Oil and Gas Investor

JANUARY 2020

Major players push the envelope—and independents—in the major shales.

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JANUARY 2020/VOLUME 40/NUMBER 1

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EVENTS | MEDIA | RESEARCH | DATA

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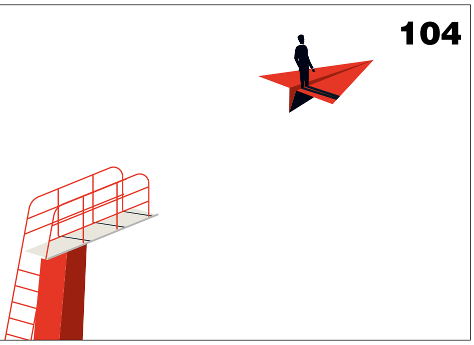

Oil and Gas Investor

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HartEnergy.com

COLUMNS

DEPARTMENTS

ABOUT THE COVER: Inside a control room, sometimes called a dog-house, a rig hand monitors ExxonMobil Corp.'s drilling operations in the Delaware Basin. Photo courtesy ExxonMobil Corp.

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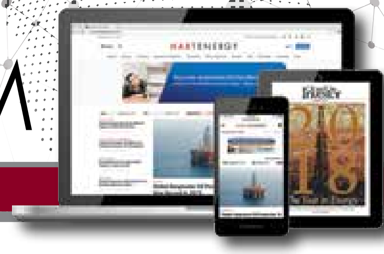


LATEST CONTENT

Goodnight Midstream Expands Eagle Ford Shale Operations
With the Eagle Ford Shale expansion, Wyatt Water Solutions also rebranded under Goodnight Midstream.

Consolidation Coming In Midstream Water Space
Analysts see headwinds leading to fewer water players in the Permian Basin region going forward.

California Toughens Drilling Oversight In Setback For Industry
The regulations, which were applauded by environmental groups, sent shares of California-based oil drillers Berry Petroleum Corp. and California Resources Corp. down sharply.

Pioneer Sees 'Success' In Permian Basin's Wolfcamp D Appraisal Program
Cumulative production has improved by 100% compared to wells drilled before 2017, the company said.

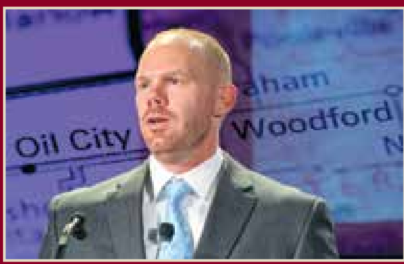
Frack Sand: Playing Nice, Improving Permian Basin 'Sandbox'
Using better technology, including frack sands, and working hand-in-hand with other operators makes Permian Basin operations more efficient.

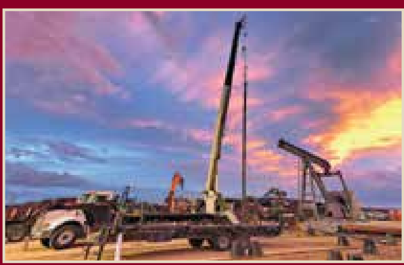
Spur Energy CEO: 'Hardest Dang Thing We've Ever Done'
Jay Graham says the company's Northwest Shelf deal got done because of extra effort.

Talos Energy Snaps Up GoM Assets In $640 Million Swoop
Talos Energy signed agreements with three different private E&Ps to acquire assets that include over 40 identified exploration prospects located on roughly 700,000 gross acres in the U.S. Gulf of Mexico.

ONLINE EXCLUSIVES

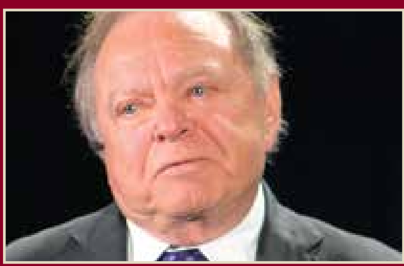
Gulfport Sees Gains With 'Aggressive' Drilling, Completions In Scoop
Increased stage spacing and proppant loading plus use of 100-mesh sand have proven favorable for Gulfport Energy Corp. in the Scoop.





'World's First' Digital Completions Tech Delivers Real-Time Results
Cold Bore's SmartPAD completions system is the first to deliver real-time, sensor-driven tracking of operations data with analytics, president Brett Chell says.

Harold Hamm: Shale-Based Growth Vital To U.S. Economy
The legendary Oklahoma oilman discussed a myriad of topics in a one-on-one keynote 'fireside chat' at Hart Energy's DUG Midcontinent conference and exhibition.



Videos

Calyx Energy III's Lean Operation
Calvin Cahill, president and CEO of Calyx Energy III, takes a look at how the company has positioned itself economically in a poor price environment.

www.HartEnergy.com/videos

What's Trending

1. Three-Way Midland Basin Combination Creates $1.5 Billion E&P
2. Big Name Investors Take Aim At Beaten-Up Energy Sector
3. Laredo Petroleum Tacks On Another Permian Basin Acquisition
4. Jones Energy Agrees To $201 Million Buyout By Revolution
5. Egypt Signs $430-Million Gas Deal With Noble Energy

Awards Program

Join top industry executives to celebrate *Oil and Gas Investor*'s 25 Influential Women In Energy honorees at a gala luncheon on March 4, 2020. Network and dine with distinguished leaders who have risen to the top of their professions and achieved outstanding success in the oil and gas industry.

WomenInEnergyLunch.com

THE COMING DECADE

STEVE TOON,
EDITOR-IN-CHIEF

When the chronological odometer clicks over to a zero year, it's always a good opportunity to pontificate on what the future might hold, and we're all certainly looking for enlightenment these days. The energy industry is experiencing great volatility as we enter the second decade of the millennium; in fact, what might be revealed as a paradigm shift by the end of the '20s.

This time last decade we were just beginning to get our heads around the vast resource potential of the gassy shale plays, and tight oil producibility was still in question. We anticipated the technology would be exported globally. Excepting in Argentina, it hasn't worked out, and maybe that's a good thing considering the world supply glut we've created.

The U.S. oil and gas industry has experienced an amazingly successful decade, in hindsight. Too successful, it could be argued. What was once a battle cry of "drill, baby, drill" has morphed into catcalls by investors of "show me the money." Just as with the advent of unconventional exploration in the early 2000s, the industry is poised for a transformation going into this decade.

First, it is shifting from a mindset of resource scarcity to resource abundance. The go-go pace of drilling and growing production as fast as possible is moderating. Dictated by soft commodity prices, the near 2020s will see E&Ps take a more measured approach to development, focused on efficiencies and returns.

Already, less capital is directed toward growth and more toward maintaining declining production, said IHS analyst Bob Frykland, addressing an IPAA audience in December. Specifically, 80% goes to keeping production flat currently.

"We don't ever see a growth period coming forward at the same magnitude" as before, he said. "We've switched from a game of growth to one of managing costs and doing more for less."

Second, investors must be appeased if producers are to hope for a return of capital to the space. Mizuho Group analyst Paul Sankey says the best E&Ps in the new decade will continue on the "right path" of constrained capex and reduced growth, with increased cash return to shareholders. And not be subtle about it.

"Oil companies need a premium return to the market to make up for their industry's lack of growth and higher volatility. So a yield in line with the S&P 500 is not attractive," he said in a Dec. 12 note. Rather, he suggests a five times return to that of the S&P500 to attract back investors.

"A sustained double-digit cash return to shareholders is outright attractive against any stock in the market, and is enough to offset the headwinds for oil. Beyond being an industry with a proven track record of destroying value, it bribes you to ignore the Tesla effect negative, the end of Peak Oil effect negative and the Greta Thunberg effect negative."

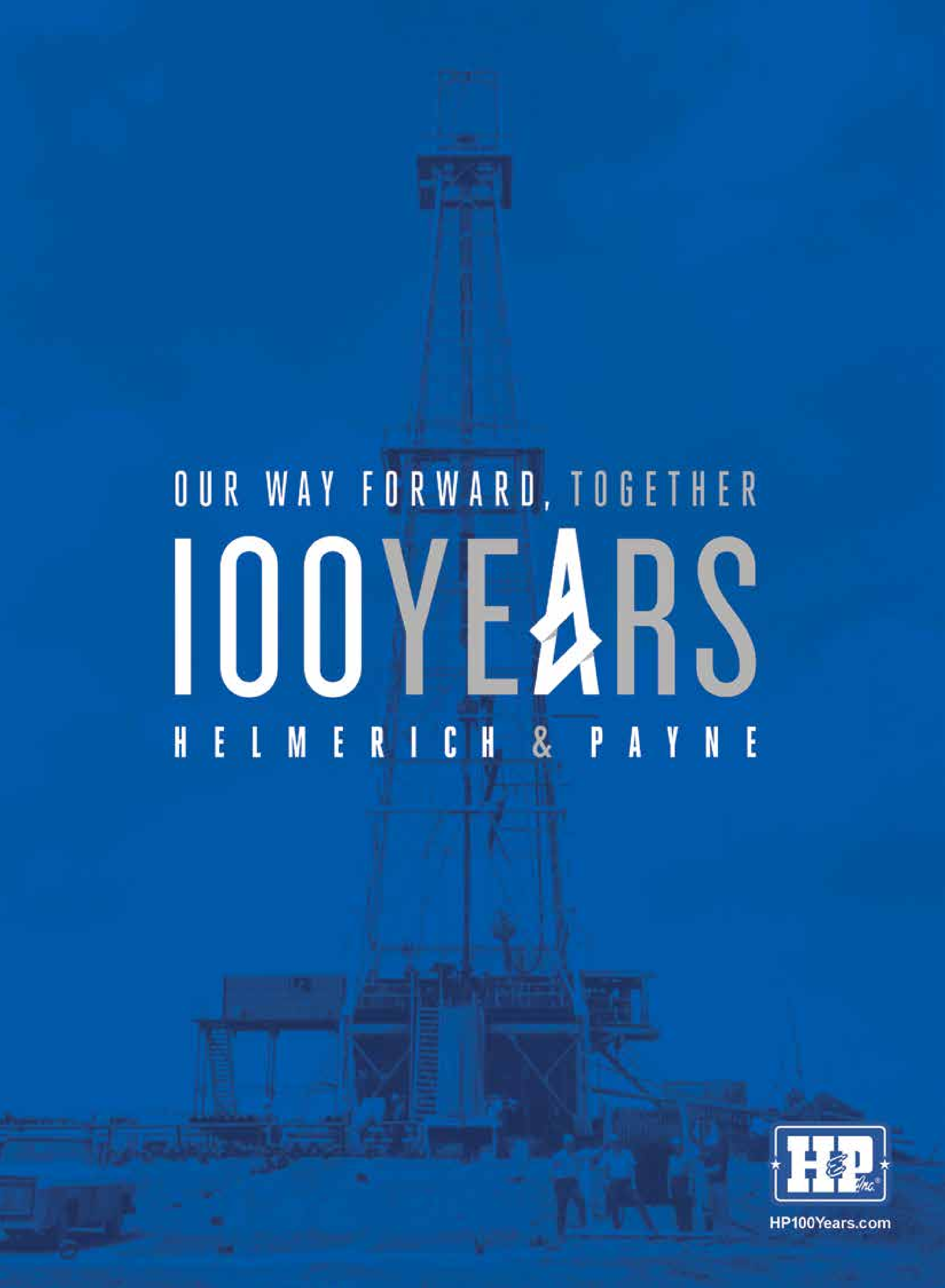
Those "effects" represent a third driver going into the new decade: Oil and gas companies must directly address energy consumers who more and more are denouncing hydrocarbons in favor of renewables. The topic of climate change evokes a lot of emotion on a national and global level, said Wil Van Loh, CEO of Quantum Energy Partners, at a talk in October.

"We have to get dead serious about ESG [environmental, sustainability and governance] issues. It's not really an option any more in my opinion," he said. "You won't have access to capital in three years if you don't recycle all your water, if you don't have emissions monitoring on all your well sites. Given the intensity of the discussion, if we don't police ourselves much better, you won't like the policing that's going to come down to us as an industry."

Fourth, expect the industry to further contract via consolidation. "With the fundamental backdrop of moderate, range-bound oil prices, a company's place on the cost curve is critical," noted Morgan Stanley analysts in a Dec. 11 note. Low-premium mergers of equals make a lot of sense, they said, but expect majors to be active buyers as well.

"The combination of deeply discounted E&P valuations relative to the majors, the overly fragmented nature of the U.S. shales and the value creation from scale operations sets the stage for potential consolidation."

These are just some of the themes that will impact industry as the new decade begins. We hope technology will open up vast new resource opportunities to keep drillbits turning, and the industry will have found its place within the hearts and minds of investors and consumers. Let's check back in 10.


OUR WAY FORWARD, TOGETHER
100YEARS
HELMERICH & PAYNE
H&P Inc.
HP100Years.com

100th ANNIVERSARY
THE PERMIAN BASIN

THE PERMIAN'S PROUD PAST, EXCITING FUTURE

Leslie Haines
Executive Editor-At-Large
Hart Energy

Few places in the world dominate headlines and affect government and company energy strategies like the Permian Basin. The special report you'll find with this issue commemorates the 100th anniversary of this great region and sheds light on its promising future, as its significance on the world energy scene increases.

The W.H. Abrams No. 1 was spud in Mitchell County in 1920, producing oil from a Permian rock layer. Even though it was a modest well, it was important because E&P companies that were focused on East Texas had not thought much about West Texas until then. Soon, drilling activity expanded out to Midland, south to Pecos, west to Artesia and Hobbs.

Lo and behold, 100 years later we are still learning where and how best to tap into this basin's vast potential. It's producing around 4.5 million barrels a day (MMbbl/d), but experts think it has so much more to give. The Global Gas and Oil Network and Oil Change International, using projections from research firm Rystad Energy, said the Permian will account for 40% of all new U.S. production over the next 30 years.

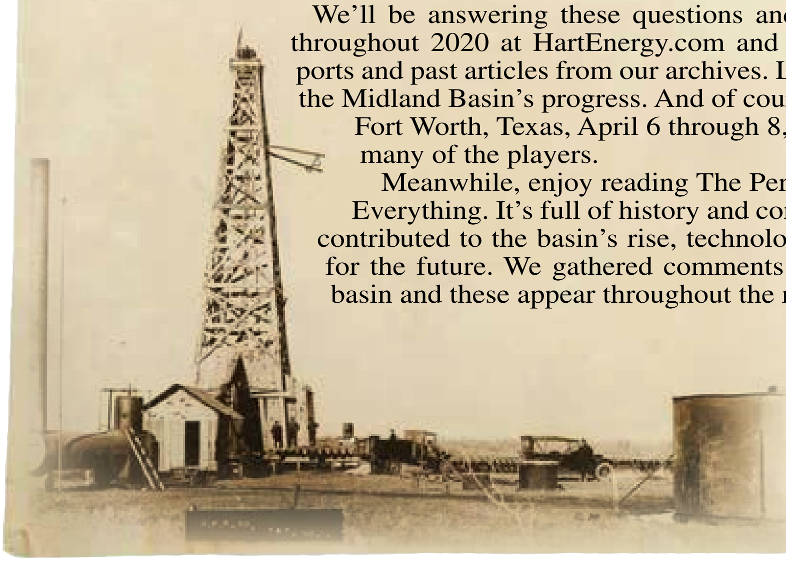
The University of Texas shared this with us: "Recent studies by the Bureau of Economic Geology indicate some 2,700 billion barrels of oil in place in the Wolfcamp and Spraberry of the Midland Basin and about 570 BBOIP in the Wolfcamp and Bone Spring formations of the Delaware Basin," said Scott Tinker, the Texas state geologist and head of the Bureau at UT, who has been studying the basin for 40 years.

"That's 3.2 trillion barrels! Even if only 5% is ultimately produced, that represents 160 billion barrels," he told us. "At 5 million barrels a day—which is approximately 5% of current global oil production—that amounts to nearly 90 years of production."

From Houston and Wall Street conference rooms to London think tanks to OPEC headquarters, not to mention in the offices of Asian oil importers, the Permian Basin is on everyone's mind. Who's in; who's out? What's next?

We'll be answering these questions and more as we cover all aspects of the basin throughout 2020 at HartEnergy.com and PermianBasin100.com, with videos, new reports and past articles from our archives. Look for our February cover story to zero in on the Midland Basin's progress. And of course, join us at the DUG Permian conference in Fort Worth, Texas, April 6 through 8, as we mark this special anniversary and meet many of the players.

Meanwhile, enjoy reading The Permian Basin at 100: The Play That's Changing Everything. It's full of history and context, the stories behind legendary people who contributed to the basin's rise, technology advances and most important, the outlook for the future. We gathered comments from many executives who are active in the basin and these appear throughout the report.



Leslie Haines

This announcement appears as a matter of record only

PetroCap

is pleased to announce the closing of

PetroCap Partners III, L.P.

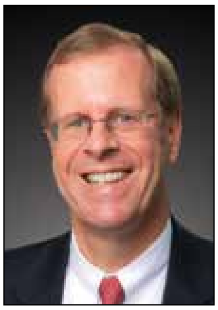
October 2019

$322.0 million

PetroCap is an oil and gas investment firm partnering with independent operators across the United States.

www.petrocap.com

NO SINGLE (OR SIMPLE) SOLUTION



CHRIS SHEEHAN, CFA
SENIOR FINANCIAL ANALYST

As we look back on 2019, and ask ourselves where the industry is headed, we may wonder where we may find wisdom. Might it come from a 16-year-old from Sweden, delivering an impassioned speech to the United Nations; or perhaps a respected CEO of an integrated producer with assets in some 60 countries, retiring after a career spanning some 40 years in energy?

Bob Dudley, due to retire in February from his position as group chief executive of BP Plc, delivered a presentation last quarter in which he provided some thoughtful perspectives on the challenges facing energy. The world needed to "move to a low-carbon energy system," he said, and it is the industry itself that "understands more deeply than many what the 'energy transition' entails."

The departing BP executive defended the role of energy in the economy, and specifically natural gas as an ongoing fuel source for the future. Natural gas has "a vital role to play in the energy transition," he said. And yet natural gas was in some circles being "increasingly marginalized, even vilified and demonized," he said, despite emitting "half the carbon of coal when burned for power."

Worldwide, switching from coal to gas "has cut more than 500 million tons of CO_2 this decade alone."

Dudley described the challenges facing energy as painting a "complex picture," with "no single answer." Each individual fuel has different attributes, costs and benefits, he observed. "To succeed, we need every tool at our disposal. To exclude gas, when so much is at stake, is to take a huge and unnecessary risk," he continued. And, of course, gas "is abundant. It's affordable."

BP has itself been moving forward with efforts to measure emissions at all its major oil and gas sites, with drones, cameras and lasers used to detect leaks that previously would have likely gone undetected, according to Dudley. "Methane leaks and flaring can and must be tackled."

More recently, BP CFO Brian Gilvary cautioned against underestimating the global appetite for energy.

"What we need to recognize is 85% of the world's energy today comes from coal, oil and gas," said Gilvary in a Bloomberg interview. "Last year [in 2018], primary energy demand increased by 2.9%; that's the highest we've seen in over a decade. We have 2 billion more people arriving on the planet over the next 20 years plus 1 billion more of today's population who want access to power."

Assuming BP's sense of the durability of global demand is reasonable, why are prospects for energy producers seemingly so poor? How is it, for instance, that the market cap of Facebook—one of the FANG stocks—comfortably exceeds that of the entire E&P sector?

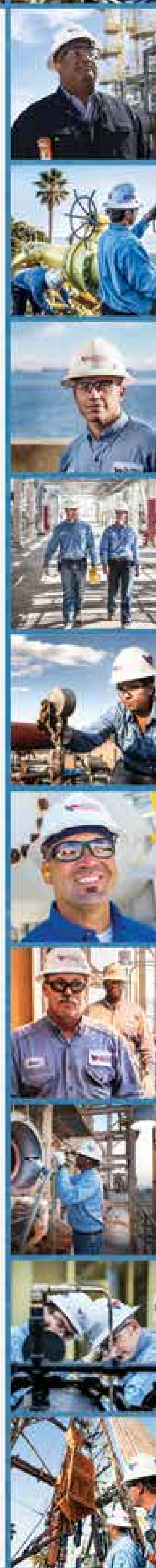
Investor has previously covered, among others, two near-term issues working against new money entering the energy space: the supply/demand imbalance in crude going into the first half of 2020, as well as uncertainty surrounding the 2020 U.S. election outcome (see "Downshifting to Make it Through 2020," OGI December 2019). Both issues loom large in the near term but may perhaps appear less formidable as investors look farther out, into 2021.

Clearly, there is a supply overhang as new production comes on from Norway, Brazil and Guyana in early 2020, but, as one analyst said, "this growth spurt is not sustainable." To use the Johan Sverdrup project offshore Norway as an example, the field is ramping up to 440,000 barrels per day (bbl/d). But the long-lead-time project was almost a decade in the making, having been discovered in 2010.

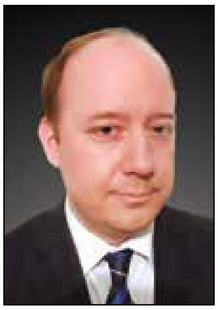
A recent Bernstein report said global offshore oil production would peak in 2020, and "it might be a decade (if ever) before it returns to those levels." Offshore supply is estimated at 27 MMbbl/d, with a 6% annual decline rate. Shallow and deepwater outputs are unlikely to return to peak levels, noted Bernstein, leaving ultra-deepwater projects to account for any growth.

Apart from the Zuluf phase 2 expansion by Saudi Arabia, most of the OPEC countries' offshore projects have sub-50,000 bbl/d peak rates. In non-OPEC countries, the best visibility is from a pipeline of projects in Brazil, Guyana and the U.S. However, with the U.S. offsetting declines elsewhere, the net growth in non-OPEC offshore output comes to just around 2.5 MMbbl/d spread over the next 10 years to 2030.

Are producers likely to rush to commit to long-lead-time, ultra-deepwater projects? Given concerns over the "energy transition," Bernstein believes the answer is "no."



GAME CHANGER



DARREN BARBEE, SENIOR EDITOR

The Dallas Fed might seem an unlikely source of unfiltered, explicit color commentary about the oil and gas industry. In fact, that's what Twitter is for.

But unidentified executives at 156 oil and gas firms, surveyed by the Dallas Fed in September, responded with a sense of maturity and insight while collectively bellowing, "ya basic!" at a variety of institutions, entities and each other.

"Over $130 billion of junk status bonds are coming due after 2020 over a two-year period for those that got in the treadmill drilling business," one executive said. (Drilling Treadmill, coming soon from Sharper Image.)

Another complained of boorish New Mexico protestors who despise fossil fuels but "want our money."

The U.S. Energy Information Administration (EIA) took a few hits over its DUC (drilled but uncompleted) estimates, including this succinct observation: "The EIA has no clue."

Another said producers were engaging in self-sabotage. "We cannot have it both ways: There cannot be a flood of Permian production which depresses global commodity prices if capital inflows (i.e., new equity and debt issuances) are at all-time lows," an executive said. "Producers must reduce capital expenditures, which will have a positive effect on medium-term (two- to four-year) commodity prices."

And, of course, several executives also pointed to the capital markets, which lately have shunned E&Ps.

Alas, friends, Permians, landmen, lend me your ears: I come to bury the market, not to praise it.

The Saudi Aramco IPO may seem an affront to many in the oil and gas world as its value soared to $2 trillion on Dec. 12. But this is merely investment thrill-seeking. The market demands free cash flow, yet Aramco has been priced at a premium to global oil majors with significantly higher yields. As Bernstein Research noted Dec. 11, "Aramco should trade at a discount rather than a premium to the supermajors."

But Aramco's IPO is a classic elephant-in-a-matchbox scenario. Investors swept up in the awe of the world's largest land IPO aren't looking for greatness in matchbox-sized E&Ps.

Why? Because of stats like these: In the past five years, U.S. energy companies have led all other industries in defaults, according to RapidRatings, a financial analytics company.

The market already clamped down on E&Ps in 2018, a year in which follow-on equity offerings were down 73%, according to Barclays. In 2019, upstream IPOs were virtually nonexistent.

"I think Brigham Minerals was the only upstream E&P company to IPO in the U.S. in 2019," Hillary H. Holmes, co-chair of Gibson Dunn's capital markets practice, told *Investor*.

Blank-check companies continue to pop up, including Alussa Energy Acquisition Corp.'s IPO that eventually tallied $287.5 million.

Yet E&Ps with assets in hand remain radioactive. In the coming year, public companies may face a better chance of being acquired and taken private, if a mini-trend continues to develop from 2019.

In October, private-equity-backed Citizen Energy said it would buy Roan Resources Inc. for $1 billion in cash, rip off its NASDAQ ticker and let it enjoy some private operator time.

In the midstream, companies already have felt private equity's love, as Buckeye Partners LP and American Midstream Partners (now Third Coast Midstream) both broke out of their public glass houses.

Investors remain fickle beings. If not backing dependable oil and gas, what are they putting money into?

Would you believe, esports? For those with a life, esports is competitive video game playing with a $1.1 billion global market, according to Bloomberg.

On Dec. 9, Denmark's Astralis became the first esports team to launch an IPO. It slightly exceeded its goal of raising US$22 million.

Reality may be breaking down, but at least it won't be boring. Astralis' game of choice is Counter-Strike: Global Offensive (is that anti-union?), and the team is currently world champion.

In fairness, Astralis differs from other tech-centric companies such as Tesla Inc. in two respects: It has a winning record, and it appears unlikely to lose $1 billion in a seven-month period.

As an energy executive told the Fed, the market is so driven by events of the moment it "makes strategic planning more like strategic speculation."

Perhaps the industry's best hope is really big data—especially if there's any hope of a deep run in the playoffs.

EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
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 Bakken and Rockies	**Feb. 18-19**	**Denver**	**Colorado Convention Center**	**dugrockies.com**
SPE A&D Symposium	Feb. 26	Houston	Petroleum Club	spegcs.org
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
TIPRO Annual Convention	Mar. 23-24	Dallas	Hilton Anatole	tipro.org
DUG Permian	**April 6-8**	**Fort Worth, Texas**	**Fort Worth Convention Center**	**dugpermian.com**
OGIS New York	April 20-22	New York	Sheraton New York Times Square	ipaa.org
Mineral & Royalty Conference	April 27-28	Houston	Post Oak Hotel	mineralconference.com
Texas Energy Alliance Annual Meeting	April 28-29	Wichita Falls, Texas	MPEC Convention Center	texasalliance.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**
CIPA Annual Meeting	June 4-7	Santa Barbara, Calif.	TBA	cipa.org
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**
Unconventional Resources Tech. Con.	July 20-22	Austin, Texas	TBA	urtec.org/2020
IPAA Midyear Meeting	June 29	Newport Beach, Calif.	Pelican Hill	ipaa.org
Summer NAPE	Aug. 12-13	Houston	George R. Brown Conv. Center	napeexpo.com
EnerCom The Oil & Gas Conference	Aug. 16-19	Denver	Westin Denver Downtown	theoilandgasconference.com
DUG Eagle Ford	**Sept. 9-11**	**San Antonio**	**Henry B. Gonzalez Conv. Center**	**dugeagleford.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.

