down the proper decisions on well placement, completion design subtleties and all the other technical factors that lead to the repeatability of better wells, that is, those with more productivity per foot, for less cost?

But even the most respected E&P companies can stumble occasionally during this type of experimentation. This should be expected, but in the unforgiving world of chasing investment returns, not so.

Exhibit 1: Concho Resources Inc.'s 23-well Dominator pad in the Permian Basin, which cost the time of seven rigs and $250 million, yet yielded disappointing well results, as reported in the second quarter. One analyst called the project a moonshot. But it has caused the company to lower its 2019 oil production forecast from earlier statements, which led analysts to lower their price targets.

Sankey said, "It was a self-inflicted wound for the company to combine the dreaded excessive target with operational underperformance in the context of relatively limited disclosure. As noted by our head of sales, Ed Heaney, the stock now looks like a screaming buy on its chart, and we would agree, adding our now-standard line: certainly [a buy] for Chevron."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