2020 Hart Energy Events:

CONFERENCE & EXHIBITION DUG BAKKEN AND ROCKIES
Feb. 18-19
Denver, CO
Colorado Convention Center
20 Years in the Bakken

energy capital CONFERENCE
March 2
Dallas, TX
Fairmont Hotel – Dallas

25 INFLUENTIAL Women IN ENERGY
March 4
Houston, TX
Hilton Americas – Houston

The world depends on energy, and energy professionals depend on us.

CONFERENCE & EXHIBITION DUG EAST | **MARCELLUS-UTICA MIDSTREAM CONFERENCE & EXHIBITION**
June 16-18
Pittsburgh, PA
David L. Lawrence Convention Center
CO-LOCATED

CONFERENCE & EXHIBITION DUG EAGLE FORD
Sept. 9-11
San Antonio, TX
Henry B. Gonzalez Convention Center

DUG *Eagle Ford* Forum:
September 9

HARTENERGY
Conferences

In 2019, Hart Energy organized ***14 events***

300+ *industry-leading speakers*

620+ *sponsors*

Where Business Meets Opportunity

CONFERENCE & EXHIBITION
DUG PERMIAN BASIN
April 6-8
Fort Worth, TX
Fort Worth Convention Center

Permian Water & Sand Forum:
April 6

100 Years of the Permian

CONFERENCE & EXHIBITION
DUG HAYNESVILLE
May 19-20
Shreveport, LA
Shreveport Convention Center

CONFERENCE & EXHIBITION
MIDSTREAM TEXAS
June 2-3
Midland, TX
Midland County Horseshoe Pavilion

A&D STRATEGIES AND OPPORTUNITIES CONFERENCE
Oct. 27-28
Dallas, TX
Fairmont Hotel – Dallas

EXECUTIVE OIL CONFERENCE & EXHIBITION
Nov. 3-4
Midland, TX
Midland County Horseshoe Pavilion

Folds of Honor Golf Tournament:
November 2

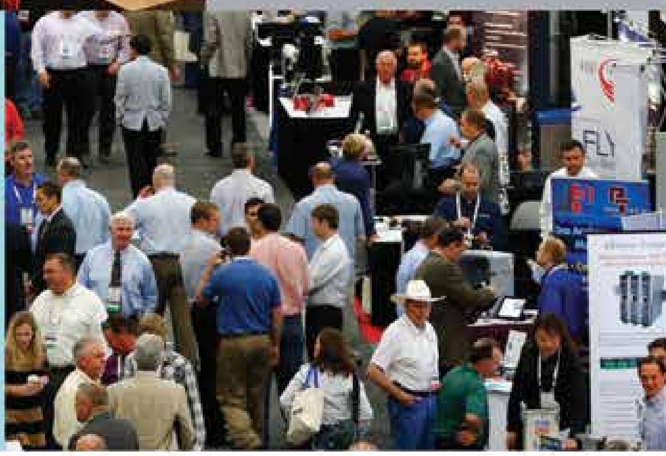
Permian Basin Water Forum:
November 3

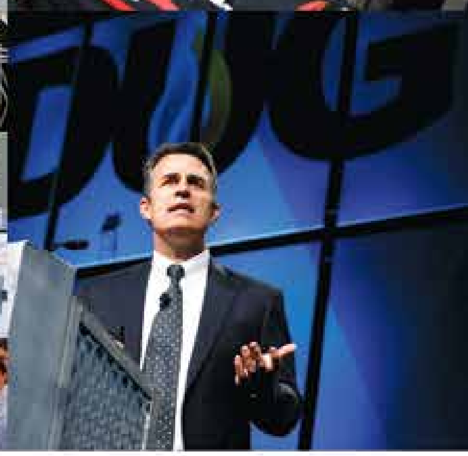
CONFERENCE & EXHIBITION
DUG MIDCONTINENT
Nov. 17-19
Oklahoma City, OK
Cox Convention Center

DUG *Midcontinent* Forum:
November 17

Attracting more than
13,000 attendees

840+
exhibitors





For more information, visit **HartEnergyConferences.com**

NewsWell

Rystad: Shale output will grow even if oil prices falter

North American oil shale supply will continue growing even in an environment with lower oil prices, consultancy Rystad Energy has forecast. After the December OPEC meeting, and members' decision to make further cuts to March 2020, the 12-month strip for West Texas Intermediate (WTI) crude rose a mere 58 cents.

"Despite the continued decline in the number of horizontal rigs since the beginning of 2019, we have not observed a significant fall in the number of spudded wells," Rystad said.

"At the same time, shale investments have declined by 6% to around $129 billion in 2019, and are expected to fall another 11% in 2020 due to the industry's focus on cash-flow discipline and free-cash-flow generation. This means the industry will lower its total investments for two subsequent years—a development we haven't seen since the oil price crash in 2014."

Sonia Mladá Passos, a product manager of Rystad Energy's shale upstream analysis team, said, "In spite of the decline in spending and activity levels, the North American shale supply is not following the downward trend."

In Rystad Energy's base-case price scenario, with oil at $55 per barrel (bbl/d), the North American light tight oil (LTO) supply will reach 11.6 million barrels per day (MMbbl/d) by 2022. This forecast implies an annual growth rate of 10% from 2019 to 2022.

In a price scenario with WTI remaining flat around $45/bbl, this supply would plateau slightly lower, at 10.1 MMbbl/d towards 2022.

"The flat development of U.S. LTO production is also possible in lower price scenarios, but we would likely see an initial period of multi-quarter production decline, with output stabilizing at a lower level," Mladá Passos said.

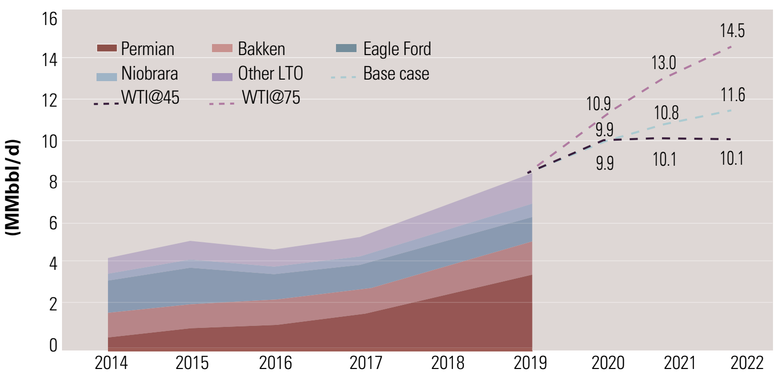
The light tight oil supply from North American shale was set to reach 8.6 MMbbl/d in 2019. Nearly 93% of this supply was driven by U.S. production, and slightly more than 600,000 bbl/d was produced in Canada.

In 2019, the industry remained on track to spud around 17,000 horizontal wells targeting shale formations in the U.S. and Canada. Going forward, Rystad Energy analysts said they expected drilling activity to remain relatively flat at around 17,000 spudded wells per year, on average, according to its base-case price scenario.

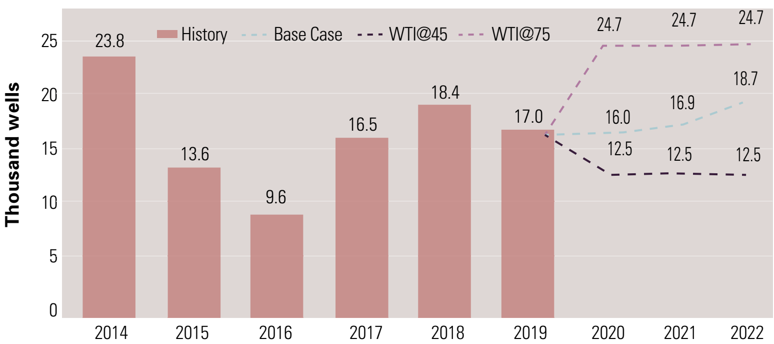
However, in the low price scenario with WTI flat at $45/bbl, activity in North American shale may begin sharply decreasing, falling by 26% in 2020 year-on-year.

—Leslie Haines

North American Tight Oil Supply By Basin



North American Shale Price Sensitivity Of Horizontal Drilling Activity, 2020-2022



Source: Rystad Energy UCube, December 2019

Midstream executive sees 'light at end of tunnel'

Natural gas prices are down, demand is weak and renewable energy sources are deepening their penetration in the residential and commercial energy sector, but Ryan Savage, vice president at The Williams Cos. Inc., said natural gas supply must rise to meet demand in the next decade.

Admittedly, "that is difficult to talk about right now," Savage said in December at the Marcellus-Utica Midstream conference in Pittsburgh.

However, the projected demand of U.S. natural gas commitments to Mexico and LNG exports worldwide will match North American residential and consumer natural gas use by 2025, he said. Exports will eventually have to rise to more than 25 billion cubic feet per day (Bcf/d) from roughly 10 Bcf/d in 2019.

"If you've got demand growth like that, then we've got to increase supply," he said.

With more than 20 years in the industry, Savage said he's seen the

North American LNG Projects Move Forward

Project	Capacity (Bcf/d)	In-service Date	Comments
Sabine Pass Train 6	0.7	2023-2024	Under construction
Corpus Christi Stage 3	1.7	2022-2023	Company aims to FID in 2020
Freeport Train 4	0.8	2025-2026	Fully permitted, awaiting FID
Calcasieu Pass	1.4	2023-2025	FID August 2019
Golden Pass	2.2	2024-2026	Under construction
Port Arthur	1.6	2025-2026	Fully permitted, awaiting FID
LNG Canada	1.9	2024-2026	FID in Fall 2018
Woodfibre LNG	0.3	2024-2025	

Source: The Williams Cos. Inc., Wood Mackenzie

ups and downs of prices before, in part because of the exuberance of producers. But the longstanding paradox of the industry is that the "cure" for low commodity prices—oil or gas—is low prices themselves.

"We've been through this before where we find something that's a good thing and maybe produce a little too much of it and move a little too much of it, and we get a little bit of an overhang," he said.

LNG export projects under construction, permitted by the Federal Energy Regulatory Agency (FERC) or awaiting a final investment decision (FID) would give U.S. producers another 10.6 Bcf/d of export capacity.

Savage said patience is required while demand catches up, though supply will also have to increase.

The Permian Basin is expected to increase gas production by 9.7 Bcf/d from 2018 to 2023, according to Wood Mackenzie. But in the Northeast, the Marcellus and other shale plays are also forecast Source: to grow production by 6.5 Bcf/d. The Haynesville Shale and Cotton Valley areas will also increase production by 5.9 Bcf/d.

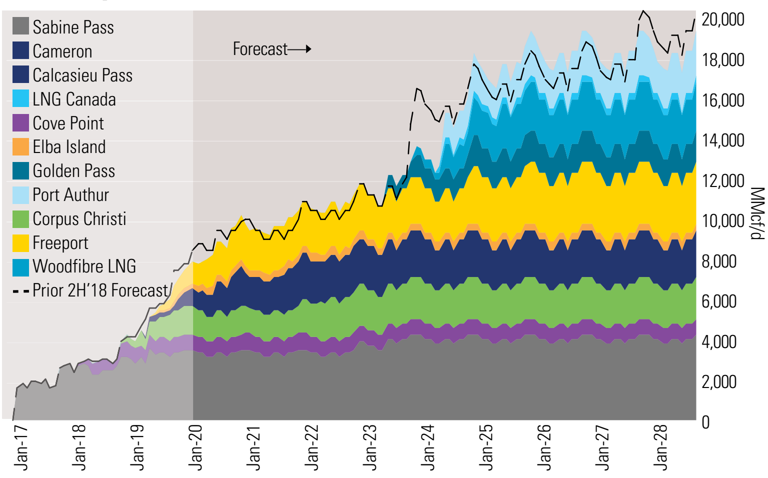
"It's clear to me that natural gas is going to have to grow to meet that demand and it's going to come from the most advantaged space," he said. "And, sure, some of those are going to be oil-based spaces, but here in the Northeast in the Marcellus we have a tremendous resource that's been proven. We've had producers that have done pretty amazing work in a low-cost environment of driving costs down."

In the near-term, however, pricing remains an ugly reality.

"It's always the elephant in the room right now," he said. "It's not good. It's very bad. But you've got to get comfortable with the demand story internationally and in the export market. I think when you get comfortable with that, you can see the light at the end of the tunnel."

—Darren Barbee

Forecasted North American LNG Export Monthly Volumes (2017-2028)



Source: Wood Mackenzie

Shale players search for 'happy median' in Permian, Eagle Ford

Longer laterals, more proppant and rising slickwater fracks are part of the formula driving production growth in the Permian Basin as operators, working with oilfield service companies, continue to tweak completion designs looking to add value.

Some notable trends have emerged, according to John Parker, technical advisor for Enverus, the data and energy analytics firm formerly called Drillinginfo Inc. Speaking during a webinar on Dec. 4, Parker focused on trends seen in the Eagle Ford and the Permian's Delaware and Midland sub-basins.

"The average lateral lengths are getting longer," Parker said, pointing out how they've grown to an average 7,838 feet in the Delaware and 7,227 feet in the Gulf Coast Basin, home of the Eagle Ford. "In the Midland Basin, we see some of the longest laterals out there in the Wolfcamp portion of it."

Lateral lengths in the Midland are averaging about 9,280 feet, with lengths in the Wolfcamp D zone averaging about 9,610 feet, according to the firm's data.

Having contiguous acreage enables longer laterals, which improves efficiency and the ability to scale. Increasing lateral lengths, which were less than 6,000 feet about five years ago in the Permian, have helped oil and gas companies improve their production profiles.

Companies, however, are still learning more about shale plays, tweaking completion methods and frack designs along the way.

Evolution is evident in new generation frack jobs. Parker used Matador Resources Co. as an example. The independent E&P is focused on the oil and liquids-rich parts of the Delaware's Wolfcamp and Bone Spring play as well as the Eagle Ford, Haynesville Shale and Cotton Valley plays. In the Delaware Basin, data gathered from investor presentations and market research show how the company's frack designs have changed reservoir-by-reservoir.

"Matador is actually dialing

back from 3,000 pounds per foot down to about 2,500 and tinkering with around 3,000," Parker said, referring to the Wolfcamp A. "There are different completion techniques and styles for each one of these [reservoirs]."

The company also moved to 2-mile laterals on 1,280-acre sections to maximize returns, instead of a 1-mile lateral on a 640-acre section, he said.

"They were gaining an extra 800-plus feet in the pay zone," Parker said.

Other trends seen across the Eagle Ford as well as the Delaware and Midland are increases in the amount of fluid and proppant used. Drillinginfo Web app data put the average amount of proppant used in the Delaware Basin at nearly 17.8 million pounds per well; about 18.3 million pounds in Midland; and 15.9 million pounds in the Gulf Coast Basin.

"Predominately what we've seen over the last year or two years is a switch from gel frack to more slickwater fracks due to the pricing, and it's just worked out better," Parker said, noting spacing also is a factor. "With the gels we're typically seeing you can get away with a 20:40 or 30:50 mesh size sand. And now, since we've gone to slick water, we see 40:70, 100-mesh typically being pumped." The latter has been the go-to choice for many operators because of its abundance, cost and how well it works with slickwater fracks.

Well spacing—how close is too close vs. not close enough—also has been a topic of focus lately as some operators have experienced well interference issues between child and parent wells.

Many shale players targeted higher production by placing wells closer together. But that has resulted in less output, in some instances, leading to more conservative spacing.

Concho Resources, a Permian Basin pure-play, decided to make spacing changes after wells drilled as part of tests underperformed in the Delaware Basin. The wells, which were completed and put on production, were spaced about 50% tighter than Concho's traditional spacing. The average lateral length was about 4,400 feet. The company planned for fewer wells per reservoir and spacing farther apart in second-half 2019.

Earlier this year, Pioneer Natural Resources CEO Scott Sheffield said the company tested 500-foot spacing in 2014 but saw interference, prompting it to move to today's Permian norm of 850-foot spacing. But Pioneer opted for wider spacing—1,200 to 1,300 feet—in the Wolfcamp D because it was a thinner zone. At the time, no interference was seen.

"With the market that we have right now, wider spacing is what's being preferred because we want to see more cash flow and returns to shareholders vs. having a high level of well inventory and production growth," he said.

In the Eagle Ford, Enverus is seeing tighter spacing of 200 to 400 feet to 400 to 600 feet and many co-completed wells, Parker

said. Wells can be spaced closer in the Eagle Ford because of the type of rock that is present.

In the Delaware Basin, where there is mudstone, Parker said the formation "breaks like glass" when hydraulic fractured with slickwater. "So, we're actually seeing wider spacing" in that area, moving from 660 feet away from the nearest well to 880 feet or up to 1,000 feet in some areas, depending on the type of rock present, to avoid hydraulic communication between wells.

Well spacing could impact estimated ultimate recovery, but it is not only of concern horizontally; vertical spacing is also something on which to keep an eye whether a cube design or wine-rack design is being used, according to Parker.

"There are multiple horizons that stack up very close to one another," he said, noting vertical spacing must also be evaluated depending on whether a cube design vs. wine-rack design is used.

In all, advances in completion designs and technology have improved EUR, Parker added.

"EURs have increased dramatically with just understanding the rock better," he said. The industry is now at a point where it's trying to find a "happy median" and "sweet spot" as it makes further adjustments.

—Velda Addison

Mexico gas demand might not be all that was expected

For years now, U.S. natural gas producers have been counting on increased demand from Mexico to sop up some of the vast quantity of gas that they can produce from the Haynesville, Permian Basin, Eagle Ford and other plays.

The EIA reported in December that U.S. production had now topped 96 billion cubic feet per day (Bcf/d). "The once unthinkable level of 100 Bcf/d for U.S. natural gas production is just around the corner, it would seem," commented Rusty Braziel of RBN Energy.

"Lower 48 gas production hit a new high of 96.4 Bcf/d, after surpassing 95 Bcf/d not too long ago (in late October). That's remarkable considering that production was only 52 Bcf/d just 12 years ago."

Higher production may be a boon, but only if there is enough demand. If the Mexican call on natural gas is lower than expected, then what?

"We have long argued that gas bulls overestimate the ability of Mexico to act as a demand sink for U.S. gas. The entire country has gas demand of about 9.4 Bcf/d, or about 10% that of the U.S., and we already supply about 6 Bcf/d of that demand through pipeline and LNG exports," said Bernstein analyst Jean Ann Salisbury in a recent research note.

"Mexico is still not the needle mover some still expect."

She said Mexico pipeline exports could grow by 3.5 Bcf/d from 2019 to 2023 (less than 1 Bcf/d per year)—but 0.5 Bcf/d of this "is knocking out U.S.-sourced LNG, which will need to find another home globally."

Analysts have been warning about the growing glut of LNG exports around the world, which have driven down LNG prices.

"Part of the confusion around the potential for Mexico gas demand stemmed from the massive amount of pipeline buildout to the border in recent years, 14 Bcf/d, anchored by CFE (Comision Federal de Electricidad)," she said.

Gas pipeline construction delays within Mexico, and disputes over pipeline rates or tariffs there, have also hampered U.S. exports to Mexico. Utilization of the 14 Bcf/d of pipes will be only 60% by 2023, she said, even when those new pipes come online.

—Leslie Haines

Analysts forecast drop in U.S. shale activity, rise in efficiency

Don't expect completions activity to increase in U.S. shale plays next year.

With the price for a barrel of West Texas Intermediate (WTI) crude expected to hover between \$54 and \$60, forget about any rise in capex, too.

Oilfield service prices are forecast to be relatively flat, and so is overall demand for pressure pumping.

What is expected to increase, however, is efficiency.

This is according to analysts at Rystad Energy, which presented its 2020 outlook during a drilling and completions (D&C) webinar.

"We have seen the rig count decline pretty substantially over the past few quarters, but wells drilled haven't really declined at that same rate due to high-grading on the rig side, causing an uptick in efficiency," said Thomas Jacob, a senior analyst for Rystad. "Essentially, we are drilling more wells on a per-rig basis."

However, operators are paring down drilling programs and spending as they focus more on returns and improved efficiency in a low-price environment. With eyes on free cash flow and heightened capital discipline, many shale players are working to prove to investors and others that they can efficiently grow within cash flow.

The slowdown is already evident, and it's expected to carry into next year.

Capex is forecast to fall by 10% by Rystad's estimates. The firm also says the number of horizontal wells spud will fall by 8% next year, compared to 2019. The count saw a 12% drop in third-quarter 2019, falling to 3,659 from 4,139 in the second quarter.

Likewise, the number of wells fracked is also expected to drop, down 2% in 2020.

"The rig count is expected to hover around that 800 mark for the next two years," Jacob said. He added, "Due to budget exhaustion, there has been a buildup of DUCs, and we do see that completions will be pushed out for the first half of next year."

All of the downward arrows—combined with crews capable of doing more with less—mean less demand for pressure pumping services. Demand for frack horsepower is expected to drop again next year, hitting 15.1 million hydraulic horsepower (HHP). That's down from 16.3 million HHP in 2018 and 15.6 million HHP in 2019. Jacob added supply will also shrink as cold-stacked HHP retires by year-end 2020, lowering the supply to 21 million HHP.

However, the trend of longer lateral lengths could bring a small boost for frack sand suppliers, which have also suffered losses due to the drilling slowdown.

Frack sand provider Carbo Ceramics Inc. issued a "going concern" warning to investors on Nov. 8 after one of its customers stopped buying its sand.

"We've seen growth and demand projections slowing down considerably in 2019," Jacob said, later noting sand intensity for most major U.S. shale plays have stabilized between 2,000 and 2,500 pounds per foot. "We only see 3% increase in frack sand demand for 2020, reaching approximately 120 million tons. We don't see demand increasing above 140 million tons in the next five years."

However, the activity slowdown comes amid continued efficiency gains. While the rig count has consistently fallen, companies have been able to produce more oil thanks to better rigs and other efficiency gains.

Looking at D&C efficiency metrics, Rystad analyst Ryan Hassler pointed out improvement in just about every category in the Permian Basin's Delaware and Midland sub-basins, Eagle Ford Shale, Appalachia's Marcellus and U.S. land as a whole.

For example, the number of HHP hours pumped per day saw a 20% improvement in the Midland Basin and 48% improvement in the Marcellus. Double-digit percentage jumps were seen in areas such as zipper frack penetration in the Delaware, horizontal wells fracked per active crew and drilling days per 1,000 feet among others.

However, there is still room for improvement, Hassler said. Such areas include zipper frack penetration in the Marcellus, stimulation days per well and multiwell pad size in the Eagle Ford and horizontal wells drilled per rig in the Delaware.

Hassler singled out the Delaware Basin as trailing other major shale plays in several areas, including multiwell pad penetration and zipper frack penetration, though strides have been made.

In the Marcellus, Bakken, Denver-Julesburg, Eagle Ford and Midland, the average multiwell pad penetration is about 90% to 95%, Hassler said. That compares to about 76% in the Delaware.

"So, going into 2020 and beyond, we expect it to continue increasing as efficiencies keep improving," he said. "This is a metric that's allowing crews to move around quicker and reduce the NPT."

Similar data were shared for zipper frack penetration with the Delaware Basin at about 66%, compared to 85% to 90% for the others.

Although capex is expected to drop by 10%, the drop in D&C won't be as steep given the continued drive for efficiency gains, according to the analysts.

"The room for growth in many of the metrics looked at today and the reduction in NPT going into 2020 will provide opportunities for operators to complete more work in less time with the same amount of equipment, all

while continuing to challenge the service providers as prices remain depressed and demand continues to be stifled," Hassler said. "We believe that we have entered a new era of operations in the shale industry, with operators putting a lot more on cost savings, supply chain optimization and efficiency gains."

—Velda Addison

Private operators explain key to Permian success

Privately held operators in the greater Permian Basin area are turning more proved undeveloped reserves into proven developed reserves in a hold-for-longer mode.

This among other developments have been key to operating in the current state of the industry, said executives from private operators Caza Oil & Gas Inc., Henry Resources LLC and Zarvona Energy LLC during a panel at the recent Executive Oil Conference.

Caza Oil & Gas Asset Overview

Net acres	~7,235
Operated	89%
HBP	90%
Locations	237
Production (boe/d)	7,200

Source: Caza Oil & Gas Inc.

Caza Oil & Gas, as CEO Mike Ford explained, is focused on its Delaware Basin acreage in Lea County (approximately 5,100 net acres) and Eddy County (approximately 2,100 net acres) in New Mexico. Most of Caza's acreage is 89% operated with 90% HBP on primarily state leases, and to a lesser degree, federal leases with 237 locations.

"Our philosophy at Caza is keep our head down, execute in all the operating disciplines to turn those returns to make those distributions back to our partners to reduce debt," Ford told conference attendees.

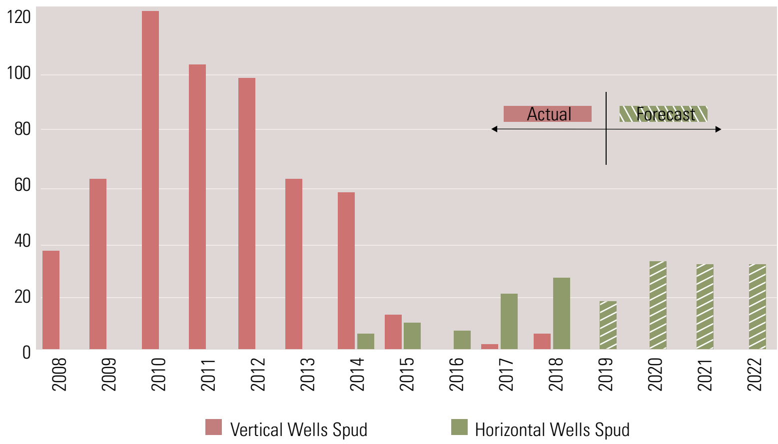
"When we came into the play in 2014, there were about six 'recognized' pay zones including lower Brushy Canyon, Avalon, Bone Spring and Wolfcamp C. Now there are more than 13 including multiple Bone Spring, Avalon and Wolfcamp horizons. It's a play that just keeps on giving."

Because of Caza's small size, Ford said the company couldn't compete at state and federal sales. In 2015, the company looked for a geologically sound place to get a foothold in complicated acreage, then take the time to build that into a significant position. Caza's original position was about 11,054 gross acres and currently, the company has about 16,000 acres and has acquired 3,800 net acres through transactions with other operators.

"Our goal has been to increase Caza net acres around our best acreage positions and trade nonop positions for operated positions, while monitoring acquisition costs," he said. "This will allow us to execute and control a preferred drilling plan on pads with longer-length laterals,


Fe 2
Shared Values.
"We first partnered with EnCap in 2011, in part because we recognized that our core values are aligned. We never compromise on integrity. We are committed to excellence in everything we do. We build high-performing teams. We value innovation and financial discipline. We are both companies that strive to be remembered not only for being successful, but also for how we conduct business."
Barry Winstead
President & CEO, Forge Energy II

Henry Resources' Recent Drilling History



Source: Henry Resources LLC

leading to better economics."

Caza currently operates about 38 wells and has participated in 28 wells since they were acquired by Talara Capital Management LLC in 2015. Since the acquisition by Talara, according to Ford, the total PDP PV-10 valuation increased from $22 million to $184.7 million. Caza's total proven PV-10 valuation increased from $88 million to $380 million, and the company is currently producing about 7,200 barrels of oil equivalent per day.

One of the costs that Caza has cut has been the lifting costs, which have been reduced from $9.60 to $6.40 per barrel of oil equivalent. Ford said: "We've done that primarily through waste and water management and saltwater disposal agreements. When we first started drilling these wells, we were trucking water, and we've been able to build the takeaway to reduce costs at all of our properties."

During the next year, Caza will have one or two rigs running and will focus on the company's key properties with the highest internal rate of return, with pad site development in northern Lea County. Ford said that Caza doesn't plan to make any large acreage block purchases.

"We plan to focus on where our key properties are," he said. "We might be interested in new acreage if it adjoins us and if it doesn't, we're probably not interested."

Henry Resources, according to president David Bledsoe, has been a long-term Wolfberry developer and drilled an average of 80 vertical wells per year. In 2008, the company had a major transaction with Concho, and it sold about 85% of its assets. However, since 2014, the company has turned its attention to horizontal drilling in the Midland and Delaware basins.

"Since that time, we've run one to two horizontal rigs and now drill 15 to 30 horizontal wells per year," Bledsoe said.

Now that Henry Resources is drilling only horizontal wells, he said the company has a new set of "problems" compared to the vertical completions.

"We now focus on low geological risk and you have to know on-lease or off-lease drilling and spacing and how you're going to develop the prospect," he said. "You also have to know where your water is coming from and if you'll have enough, and how to truck wastewater. All of this means that you have to have lots of cash available before you even drop a bit. Cash flow management is certainly an issue."

Henry's plan is to test an area and zone first, then drill the tranches to determine bench performance and co-development, spacing assumptions, landing points and stimulation design. When drilling the tranches, the company drills as many wells as possible within cash flow, reserve timing and peak production guidelines, then come back and drill remaining wells on the drilling spacing unit, according to Bledsoe.

Meanwhile, Zarvona Energy opened in 2010, and the company bought its first operated asset in 2012, said Rob MacAskie, the company's CFO and vice president of acquisitions.

Zarvona manages about 21,000 bbl/d and operates more than 400 producing wells in three core basins—East Texas/Louisiana in the Austin Chalk play, the Permian Basin, and Caddo and Grady counties in Oklahoma.

"We directly invest limited partnership funds on behalf of our investors in oil and gas assets, and all of those assets are managed and operated by a single entity, Zarvona LLC," MacAskie said.

"This direct-investment approach allows us to stay at a lower-cost basis from an operating perspective than a lot of our private and public competitors. The majority of private companies are sponsored by private-equity firms, which is less efficient than us because we are both the sponsor and the operating entity in one. We cut out a layer of expenses and by using a single operating entity."

The company's long-term focus is to manage its budget out of cash flow. Growing out of cash flow, according to MacAskie, is by "buying right and developing right. We target foot-hold acquisitions and look for high-margin existing cash flow, and this is important so we can really redeploy into our highest return capital projects."

Zarvona also looks for development drilling and for workover programs, cost-reduction opportunities, enhanced recovery—"anything that can add value to the assets we've acquired," MacAskie added.

Zarvona recently entered the lower Barnett Permian play in mostly Andrews and Ector counties in Texas. "We've drilled more than 20 horizontal wells with an average lateral length of more than 7,500 feet," he said

The company is also exploring other emerging opportunities like the Hoxbar in Oklahoma, and the Woodbine and Austin Chalk in East Texas. MacAskie said Zarvona will also be looking at Wolfcamp developments in the Permian Basin.

"But you still have to pace yourself," he said, "and stay within what your budget allows."

—Larry Prado

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ROCKCLIFF ENERGY LLC

BP exec: Inflection point requires shift in industry thinking

The energy industry is facing a major inflection point, bringing with it plenty of challenges that require preparation and new ways of thinking to uncover solutions.

This, according to BP's Ryan Malone, could impact how business is conducted and shift conversations happening today among industry players. And he predicts that change could arrive within five years, meaning today's workers—not future generations—will be charged with collaborating to solve challenges.

As chief transformation officer for BP's Gulf of Mexico (GoM) and Canadian operations, a role he carries alongside general manager of projects, Malone is tasked with helping the business bring in more cash flow. "But it's also more importantly about positioning the company and the business for the transformation that I think is not only underfoot—if you feel the rumblings heading our way," but have already arrived in certain parts of the world for the industry, he told attendees of Teledyne Marine's Technology Focus Day on Nov. 20.

Some might already be "behind the eight ball."

The words were delivered as companies address lackluster returns and seek out more capital and operational efficiencies today, while watching for whatever changes may come their way as parts of the world embraces cleaner forms of energy.

Among the tasks is what Malone called the "dual challenge" of supplying more energy while reducing emissions. The U.S. may be somewhat isolated from global dialogues taking place, but "I think it's right on our doorstep" regardless of which direction global energy demand swings.

Malone pointed out that the world's population has jumped to about 7 billion from 5 billion within the past 30 years and expectations are the count will grow by 2 billion over the next 20 years. The surge has come alongside a rise in GDP to about $70 trillion from $20 trillion with poverty cut in half.

More energy will be needed.

"We recognize that there's unsustainable levels of emissions in the atmosphere right now. Our outlook estimates that carbon emissions are going to rise by 10% to 2040," Malone said. BP aims to reduce its carbon footprint by roughly 3.5 million tons by 2025. "It's essentially the elimination of the carbon footprint of two of our major operating regions within the next five years."

The company aims to find more ways to produce energy more sustainably while adding value. Within six to 12 months, he said he predicts carbon footprints will be a key metric in evaluating capital investments for BP.

On another front, millennials are expected to make up 75% of the workforce within five years—up from 35% today—and this, he said, could reshape how the industry interacts with a digital world, considering this generation is mostly seen as being digital subscribers.

He encouraged attendees to prepare for the mindset shift and different ways of working.

BP, like some of its peers, has embraced digital technologies.

"We outsourced an entire segment of our company with venture capital funded by BP to form a virtual shark tank," Malone said.

Earlier this year BP Ventures invested $5 million in Houston start-up Belmont Technology to boost BP's artificial intelligence (AI) capabilities. The company has developed an AI program that will allow BP to interconnect its reservoir data globally, creating what BP called a "robust knowledge-graph of subsurface assets" with data that its experts interpret, analyze and perform rapid simulations.

Speaking generally on digital, Malone said that "there's going to be more interconnectivity and connection points. The data lakes are going to be getting bigger and the navigation streams for how to take that data out of those lakes and make it into something useful is just going to get more complex."

Also changing will be how energy companies interact with the supply chain and standardization. BP, he said, mostly buys stock components—like subsea trees—off the shelf, making needed modifications and weighing any risks.

But eventually, Malone added, the industry will reach a stopping point on standardization at the component level, and more "collaboration" will be needed. Historically, the industry has not standardized around collaboration.

"It pits operators against suppliers, suppliers against each other. It forces conversations that are not helpful. It keeps operators from asking what we really want," he said, encouraging more dialogue.

The pathway forward likely won't be linear, according to Malone. No one knows what the future will bring. But it will take a collective power and the ability to adjust agilely to prepare for challenges and change ahead.

What isn't changing, however, is BP's commitment to the U.S. and the GoM, he said.

"We still need a lot of oil. We still need a lot of gas," Malone said, "but we're going to need a lot more on the technology front and a lot more on the carbon reduction front."

In the past five years, BP has grown its GoM production by nearly 60% to more than 315,000 bbl/d. The company forecasts production will reach 500,000 bbl/d within the next five to 10 years. It is deploying technology and carrying out intervention, infill and infrastructure-led exploration programs, exploring Paleogene, Cretaceous and Jurassic reservoirs that could lead to new hubs.

"By the end of next year, we're hoping to add upward of 100,000 barrels a day of additional oil at [the] Thunder Horse [platform]," Malone said. Additional barrels are also expected when the $1.3 billion Atlantis Phase 3 development comes onstream in mid-2020.

—*Velda Addison*

'Generalist investors are running away' from oil and gas

U.S. oil producers have "changed their spots" from "filling up the box" with land and resource inventory to focusing now on developing it.

"Now the box is full," Reed Olmstead, IHS Markit director of North American onshore research and business development, told attendees at the Executive Oil Conference.

And investors have changed as well. "The generalist investors are running away," Olmstead said. "The investment houses have lost their love for us."

A colleague who analyzes securities told him "it seems almost like a bait and switch by investors: We built these companies to be 'growth' and, all of a sudden, we're going to switch to be value-oriented companies."

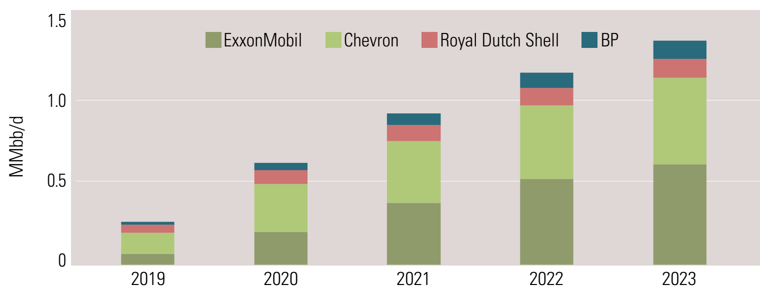
The independents are working through that pain now. Meanwhile, the majors are growing their presence in the Permian Basin.

"How are the majors going to change how this basin looks? Well, they matter a lot," Olmstead said. "These guys are catching up to the independents."

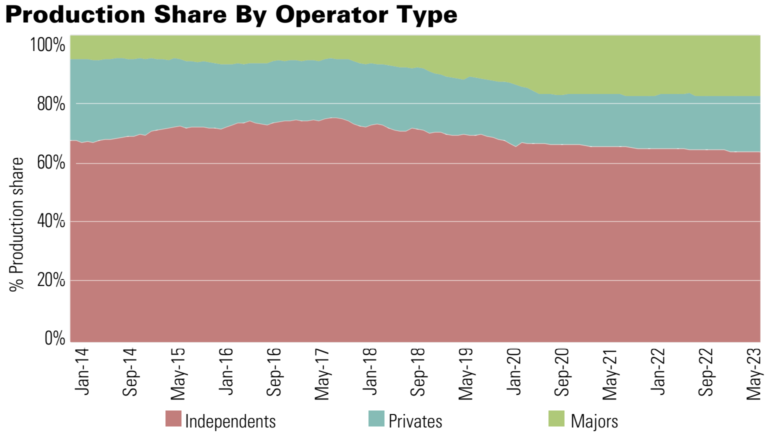
Well productivity continues to improve for ExxonMobil Corp. subsidiary XTO Energy Inc. and for Chevron Corp., in particular.

Olmstead said XTO's footprint is fascinating. It and Chevron are "the companies that are really driving the basin from a major's perspective."

Majors' Permian Unconventional Oil Production



Production Share By Operator Type



Source: IHS Markit

And the majors cruise along a different jet stream than the independents.

"They don't have to live within cash flow for U.S. production. They can take it internationally and bring it onshore," Olmstead said.

Also, "they have a lower cost of capital when they borrow." And being able to borrow at all is something elusive to many independents right now.

"Investors have a different objective for why they buy [majors'] stock."

Going forward—based on the current list of operators and based on the current oil-price forecast—the majors will be material to Permian development, accounting for roughly 15% of basin production.

But "it will mainly be driven by the U.S. independents," he said.

For them, "it's about managing that resource" of inventory they've developed. "It's a very different operating environment. So what do we see now? Death by a thousand wells. Do I have enough capital availability to fully develop this resource?"

EOG Resources Inc. previously announced that it added two Permian benches to its inventory: Wolfcamp M and Third Bone Spring. Marathon Oil Corp. announced additions of the Woodford and Meramec.

The Wall Street Journal previously did a "three-week series of hit pieces on unconventionals," saying U.S. producers were "going to run out of inventory," Olmstead said.

But what he sees is that "we're not running into an inventory problem, not in the Permian."

Concerns there are aboveground. "We've got this problem. We're not continuing to excite investors."

In lieu, producers are going about "managing our resource base in the most efficient way possible."

Meanwhile, every day, Permian operators have to replace 4 MMbbl/d to keep production flat.

"You can't grow your production base as an industry until you replace 4 MMbbl/d. ... That's the hole you face on Jan. 1 of each year. How do we replace 4 MMbbl/d? And then we can grow production?"

—Nissa Darbonne

Midcon operators tout varied upside in out-of-favor region

The Midcontinent confirms two rules of the exploration and production business: Every pay zone's different; and the best place to find oil and gas is where it's already been found.

Two executives who head privately held Oklahoma upstream players emphasized those points in a panel discussion at Hart Energy's recent DUG Midcontinent conference and exhibition.

The western half of the Sooner state may get more publicity, but there's great potential on the state's eastern side, Nathaniel Harding, founder and president of Antioch Energy LLC, told conference attendees.

"There is a tremendous


Fueling
the oil
and gas
industry

recoverable resource here," Harding said of his firm's 24,000 net acres, "a large, quality position," in Hughes County, Okla., that is "scalable, stacked and saturated." Its wells target the liquids-rich Arkoma Stack, a play he rated "world class."

Antioch targets three resource plays, the Caney, Mayes and Woodford that, combined, can offer 500 feet of potential pay. Wells with 2-mile laterals cost some $4- to $6 million with "fewer failure scenarios," Harding said.

"We're shallow… we have low decline rates and we have optionality between markets," with direct access to both the Cushing, Okla., oil hub and Gulf Coast markets through "good midstream assets," Harding noted. Residue gas also enjoys optionality, he said. "It's a classic case of finding oil and gas where it's been found before," Harding added, noting eastern Oklahoma has produced hydrocarbons for more than a hundred years.

And like the rest of the Oklahoma energy industry, Antioch works within a comparatively friendly regulatory and community support environment, he said.

"It's a nice place to be with the macro trends coming down the pike," Harding added.

Will Ulrich, co-CEO of Presidio Petroleum LLC, gave a broad review of the oil and gas industry's current challenges—those macro trends Harding noted—with investors and the public. Presidio is the second-largest producer in the western Anadarko Basin, which extends from northwestern Oklahoma into a corner of the Texas Panhandle, he said.

He quoted Pioneer Natural Resources, which Ulrich rated "a super-efficient company," had a 9% return on capital employed (ROCE) last year—up from a 4% ROCE in 2017.

He compared that result to Google, Disney and Apple that reported ROCEs of 16%, 18% and 28%, respectively, in 2018.

"We have a return problem," he said of the industry, and that explains why investors have walked away from oil and gas.

Given the current business climate, "Presidio Petroleum is uniquely positioned to navigate today's energy environment," Ulrich said. As a "21st Century start-up," Presidio emphasizes contrarian thinking, values systems over goals and is technologically savvy. But he noted "every [E&P] company is now a tech company" as producers incorporate big data and work to find the best ways to employ it to cut costs and increase production. It targets "to operate and acquire out-of-favor, developed assets."

Contrarian thinking includes seeking attractive opportunities in the well-established Anadarko that currently are out of favor. "We want to be in dry gas, that makes a lot of sense" for long-term potential, Ulrich said in response to an audience question.

He said technology "empowers employees at all levels to take ownership and innovate, provides an intense focus on measurement that gives everyone—from the pumper to the CEO—the information and responsibility to drive ownership and maximize profitability.

"If the software and hardware don't exist to let us do our job, we will create it," Ulrich added.

For 2020, the firm has targeted a potential $1 billion in acquisitions by employing "a simple, virtuous cycle" that moves from acquisition, to optimization, to enhancement, to optimization of the firm's capital structure.

—Paul Hart

Geopolitical issues impact global energy markets

Tom Petrie, chairman of Petrie Partners, laid out the multitude of geopolitical dynamics that will impact global energy markets, noting that energy price volatility is unlikely to abate.

Petrie discussed the implications of geopolitical world events on the oil and gas industry at the recent Executive Oil Conference.

Petrie said that as the U.S. has increased its oil production—up to 12,800 barrels per day (bbl/d), according to the U.S. Energy Information Administration—and lessened its reliance on Saudi supply, Saudi supply has increasingly found an export market to China. Such a relationship, he explained, was indicative of the changing dynamics of energy supply partnerships around the world.

Petrie described the emergence of the "overlapping power triangles" as trade relationships among Russia, China, Iran and India.

"[These relationships] did not characterize the oil industry that we knew from the end of World War II up until 9/11, but since 9/11 it became pretty evident, and over the years it's seemed to solidify further," Petrie said. "That means we have yet to understand that policy makers and strategists in Washington, D.C. need to take that more into account than they usually did for over half a century. So it will be a challenge for them to do that and make decisions."

Petrie explained that although 2011 Arab Spring brought about popular elections in North Africa and the Middle East, it also ultimately led to three failed states in Libya, Syria and Yemen. Petrie pointed to the unrest in Libya in which Khalifa Haftar is leading the rebel Libyan National Army against the internationally recognized government in Tripoli.

More fallout from the Arab Spring, Petrie said, was the creation of a "virtual" cold war between Iran and Saudi Arabia, one that he said might be intensifying as evidenced by this summer's drone attacks by Iran on Saudi oil infrastructure.

"A little over a month ago, drones and cruise missiles honed in on the infrastructure in Saudi Arabia for processing and exporting oil," Petrie said. "It's certainly a heating up cold war. It's not as cold as we once thought it was."

Another result of the Arab Spring is the possibility of a "merger" or "elevated hegemony" by Iran over Iraq. Petrie explained

that Saudi Arabia took issue with the U.S. invasion of Iraq in 2003 because of what he described as "the second order of consequence" shifting from a Sunni-led government to a Shiite government in Iraq.

Petrie said that Ayatollah Sistani has worked to keep Iranian influence over Iraq, but his efforts were diminished with the emergence of the ISIS threat in Iraq and Iranian militias aiding in the fight.

"[The militias] didn't go home when success was achieved," Petrie said. "They stayed around, which would be a complicating factor."

He said the eventual death of 87-year-old Sistani could trigger an Iranian bid to have an Iranian-Shiite Ayatollah become the Grand Ayatollah.

"So, against all of that, we've still got a tough legacy and lots of reasons to expect continued challenges in the Middle East," Petrie said. Another of the challenges that he discussed was the possibility that Saudi Arabia may be looking to balance the oil markets "at any cost" with increased production levels while the U.S. continues to produce record amounts of oil. He said accommodating that growth in supply could prove to be a challenge.

"The real key for the U.S. and for Saudi Arabia as they work to achieve a price is where all that oil goes," he said.

According to data Petrie provided during his presentation, the Americas, Asia Pacific and Europe import about 3 MMbbl/d of U.S. light crude and condensate. That amount is projected to increase to nearly 4 MMbbl/d by 2024.

"We've got a situation where the U.S. has doubled its production in less than 15 years," Petrie said. "That doubling in that period of time is going to continue to present something of a challenge to both Russia and Saudi Arabia to achieve their goals of higher prices."

While Russia and Saudi Arabia might need as much as $80/bbl WTI prices to achieve those goals, Petrie said, the U.S. market can remain competitive at prices of about $65/bbl. He said a potential trade agreement between the U.S. and China could have a positive effect on markets.

"But we still have an ongoing need for Saudi-Russian discipline, and that means the energy price volatility that we have been dealing with is going to be continuing as a challenge," he said. "That doesn't negate the basic fact that the U.S. position is likely to be a key competitive advantage as we work through one of the most geopolitically challenged times I've seen in my 47 years of serving."

—Brian Wazel

Barclays annual survey points to 10% drop in U.S. spending

Capital discipline and low oil and gas prices will again cause drilling activity in the Lower 48 to be slow in 2020. Barclays' 35th annual spending survey has indicated that U.S. onshore spending will

North America E&P Spend By Company Type ($MM)

Company	2018	2019E	2020E
IOCs	36,434	41,382	43,829
U.S. Large-caps	41,214	38,202	34,157
U.S. SMID Caps	25,957	20,996	19,352
Canada E&Ps	16,038	13,526	13,894
Private E&Ps	32,691	29,422	26,480
North America Spending	$152,335	$143,527	$137,712

Source: Barclays

decline 10% in 2020.

Some 14 large-cap E&Ps and 36 small and mid-caps, make up Barclays' proxy for 2020 U.S. land spending.

However, overall North America spending, including Canada, will decline only 4%, since woefully low Canadian spending will inch up by about 3% this year, appearing to turn the corner from a disastrous 2018-2019.

Twenty-one U.S. E&P companies had issued their formal guidance and 2020 plans as of the time of the survey, representing about 20% of the total spend. The survey of more than 100 companies was done in late November and early December when WTI was around $57/bbl.

Capital discipline couldn't be more apparent, Barclays said, citing the fact that in 2019, E&P cash-flow plowback ratios plummeted to their lowest levels in more than 20 years, and 2020 looks to be about the same.

The analysts said capex was almost down to maintenance levels as large E&Ps spent only 83% of their discretionary cash flow in 2019.

"We believe a 10% decline in U.S. land spending [for 2020] is generally reflected in consensus oilfield service estimates and note that pricing for pumps, rigs and other services has largely stabilized with little to no capacity being added," the survey said.

For the second straight year, majors and international oil companies (IOCs) are offsetting North America spending declines by the E&Ps, with their spending to increase 6%, following on the heels of a 14% increase seen in 2019.

Growth will be driven by ExxonMobil, ConocoPhillips and Shell.

Private E&P company activity is the "huge wildcard," according to Barclays. This represents about 40% of the U.S. land rig count, but it is subject to more volatility, as private E&Ps tend to have relatively smaller balances sheets than the majors and they are under greater pressure from investors to rein in overspend.

Barclays was able to get responses from almost 100 private companies, but that is still a fraction of the number of such companies. "… our understanding is financing terms are getting increasingly onerous. In other words, private E&Ps are a high-risk group in the event of a decline in oil prices to the $40s," Barclays said.

Looking to international markets where national oil companies and internationals hold sway, the survey found that Middle East spending will trend up by 6%, with natural gas drilling on the upswing throughout the region.

In Latin America, Pemex revealed a 53% budget increase and Brazil's Petrobras guided spending up 15% in 2020, but these projections "give us pause" as the Barclays analysts wonder if these bigger spending plans really will occur.

—Leslie Haines

Upstream M&A, capital raising fell 50% quarter over quarter

Deal volume in the upstream industry decreased by 30% in the third quarter of 2019 vs. the second, according to a recent report from GlobalData, a data and analytics company. M&A and capital raising value in the upstream fell by 50% from the previous quarter's $126.8 billion,

Selected E&P Spending In North America ($MM)*

Company	2018	2019	2020	Growth '19	Growth '20
Apache	3,190	2,414	2,124	-24.3%	-12.0%
Continental	2,369	2,192	2,425	-7.4%	10.6%
Concho	2,638	2,910	2,426	10.3%	-16.6%
Devon	2,323	2,040	1,834	-12.2%	-10.1%
Encana	1,956	2,581	2,555	31.9%	-1.0%
EOG	4,935	5,103	5,351	3.4%	4.8%
Diamondback	1,461	2,376	2,438	62.7%	2.6%
Hess	2,069	2,420	1,825	16.9%	-24.6%
Marathon	2,286	2,378	2,251	4.0%	-5.3%
Noble	2,705	2,127	1,608	-21.4%	-24.4%
Oxy	4,413	4,989	4,901	13.1%	-1.8%
Parsley	1,514	1,187	1,682	-21.6%	41.6%
Pioneer	3,245	2,782	3,032	-14.3%	9.0%
Cimarex	1,350	1,091	1,031	-19.2%	-5.5%

Source: Barclays

*Drilling and completion capex; midstream not included.

totaling $63.4 billion.

The largest M&A deal of the third quarter was the sale of BP Plc's Alaska business to Hilcorp Energy Co. It involves the sale of its upstream and midstream business in Alaska for a hefty $5.6 billion, marking BP's departure from the Alaska scene.

"The transaction is in line with Hilcorp's historical strategy of acquiring mature fields from major oil corporations and slashing costs," GlobalData's analysts noted. According to the firm, BP's net oil production from Alaska in 2019 was projected to average almost 74,000 bbl/d. The upstream assets include interests in Prudhoe Bay (26%), Milne Point (50%), Point Thomson (32%), the Liberty project (50%) and nonoperating interests in exploration leases in the Arctic National Wildlife Refuge.

As for capital raising, the top deal in the third quarter was Petroleos Mexicanos' public offering of notes for gross proceeds of $7.5 billion, according to the report. "The company intends to use the net proceeds from the offering for its general corporate purposes, including the repayment of short-term loans," GlobalData said.

Capital raising through equity offerings alone also tumbled, from $14.5 billion in the second quarter of 2019 to $1.2 billion in the third. Equity offerings fell 17% in number over the same period. Debt activity mirrored equity's performance.

"Capital raising, through debt offerings, registered a decrease of 17% in the number of deals and a marginal increase in deal value with 43 deals, of a combined value of $30 billion, in the third quarter, compared with 52 deals, of a combined value of $29.1 billion, in the previous quarter," according to Praveen Kumar Karnati, an oil and gas analyst with GlobalData.

Private-equity/venture capital deals in the upstream were fewer in number in the third quarter but larger in overall value vs. the second-quarter tallies. Ten deals had a combined value of $1.4 billion compared with 13 deals with a value of $504.2 million total in the previous quarter.

Conventional M&A deals, of which there were 90 in the third quarter, had a combined value of $13.7 billion. The unconventional market hosted 36 deals with a combined value of $17.1 billion.

For the year-ago third-quarter period, upstream M&A deal value was $46.7 billion, and the deal count was 290. For upstream capital-raising deal value, the year-ago value was $36.7 billion, and the deal count was 180. The second quarter of 2019 represented a sharp rise for both upstream capital raising and M&A deal value.

—Susan Klann

Outlook cloudy for oversupplied natural gas market

Next year could be another challenging one for natural gas with analysts forecasting a slowdown in natural gas production growth based on downward guidance from producers.

Natural gas prices, which have consistently traded lower than $3 per million British thermal units throughout the year, aren't expected to help the situation much. Neither is demand from Mexico, and LNG export concerns could add to worries. The gas glut remains.

However, even if the outlook turned positive—surprising to the upside—capacity constraints could become an obstacle in some basins, analysts with S&P Global Platts said during its recent North American natural gas winter outlook webinar.

The slowdown is already visible in the Appalachian Basin in the Northeast, where S&P Global Platts natural gas analyst Luke Jackson said the rig count has fallen from about 84 rigs earlier this year to about 50. While efficiency gains have enabled production to still grow, reaching as much as 34 billion cubic feet per day (Bcf/d) despite the lower rig count, future output could be impacted as producers cope with weak prices.

"We do believe we're sort of approaching that tipping point. We think that tipping point is very near likely starting this month or even into January," Jackson said.

Looking at 2020 dry-gas production guidance in Appalachia from the top nine producers, which account for about 70% of the region's production, Jackson pointed out that "most are guiding a substantially slower growth rate year-over-year."

Four of the producers planned no production growth for 2020, while three planned for single-digit growth and one double-digit, according to Jackson, team lead of North American natural gas analytics for the firm. Seneca Resources Co., the E&P segment of Houston-based National Fuel Gas Co., aims to grow production by 14% next year.

In all, the top producers in the Northeast are planning to produce a combined 17 Bcf/d, up 2% from 2019. "The growth rate year-over-year is only around 300- to 400 million cubic feet per day," Jackson said. "If we compare this same peer group and looked at their growth rates in 2019 vs. 2018, we would see that they collectively grew around 2, maybe 2.5 Bcf/d year-on-year. So definitely a much, much steeper drop in growth."

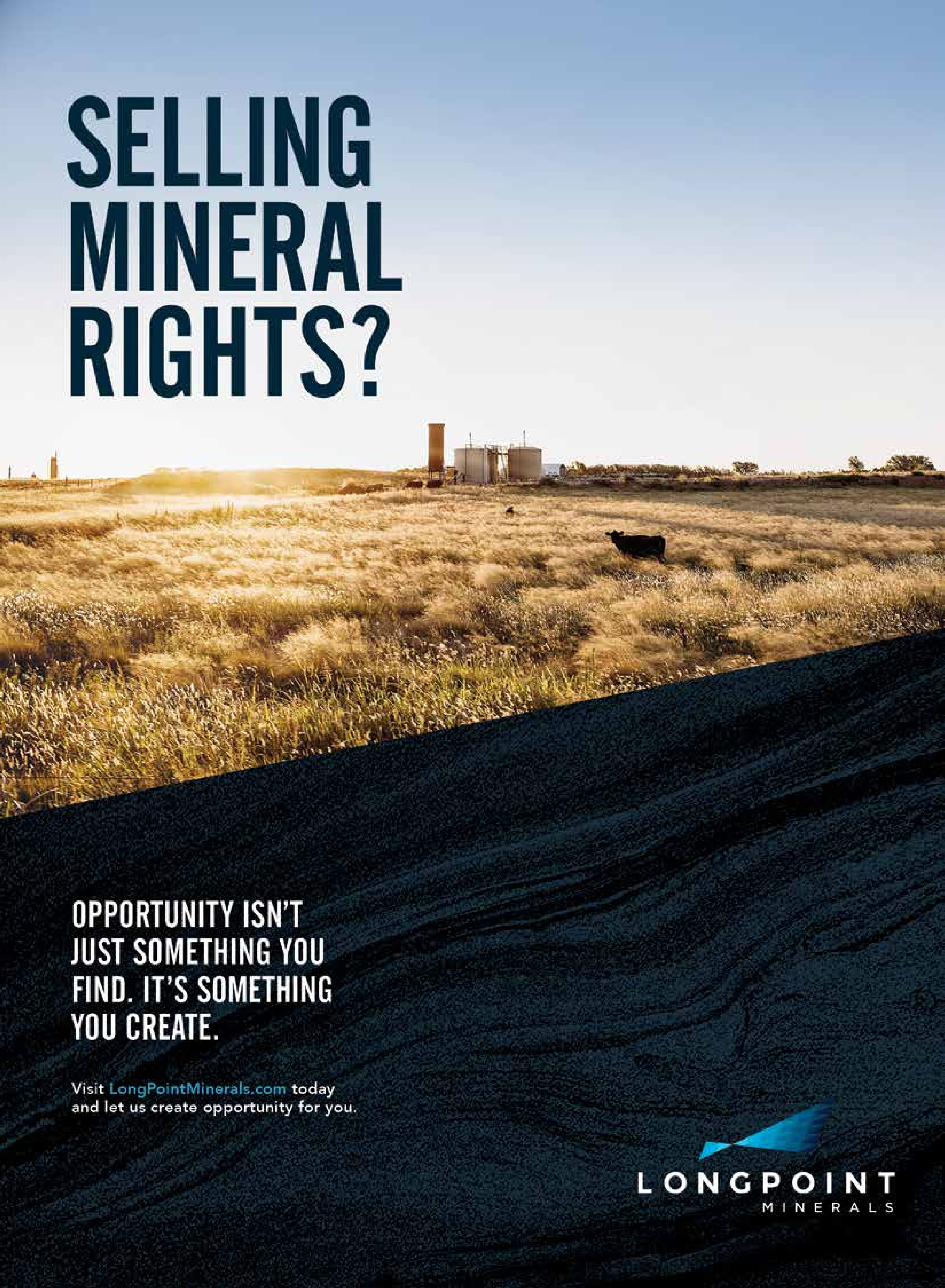
Capacity constraints leave little room for incremental growth.

Kevin Sakofs, senior analyst for North American natural gas for S&P Global Platts, said activity levels across key dry gas plays have dropped precipitously since June, and "this is largely due to a softening dry gas commodity backdrop."

Chevron Corp. said on Dec. 11 it expects $10- to $11 billion in write-downs in fourth-quarter 2019, mostly due to its Appalachia shale gas assets. The company said it will spend less money in 2020 on gas-related projects, including those in Appalachia, and is considering divestments.

"The announcement continues a wave of write-downs related to price downgrades," Tom Ellacott, senior vice president, corporate analysts, at Wood Mackenzie said in a statement. "U.S. shale gas assets have been hardest hit, reflecting the weak outlook for U.S. gas prices. "We expect the trend of write-downs to continue as price outlooks are adjusted down."

Analysts are forecasting gas supply will again outpace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demand next year.

The market entered this upcoming winter with 3.75 Tcf [trillion cubic feet] of supply, which is roughly 500 Bcf higher than last year, Sakofs said. Assuming normal weather, Platts estimated the year-on-year surplus would expand to about 2 Tcf by the end of March.

U.S. gas supply is forecast to grow by 5.9 Bcf/d this winter compared to a year ago, according to the outlook.

The key wildcard, Sakofs said, is associated gas from producers targeting oil and NGL—something he said has kept production from declining in 2020.

Adding to worries is a challenged global gas market and its potential impact on LNG exports, which Sakofs said is a critical component of the demand forecast. About 2.7 Bcf/d of additional liquefaction capacity is expected in 2020, pushing feed gas flow to terminals to new highs, the analysts said. However, market conditions could impact the growth.

"A lot is riding on Asia having a cold winter," but it doesn't have much storage. That means LNG molecules must flow elsewhere, Sakofs said, questioning whether Europe—which has high storage—could be the balancing mechanism again next year.

Jackson later added that the Asian and European markets are already oversupplied.

"We think that that is a trend that could continue into next summer and cause some issues in terms of dispatch of U.S. LNG exports," he said.

—Velda Addison

Gulfport sees gains with aggressive D&C in the Scoop

Three years ago, Gulfport Energy Corp. took a $1.85 billion gamble to enter Oklahoma's Scoop play. In third-quarter 2019, the company exceeded target production averaging 281.5 million cubic feet of gas equivalent per day (MMcfe/d) to round off a successful year in the play.

Back in 2018, the Oklahoma-based natural gas-focused E&P shifted to full section development in the Scoop after an underwhelming 2017. Today, Gulfport's decision has enabled its Scoop position to contend with its Utica assets, where it holds over 210,000 net acres in Ohio and is the play's second largest gas producer.

Though a smaller position with roughly 92,000 net reservoir acres, the Scoop has shown more potential for liquids than its larger counterpart, according to Gulfport's vice president of operations Joshua Lawson.

"[The Scoop] is definitely an important part of our portfolio and what we're really excited about from the onset, as far as the Scoop's concerned, was the exposure to liquid," Lawson said at Hart Energy's recent DUG Midcontinent conference and exhibition.

Lawson said in the full development plan Gulfport utilized information from an appraisal well and applied it to the remaining wells in the unit. The company extended that strategy into 2019 with its eight-well development program in the Woodford Shale.

"We gained a lot of information from that project and we feel very comfortable with the efficiency gains that we've made on the drilling and completions side that we're going to be able to take that information, deploy that into our program for 2020 and actually be able to deliver more with less," Lawson said.

"In the drill-out phase of the operation, we've seen a 31% reduction in our cycle time. A well that would take us 8.5 days to drill out, get the wellbore cleaned out and get it ready for production is now getting knocked out in about five days."

Over three years, Gulfport has reduced drilling times in its Woodford wet gas wells from 72 days to a current average of 54 days while still increasing lateral footage. Lawson said this advancement is the result of Gulfport utilizing its seismic data to understand formation bed dips and paying "critical attention" toward pad placement.

About "85% of our lateral footage in 2017 was landed in-zone in the target area that we were shooting for," he said, adding, "In 2019, 99.2% of our lateral footage was drilled exactly where we wanted it to be so that was absolutely critical to the advancements that we made."

"To be able to operate in this environment, especially in a basin like the Scoop, the cycle times are absolutely critical," he said.

This year, Gulfport kicked off its eight-well development project. Lawson said the objective was to test increased sand loading, increased stage spacing and the utilization of 100 mesh sand. "We were very intentional in the way that we set this project up."

"Our base frack design was 210-foot stage spacing, 2,100 pounds per foot, 15% 100 mesh on the front end and 85% 40:70 on the back end," he explained.

"We didn't want our results to be influenced by an unbounded well. So, as we took the four wells on the outside of the unit—wells 1 and 2 on the west of the unit, and wells 7 and 8 on the east side—we made those our control wells," Lawson added. "We ran our base design on those control wells and focused in on those interior, bounded wells. Those were the wells that we decided to turn the knob, so to speak."

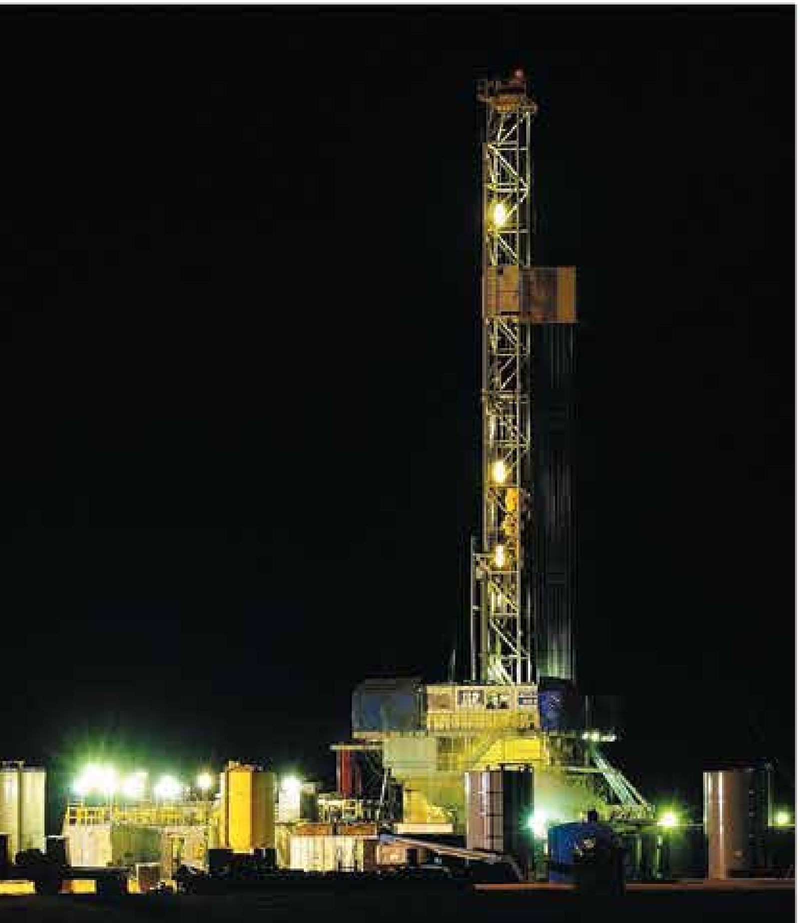
With the interior wells, Gulfport took a more aggressive approach by increasing sand loading, stage spacing and the use of 100 mesh in all of the wells. But, on wells 3 and 4 Gulfport held the design constant and just increased the proppant loading to about 3,000 pounds per foot with 210-foot stage spacing. With wells 5 and 6, however, Gulfport increased stage spacing to 315 feet and roughly 2,000 pounds per foot, and the company also ran diverters in well 5.

The wells, with the exception of well 2 in the lower area, landed in the upper Woodford.

"We really wanted to try and determine on a full section development project or when you're coming in to infill a unit, what is the point of diminishing returns," he said in regards to increasing the proppant loading on wells 3 and 4. He noted that these wells performed the best and produced the most to date.

"We all know from pumping more proppant and increasing


Buying Minerals,
Royalty, Non-Operated
Working Interest



these job sizes, operators have started to see better well performance. But, when you're coming in to infill a unit or coming in for full section development, where is that break-over? Would we still continue to see improved performance by increasing that proppant loading," he added.

"We definitely did see an improvement in production by ramping up our proppant loading and going to that 3,000 pounds per foot. That was pretty significant considering the fact that they were interior wells and they were actually outperforming the unbounded wells just by ramping up our proppant intensity," Lawson said.

Gulfport is looking into finding the point of diminishing returns, especially with the eight-well program.

"It is a balance between how much capital you actually want to put into the ground and the amount of incremental gain you're getting from that," he said. "We've had discussions as to whether we need to push the boundaries further or if we're happy with the current results that we have."

On increasing stage spacing, Lawson said the company didn't want to take too big of a step out because limited entry and cluster efficiency was a concern.

"If you're trying to achieve 2,100 pounds per foot, you go to a 500-foot stage. In the Scoop, we're treating at 12,000 psi, many times so it's very high pressure and taxing on the equipment," he said, "and the ability to pump a six-hour job successfully and remain efficient is difficult to do. Plus, as you continue to increase your stage spacing, the cost savings begin to flatten out."

Lawson warned operators that wanted to save capital by increasing stage spacing to take a hard look at their limited entry design and consider running some diverters, but he also made clear that "there's no one size that fits all."

The bigger decision of pumping 100 mesh, Lawson said, was due to proppant carrying capabilities and also seeing a 22% reduction in cost savings by using local sand mines and regional proppant.

Collectively, the program boosted Gulfport's production in the Scoop by 9% and reduced stage costs by 15% to 25%.

"Everybody knows that the times we're currently living in, being able to produce and gain the same well results with deploying less capital, is kind of the name of the game," he said. "Trying to find every little penny that we can—pick it up off the ground and stick it in our pockets—is what everybody is shooting for."

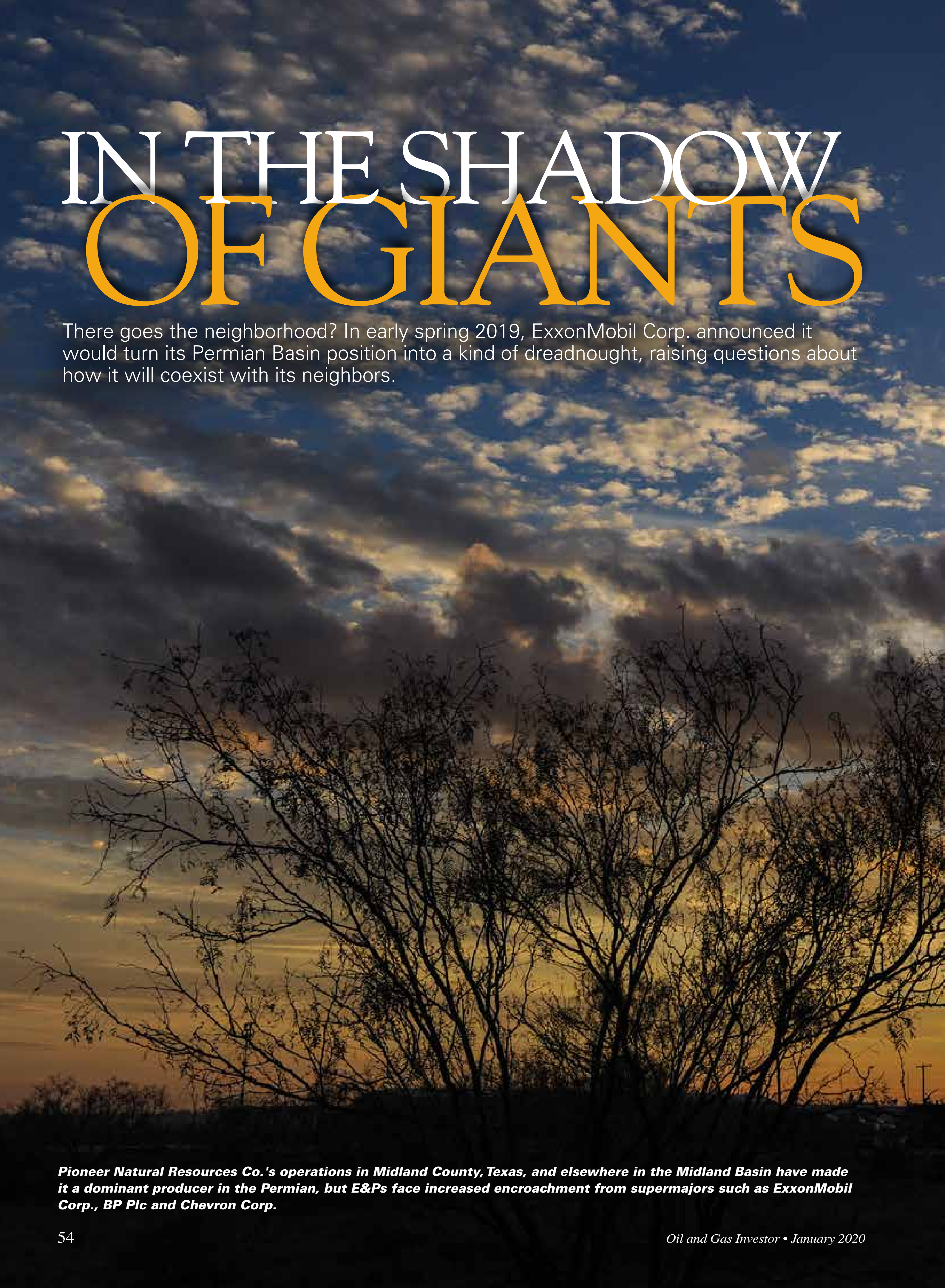
Moving into 2020, Gulfport targets 230-foot stage spacing at a minimum of 2,400 pounds per foot and longer laterals that reach 10,000 feet. Gulfport will also continue to run 100 mesh, Lawson said.

"The Scoop will continue to be a meaningful piece of our portfolio moving forward," he said.

—Mary Holcomb

IN THE SHADOW OF GIANTS

There goes the neighborhood? In early spring 2019, ExxonMobil Corp. announced it would turn its Permian Basin position into a kind of dreadnought, raising questions about how it will coexist with its neighbors.



Pioneer Natural Resources Co.'s operations in Midland County, Texas, and elsewhere in the Midland Basin have made it a dominant producer in the Permian, but E&Ps face increased encroachment from supermajors such as ExxonMobil Corp., BP Plc and Chevron Corp.

PHOTO COURTESY PIONEER NATURAL RESOURCES CO.

ARTICLE BY
DARREN BARBEE

The desert city of Midland, Texas, is generally a poor barometer by which to measure booms, busts or even the passing of seasons. Year-round, the landscape alternates between the rugged chaparral brush and the 11 evergreen golf courses catering to the city. But something has caught in the air in Midland, like ragweed or discontent.

Grumbles from Uber drivers notwithstanding, it's difficult to divine any outward sign of either good or bad times in the oil business. As it has for decades, the West Texas metropolis of 140,000 souls faithfully orbits the industry, the source of its life, regardless.

Facing page, annually, Pioneer Natural Resources Co.'s Midland County, Texas, operations in the Permian Basin make it one of the top crude producers in Texas with more than 242,000 barrels per day of oil in 2018.

"There's a slowdown going on in the Permian," Pioneer Natural Resources Co. CEO Scott Sheffield told *Investor*, "while oil majors are increasing production."

In early November, CNN Business heralded Midland's mystique as "America's ultimate boomtown" and featured an interview with Sheffield, speaking in the distinct Midlandese accent that President George W. Bush is known for.

As CNN's story was playing on cable TV on Nov. 7, the Federal Reserve Bank of Dallas reported unemployment rates in Midland and Odessa (though still lowest in the state) had ticked up with activity in the energy sector declining, particularly among service companies, as oil prices fell in the third quarter.

From March to October, E&Ps' compounded annualized loss rate hit 33%, according to the Federal Reserve Bank of Dallas. Those figures exclude integrated companies. Indeed, ExxonMobil Corp. has been hyperactive. In 2019, the company built a contrarian rig program in the Permian Basin.

Staale Gjervik, president of XTO Energy Inc., a subsidiary of ExxonMobil Corp., said the ability to bring research and expertise to the unconventional, "like we've done on other basins … is going to yield a lot of benefits."

In the late afternoon on Nov. 4, XTO Energy Inc. president Staale Gjervik arrived by passenger car at the DoubleTree by Hilton hotel in downtown Midland. Cinematic presidents of giant conglomerates are often depicted arriving under whirling helicopter blades atop skyscrapers, but the tallest building in Midland is a 24-story bank. Besides, to anyone who recognizes Gjervik, a rooftop landing isn't necessary to convey the power and influence that XTO and its owner, ExxonMobil, now wield in the Permian.

In the hotel lobby, flanked by two ExxonMobil public relations employees, Gjervik, who is from Norway, said XTO is like other oil and gas companies—it's still learning.

"The unconventional industry is perhaps 10 or 15 years old depending on how you look at it. So, we have a lot to learn particularly in the subsurface, as we look at our capability, whether it's people or modeling capacity or fundamental research, it's pretty unique," Gjervik said. "Being able to apply that to the unconventional like we've done on other basins and resource types around the world is going to yield a lot of benefits."

XTO sees the ability to build scale as one of its primary advantages. The company has committed to running 55 rigs in the Permian by the end of 2019 and, as of November, had 75 rigs deployed throughout the U.S.

Gjervik said there are clear benefits to growing larger in unconventional plays, though it's not yet clear what the optimal size is or what a full-fledged manufacturing mode would look like.

"Is it yea big, or is it yea big," Gjervik said, widening the space between his hands to emphasize the point. "That's kind of a bit of a debate out there these days."

For major oil corporations, the critical factor is making the transition from learning mode to manufacturing.

The size and scope of XTO's operations already requires it to consider not just capital efficiency but also the changing geology in an unconventional play. Having enough running room—again, not yet quantifiable—in an area frees a company from being "constantly in learning mode," he said.

"I think it is critical from a cost efficiency—but also from a resource extraction—point of view to understand the rocks and then be able to maximize the recovery. I think if your patch of land is too small, it's hard to do that," he said.

As XTO has been upping its Permian rig count, generally, since November 2018, the trend has been for companies to lay down rigs. Meanwhile, production continues to climb, reaching 4.47 million barrels per day in September 2019, according to the Dallas Fed.

In an interview with *Investor*, Pioneer's Sheffield dismissed any concerns over oil majors ramping up production in a time of chronic oversupply, especially as independents begin to cut back on capex.

"The majors are running more rigs, so they're eventually going to slow down themselves, because they're exhausting their inventory," he said.

Public independents and the private-equity independents are slowing down and some operators are drilling Tier 2 locations.

"We're all developing a free-cash-flow model, giving back money to the investors in dividends and [stock] buybacks," he said. "People don't want to jeopardize their balance sheet."

Through Nov. 21, spending guidance for nearly two dozen E&Ps was down 13% compared to 2019, according to Cowen Equity Research. However, the Dallas Fed reported that third-quarter 2019 energy sector returns "eroded sharply" even with improvements in cash flow. From March to October, E&Ps' compounded annualized loss rate was 33%, excluding integrated companies such as ExxonMobil.

"All that contributes to less production coming out of the Permian," Sheffield said. "So, I'm not worried about a lot of extra production coming out of the Permian, long term, even from the majors."

Nevertheless, the future appears to be in the hands of large, integrated companies, particularly as the majors become active in the Permian.

"I think it's the majors' game to play now," said Regina Mayor, global and U.S. sector lead-

PHOTO COURTESY PIONEER NATURAL RESOURCES CO.

Pioneer Natural Resources Co. CEO Scott Sheffield said he welcomes the majors, their money and research to the Permian Basin but adds, "I know for a fact that they are not making better wells than Pioneer, whether it's Exxon, Chevron, Shell or BP."

er for energy and natural resources at KPMG. "And the speculative money goes elsewhere, like Scoop-Stack and Powder River."

While the heyday of shale prospects may be over, "that doesn't mean it goes away," she added.

"It just means you have to be incredibly good at what you do, and you have to be more able to pull it off on your own vs. trying to tap into liquid markets," she said. "And I hate that I'm so pessimistic. But I have to be a realist. I can't be a Pollyanna anymore."

The tide has shifted toward the massive pull of major integrated companies. On Nov. 26, Simmons Energy, a division of Piper Jaffray, initiated coverage of several majors, including BP Plc, Total SA and Royal Dutch Shell Plc, citing the companies as "both relatively advantaged within energy and likely the primary destination for capital if/when it returns."

Industry analysts acknowledge that the supermajors have siphoned off investors from other oil and gas concerns, though the extent of that shift isn't clear. The majors bring a mix of intense competitiveness to shale plays, as well as a surprisingly amount of hope for independents eager to see what their money and research can bring to the industry.

Perhaps one of the biggest questions now is the majors' approach as they peg the Permian and other Lower 48 plays as key production growth engines. In theory, shale offers more easily replaceable reserves for majors. The degree to which they pursue M&A could affect deal flow dramatically. They have access to capital that their independent E&P peers lack. Among some supermajors, their ability to innovate, research and develop is comparable to Amazon and Google.

"Very few companies are able to have the internal knowhow, and I should say capacity and capability to take on true research and move things forward," Gjervik said.

Few experts or industry observers think the giants will make any sudden moves. Mayor said shale plays' short cycles allow majors to adjust production depending on prices and how their longer-cycle plays pan out for them.

"You still have your long-term investors that love these companies for the stability and the dividend, and they're not going to change their overall operating philosophy just because they're in the Permian," she said. "I don't think they're all just going to jump in, and it's going to be 'Katy, bar the door.'"

The outlook for smaller E&Ps is that they will be "either gobbled up or ... consolidate with larger caps," said Ian Nieboer, managing director at RS Energy Group.

Mutually assured consolidation

Nearly three years have passed since ExxonMobil's most recent, large-scale acquisition: the purchase of the Bass family's BOPCO LP, which largely consisted of assets in the Permian.

"That doesn't mean we stopped looking," Gjervik said. "There's a lot of movement in the market and maybe more so now than it's been historically."

At some point, expectations are that the majors will play a significant role in shale M&A.

Andrew McConn, principal analyst, operator intelligence, at Enverus, pointed out in October that the majors need shale, too.

"The game forever has been constantly trying to replace reserves," McConn said during a Hart Energy event in Dallas. "Even though sentiment has soured so much, I think there's still a consensus that shale does represent not only the largest, but the most attractive resource theme for the future of oil and gas resource supply.

"From their perspective, it's kind of a mutual need," he said.

As majors begin to roam stacked shale plays, mid- and small-cap companies will likely have the most difficult time competing, or getting attention, until they consolidate, said Ian Nieboer, managing director at RS Energy Group.

Those companies will be "either gobbled up or probably have to consolidate amongst peers to get to a scale that makes some sense for the majors [to acquire] or to compete with the larger caps," he said.

For now, the majors likely have little incentive to look for more assets until they begin to feel insecure about inventory, said Dane Gregoris, senior vice president at RS Energy Group.

ExxonMobil's deals in the Permian show the company's been acquisitive. But Gregoris suspects it will stand pat for a while.

PHOTO COURTESY PIONEER NATURAL RESOURCES CO.

"I think right now they're probably pretty secure, because … they're not buying anywhere else, and [inventory] is probably good for a couple years," he said.

Gjervik said XTO is continuing to pursue M&A, though the company wants acreage that is the "right fit," meaning it competes for capital within the company's portfolio.

"We're always looking for good deals in the market: What to buy and what to sell is part of our ongoing optimization of our portfolio, and it's a focus for ExxonMobil and a focus for our shale business too."

Sheffield's been on the record saying that consolidation won't happen until the majors' inventory is more depleted.

"Then they may get aggressive," he said. "So, the question [for] the Permian Basin is, if they end up buying everybody up over time, is that a positive or a negative? But that hasn't happened, so it's sort of hard to speculate about that."

What did catch Sheffield's attention was Shell's interest in acquiring Endeavor Energy Resources LP for a reported $8 billion.

"That sales process has been called off," he said. "It's mostly in Midland County, and all the majors went through the data room from what I understand. It tells me that the majors aren't willing to pay a very high price for acreage at this point in time."

As far as the possibility of Pioneer being purchased, Sheffield said, "I'm the first one to say if we ever get an offer from a major, the board will do the right thing for its shareholders."

Until then, the most active part of the A&D market for majors and large companies may be trades. Recent deals, such as an all-stock deal by Parsley Energy Inc. to purchase Jagged Peak Energy Inc. and a merger between Carrizo Oil & Gas Inc. and Callon Petroleum Co., have been torched in the market.

As deal activity began slowing last year, majors such as Chevron Corp. aimed to build a contiguous Permian position through trades of 150,000 to 200,000 acres, Goldman Sachs analysts said in June 2018.

Sheffield said trades with majors and other companies are practically a daily occurrence.

"We have a lot of 5,000-foot locations. We're talking to Exxon about trading a bunch of their 5,000-foot [laterals]. Everybody wants to drill a 10,000-foot lateral because that's the most economic location," he said. "So, we're making trades with the majors all the time, day in, day out. And it's not just us, it's all independents."

Dane Gregoris, senior vice president at RS Energy Group, said interest in diversified asset types had led to investors "flocking" to companies such as Hess Corp.

In the quiet of the Permian Basin, supermajors fortify operations at a time when uncertainty and low commodity prices are causing independent E&Ps to reduce spending. While Pioneer Natural Resources Co. intends to hold capex essentially flat in 2020 and add two to three rigs, dozens of other U.S. shale players have announced diminished budgets.

Gjervik said trades are important for the company materially as "we optimize the acreage we have."

"Historically, the Lower 48 has in many areas been fairly fragmented as far as the ownership," he said. "It's kind of bringing it back together to what may have made sense years and decades ago when we did vertical developments. As we now look at it, drilling long horizontals, you need different size patches than you did in the past."

The company is assembling acreage in order to drill horizontal wells ranging from 5,000 to 10,000 feet.

"A very important part of what we do, and our M&A group does, is to create those trades. It's to drive toward those same kinds of contiguous acreage [positions] to get that benefit."

Those efforts aren't limited to the Permian. XTO trades within basins and even between basins. "Sometimes it can be easier to find a win-win commercial solution vs. buying and selling," he said. "There were a lot of deals to be made where you can find a win-win."

In shale plays, the company looks at a full spectrum of bolt-on and corporate deals, though what constitutes a bolt-on acquisition is in the eye of the beholder. In 2007, prior to its acquisition by ExxonMobil, XTO announced it would purchase Dominion Resources for about $2.5 billion. At the time, XTO co-founder Bob R. Simpson described the deal as a "supersized bolt-on."

"There's nothing unique about how we view [bolt-ons] vs. others," Gjervik said.

The principle, he said, is the same: Adding acreage where a company already has operations can be more efficient and cost effective than setting up in a brand-new area.

"That's kind of what we think about bolt-ons. What more synergies and benefits can you get?"

Fleeting secrets

The interplay between supermajors and independent U.S. shale companies is a matter of curiosity in and outside of the U.S. On recent trips in India and particularly the Middle East, Mayor said, she was frequently asked about her views on how supermajors and independents would operate alongside one another.

XTO Energy Inc.'s expansive Permian Basin operations promise to grow bigger as the company plans production to reach 1 million barrels of oil equivalent per day as early as 2024.

PHOTO COURTESY EXXONMOBIL CORP.

"The folks that are close to OPEC are really curious about shale and what's going to happen now that the integrateds have stronger footprints there," she said.

Mayor's view has been consistent. As she told *Investor* in October 2018, "Once the IOCs are in the basin it's pretty well-played."

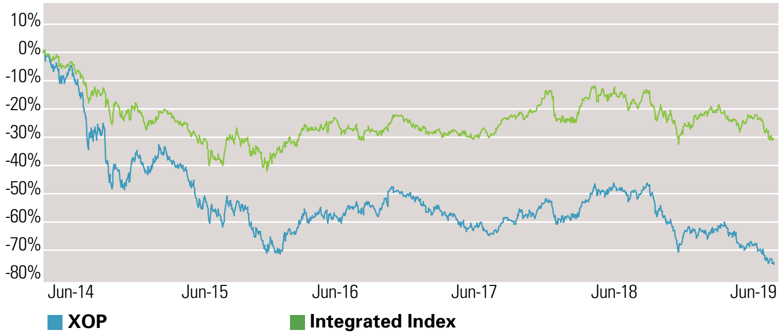
"I do think the integrated companies [as a group] are advantaged in onshore U.S. and in particular in shale in the coming period as we move from maybe more of the wildcatter types of prospects and the freer access to capital and financing that some of the smaller players had."

The drying up of capital for small companies is difficult to overcome. "I see it having a material impact on many of the smaller players," she said, adding that activity will also continue to fall among smaller companies.

Gjervik's own take on independents—as rivals, competitors or partners—is that "it's all of the above."

"Clearly, we are competitors. We are also partners. We have nonoperated positions like everybody else and joint ventures," he said. "And then you also have certain aspects of the industry that have to be worked [on] in a partnership, whether that's safety, whether that's some of the sustainability aspects."

Majors Maintain Market Advantage As E&Ps Continue Downward Spiral



Source: Enverus

Gjervik noted that many of the employees work in the same communities and with the same stakeholders. But it's a relationship admittedly in flux.

"You've got to be able to play across that," he said.

The majors didn't arrive in the dead of night to set up operations in the Permian, Bakken,

"It's the majors' game to play now," said Regina Mayor, global and U.S. sector leader for energy and natural resources at KPMG. Speculative money will likely go to the Scoop-Stack or Powder River Basin.

Eagle Ford or other shale plays. But more recent aggressiveness in staking out shale—and the Permian in particular—has followed steady increases in production.

In Texas, for instance, XTO has been the largest natural gas producer since 2015, according to Texas Railroad Commission reports. But XTO didn't consistently crack the Top 10 in oil production until 2016. In each successive year, the company has crept up the list, sitting at fifth in 2018.

Sheffield, whose Pioneer Natural Resources has consistently been a top oil producer, said he's "all for" ExxonMobil and other majors operating in the Permian.

Sheffield's case for the majors is that they bring more money and therefore more variation to the shale world.

"It's been a plus for the Permian Basin because they take a different approach," Sheffield said. "They do tend to spend more capital. They'll experiment more, and we'll learn from them—because it's hard to keep a secret out there."

Sheffield said Pioneer has a good exchange of information with the majors—and he's clearly been watching them.

"I knew that Chevron already had a great base there from previous acquisitions, primarily Texaco, so Chevron didn't have to go out and buy somebody," he said. "And Exxon, obviously, made a couple of acquisitions."

ExxonMobil also telegraphed the company's moves into the Permian, Sheffield said, noting that its 2018 and 2019 investor days focused entirely on the Permian.

At first, Sheffield was watchful of whether ExxonMobil's increased activity might cause service costs to rise, but that hasn't happened. The rig count has fallen by about 88 in the past 12 months, which Sheffield attributes to a decrease in public independent operators as well as private-equity-backed firms.

"Having a $300 billion company and a $250 billion company coming to the Permian Basin is a plus," Sheffield said. "And then the other two majors, Shell and BP, are starting to expand."

Sheffield noted BP's October 2018 purchase of BHP's Lower 48 assets for $10.5 billion. Shell likewise "bumped up their assets" in 2012 in a purchase of Permian leasehold from Chesapeake Energy Corp. for $1.9 billion.

"So they're ramping up activity," he said, adding that large companies such as Pioneer will share in their findings whether the majors "ramp up or not."

"Everybody's wells are being monitored, their lateral lengths are being reported, the amount of frack flow and the type of frack fluid they're using—everybody's got to report their frack jobs to FracFocus, so all the data becomes public anyway," he said.

ExxonMobil's ability to innovate gives it clear advantages over its peers, although Gjervik agreed that "Scott is probably right" that the broader industry will eventually benefit from the company's discoveries. The company would, naturally, like to keep "a lot of that benefit to ourselves," he said.

However, ExxonMobil's colossal resources make it one of the few companies with the "internal know-how and, I should say, capacity and capability, to take on research and move things forward."

On Nov. 22, the Drucker Institute at Claremont Graduate University ranked ExxonMobil among the five most innovative companies in a list headed by Amazon.com, Microsoft Corp., Apple Inc. and IMB Corp., The Wall Street Journal reported.

"You look back in history of oil and gas and today we take something like 3-D seismic as a given—surely that was there from day one," Gjervik said.

Today, the oil industry uses 3-D and 4-D seismic that ExxonMobil helped develop, he said. "That's how technology development goes but staying ahead of the curve for us to reap benefit from that as a company" continues to distinguish the company from the field.

Where Sheffield doesn't cede any ground is in Pioneer's dominance over well productivity or cost.

"Their production curve is public information. So we know everybody's type curve and production curve," he said. "And so I know for a fact that they are not making better wells than Pioneer, whether it's Exxon, Chevron, Shell or BP. We still have the best type curve in the Permian Basin. The only thing we don't know … is their well cost."

However, Sheffield said that, historically, the majors haven't been able to drill as inexpensively as the independents.

"Even though they don't publish their AFEs or well costs, I know for a fact there is no way that their well costs are going to be cheaper than an independent's," he said.

Where Sheffield and Gjervik agree is that the presence of the majors is good for the unconventional space. And with their arrival, Gjervik, the majors want to know, "How do we accelerate that to keep it competitive?"

ExxonMobil, of course, already believes it has part of the answer.

Manufacturer's guarantee

Gjervik turns the question over in his mind. How far along is ExxonMobil in developing a manufacturing mode in its shale plays? Is it in place? In progress? Does it exist at all?

He settles on the most appealing question, which is the one he posits himself: What does manufacturing really mean?

In some ways, the answer is the make or break for ExxonMobil's and XTO's plans for the Permian.

In one sense, Gjervik says, ExxonMobil is industrializing the unconventional. And like any manufacturing process, it must be broken down into its components for assembly.

"There is a manufacturing aspect from a resource development planning and kind of what's being done literally in the office where you take seismic, you take well data, you apply modeling, you apply science to it to then let that inform how and what you want to develop," he said.

The scale of production demands efficiency. With, for instance, 10,000 well potential targets, finding an cost-effective way to choose targets is vital. The industry has largely tackled that, though it still "has a ways to go," he said.

And then there's execution—drilling, completing and bringing a well on efficiently.

"Unless you have running room and you've got a certain level of scale, I don't think you can do manufacturing to set up a manufacturing plant," he said. "Just think about it. You've got to have more than two widgets to produce, right? You'd like to have to do 10,000 every day for 365 days a year."

At that level, scale is everything, Gjervik said—and XTO's edge. XTO holds more than 1.6 million acres in the Permian and plans to grow its total daily production there to 1 million barrels of oil equivalent by 2024 or 2025. Overall, the company holds huge swaths of acreage in the Appalachian and Williston basins and multiple U.S. states.

Part of XTO's plan centers on a 75-rig drilling fleet that as of late November dwarfs the total rig counts in the Eagle Ford, Williston, Haynesville or Marcellus and, separately, 11 U.S. states.

The rigs aren't searing through cash haphazardly, but as part of projects as intricate as the company's nearly 6-mile discovery wells offshore Guyana.

"Historically, there aren't that many companies that have been running even 10, 15, 20 rigs in one area," Gjervik said. "So I think we've gotten into it, a few other players are … starting to see the benefit of that."

ExxonMobil is already implementing real-time data gathering for its rigs in the U.S.

"Data is gathered centrally, and there are people who determine the insights every day and then apply that straight back either on the same well or the next well that is starting up two days later," he said. Historically that has been done manually.

"If you have a lot of rigs, that takes a lot of people, it takes a lot of time. How do you create a digital process around that where this can almost be a closed loop," he said.

Results from operations can be used to fine-tune well construction and feed into the company's permitting process based on information from "the well that you drilled last night, not the one you drilled six months ago," Gjervik said.

As XTO moves into large-scale production, the company is working to "fully stitch it together" and create a process that's not unlike the manufacture of cars on a conveyor belt.

"We aren't fully there yet … overall, I see that as a good thing as we have more running room. I haven't read a book yet on manufacturing for the unconventional, but we're definitely trying to write that internally."

Despite the majors' position of strength in capital, technology and procurement, one wild card remains in the shale plays, Mayor said: the affect big data will have on improving shale exploration, extraction and production.

"The majors all have significant efforts with big data in shale. And a couple of them are

As the U.S. rig count has plummeted, ExxonMobil and XTO have continued to ramp up their drilling program in the Permian to 55 rigs with at least another 20 rigs in other basins.

PHOTO COURTESY EXXONMOBIL CORP.

XTO Energy's presence stretches from this rig in Ardmore, Okla., to encompass roughly 11 million acres across every major shale play. The company estimates its total resource base is about 33 Bboe.

having decent success," she said. "So, it's being able to find and extract the hydrocarbons cheaper and more precisely and quicker, which is also part of the cheaper."

A technology breakthrough could yet disrupt shale innovation and the industry. With the majors able to parlay so many data points and analytics to improve their process, they've taken some of the human element out of the equation.

Proving techniques or processes that could make small-scale development more successful could be a disruptor. "Which would be something that a smaller independent—they wouldn't have the scale—but that could be exactly where they might be able to learn from the majors coming in."

But it will take time to develop and build ExxonMobil's vision. In the meantime, the hurdles facing the majors are likely familiar to shale veterans.

The chain

Eleven months into 2019's long, slow unraveling of E&P stocks, seemingly one ticker symbol after the next has been ripped apart at the seams. While oil prices in that time have increased by about 12%, according to U.S. Energy Information Administration data, the index of publicly traded oil and gas companies—the XOP—was down nearly 26%.

By contrast, Shell is down 3%, ExxonMobil by 2% and Chevron is up 6% through 11 months.

The downshifting of growth among oil and gas companies in favor of free cash flow has so far proven unconvincing.

"Energy has struggled to gain any sort of traction in the broader market," wrote Simmons analyst Ryan M. Todd in a Nov. 26 note initiating coverage of six oil majors.

"Investor preferences have evolved to favor moderate growth and shareholder returns," Todd said, adding that the potential for growth and dividends favored integrated companies through at least 2021.

Sheffield said majors' inherent advantage is in their integration of upstream, midstream and downstream and the ability to sell their products to their own petrochemical plants and refineries on the U.S. Gulf Coast.

"Their big upside is that they can take their products downstream," he said.

Mayor agrees that a fully realized upstream and downstream chain gives majors the ability to move crude from the Permian, push polypropylene to Singapore or excess gasoline barrels into South America.

"They can make really fundamentally different margins optimizing choices across their whole value chain. So that's sort of point number one of why they're differentiated," she said.

Supermajors are also less beholden to capital markets. "They have deeper pockets and can do their own financing," she said. "They'll have more flexibility as access to capital for some of the smaller players dries up."

ExxonMobil sees its integrated model yielding "far more value" than a single sector of oil and gas, Gjervik said. The company structure also provides a more complete understanding of each segment and a knowledge of the market that can make assumptions three to five years out.

"Not too many companies are able to do that," he said. "As you think about an upstreamer, it's go to sell its product somewhere.

"Being able to combine what we're doing in the upstream with the demand centers we have is also something that is very beneficial as you take out commitments and you weather the up and the down. Again, in a very different way than somebody playing only in one end of the value stream."

That value chain has clearly been of interest to investors, RS Energy's Gregoris said.

Investors have likely moved toward integrated companies, or at least diversified energy companies "in a big way over the last couple of years," he said.

In part, that's due to the variety of assets that immunizes them to the volatility that bucks shale producers.

Hess Corp., with assets in both offshore Guyana and the Bakken, is among the standouts among energy companies. The company's stock is up 47% from January 2019 through November 2019.

"That stock has held up miraculously well vs. shale peers," Gregoris said. "It's sort of a company in transition. That's a good example of investors flocking to different types of assets."

The shale space has seemingly lost its luster, he added.

Reid Morrison, PwC's global and U.S. energy advisory leader, said he's also seen oil and gas investors "prioritizing the majors over the shale players." However, PwC hasn't been able to quantify the shift toward the majors.

Morrison said that integrated companies are built for a market focused on delivering returns and dividends through all market cycles.

"Because the supermajors have assets in upstream, downstream and chemicals industries, they are able to drive free cash flow in all cycles, which is a key characteristic for value investors," Morrison told *Investor*. Companies have also exercised discipline over future capital investments in exploration and development which he said resonates with value investors.

Shale-focused companies will continue to produce their lowest cost wells and respond more to market prices and liquidity.

In initiating Simmons' coverage of oil majors, Todd wrote on that E&Ps tied to shale continue to suffer "growing pains" due to concerns around long-term resource depth and its economics, "including parent-child issues and well productivity."

With a slew of majors investing heavily in shale plays, the performance of the majors will either validate those concerns or alleviate them on a grand scale.

So far, ExxonMobil's Permian production volumes are rising in line with its guidance, Moody's Investors Service wrote on Nov. 19. But the financial services company also revised its credit outlook on ExxonMobil from stable to negative.

Moody's said the major is using debt to fund expensive campaigns across the globe—in the Permian, offshore Guyana, expansion in its LNG business and improvements to midstream and refineries.

Pete Speer, Moody's senior vice president, said in a Nov. 19 rating action that the company's debt is forecast to rise despite asset sales, "causing ExxonMobil's credit metrics to weaken for the next few years."

Barring a substantial change in commodity prices, the outlook estimated that ExxonMobil's negative free cash flow will be about $7 billion in 2019 and $9 billion in 2020 as the company funds growth while maintaining a dividend.

Gjervik said the company continues to invest through cycles rather than in response to them—a strategy that has yielded benefits in the past. ExxonMobil gains "efficiencies and by staying more consistent and you get a better result [at the] end of the day in doing that. And that's whether it's unconventional or the more conventional oil and gas around the world."

During CERAWeek by IHS Markit in March, Gjervik told Bloomberg that its Permian development, operations and land acquisition costs would be "in and around $15 a barrel." But Gjervik said ExxonMobil generally prefers to look at the returns it will generate.

"The way to look at it … is maybe from a 10% return [perspective], and what kind of oil price and how far down can the oil price go and still get a 10% return. For us this is around $35 per barrel. And then you can calculate from there, as far as what that means from a capital cost and operating cost."

Gjervik sees that as a better measure than breakeven costs because "when people quote kind of cost levels, you've got to be very clear here on what's included," he said. "So, I think that's a good measure."

Nieboer with RS Energy said that at this stage for ExxonMobil, the Permian is a rapid growth area where the company is investing a lot of capital for a cash-flow stream that should ultimately materialize.

"You know, not too long ago you would have said that the independents would've have an operational advantage over the majors," he said. "I don't think that's nearly as true today. The majors are really coming around quite quickly and becoming pretty good operators in a lot of cases."

Once the majors steady their investments and drilling programs, the dynamics of large-scale production and cash-flow profiles look likely to improve, he said.

"It's getting to that point and that sort of sustainability … that becomes the bigger, fundamental question." □

Reid Morrison, PwC's global and U.S. energy advisory leader, said supermajors are more attractive to investors because their integrated upstream, downstream and chemical companies can drive free cash flow in all cycles.

A TIME TO PAUSE, A TIME TO BUY

To everything there is a season, and while others might find this a time to scatter stones, this disciplined and prepared E&P is busy gathering them. The principals of Lime Rock Resources talk strategy, A&D and practiced patience.

INTERVIEW BY
STEVE TOON

It's been a good ride, the fast and furious ramp up and build out of the shale plays, fueled by a slug of capital looking for quick returns. But it's the patient money that once ruled oil and gas investments, and is coming to the fore once again as investors call for capital discipline.

One company in particular never wavered on that model.

Lime Rock Resources LP, a Houston-based private-equity firm that directly buys and operates its own assets, was formed 15 years ago on an acquire-and-exploit strategy with intent to generate investor returns through distributions and long-term gains. That was the polar opposite of the find-and-flip model other private equity pursued during the nadir of shale, and which is essentially defunct today.

Founded in 2005, the Houston E&P firm has raised some $2.4 billion over the course of its tenure, with a directive to target low-risk, mature and high proved developed producing (PDP) reserves. It is currently investing its fourth fund, a $754 million fund raised in 2016.

Lime Rock Resources is led by co-CEOs and managing directors Eric Mullins and Charlie Adcock. Mullins joined Lime Rock from the financial side of the industry, having spent 15 years in the investment banking division of Goldman Sachs before launching the investment E&P vehicle. Adcock's background is rooted in the operational side, with 12 years at The Houston Exploration Co. and before that with other E&Ps prior to joining Lime Rock Resources.

Three of the funds still hold active investments spread across the Williston, Permian, Anadarko and Appalachia basins. Current estimated reserves within the various funds total 328 million barrels of oil equivalent (MMboe), about 70% PDP, with daily production of approximately 57,000 boe/d.

Since the beginning of 2018, Lime Rock Resources has completed five acquisitions in a tepid A&D market. These include a $230 million deal for ConocoPhillips Co.'s Barnett Shale assets, Oklahoma Swoop producing properties from major BP Plc and a $300 million purchase of overriding royalty interests (ORRI) in the Marcellus Shale from Range Resources Inc., a co-investment with San Jacinto Minerals II.

"A lot of folks ask what's the inherent value of this asset," Mullins said, regarding Lime Rock Resources' acquisition strategy, "but that's not the question we're asking. The question we're asking is what price can we pay for this asset and make money for our investors. It's a very different question if you think about it."

Investor *visited with Mullins and Adcock in their Houston office in December.*

Investor The marketplace today is a bit volatile. A lot of E&Ps are struggling, looking for a new strategy. In today's environment, what would you say differentiates Lime Rock Resources?

Mullins One thing is we have committed capital, which gives potential sellers the certainty that we can close. Typically, when we make offers, they are not subject to financing, so that gives sellers confidence that we can follow through.

Adcock That's a very crucial point nowadays because when you talk to A&D advisors, I think they would unanimously tell you their biggest problem is finding people that really have money, and it's not something they have to go and get after they make you an offer. And so I think we have a very good reputation in the business for being able to close deals and follow through.

Investor How is Lime Rock Resources funded?

Mullins Most of our investors are institutions. They're pension funds, college endowments, foundations and a few high net worth individuals. So we go and market and raise our funds directly with investors.

Investor Have limited partners become more skittish about investing in recent times? Are you finding that it's harder to raise money now?

Mullins No doubt it's more difficult today.

PHOTO BY STEVE TOON

Fifteen years ago Lime Rock Resources LP co-CEOs Eric Mullins (right) and Charlie Adcock built the direct investment fund on an acquire-and-exploit strategy, which still works today. "A lot of folks ask what's the inherent value of [an] asset," said Mullins, "but that's not the question we're asking. The question we're asking is 'What price can we pay for this asset and make money for our investors?' It's a very different question if you think about it."

Some investors haven't done well in the past five years in energy, public and private, and that's part of the issue. Some investors just don't want to invest in energy because of the fossil fuel pushback. They're skittish, and so it is harder to raise money today.

Adcock One thing we hear over and over from people that have invested in this space continuously over the past 10 years is it's not that they want to leave energy, but they haven't gotten any realizations back. Most of these institutions do everything on an allocation model, and so they have a certain amount of their endowment dedicated to energy. And because they haven't gotten any realizations back, they're stuck. But some have just made the decision to move out of energy.

Mullins But there are others that view this current environment as a really good opportunity. Our markets are very cyclical, and a lot of times properties just don't trade when things get soft. But one thing I think is unique about today's environment is that we're still seeing transactions happen. It's somewhat of a soft market, but deals are getting done and that's what makes it unusual.

Investor In lieu of the current challenged marketplace, have you found a need to change or adapt your business model in any way as have some private equity backed E&Ps? Or does your model work throughout all types of markets?

Mullins I'd say it's closer to the latter. We're pretty consistent. We're acquire and exploit, we pursue both hydrocarbons. They're different, but we are open to buying either one. It's the exact same strategy. We really haven't changed.

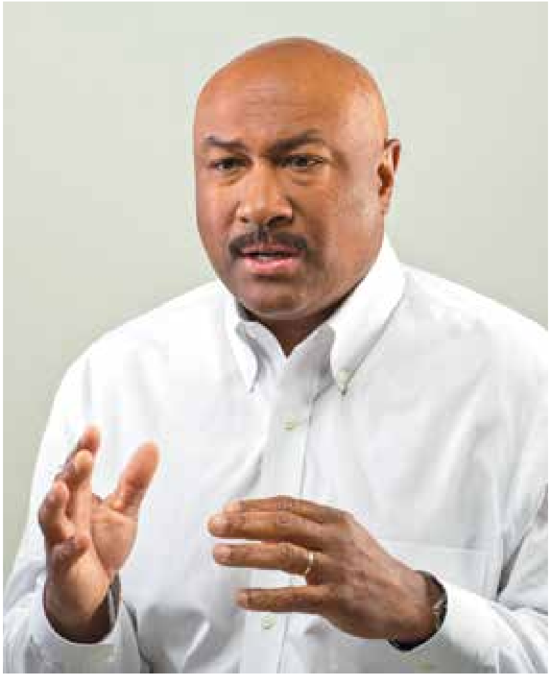
Investor Originally when you formed, why did you choose to focus your business model on more mature assets?

Adcock We felt that there was opportunity in that space that suited a different risk profile than the typical E&P private-equity play in upstream E&P. The reason it's lower risk is when you start buying properties and they contain more than 50% PDP reserves, you can touch it, you can feel it. You have the advantage of seeing the history not only of the production but also the cost side. So your outcome becomes a little more predictable.

We do drill quite a bit, but the areas we drill in, we try to focus in places where there's been enough drilling done that the results are predictable. We're not the type of company that's going to go in and buy 100,000 acres in a new area and start testing the premise, tweaking the completions to find the best model. It is much

"In the past 16 months, we've completed five transactions, and the 13 months prior to that we didn't complete any. It has been very active in the last year and a half or so."

—Eric Mullins



riskier, but it also has a lot more upside. We're more middle of the fairway.

Investor Do you think this is a model that others wish they were in right now or that you see them returning to?

Mullins It's very difficult today to execute on a lease and flip model. The larger public companies are not really hungry for inventory today. If anything, they're scaling back the way the public markets want them to live within cash flow and to have lower debt. So that is a tougher model, and I think in general companies have to hang onto those properties longer, develop them more.

We're definitely seeing that. Some groups have moved closer toward acquire and exploit and others are just holding on to the earlier-stage properties longer and developing those more.

Investor What is your acquisition strategy?

Mullins The strategy is to find properties that have a significant portion of PDP that we operate to get returns in two ways. One is we try to lower cost, and we're pretty good about lowering costs. The other is drilling new wells that are accretive to the acquisition.

Adcock Keep in mind, most of the properties, by the time we're ready to buy them, the previous owner has moved on to bigger things and so they need a little TLC. A lot of times we're able to go in and do a lot of simple maintenance work and get production up without spending a whole lot of money.

Investor What does the deal market look like today? Are you able to find quality properties to bid on?

Mullins We are finding deals to look at, and we've been very active. In the past 16 months, we've completed five transactions, and the 13 months prior to that we didn't complete any. It has been very active in the last year and a half or so.

Investor What would you say are the seller motivations?

Mullins A lot of companies are trying to pay their debt down. They're trying to live within cash flow and as a result they're paring off some properties that are not going to get their focus so they can take that capital and pay down debt.

Also, there's a decent amount of inventory in more traditional private-equity energy firms that have E&P portfolio companies that they would like to sell, but for whatever reason they haven't been able to sell yet. That's another source of potential opportunities. So of those five transactions, two of them were bought from traditional energy private-equity firms.

Adcock Traditionally, those groups get a big acreage position, drill as few wells as possible and flip it. But that's off the table right now.

The horizontal San Andres play we have was from a private-equity backed-portfolio company. They were moving forward when '14 hit and the prices fell and they couldn't flip. They had to continue drilling because of lease obligations, so by the time we looked at it, it was right at 50% PDP. They had already drilled enough to give us comfort with the additional drilling. It worked for both groups. We're actually seeing more of that.

Investor Are these distressed sales?

Adcock I wouldn't call it distressed. I just think they're motivated for a lot of reasons. All these private-equity funds, they have a certain life. Management teams, in a lot of cases, they want to move on.

Mullins The second transaction we bought from a private-equity-backed company was at the end of their term life. They just needed to wrap everything up, and that's why they were sold.

Investor Are the overrides becoming a bigger part of your acquisition strategy?

Adcock It's a sign of the times. A lot of these companies either need more money to drill or they need to pay down debt, and they don't really want to sell part of their crown jewel because they're not going to get a good metric on it right now. So you sell this little sliver off the top, and still retain control of your entire acreage base.

In the case of the override we did with the private group, they had a deal in hand from a major and were looking to fund that deal. They did it through this override structure rather than taking down additional debt. That truly was a win-win deal there.

We like them. You buy it and then you have no more capital commitment. But the problem is we think that's just the short term. When and if this turns around, people will quit doing it. They're doing it now because it fits. We're certainly going to look at all of them we can.

Mullins It's representative of the equity markets being closed to oil and gas companies right now. I don't think that's always going to be the case—there'll be cheaper ways to finance your business as we move through these cycles. And as that happens, I think there'll be fewer opportunities for overrides. But for the time being, for us it's an attractive way to invest dollars.

We look at them as a portion of each one of our portfolios that's nonoperated. We want the majority of our portfolio to be operated, but we will look at nonoperated opportunities as well. This falls in that category.

Investor Do you find the A&D space is becoming more competitive?

Adcock It's always competitive. I think the one difference right now is it's a lot more rational.

We've had periods as long as 18 months when we didn't buy anything. One of those periods was when the MLPs were going crazy. That was an irrational market because what they were paying for assets was too much. One thing about this market is I think you're going to see the valuations tighten quite a bit.

Investor How has the market affected the deal metrics?

Mullins Deal metrics have come down. Pre 2014, oil properties were trading around \$100,000 per flowing barrel. Today, those properties are trading around \$40,000 to \$50,000 per flowing barrel, so half of that metric. Deal metrics have been cut in half if not more.

Investor Do you see this as an opportunistic market, or are you concerned about catching the falling knife at this point?

Mullins No, it's attractive. It's attractive partly because there are just fewer buyers. The point Charlie made earlier is that the E&P MLPs are out of the market now. The public companies are more focused on living within cash flow and reducing their debt, so they're not competing as aggressively as they have historically with a few exceptions. And a lot of the private-equity energy-focused firms have this inventory of E&P companies that they haven't been able to sell, and so they're not aggressively letting their portfolio companies go out and buy either. So there are just fewer buyers in this market, which is partly what makes it attractive if you're a buyer today.

Investor How much of a typical acquisition do you fund with bank debt, and can you still access commercial bank debt these days?

Mullins We target about 50:50, so 50% of the acquisition we fund with bank debt. Some transactions, if you have a little bit more drilling, maybe a little bit less than that, but I would say for the portfolio in general, it's about 50:50. Every one of those five transactions that we completed in the past 16 months, we used bank debt. The banks are still lending.

There have been some high profile collapses of energy companies recently, and the banks have lost some money, so in general it's tighter today than pre 2014, but they're still open. It's still an important part of our strategy.

Investor Do you think with the absence of capital, particularly in the public markets, that more assets will fall into private hands?

Adcock Yes. Our BP deal is a perfect example. Given the big picture for BP and where they're focused in buying BHP (Billiton's \$10.5 billion unconventional asset portfolio), this was a little carve out for them. And even though it turns good cash flow and it has good metrics, that takes time. So if you pull human assets away to work on that, they could be working on something that has an EUR magnitude 10 times greater. I definitely think this is going to create more opportunities.

Everybody has to be very cognizant of their human resources right now and working on meaningful projects for their structure. I think we'll see more of that.

Investor Like with other private-equity-backed companies, are you facing challenges with exits presently?

Adcock It's a tough sell market right now. We do have a little more luxury because our fund life is longer than the typical private-equity model.

Mullins Terminal value is very relevant today because the exit markets are so difficult. We push our terminal value out 10 years, so you're not depending on some rogue sale number to make your numbers work in years five or six. It forces the assets to get our returns based on cash flows that are coming out of those properties as opposed to depending on some important asset sale.

Investor Is that an advantageous model in today's marketplace?

Mullins Sure. It's worked for us, and we haven't changed that. We basically have three uses for our cash flow. One would be to reinvest in the properties, whether it's drilling or building out infrastructure—anything we can do to enhance the property. Two, pay down debt. Three, make distributions.

Investor How do you choose between those three?

Mullins Anytime you have attractive opportunities where you can spend your capital and do work that's accretive to that property, we take the opportunity to try and do that. And typically, a plain vanilla strategy would be something like 50% of your cash flow you reinvest in the property, 25% you pay down debt and 25% you make distributions.

If prices get really weak, you may shift that and you may spend 75% on debt repayment to be defensive and 25% on the other two. And then if prices are really strong, you may flip that again and 75% reinvestment and 25% for the other two. So it's moving all the time, and you're always evaluating what's the optimal way to allocate your capital in terms of that cash flow.

Investor Do you have a target debt ratio you try to stay within?

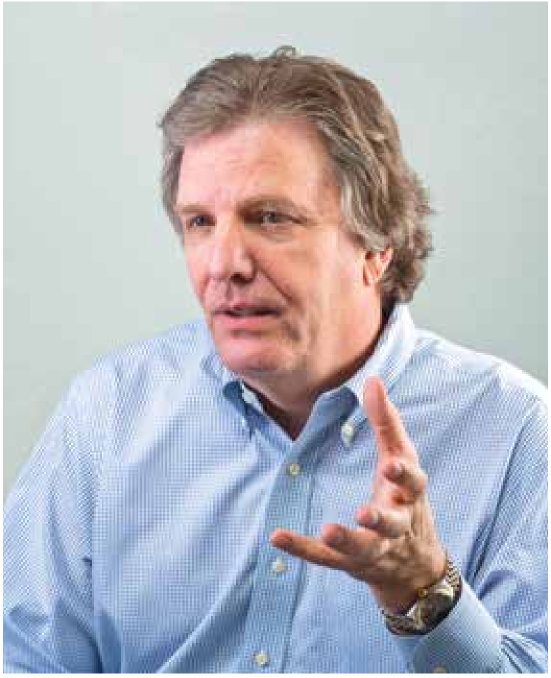
Mullins We try to keep our debt between two and two and a half times debt-to-EBITDA. You always have to keep a reasonable balance sheet just to allow you to get through the lower part of these cycles. That's the key. We focus on that a lot.

Investor How big of a deal can you do?

Mullins The largest transaction we've completed was just over \$600 million. We could probably do a transaction a little bit bigger than that; it's hard to say. It just depends on how attractive the opportunity is.

"Our goal isn't to drill, drill, drill nonstop and then at the end of the day after you've driven the truck through the china shop, look back and see what isn't broken. We can't afford to do that."

—Charlie Adcock



Adcock One of the things that's changing about private equity is everybody wants to do co-investments now. We hear it more and more from our investors, "We want co-investment opportunities," because it gives them a bigger bite at the apple. So you reach out to all of the current investors and see who wants to put in additional money. If we had a little bit bigger deal than we wanted to do, we could potentially go to our investors and try to get co-investment to cover the rest of it.

Mullins To Charlie's point, if we found something that was a billion dollars and it was really attractive, we could go to our existing investors and probably fill that in, say the difference between $700 million and $1 billion, or whatever it ends up being.

Investor Hedging is a big part of your strategy. Can you give me some perspective on how you view hedging and why is it a critical part of your strategy?

Mullins It's part of our risk management in that we are using some leverage when we buy these properties. So philosophically we think you're most vulnerable right after you acquire the property. You haven't started amortizing the debt yet. You haven't really gotten into your exploitation process. So we will hedge anywhere from say two to six years, and we hedge generally 75% to 85% of our PDP production.

And it's not because we believe that we know what prices are going to do in the future; precisely the opposite of that. We don't know what prices are going to do. We do know that at the time of the acquisition where prices are generally, and we know that price range works for that property. So we approach it more like a corporate finance decision, which is to lock in a substantial part of your price exposure, especially in the early part of that acquisition.

And it's really a win-win. If prices run up a huge amount, yes, you're going to lose some value on what you have locked in, but your enterprise value is probably tripled or quadrupled because prices have gone up so much. And that swamps the amount you're going to lose on, say, five years' worth of hedges.

On the other side, it's a win if prices go down significantly because it just gives you a bridge to wait for another day when maybe prices can rebound. So it keeps your cash flows up at just the time that you're most vulnerable if you're in a low price environment. You're in a pretty good position if prices go down, you're in a pretty good position if prices go up.

Investor What's your plan going into 2020?

Mullins We're active in Andrews County, Texas. We're going to be active in the Barnett Shale, and in Oklahoma, where we're going to be drilling on the Swoop property we acquired.

Adcock Also in the Bakken. One thing we do a little differently is we don't go into an area and just contract a rig for two years and drill constantly. We tend to take smaller bites of the apple, six- to 12-well packages, and maybe drill 10 wells. And then we release the rig, complete it, see what the results are and get comfortable gauging the completions.

Completion technology has been changing rapidly over the past three or four years at a fierce pace. We want to make sure that we're completing the wells correctly. When we see that and get really comfortable, then we'll pick out 10 more locations and get a rig.

Our goal isn't to drill, drill, drill nonstop and then at the end of the day after you've driven the truck through the china shop, look back and see what isn't broken. We can't afford to do that because we are time limited. We have to be very judicious about how we invest our capital because if you go out and just drill willy nilly and it's not working out, you're never going to catch up.

Investor What is your outlook for 2020?

Adcock The industry's tough right now, it's tough. We feel very fortunate because our house is in order, and we've got good cash flow from all our properties.

Investor Any hope?

Adcock There's always hope. The capital markets will reopen. People will finally realize the value spread and the capital markets will reopen and once that happens, then it's going to invigorate the whole industry.

The rig count has fallen pretty dramatically. Everybody knows that in these shale areas, when you start taking rigs off the table, your production starts dropping. When the price dropped in 2014 and then you look at the next nine months of production for the U.S., we lost a half million barrels a day just in that nine months. So, yes, there's hope.

Mullins I'm very excited about looking at 2020 and the opportunities that we're seeing to acquire properties. We're just going to have to be patient and opportunistic on the sell side and wait until the market improves. But it's very exciting looking at the opportunity set for 2020 on the buy side. □

STRETCHING THE ENERGY DOLLAR

E&Ps are exploring all avenues to access capital on terms that make sense for their situations.

ARTICLE BY
CHRIS SHEEHAN, CFA

"We're not going to just trade dollars. Getting money upfront, and then having higher well costs, doesn't make a lot of sense if you're just paying it back over time," said Rich Dealy, CFO of Pioneer Natural Resources.

It comes as little surprise that capital markets for energy barely have a pulse. Discipline is the order of the day, and capital constraints are enforced on E&Ps by market pressure. A market mandate asks E&Ps to pursue multiple goals at once: keeping capex within cash flow, while pushing production higher at a sustainable rate, offering a rising dividend, buying back stock, rolling over debt, etc.

No easy task for what was once recognized to be a "capital-heavy" industry. And, for public E&Ps, life is made no simpler by an apparent assumption that the cadence of capital outlays and increases in output will tend to neatly match one another. Yes, capital efficiency may tend to move forward based on those factors, but capital projects do not always progress at a uniform pace each quarter.

So, if the spigot for sourcing capital is down to a dribble, how are E&Ps coping with capital constraints?

It's not as if the energy industry has lacked resourcefulness in adjusting to varying levels of capital or finding new capital sources. If capital is tight, dropping rigs and crews is obviously an option. Less drastic are moves to sell noncore acreage and nonoperated assets. Then there are less frequently used moves, such as the sale of overriding royalty interests (ORRI) or volumetric production payments.

Of late, E&Ps have also focused on substantial investments in water infrastructure that can be partly or wholly monetized to boost sources of capital. Likewise, interests in gathering and processing facilities may also be put up for sale. Such sales, however, are likely to come with a measurable move higher in lease operating expenses. A third option is spinning off at least part of an E&P's mineral interests.

"The key is to limit our capital in infrastructure projects so we can generate incremental free cash."

—Rich Dealy, Pioneer Natural Resources Co.

Levers to pull

Pioneer Natural Resources Co. has several levers it can pull—and the luxury of not having to use any of them.

Pioneer in some ways offers a textbook example of moves to enhance its self-funding. These include asset sales, a possible further sale of gathering and processing assets, and an evaluation of strategic alternatives for its water infrastructure. However, with a pristine balance sheet—debt is only 0.7x trailing EBITDA—the timing to push forward along any of these avenues is largely at its discretion.

Last summer, Pioneer made a sale in the Permian of some 3,300 net acres in Martin County, Texas. The position traded hands at about $20,000 per acre in two transactions with the same buyer. Subsequently, Pioneer also considered a possible sale of acreage farther south. However, due to deteriorating acquisitions and divestitures market conditions, an outright sale was dropped in favor of a Drillco.

"We would have considered a monetization, but we didn't think we would get the right value for the property," Rich Dealy, Pioneer's CFO, told *Investor*. "The A&D market has virtually dried up. We thought the Drillco was probably a better outcome for us rather than trying to sell the acreage outright at this point in time. A Drillco is in essence a wellbore deal; it doesn't involve any acreage."

While Pioneer could easily have drilled the acreage itself, given its "great balance sheet," bringing in a partner in a Drillco "is a way for us to accelerate the value of some of our long-dated inventory," said Dealy. "Given the tremendous inventory that we have, these projects can be farther out or at the tail end of that inventory. Some of it has drilling obligations associated with it."

Drillco 'in process stage'

Drillcos are typically structured so the economics heavily favor the joint-venture (JV) partner until the latter has earned a hurdle rate, "typically in a 12% to 15% range," at which point much of the economics revert to Pioneer, said Dealy. A key variable is how long it takes

"I view hedging as even more critical now, because we can't go backward," observed Ryan Dalton, CFO of Parsley Energy Inc. "We've committed to be free-cash-flow positive to ourselves and to the market. We want to be one of the companies that grows its dividend over time."

the partner to reach the hurdle. "That could be forecast to be, say, three to five years. But if commodity prices dip, it could be seven or eight years."

Any initiative on a possible Drillco is "in the process stage," stated Pioneer in its third-quarter report.

In its gathering and processing JV with Targa Resources Corp., Pioneer is "in the process of trying to sell our 27% interest," said Dealy. "It's something we would like to monetize. The key is to limit our capital in infrastructure projects so we can generate incremental free cash flow [FCF]. We'll improve our FCF yield by not investing in plants that have a lower rate of return than we achieve with our drilling investments."

Pioneer estimated its 27% interest in the Targa asset was throwing off some \$50- to \$60 million of EBITDA, although this was earlier in 2019 when NGL prices were higher, according to Dealy. Midstream deals have historically traded at an 8 to 10 multiple of EBITDA, but the multiple may be somewhat lower today, he said. "NGL prices have declined over the course of the year."

On water infrastructure, Pioneer's situation differs from many other projects in that the buildout is designed to source water used for hydraulic fracking of wells rather than for the disposal of produced water. Pioneer currently has access to 120,000 barrels per day (bbl/d) of effluent water from the city of Odessa, and it is building a water treatment plant with the city of Midland from which it will take 240,000 bbl/d.

"We're evaluating it," said Dealy. "The board will likely make a late-2020 decision. One reason is we need to complete the Midland water treatment facility. We want to evaluate what the right structure is. We're not going to just trade dollars. Getting money upfront, and then having higher well costs, doesn't make a lot of sense if you're just paying it back over time."

Options for Pioneer range from "keeping it 100%" to "monetizing it 100%," as well as a multitude of opportunities in-between, according to Dealy. These may include selling volumes to third parties when the pipeline system has spare capacity, which is expected as the Midland facility comes online and as Pioneer increases the company's recycling of its produced water.

Capex for water and gathering and processing facilities was budgeted at \$250 million for 2019. With the water pipeline buildout over its peak expenditure period, and a likely resolution of a Targa asset sale, Pioneer expects capex for the two sectors in 2020 to be "substantially less," said Dealy.

Casting a wide net

Parsley Energy Inc. has got its sights on monetizing parts of its water infrastructure and its minerals interests, but has indicated it is prioritizing water, with a transaction that could be finalized by year-end 2019. A monetization of minerals is "something on the docket to explore in 2020, but the near-term focus is on water," according to Ryan Dalton, CFO of Austin, Texas-based Parsley.

In the interim, of course, the major event happening at Parsley is its combination with Jagged Peak Energy Inc. With Parsley already FCF positive, the merger plans call for Jagged Peak to drop one of its five rigs in 2020 so internally generated cash flow covers its capex. In broad terms, this "makes Jagged Peak FCF positive and makes the acquisition accretive to Parsley on FCF," said Dalton.

PHOTO COURTESY BAYSWATER EXPLORATION & PRODUCTION LLC

Bayswater Exploration & Production LLC drills out of direct investment funds. Here, its Leffler Pad in the D-J Basin in Weld County, Colo.

The timing of any water monetization may prove fortuitous for financing the Jagged Peak acquisition.

Incremental debt assumed with the Jagged Peak purchase is "manageable" and could be paid down over time, said Dalton. "But the timing of events could line up perfectly such that if the water transaction closes by the end of 2019 and the Jagged Peak transaction closes in the first quarter of 2020, then we could take part of the proceeds from the water transaction and use it to pay down the revolver balance."

As for a monetizing part of its water assets, Parsley "cast a wide net" in examining potential strategies.

In the end, according to Dalton, "it was important to management and the board that we maintain operational control. It's important to us that, if a saltwater disposal well runs into a mechanical issue during the night, one of our guys is going to get the alarm and we know the problem is going to be addressed. For operational continuity, it's important we keep control."

This led to Parsley working on a minority sale of less than 50% of its water assets to an unnamed party. Parsley termed the process as involving "exclusive negotiations" with a single party, which it describes as a "true financial party" as opposed to a well-known water infrastructure company. "This is more an entity that is going to invest some cash and let us run the business," commented Dalton.

An option down the road

The prospect of a divestment of minerals in some form "is still an option for us down the road," said the Parsley CFO. "Our mineral ownership is concentrated more in the Delaware Basin, primarily in the old Trees Ranch area. We have minerals on a good portion of our Delaware acreage; approximately three quarters or more of our minerals are on the Delaware side."

Another tool used by Parsley to pursue strategic options in a capital-constrained setting is commodity hedging. In the past, Parsley has had "a high utilization of hedges," noted Dalton, and the hedging of a growing portion of production has gained importance as the company has emphasized a policy of being FCF positive and delivering a dividend.

"I view hedging as even more critical now, because we can't go backward," observed Dalton. "We've committed to be FCF positive to ourselves and to the market. We want to be one of the companies that grows its dividend over time. We can speculate as to what may happen in 2020 and beyond. But for us to sleep at night, we must know we can pay our dividend, and so hedging is going to be a very critical component."

Parsley has hedged 65% to 70% of its oil production for 2020, pro forma for the Jagged Peak acquisition, based on guidance given at the time of its third quarter earnings release.

As for availability of credit under reserve-based lending (RBL), Parsley has now gone to an annual redetermination, so it did not go through a fall redetermination. However, it has heard that some of the major commercial banks are lowering their price decks, which coupled with an increase in discount rates has led to meaningful cuts in some E&P borrowing base amounts.

Temporarily slowing down

Steve Struna, CEO of Bayswater Exploration & Production LLC, has worked hard to gain an advantage from financial strategies amidst largely moribund capital markets. Strategies it has used or explored include: marketing non-op interests; selectively selling down working interests in company-operated projects; and selling future crude production via volumetric production payments, among others.

However, current tightness in credit and capital markets also offers attractive opportunities, in his view, and privately held Bayswater has raised a series of energy funds chiefly from college endowments, pension funds, foundations and other institutions.

Struna sees the pace of industry activity moderating, but not likely decelerating into a steep decline.

"We're seeing a decrease in activity. I would characterize it as people are temporarily slowing down. How long 'temporary' ends up being is hard to say. The industry is in a slowdown for a while in which players likely defer some activity, let cash flows come in, and consider other sources of debt and equity. But slowing down is key in the first instance, so that you have options in the future."

Bayswater's track record and its conservative capital structure gives it perhaps greater flexibility than some industry players have in setting strategy. Its first two institutional funds have been realized, with returns to investors "near what we projected," said Struna. Its third fund, which closed in early 2017, diversified from mainly the Denver-Julesburg Basin to include investments in the Midland and Delaware sections of the Permian Basin.

An initial investment in the Midland Basin was in Howard County, Texas, where SM Energy Co., Diamondback Energy Inc. and Callon Petroleum Co., among others, have enjoyed considerable success. After acquiring leases on what then was thought to be Tier 2 acreage, Bayswater was "very encouraged" by its initial well results and went on to drill 10 wells, and it is now considering a 30-well program for 2020. Bayswater currently holds some 20,000 net acres in the play.

Bayswater also continued investing in minerals in the core of the Delaware portion of the Permian Basin.

For funds, a longer hold period due to the thin A&D market has increased financing needs, said Struna.

"Our fundamental model has been 'acquire, develop and exit.' But given the change in the market, our hold time is now much longer, requiring more capital and a greater percentage of development of the assets," he observed. "May-

"Our fundamental model has been 'acquire, develop and exit.' But given the change in the market, our hold time is now much longer, requiring more capital and a greater percentage of development of the assets," said Steve Struna, CEO of Bayswater Exploration & Production LLC.

"First lien financing is more expensive than bank financing, but not hugely so," according to Tim Perry, global co-head of oil and gas investment banking at Credit Suisse.

PHOTO COURTESY BAYSWATER EXPLORATION & PRODUCTION LLC

Bayswater Exploration & Production is entering joint development partnerships to strategically stretch capital. Above, completions operations at its City of Thornton well in Weld County, Colo.

be 'full development' is now our new model. And with that in mind, expanding the use of our RBL through the semiannual redetermination process has been one option for us."

The price deck used for redetermining its RBL remains below the strip, commented Struna, but commodity price assumptions for Bayswater "have not changed as dramatically as we've heard for others." In large part, he explained, this may reflect that "we've got some built-in constraints on borrowing inside our funds that leaves us relatively underlevered compared to our peers."

Helping capital go further

Meanwhile, Bayswater has turned to several financial instruments in hopes of helping capital go further.

These measures have included selling down working interests in company-operated projects in a farm-out or Drillco-like transaction, as well as marketing a package of nonoperated interests that have drawn interest, said Struna. "If our hold is longer, we have to stretch our capital. A farm-out or Drillco-like transaction is one where a joint development partner puts up a portion of the initial capital and, in return, we get a reversionary interest down the road." Bayswater recently entered into a joint development agreement with Houston-based Millennial Energy Partners covering the drilling and completion of six multiwell pads in the Denver-Julesburg Basin's Wattenberg Field.

Even with alternative sources of capital, Struna sees a need for a reopening of traditional capital markets.

"The capital markets have to come back in our industry. The question is when," observed Struna. "There are some solid opportunities. We all have attractive, high-return projects in front of us."

> "We're very confident that first lien financing will be available. Whether people will take advantage of it, we don't know for certain."
>
> —Tim Perry, Credit Suisse

Tim Perry, who serves as global co-head of oil and gas investment banking at Credit Suisse, pointed to a number of instruments that E&Ps may turn to for financing. These included a new format for asset-backed financing by Raisa Energy LLC (see article on p. 97), a sale of overriding royalty interests—a choice employed by Range Resources Corp.—and first lien financing as a possible further avenue.

On the topic of first liens, Perry recalled its use in the downturns four years ago and again in 2009 through 2010, and he expressed confidence that it would be available—and quite likely used—if current conditions in the industry "continued to deteriorate, which might happen. We're very confident that first lien financing will be available. Whether people will take advantage of it, we don't know for certain."

First lien financing is "more expensive than bank financing, but not hugely so," according to Perry. As compared to RBL funding from a bank at 4.5% to 5.5%, a first lien loan would be priced in a range of 6% to 8%, depending on individual circumstances, he said. "It's not really a revolver," he commented, "but you can raise capital that way on a secured basis."

First lien financing is typically issued with a term of five to eight years.

Reducing revolver 'dollar for dollar'

A first lien financing may be attractive to E&Ps that have a "highly utilized revolver," which could then be paid down in part or in full "so they can significantly reduce a banking facility," said Perry. "It may be a way of eliminating it or just making it a lot smaller. It will reduce the revolver dollar for dollar."

As an example, a significant $500 million RBL credit could be replaced by a $300 million first lien and a $200 million revolver, or paid off entirely by a $500 million first lien. In the former case, the RBL and first lien financing would be considered pari passu, allowing each of them an equal claim on the prorated assets, according to Perry.

While borrowing bases are "still pretty large," bearish commodity forecasts may spark greater use of first liens "if the borrowing bases start to shrink," said Perry. "If the commodity strip is right, we're in a backwardated curve for both oil and natural gas. The fact of the matter is that a lot of the hedges for E&Ps start rolling off in 2021 or 2022, and mostly in 2021."

First tier financing has historically been "extremely well-secured," with minimal losses even at times of challenging commodity prices, according to Perry. For first tier financing, he said, "I think there's a lot of capacity out there." □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IT'S THE MATRIX

Another century, another sequel to the indomitable Austin Chalk where it all began: East Texas. This rock still has a lot of oil and gas.

ARTICLE BY
NISSA DARBONNE

BlackBrush Oil & Gas LP's new Chalk prospect in Washington County, Texas, sits in both the quiet window and in the fractured window, said Mark Norville, president.

The Austin Chalk is legend. Some operators it's made; others, it's broken. In some areas, it's quiet, without many or any natural fractures; in others, it's noisy.

It's gassy here; it's oily there. In a way, it's ubiquitous. But, over the decades, it's also been quixotic.

In Texas, the saying goes that everyone has a story about a pickup—as many as there are bluebonnets. In East Texas, most every operator has a story about the Chalk.

Every so often, a wildcatter comes up with a new idea, walks into a county courthouse and files new lease papers. Some of these ideas have worked out using the technology that was *a la mode*, thus the stuff of legend.

In this decade, the newest iteration of how to wrangle the Chalk—super-fracked, staged-interval laterals—is working where Chalk pay was left behind or hadn't been attempted.

The traditional play in East Texas had been on the natural fractures. Operators today are tapping both the fractures as well as the matrix porosity. Increasingly, some are focusing on the quiet areas of the formation.

Chesapeake Energy Corp. bought East Texas-focused WildHorse Resource Development Corp. last year for $4 billion for its dual Eagle Ford and Chalk. Magnolia Oil & Gas Corp. bought EnerVest Ltd. property for its dual Eagle Ford and Chalk in both South and East Texas for $2.7 billion.

Smaller operators are working to prove their eastern Chalk as well. Here's a look at what each has found and plans.

Quiet, not quiet

San Antonio-based BlackBrush Oil & Gas LP has plays in Washington County in both the fractured Chalk and the quiet Chalk. About half of its 24,600-net-acre block there is in one; the balance, in the other.

The privately held Ares Management Corp.-backed E&P made the first successful co-development of Chalk and the Eagle Ford in South Texas' Karnes County in 2015, spawning a sub-play within the super-basin. Nearly all of this was sold to EnerVest in 2016.

With a Chalk map from the Rio Grande to central Louisiana, it headed east to Washington County for a new play. "Washington County is particularly intriguing," said Mark Norville, BlackBrush president.

"We saw this quiet area that reminded us of what we saw in Karnes County where the production turned out to be so fantastic."

After processing new 3-D data, however, the portion of the BlackBrush block in what's known as Giddings East Field showed "tremendous fractured intervals

PHOTO COURTESY TREADSTONE ENERGY PARTNERS II LLC

"What people are missing about the Austin Chalk is that, yes, it's a naturally fractured reservoir, but it's also an 8% to 10%-plus porosity reservoir. It contains a lot of oil that's not just in the natural fractures," said Frank McCorkle, president, Treadstone Energy Partners II LLC.

still left to be drilled."

It was no surprise that the area is naturally fractured, he added; rather, the number of untapped fractures was surprising. Giddings East operators in the 1990s had made several 20- and 30 billion cubic feet (Bcf) wells.

In this new play, BlackBrush has tried one well. Cassidy 1 "crossed one of those fractures, and it had a tremendous kick. It's the type of drilling I hadn't seen since I started in this business in the 1980s when I worked for Clayton Williams [Energy Inc.]," Norville said.

It was a short lateral—about 2,500 feet—and had a first-30-day IP of 6.4 million cubic feet equivalent per day (MMcfe/d), peaking at 9 MMcfe/d. On a per-lateral-foot basis, it's the second-best well in the field, Norville said.

BlackBrush is looking for a partner in that area. "If we can drill wells you don't have to frack, that's a $3.5- to almost $4 million savings on a per-well basis on a potential 10 to 20 Bcf well, which all of a sudden becomes very economic, even in the dry-gas environment," he said.

The other half of the leasehold, "we're going to have to frack," he added. "But we've opened a door [in the overall block] where there could be some drilling for a nonstimulated, openhole completion play here as well."

The company has about 49,000 net acres for Chalk in Texas. (It also has Chalk leasehold in Louisiana.) These are the 24,600 in Washington County; about 1,400 remaining in Karnes; and 23,350 in Frio County.

Of that, about half is HBP. Drilling continues in Karnes and Frio counties; it's oily there—about 2,000:1 GOR. And wells are strong, IP-ing up to 1,500 barrels per day (bbl/d) from short laterals of 3,500 feet or less.

Washington is particular intriguing "when you look at the porosity—up to 8%. It's a great position," Norville said. BlackBrush's pay-model cutoff is a minimum of 6% porosity. "It's well up into that neighborhood."

Here and previous page, Treadstone is drilling and completing in the Chalk at the intersection of Burleson, Milam and Robertson counties, Texas, near the town of Hearne.

Business plan 3.0

Just one thing, though: It's gas. How much gas? "One-hundred percent dry gas."

In Washington County, the BlackBrush leasehold is along a slope margin. Early migration of hydrocarbons from Eagle Ford preserved porosity in the area at the time of Chalk deposition. It's deep, overpressured and the temperature is high, thus it's gas.

Up in Burleson and Lee counties, that's the platform. It gets oily there.

In Norville's Clayton Williams Energy days, wells tapped hydrocarbons that were in the natural fractures. Fracture stimulation would be needed to tap what's embedded in the rock itself—the matrix porosity—and the economics for this also require horizontal wells.

That's similar to what BlackBrush did in creating a new Chalk play in Karnes, where the Chalk is quiet. "In Karnes, we weren't the first to try Austin Chalk over there, but we were the first to frack it with an Eagle Ford-style frack."

The E&P began as a conventional-rock shop in 2005. While it was focused on South Texas for Olmos, San Miguel and Edwards, the Eagle Ford play developed around it, "so we morphed into an unconventional shop," Norville said.

For that, it had to get private-equity (PE) financing; super-fracked, long laterals are much more expensive than verticals. As the PE "market's dried up for now," Norville said, it's looking at drilling "completely through the PDP process."

So, again, "we're morphing into something new. We're not going to be the type of company just flipping things—a transactional company. We're going to be a company that's going to be a long-time player."

It expects to exit 2019 with 11,600 barrels of oil equivalent per day (boe/d) net. In November, it was completing an eight-well pad—landed in the Chalk, lower Eagle Ford and upper Eagle Ford—with Inpex Eagle Ford LLC.

Plans for 2020 are to continue drilling for Chalk and Eagle Ford in Karnes and Frio counties and for Eagle Ford in McMullen County. If costs decline, Norville expects BlackBrush could drill for Chalk in Washington County and for Eagle Ford in Maverick County.

Hearne-area oil

Houston-based Treadstone Energy Partners II LLC is on the northern end of the East Texas Chalk, up on that platform, in the oil window. It has two rigs drilling and plans to average between 1.5 and two rigs at work this year.

It's drilled 20 Chalk wells and five Eagle Ford wells in the area to date. "Our Eagle Ford is very economic," said Frank McCorkle, president. "It's just not as economic as our Austin Chalk."

Operating most of the other rigs in its neighborhood are Chesapeake and privately held Hawkwood Energy LLC.

Treadstone I sold its Buda-producing Fort Trinidad Field in Houston and Madison counties in 2014 for $715 million. It had grown production there from about 20 bbl/d in 2011 to more than 10,000 bbl/d.

In 2016, it picked up 42,000 net acres from Anadarko Petroleum Corp. for Chalk, Eagle Ford and Buda in northern Burleson, southern Milam and western Robertson in an area known as Hearne. That came with 650 bbl/d.

It's bolted on about 4,000 net more since then. Kayne Anderson Energy Fund VI LP is backing Treadstone II; it backed the first Treadstone, too.

It's all contiguous, except for a few spots, McCorkle said. The Chalk is fractured where Treadstone is.

The acreage also contains about 43,000 net for underlying Eagle Ford. And deeper Buda's prospective on all of it as well. The Anadarko acreage was all HBP; what's been added since isn't.

"We will start drilling into it," McCorkle said. "But it's very recent leasing, so we have three to five years on most of that."

Unlike the rest of Giddings Field, the Hearne area wasn't drilled heavily. He suspects it's still relatively pristine because of "what we're taught about fractured carbonates when we're in school and throughout our early careers: You drill them, you produce out the natural fractures, you don't produce anything from the matrix, it goes to water and it's done."

It gets dismissed. But "what people are missing about the Austin Chalk is that, yes, it's a naturally fractured reservoir, but it's also an 8% to 10%-plus-porosity reservoir. It contains a lot of oil that's not just in the natural fractures," McCorkle said.

Without fracking the formation to tap the matrix porosity in the past century, "the wells behaved exactly as people expected them to. We came back in and did a fracture-stimulation design—accessing the matrix oil and not the natural fractures—and that's where our oil is coming from.

"It's coming from the matrix of the reservoir." That's in addition to the oil from the natural fractures.

'Oil, not boe'

Treadstone's Chalk laterals are primarily 6,000 feet. It's using between 60 and 70 bbl of water and about 2,000 pounds of sand per lateral foot. Wells are cased and cemented and have ESP lift. Stage spacing is between 100 and 150 feet.

"It's worked better than we had anticipated," McCorkle said. Treadstone's Chalk wells to date average 945 bbl/d in 30-day IPs—vs. 300 bbl/d from old-model wells—and cumulative production of 160,000 bbl in their first 10 months vs. 53,000.

"This is oil, not boe," he added. "I don't report boe; we're not in the natural gas business."

Its Holden-Moore 3HA had a 24-hour IP of 2,230 bbl/d and made 438,000 bbl in its first 11 months. Its smallest IP-24 well was Sophie 1HA with 771 bbl/d.

Overall from its leasehold, including Eagle Ford wells, Treadstone's current production is now more than 10,000 bbl/d.

And some of the additional production is actually coming from the old wells, which are experiencing incidental stimulation from completions in new wells. "Base production has increased about 40% since acquisition," McCorkle said.

Operators—and investors—have been concerned about repeatability of performance from the Chalk, but that's a vestige of when Chalk wells were openhole, tapping natural fractures. Instead, in Treadstone's modern Chalk play, "there is not as wide a range in the performance in our wells as there are in most of the resource plays."

The initial rate is strong, "but it also has exceptional long-term performance," he said.

Operators do have to prepare for the water cut, though. In Treadstone's area, it ranges from 30% to 80%, averaging about 70%.

It expects to be free-cash-flow positive this year, McCorkle said. Plans are to continue drilling until the opportunity to sell the asset arises. "This asset was truly a diamond in the rough for Treadstone."

More proppant

New Century Exploration Inc. has about 10,000 net acres—more than 50% HBP—in Burleson County on trend with Treadstone and a little bit updip of it. In addition, New Century is in the oil window; GOR is about 400:1. It's on the northern edge of Chesapeake's leasehold.

The position is contiguous except for about 700 acres, said Phil Martin, New Century CEO, "and it is also extremely well configured for development." The northwesterly/southeasterly orientation is perpendicular to the planes of maximum stress.

"The chalk is high-porosity, but it's a low-permeability rock. What the industry is doing now is going into areas where you don't have as many natural fractures and, then, making your own fractures," Martin said.

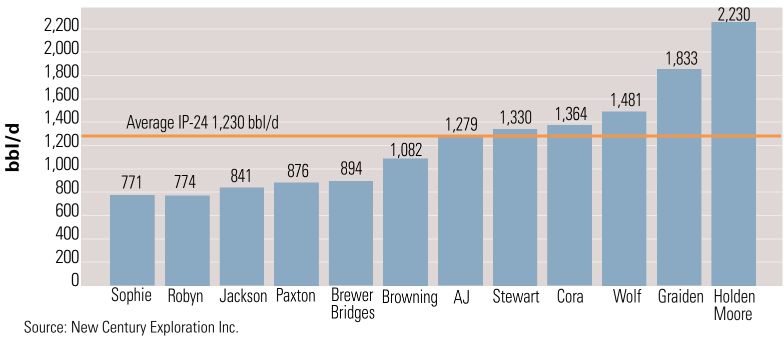
Studying the Treadstone wells, he has found that the more proppant it uses in a well, "the better they do—almost without exception." Also, Martin said, "as they get farther and farther away from the natural-fracture field, the better they do."

The EUR on Treadstone's Holden Moore 3HA "projects out over 1 MMbbl." Martin estimates a well cost of $4.5 million, IRR of 120% at $55 oil, an ROI of 3.3 and payout in less than a year.

Giddings Field was believed to be depleted, "but it's not depleted at all. You'd just taken out what could be obtained from natural fractures; now you can go back in and get the rest of it," said Phil Martin, CEO, New Century Exploration Inc.

New Century Exploration is on trend with Treadstone's Hearne play where the latter is making increasingly prolific wells.

Recent Austin Chalk Wells By Treadstone



Source: New Century Exploration Inc.

He has also found that—in the matrix-porosity play versus the fracture-porosity play—chemicals, particularly clay-control, have been helpful in increasing connectivity.

"The Chalk has very widespread layers of volcanic ash intermittently spaced through the formation and they can seal the fractures kind of like putty."

Chemicals that move through these ash seals extend the induced fractures, allowing them to reach more of the formation in Austin A, B and C. "That's another technology that I think has been very helpful," Martin said.

Past disrespect of the Chalk was "really just a lack of understanding." Rather, most of the Chalk's potential is held within the matrix porosity, rather than within the natural fractures. "It's very oil-saturated," he said.

Giddings Field was believed to be depleted, "but it's not depleted at all. You'd just taken out what could be obtained from natural fractures; now you can go back in and get the rest of it."

Chemicals in completions are helping to penetrate ash seals between Chalk A, B and C. New Century, Treadstone and BlackBrush have many neighbors in the East Texas Chalk play.

A time to buy

A limestone, the Chalk was deposited during the Cretaceous in a shallow marine environment over the Eagle Ford, which is where most of the Chalk oil comes from. Later, the Taylor Group—another shale—was laid over it.

"So you have your top seal, you've got your source and you've got a high-porosity formation to produce from if you can figure out how to get it out," Martin said.

The Chalk has produced some 600 MMbbl to date at Giddings Field. Calculating its oil in place is tricky, though, Martin said. There's the oil in the fracture porosity, and there's the oil in the matrix porosity.

"Also, permeability is very low, and that's not something easily measured by logs," he said. "You can get some of that from cores, but, again, the difference in matrix and fractures complicates things."

Water-saturation calculation is also tricky and, in general, storage capacity in a mixed-lithology, fractured limestone is difficult too.

Martin has observed, though, that every EUR calculation continues to be exceeded in time, "fortunately. Whatever we calculate EUR to be, [the actual recovery] ends up higher than we thought."

The Talara Capital Management-backed E&P is "kind of hunkering down right now," meanwhile; it isn't drilling. Rather, it's watching operators develop all around it, further de-risking its leasehold that way.

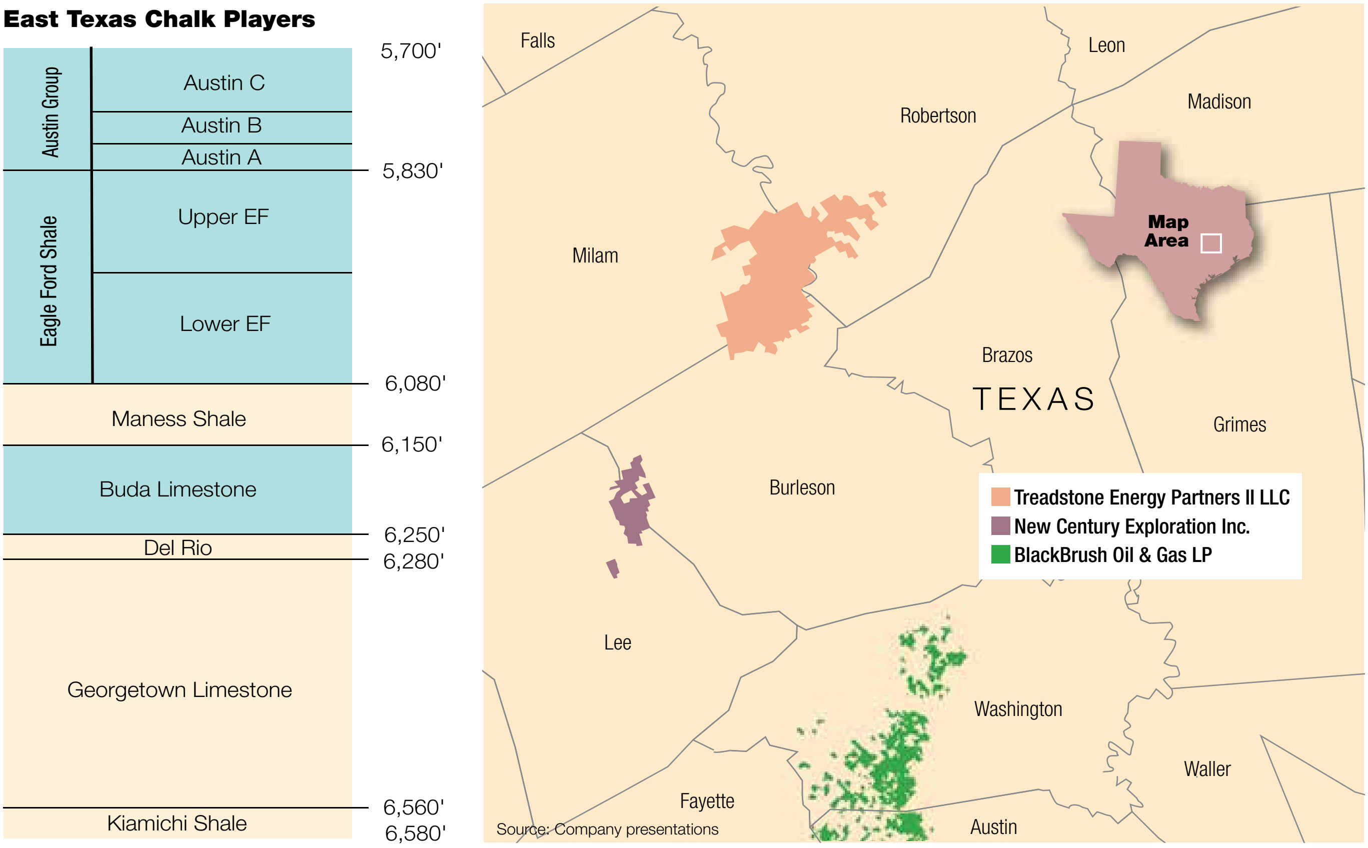
"This play is just like the Eagle Ford," Martin said. "The technology is moving very rapidly, and we're learning from others. Technology keeps getting better; it never moves backwards."

In addition to drilling, "there are areas I'd like to be acquiring right now to expand our block." New Century has up to $100 million for the right deal.

In the current capital-constrained era of oil and gas E&P, the PE-backed, build-and-flip model is stalled. "I really think that's a boneyard now," Martin said. "Investment capital is a lot more focused on a model that delivers dependable returns than just on growing acreage and PUDs.

"To realize returns from asset sales is just kind of a pipe dream right now." □

East Texas Chalk Players



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DUC AND COVER!

Drilled but uncompleted wells have become an increasing point of contention—in both how to define them and how to count them.

ARTICLE BY
BLAKE WRIGHT

IHS Markit principal analyst Narmadha Navaneethan said her group carries a net DUC count consisting of wells available for completion today.

In the oil and gas industry, counting is everywhere—active rigs, barrels produced, dollars earned (or lost) and, of course, wells drilled. Counting wells is a fairly straightforward exercise until you reach the drilled but uncompleted, or DUC, phase.

DUCs are counted for several reasons, the most prominent of which is to gauge size and timing of the domestic supply response to changes in oil prices, with or without significant changes in the number of active drilling rigs. The more DUCs there are, the faster reaction time the industry can have to increase production. Fewer DUCs mean less opportunities for swift supply additions.

What's a DUC? ... and how to count them

In simplest terms, a DUC is a drilled but uncompleted well. That means that a rig was used to drill a bore to target depth, but no completion work—the prep needed to bring the well onstream—has been conducted: no production casing, no cement, nothing. This is basically how the U.S. Energy Information Adminstration (EIA), the federal agency that is the keeper of most statistics related to the nation's energy production, including DUCs, defines them.

The group started releasing DUC counts by basin in the fall of 2016. As of the end of August 2019, the EIA estimated that almost 8,000 DUCs were spread across seven unconventional oil and gas plays in the U.S. A little less than half of those, around 3,800, were in the bustling Permian Basin of West Texas and southeastern New Mexico.

The EIA uses a range of sources to arrive at its DUC numbers, including various state agencies such as oilfield data specialists Enverus and FracFocus.org, the national hydraulic fracturing chemical registry managed by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission. The FracFocus data are key to the EIA count. According to the agency, if a drilled well has not been reported to FracFocus, it's a DUC.

The EIA begins counting from December 2013 under the assumption that all wells drilled before then have by now been completed and reported to FracFocus.org, explained Jozef Lieskovsky, senior analyst for the EIA. However, "from that point we add the estimated number of wells drilled and subtract the wells reported to FracFocus.org. Since there is a delay in FracFocus reporting, we estimate the completions in the most recent months."

During the same period, researchers at IHS Markit, which does not use the EIA numbers and has its own DUC count, tallied a slightly lower 7,844 total DUCs, with 3,346 located across the Permian. These are what IHS refers to as gross DUCs. There is also a net DUC number, which ranges significantly lower. The total net DUCs across the U.S. is closer to 5,700, with just over 2,500 in the Permian.

"A drilled but uncompleted well can be defined as a well that has spud or spud and reached the target depth but has not undergone any of the well completion process like hydraulic fracturing, casing or cementing," Narmadha Navaneethan, principal analyst with IHS, told *Investor*. "In our database, we have an intermediate well category where there is indication of perforations or we have some well test or treatment records, but still no production records. We count these as DUCs for our supply estimate purpose because we don't have any production record associated with it."

For its recording and research purposes, IHS uses the net DUC number, which assumes a time lag between operators drilling a well and the completion of that well.

"Gross DUCs is any well that gets drilled but not completed," said Navaneethan. "It takes at least two to nine months after drilling to get completed, with the majority of completions between three to six months. By counting all the gross DUCs, we are overestimating."

Net DUCs are those generally available to the operator for completion. That discounts certain wells. For example, a well drilled yesterday would not be available for completion today. IHS considers a "natural lag" of at least two to three months before any well gets completed—a "steady-state inventory period."

"You can't move these to zero because there is always a natural lag between drilling and completions," Navaneethan added. "What's left is the net DUCs, and that is what we publish."

Some wells, either due to field economics or capital allocation, may never be completed, according to Bernadette Johnson, vice president of strategic analytics at Enverus.

Enverus (formerly Drillinginfo Inc.) also separates DUCs due to vintage, but most agree there is an invisible window of opportunity or a shelf-life to most DUCs. A six-month lag in completions is normal, according to the data gatherers. But once that span grows larger, it usually signals something out of the ordinary, such as a bottleneck awaiting new infrastructure or perhaps operators in specific regions waiting for seasonal shifts in pricing.

The recent dive in DUCs in the Permian Basin can be attributed to the combination of lower rig activity and the introduction of new takeaway capacity. In September 2019, when the Kinder Morgan-led $1.75 billion Gulf Coast Express Pipeline came online, operators completed gas wells in order to fill the 2-billion-cubic-feet-per-day conduit to Texas coastal refiners in a month's time.

"If we have the data, we're going to keep the data, but at a certain point DUCs do fall off," said Bernadette Johnson, vice president of strategic analytics at Enverus.

An example of this is reflected in the northeastern Pennsylvania operations of Anadarko Petroleum Corp., which was drilling wells there during 2009 to 2010 when takeaway bottlenecks began hindering production.

"They had a bunch of drilled, uncompleted wells, but then they moved the budget dollars somewhere else, so those wells effectively became 'dead' DUCs," said Johnson. "They were never going to be completed."

A similar situation occurred in the Bakken, but it was more commodity price driven. Enverus estimates around 250 wells in the region that were drilled from 2014 to 2015 and may likely never be completed due to project economics. These wells, drilled during a robust commodities pricing cycle, have high breakeven thresholds. At $100 per barrel, they made economic sense and offered a good return.

However, once oil prices tanked, these wells' economics also cratered. In today's environment, completing these wells would not be good business, especially as a significant portion of the cost equation is on the completions side.

DUCs carried by the EIA have no expiration date. If a producer drills three wells on a pad, completes one and then realizes, for example, that the wells were not landed properly and moves locations to try again, those two uncompleted wells—like those older Pennsylvania and Bakken wells—would be counted as DUCs by the EIA indefinitely.

"We have no way to know which of the wells will not be completed," said Lieskovsky. "There is also a possibility that the well was completed, but it is yet to be reported to FracFocus.org. We are evaluating various proposals on how to improve the methodology and our estimates."

Then there are more radical methods of counting DUCs, like the one adopted by the petroleum consultancy Spears & Associates. In an August 2019 bulletin, the company proclaimed it doesn't believe there are any DUCs. None. Zero.

While it does believe drilled wells are out there awaiting hydraulic fracturing jobs (which most define as DUCs), it does not see any sort of overhang that will lead to a completion boom.

"The very same economics that cause a new well to be drilled cause each of those wells to be completed as soon as possible," the bulletin read. "In this era of capital discipline, what oil company management team would admit to shareholders that they took a bunch of capital, drilled holes in the ground at $3 million per and left them there without completing them?"

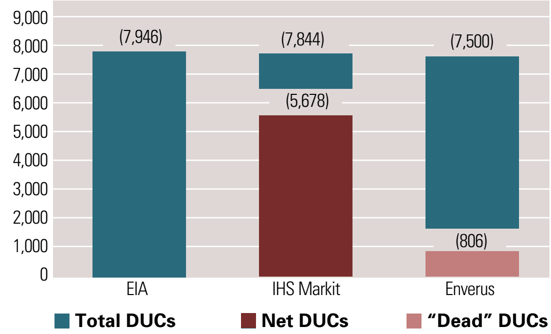
Spears also downplays the idea of the Permian Basin being a "big spigot" of DUCs that can be turned on when needed.

"This does not exist," the consultancy said. "The oil markets price WTI at a modest $55 because traders think there is a lot more available on demand. Not without a massive incremental investment increase!"

A DUC discrepancy

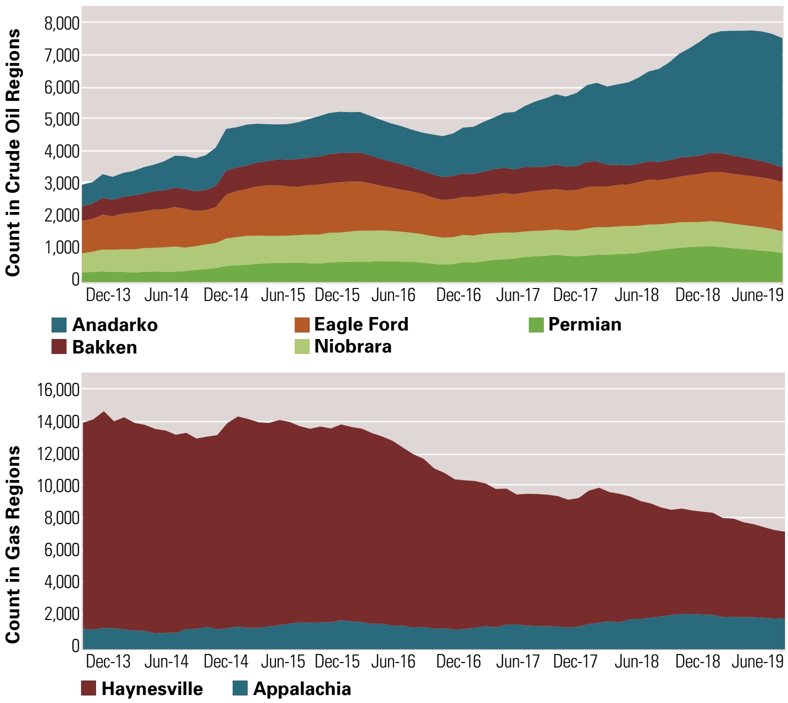
With differing methodologies on first, what a DUC is and, second, how best to count them, you can imagine that it makes for a certain de-

U.S. DUC Count (As of Q319)



Source: EIA, IHS Markit, Enverus

DUCs In Crude Oil And Natural Gas Regions



Source: U.S. Energy Information Administration gree of difficulty in coming up with an accurate number for just how many exist.

Everyone agrees that the largest population of DUCs in the U.S. is in the Permian Basin, and most agree that new takeaway capacity in the area is driving the counts down.

However, petroleum analytics firm Kayrros sees that number on the rise.

Kayrros, founded in 2016 by former Schlumberger Ltd. executive Antoine Rostand and Antoine Halff, a former lead industry economist at the EIA and former chief oil analyst of the International Energy Agency, made waves over the summer of 2019. The firm released a report that stated that the EIA DUC numbers were skewed high and operators had been underreporting completions operations.

On any given month, Kayrros believes, the Permian DUC inventory runs just around 1,000 wells. In an October blog post, the group said it saw the Permian DUC backlog grow 5% to its highest level since March 2016, however, starting from a much lower base than the EIA numbers.

"The disparity between the two counts reflects a difference in methodologies: On [the] one hand, the old-fashioned way of compiling statistics from self-reporting by companies, and on the other hand, the cutting-edge approach based on direct measurements enabled by recent advances in technology, data storage and computing capacity," the post read.

According to Kayrros, satellite-based measurements show that many light, tight oil producers fail to report their well completions to FracFocus and state commissions in a timely manner, if at all.

"This has led to significant undercounting of well completions in EIA data that are widely used and considered reliable by industry analysts," the post continued. "In 2018 alone, in the Permian, more than 20% of wells went unreported to FracFocus or state commissions."

Enverus, which also tracks rigs via satellite positioning, disputes the Kayrros numbers, saying that reporting lags—even at the operator level—are consistent with what they have seen historically in the data and that they were unable to verify any of the claims made in the Kayrros study.

Kayrros isn't the only one that believes the EIA numbers are too high. A September 2019 survey polling 73 oil and gas executives, conducted by the Federal Reserve Bank in Dallas, found half of participants responding said that their estimate for the number of DUCs in the Permian Basin is lower than the EIA estimate, with 23% saying significantly lower and 27% saying slightly lower. Thirty-seven percent said their estimate is close to the EIA estimate, while the remaining 12% said it was higher.

DUCs as storage

Some view DUCs as a type of storage for the nation's hydrocarbon resources that can simply be "turned on" via completions when supply is needed. It is one of the main reasons these uncompleted wells are counted in the first place: to gauge, at least partially, future production volume growth. While that historically has held some merit, it can depend on the region and, more so today, the operators' development method.

"If you are in the Northeast, I think it is accurate to think about DUCs as storage," said Enverus' Johnson. "You are drilling them throughout the year and waiting on winter to complete them. That is a storage-like behavior.

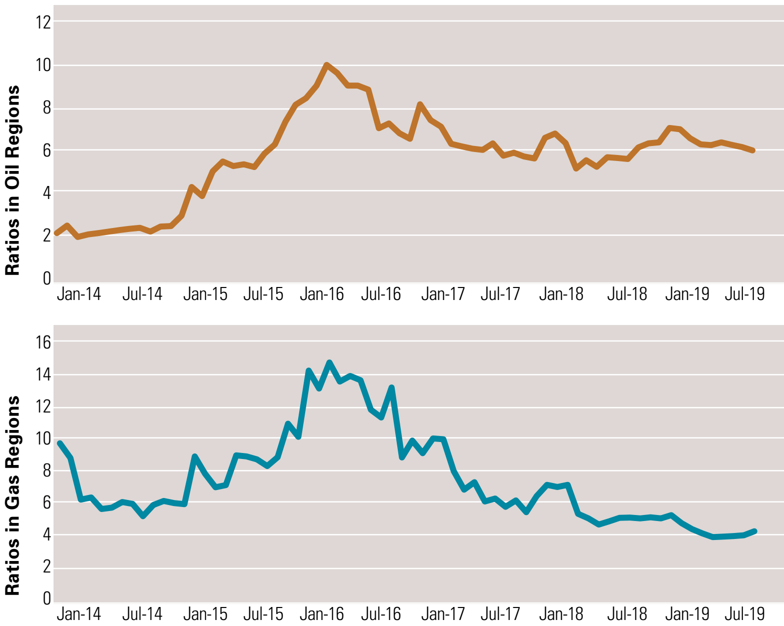
"If you are anywhere else, I would say no. It is storage, but it is not acting the way that typical storage would, meaning you put it in the ground when it's cheaper and pull it out when the price goes up. You can't count on them to show up during periods of peak demand or price spikes."

A recent report from energy analysts BTU Analytics has placed a new wrinkle on the DUCs-as-storage issue by calling into question not the quantity, but the quality of the current backlog. For example, the Permian Basin is estimated to have added around 1,100 DUCs over the past two years, a period when operators were experimenting with spacing. The activity nearly tripled the total count—from 600 at the end of 2016 to almost 1,800 by the end of 2018. Of those, more than 60% were added in 2018, a time when the average distance between wells was the tightest.

"This has raised concerns that the large backlog of DUCs may be primarily composed of potentially underperforming wells," the report said.

Whether the DUC backlog is affected by well spacing issues remains to be seen; however, as cost-conscious operators move to complete well vs. drilling new ones to keep resources flowing into the system, we might not have to wait very long. □

DUC To Completion Ratios



Source: U.S. Energy Information Administration

DUC to completion ratios increased in 2015 and peaked in 2016. Although the gas-region ratio returned to the 2014 level of 4:1, the oil-region ratio settled at a new level of 6:1.

DUCs By Region

Region	July 2019	August 2019	Change
Anadarko	906	860	(46)
Appalachia	529	517	(12)
Bakken	674	652	(22)
Eagle Ford	1,474	1,458	(16)
Haynesville	184	186	2
Niobrara	461	438	(23)
Permian	3,864	3,839	(25)
Total	8,092	7,950	(142)

Source: U.S. Energy Information Administration


PHOTO BY RICARDO MERENDONI

DRIVEN

Tracy Krohn puts his money where his assets are … in the oil patch, on the race track and in Hollywood.

ARTICLE BY
BLAKE WRIGHT

It was Christmas Eve, 1985 … and 31-year-old Tracy Krohn was freezing. Wrapped in a diver's wet suit and loaded down with gear, he was submerged into the Gulf Intracoastal Waterway of south Louisiana blindly searching for the problem that could wreck his three-year-old company.

With zero visibility, he was left to use his hands to locate and assess the issue. The unscheduled, late night swim was prompted by a phone call earlier in the day from the U.S. Army Corps of Engineers. One of his newly acquired natural gas pipelines had sprung a leak. It was the line that supplied natural gas as a lift mechanism for the wells on the north side of the canal, which was what carried most of his young company's revenue. Making matters worse, a permit from the Corps to pull the line and make repairs by the light of the day would take upward of six months to receive. It was a death sentence for W&T Oil Properties Inc.—now W&T Offshore.

Three months prior, in September, Krohn had taken a bank loan and purchased the property—the company's first transaction—for $500,000. And now, there he was, taking things into his own hands, literally, in a desperate bid to save his company. He was able to locate the leak, but unfortunately, it was in a tricky spot—notched in a seam where two individual lines were bound together. The situation looked dire.

"I had to figure out how to repair that internally," Krohn recalled. "I actually modified an existing tool, invented a way to do that and ran it from the north to the south, spaced it out across the leak, pressured up, and it held.

"It was a cup packer, which we use generally for injection well purposes. I spent the better part of that week at the machine shop trying to figure out how to get this done. I had to shave the whole tool down. But, if we don't get this done, the company's out of business in a short period of time."

Six months later, Krohn sold half of the field interest for double what he had paid for it. Meanwhile, oil prices were cratering, dropping below $10 per barrel.

Today, W&T Offshore employs roughly 300 people and has a market capitalization of $615 million. The company's Gulf of Mexico assets are located across both the shallow and deep water. Its 605,000 gross acres on the shelf generate over 70% of the company's total daily production, with the remainder coming from its 221,000 gross acres in the deep. As of the third quarter of 2019, the company was producing just over 41,000 barrels of oil equivalent per day (boe/d), which included just one month of production from its most recent acquisition from ExxonMobil Corp. at Mobile Bay.

Krohn's office is a mix of paperwork and racing paraphernalia dominated on the right by a conference table flanked by high back chairs that stand out due to the integration of his racing team's neon green color scheme. The space gives the impression of a man dedicated to the treasure hunt that will move his company forward while still respecting and learning from what has come before.

Challenging terrains

Krohn got his start in the oil field in 1972. His mother worked for Pat Taylor of Taylor Energy, and through that connection, Tracy was able to get on as a roustabout with a division of Fluor Drilling. It was Oct. 4, 1972; Krohn was 18 years old.

"I ended up on this drilling rig after this horrendous boat ride," he said. "Everybody on the boat was sick, and it was a horrible ride. Somehow I ended up in a bunk room, out of the bed. Got out of it, and I'm sure I was just nasty. I hadn't been there very long when the door slammed wide open and one of the biggest humans I've ever seen in my life said, 'Boy, what in the hell are you doing in my bed?!' And it got worse from there."

From the rocky starts, Krohn and W&T have persevered. The company's most recent triumph is a $200 million acquisition from ExxonMobil covering nine producing fields and related onshore facilities in Mobile Bay offshore Alabama immediately adjacent to existing W&T properties. The deal was an accretive acquisition, according to Krohn, that included working interests in nine shallow-water producing fields and related operatorship, as well as offshore and onshore facilities and infra-

FROM THE RACING RUSH TO THE SILVER SCREEN

One thing Krohn will never be categorized as is risk averse. Not in oil exploration, and not in his "other gig" as a race car owner—and driver. He's been behind the wheel at LeMans, as has his regular co-driver, Nic Jonsson, 13 times, a fantasy of his when he used to race his MGB back at autocross pop-ups in the parking lots at Louisiana State University.

He followed that dream initially, but soon realized that racing was an expensive sport. So he put it on hold. Then, at 48 years old, he climbed back behind the wheel and not long after, Krohn Racing was born.

He attended racing school and drove in a spec series. After some success there, he decided to take it to the next level and started racing against factory pros and factory teams.

"It was like going from kindergarten to college, but it was a lot of fun and a good education," he quipped.

He was behind the wheel of the neon green Krohn Racing Ferrari at LeMans in 2013 when a failure during a practice run sent him into a half-spin and careening off of a tire wall at high speed.

"It was a compression right turn," he said. "So, as I was turning right, the car bottomed out. It pins the front, swings it around, went into the tire wall and made a bunch of noise. That's not the way you want to make Sports Center, right?"

Earlier this year, another practice crash kept Krohn out of the LeMans competition. This past June, he slammed his Porsche into a wall at 160 miles per hour. It measured a 60G initial impact. You're not supposed to survive that. The car did its job and absorbed the brunt of the impact. Krohn escaped with lower back pain and some internal bruising, but nothing broken. The crash ended his 2019 racing campaign.

"Kudos to Porsche for building just an incredible machine," said Krohn. "I mean, it took the hit and did everything it was supposed to do. And I did everything I was supposed to do. When I knew I was going to hit the wall, I pulled back hands and feet and everything else. Didn't break anything in my hands or my legs or my feet or anything. I didn't have a concussion."

This past August, Krohn turned 65—historically a significant mile-marker in most professional lives. Reaching that landmark begged the question: Any thoughts of retiring?

"No," he said without hesitation. "I would like to be in this business as long as it's still interesting to me and we're still having success, that's what I'd like to carry on doing.

"Actually, I'm in very good physical shape, otherwise I wouldn't have gotten through that crash as well as I did. I do take care of myself. I think it's important that you do that anyway. I still get a kick out of making a new well, making a new acquisition. This is how we make money. It employs a lot of people that I feel very privileged to work with. I think this is a great business. It does a lot of things for our country."

Beyond oil and racing, Krohn also has proven a somewhat savvy investor in another high-stakes business: Hollywood. A few years back, he put some money into a fund to back a small-budget film about a ballet dancer struggling with her sanity. The movie was 2010's "Black Swan," directed by Darren Aronofsky. The film, starring Natalie Portman and Mila Kunis, carried a budget of $13 million. It made $330 million worldwide at the box office.

"As it turned out, I was the largest investor in that movie," said Krohn. "I did very well with it. Just pure dumb ass luck, I mean really. I tried to figure out how you know when you're going to have a really good film. And I did some due diligence on it. You really don't know when you're going to have a successful film. There's different ways that people try to figure that out. But at the end of the day, it's just pretty random."

PHOTO COURTESY KROHN RACING/M&T OFFSHORE structure. The new assets basically surround W&T's Fairway Field, in which a controlling interest was purchased from Shell in 2011.

Not only would the deal add almost 75 million barrels of oil equivalent (MMboe) in net proved reserves to the company's coffers, it was a true full circle moment for Krohn. He had spent some time on the rig that drilled the discovery well in the area for Mobil back in 1979.

"We made a great discovery there, and then here I am 40 years later buying this field," he said. "We went over and did a little town hall with the Exxon folks that we were interested in staying with us, and I told them, 'You know I've been working on this transaction for 40 years.' That's my story, I'm sticking with it."

During the past three-plus decades, Krohn has been successful in guiding W&T through the peaks and valleys of the oil patch—downturns in 1986, 1999, 2008 and 2015, the Macondo disaster in 2010, and Hurricanes Katrina, Rita and Ike.

In the most recent downturn, the company found itself with a crushing debt load ($1.5 billion at one point) in a soft commodities pricing environment and was teetering on the brink of collapse.

"That's the only time I've been caught on the wrong side of the debt equation," recalled Krohn. "Unfortunately, we had to swap debt for equity at an unfavorable time."

In the fall of 2016, the company commenced an exchange offer that swapped $710 million in senior notes due in 2019 for just over 60 million shares of W&T common stock. The move reduced the company's overall outstanding indebtedness by $408 million ahead of a new financing package.

"I went from being majority interest owner to largest shareholder," he said. "Doesn't sound like a big difference, but it was a big difference for me. In spite of that, we didn't do anything that killed the company. I learned a long time ago that you don't do any one thing that could bring your company down, that's too much risk. So, if you're doing a managed risk portfolio, then you try to get some diversification in it, right?"

Those were shaky years, and though he swears he never thought the company was in danger of going bankrupt, Krohn knew that things had to change. The company cut spending drastically and with the assistance of those less-than-ideal but effective financial maneuvers, pushed out or eliminated a chunk of its debt maturities.

"The hard part about that was giving up the shares at a not very good time," he said. "I think that we did that very well."

Krohn tells the story of a specialist brought in from a large legal firm that was retained to assist W&T through the company's financial straits. It was an attorney out of Chicago that Krohn didn't really see eye-to-eye with.

"He looks at me, and the first thing he says is, 'Mr. Krohn, you just need to give up on the idea of owning equity in this company.' I'm a majority interest owner of this company for three decades at that point, right? Basically what he was telling me was give up on my equity, he would get me a nice contract, and I could pay him $10 million a month for the privilege of letting him fix this for me. It was a very short conversation."

With net debt levels around $580 million at mid-year 2019, W&T's current capital allocation plan includes maintenance of a prudent balance sheet and the use of free cash flow to grow opportunistically. The operator's chief focus remains on high rate of return projects that can generate cash flow quickly, as well as the pursuit of compelling acquisitions and inventory expansion.

PHOTO BY RICARDO MERENDONI

Krohn, 65, founded W&T Offshore in 1983 and said the current environment in the Gulf of Mexico today is as good as he's ever seen. "Go where they ain't. I do have less competition now."

The event that changed everything

Macondo was a different challenge for W&T—one not of its own making. On April 20, 2010, a BP-operated well in the deepwater U.S. Gulf experienced a catastrophic blowout. Eleven men died. What followed was a series of very public missteps that would lead to the Macondo well in Mississippi Canyon 252 spewing uncontrolled hydrocarbons into the Gulf of Mexico for 87 days.

In the wake of the disaster, the regulatory agencies governing offshore drilling were razed, built anew and a moratoria on new wells in the region was put in place.

"There were some other things that occurred that shouldn't have been that way," said Krohn. "The fallout from it was increased regulation, increased scrutiny. The only silver lining around that is BP could afford to pay for it. It didn't really roil the insurance markets."

Krohn said the fallout from Macondo was not as dire as it could have been for W&T, confessing, however, that the regulatory system "swung a little bit too far out on a pendulum."

One thing that did occur post-Macondo was increasing inspections. Prior to the accident, the company would expect to get one or two inspections per year. In the post-Macondo world, they occur twice a week in many cases.

"I don't necessarily think that's a bad thing, but it is an expensive thing," said Krohn. "Because whenever they show up, it's about $18,000 for the inspection that we get to pay for. So, if you got three or four rigs running out there, it's a pretty big bill. And they hired a bunch more people, and they hired a bunch more helicopters.

"The inspection times have increased remarkably. But I think those were kind of the bigger issues that came out of Macondo."

In response to Macondo, U.S. Gulf operators faced a federally mandated drilling moratorium that slammed the brakes on all offshore wells for six months. However, it was more than 10 months before any permits were issued in the region due in part to new rule requirements on oil containment. It was during this stretch that a lot of Gulf-centric companies began to look elsewhere for drillable assets, and W&T was no different. In 2011, and out of character, the operator purchased a tranche of onshore acreage in West Texas.

Welcoming waters

With all of the risks and challenges associated with offshore, it has always been home for W&T.

Today, with so many operators having moved onshore, and having either deemphasized or sold out of the U.S. Gulf, it begs the question, why does the Gulf remain W&T's sole focus? Perhaps that lesson can be best told by the company's entry (and exit) from West Texas—a 21,900 gross leasehold acres (21,500 net acres) position in the Permian Basin it purchased for $366 million.

"We took a brief foray over into West Texas and bought some properties," recalled Krohn.

"Drilled a bunch of wells and spent a bunch of money, trying to catch up with the cash flow. We proved the horizontal model. For the last couple of wells, 1,500 and 1,700 barrels a day on a 5,500-foot lateral. Good wells. We were making plans to spin the company off, take it public, or sell it or some other way to extinguish much of the debt. Then, prices dropped. The timing wasn't good and we were spending too much money."

In September 2015, W&T sold its Permian interests for $376.1 million to start-up Ajax Resources LLC. In 2018, Ajax sold out to Diamondback Energy Inc. for $1.25 billion.

"The idea of free-cash-flow positive is very compelling to me."

PHOTO BY RICARDO MERENDONI

"At the end of the exercise, we came back to the Gulf of Mexico exclusively," said Krohn. "When you think about the amount of money we spent, and what we got in return, West Texas just doesn't cash flow.

"Overall, for the oil and gas business, the onshore shale basins just don't cash flow. There are certain areas that produce better than others, and that's why you have type curves, right? You're looking for the best geology. It's still about rock properties. The Gulf of Mexico is primarily structural and stratigraphic in nature and for that reason, we don't have type curves. You have to analyze each one of these prospects individually.

"The good news is it can be quite lucrative. So, it does tend to be cash-flow positive. The idea of free-cash-flow positive is very compelling to me. And because I'm the largest shareholder, that's extremely compelling."

One of the company's flagship assets is Mahogany Field in Ship Shoal 349/359. Originally discovered by Phillips in 1994, it was one of the region's first commercial subsalt projects.

Historically, most of Mahogany's production came from the main P-sand. W&T has drilled and completed over a dozen wells at the field since 2011, including the deeper T and U sands. These wells, recompletions and selective remedial work at the field have yielded over 16 MMboe since 2011.

In July, the company brought the A-19 well online at the field and produced over 7,000 boe/d from the T-sand.

The A-6ST well, a P-sand completion, was successfully drilled during the third quarter of 2019 and is scheduled to be brought online prior to year-end. W&T has grown production more than 10 times at Mahogany since 2011, with 76% of that being liquids. Also recently, the company has struck pay dirt on a handful of additional shallow and deepwater tests.

"We've had good success out in the South Timbalier area in medium deepwater depths," said Krohn. "Good discoveries there. Of course, we've done Big Bend and Dantzler, which were green field exploration projects that we did along with Noble. Those are great assets, along with stuff that we bought. We've also done a drilling joint venture recently."

The venture, called Monza, has yielded success. It's a three-year-plus, 14-well program valued at over $360 million funded in part by an entity owned and controlled by funds managed by HarbourVest Partners, a Boston based private-equity fund sponsor, and Baker Hughes, a GE company.

W&T offered up working interest in the wells in return for the funds to drill. Krohn personally owns a little over 4% of the fund. The initiative has helped the company to reduce capex and increase free cash flow.

"We've drilled nine wells there now, and we're finding a pretty decent share of reserves," he explained.

"We had a recent discovery at Mississippi Canyon in what we call our Gladden Field. So, a new discovery there that's recently come online. It's not what I would call a home run, but it's about what we expected.


PHOTO COURTESY W&T OFFSHORE

W&T's Matterhorn tension-leg platform is located in Mississippi Canyon 243.

"I like the wells. I like the fact that we were going to be able to drill them and make money with it. We get a 10% carry on our 20% stake. It's not rocket science. Some of it was pretty proprietary in how we structured it. We spent a lot of time on structuring this deal. Part of the reason for it is that we envisioned that we could do it again."

The most recent well at Gladden in Mississippi Canyon Block 800 was drilled using semisub Noble Sam Croft in just over 3,100 feet of water and encountered 200 feet of net oil pay. The well was completed and placed on production ahead of schedule in the third quarter at about 4,600 gross boe/d, with 89% oil.

Elsewhere, the joint venture has enjoyed success on a pair of wells at the Ewing Bank 910 field area. Both the ST 320 A-2 and A-3 wells encountered commercial pay. The A-2 was producing around 7,000 boe/d by mid-April, and the A-3 was flowing around 5,500 boe/d following start-up during the third quarter.

At Virgo Field in Viosca Knoll 832, the A-13 well struck 77 feet of net vertical pay and was brought online in the first half of the year. Wells at Ship Shoal 28 and East Cameron 321 were also deemed commercially successful with the latter encountering better-than-expected 84 feet of net vertical pay. Both wells are expected to be brought online by year-end.

Still standing

Outlier investments aside, most of Krohn's energy remains focused … on energy.

W&T will continue to pursue acquisitions that make sense. Krohn still actively gets in the weeds when opportunities arise to vet the pros and cons of every deal, as well as arriving at the right number price-wise. W&T itself has been targeted for acquisition over the years. Krohn estimates it has happened seriously around three times, with one of those almost coming to fruition. His ownership stake in the company makes deals like that a bit more complicated.

"Go where they ain't," said Krohn. "I do have less competition now. It doesn't mean I don't have competition, but when we took the company public there was a pretty large list of competitors that we disclosed and told the public about."

During a road show years ago, Krohn was asked how many of W&T's publicly traded Gulf of Mexico (GoM) competitors he expected to be around in five years' time. He answered without hesitation.

"None." he said, "Five years from now none of these guys as you know them today will be here. And I was right. Many of those companies were merged or bought."

There was one exception, Stone Energy. Stone remained a publicly traded GoM peer and later filed for bankruptcy in December 2016. The company eventually reorganized and emerged from Chapter 11 in 2017 and then merged with Talos Energy Inc.

"So, they're all gone, every one of them. Unlike us, many weren't in it for the long run in the Gulf of Mexico, and others took outsized risk because management had no skin in the game," said Krohn.

Newer companies, like Talos, Fieldwood, EnVen, Kosmos and others have come into the region, but not near as many players as there were earlier this decade.

"Admittedly, it's a mature basin," said Krohn of the U.S. Gulf. "The risk on finding reserves is greater. But, our success rate has been over 90%. It had been 75% to 80% traditionally. A good place to look for oil and gas is in oil and gas fields. That's pretty much been the philosophy most of the time."

For 2020, W&T expects to spend something north of $100 million, after a capex campaign of an estimated $140 million in 2019. The company will likely continue to pursue attractive acquisitions in what Krohn calls the current environment for deals in the Gulf "as good as I've ever seen." □

Platform infrastructure at W&T's Main Pass 252 Field in the shallow-water U.S. Gulf.

PHOTO COURTESY W&T OFFSHORE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ACCESSING ASSET-BACKED SECURITIES

Raisa Energy has created an investment grade security backed by a highly diversified pool of E&P assets.

ARTICLE BY
CHRIS SHEEHAN, CFA

"I can't think of a larger industry in the U.S. that has not tapped this form of financing," said Jeremy Cook, Raisa Energy LLC CFO. "We think this deal is potentially the tip of the iceberg."

Financial markets have proven adept at creating markets for asset-backed securities. An individual auto loan may lack appeal, for example, but a highly diversified package of auto loans may be attractive, assuming it is appropriately collateralized and offers a competitive yield. Diversification lowers the risk of individual loans, allowing a loan package to be rated by a respected rating agency.

Now something similar has been developed in the energy area. Using proprietary software and machine learning models, working interests in wellbores are being packaged together to garner an investment grade rating. The highly diversified pools are collateralized by interests across multiple basins and throw off a yield—in certain cases approaching 6%—that institutional investors have found attractive.

The move to securitize energy interests is seen by some as a key first step. Historically, interests in oil and gas have been highly fractionalized with few options for liquidity. But now, sometimes small, nonoperated working interest holders are being connected with institutional investors and vice versa, according to Raisa Energy LLC, the sponsor of a new class of asset-backed securities.

Connecting two markets

"We set up Raisa with the thought that a nonoperated working interest holder in oil and gas wells has historically had a very difficult time getting tied into the institutional investor market," Raisa CFO Jeremy Cook told *Investor*. "We're basically connecting the two markets together by aggregating all these nonop interests and getting them to an end-point of institutional capital."

To date, Raisa's first securitization deal involves some 700 wellbores in five states: Texas, North Dakota, Colorado, Wyoming and Oklahoma. The wells are operated by 35 different producers, with no single well representing more than 1% of the total package of wells. Operations are spread throughout some 20 counties in five basins, lowering possible risk from concentrated, single-basin operations.

"Diversification is absolutely critical in working with the rating agencies to get a transaction done," observed Cook. "It is the diversity of those wells that allows for the variance of the results to be low enough to make it investment grade."

Raisa's initial securitization, he noted, earned investment grade ratings from two rating agencies, including one of the major rating agencies.

Institutions searching for yield

"There is big institutional money that is searching for yield," commented Cook. "There was tremendous excitement and appetite from institutional investors for the investment grade piece. And there was also a lot of interest on a smaller, sub-investment grade piece [rated BB+, BB-] from other parties, including hedge funds and other investors."

While Raisa did not specify the coupon on its initial securitization, it was "commensurate" with yields of instruments with a similar investment grade rating, it said. A coupon of "nearly 6%" was cited by The Wall Street Journal in a recent article.

Raisa has structured the issuance of its bonds, or asset-backed securities, by way of an SPV, or special purpose vehicle. Raisa retained its ownership in the acreage but sold the wellbore interests to the SPV—some 700 wellbores in the most recent issuance—as collateral for the bonds, based on an audited reserve report using a present value analysis (PV10 discount rate).

"A producing wellbore is a stream of cash flows," observed Cook. "A wellbore has its own unique factors and variables, but at the end of the day it's simply a stream of cash flows. And by pulling 700 unique and distinct individual cash flows, you're able to lower the variance in order to achieve an investment grade rating, which is critical to this transaction."

Hedging against price risk

Two potential risks to the strategy—commodity price risk and production risk—are addressed by Cook.

Given that production from unconventional wells is heavily front-end weighted, hedging has been a "key component in offsetting price risk, so you're able to hedge a good portion of those cash flows," said Cook. As for risk to pro-

"With machine learning, I can grab all that data to give me a better understanding as to how I've invested in the past or how I can invest in the future," said Luis Rodriguez, CEO and founder of Raisa Energy LLC.

duction, the latter "is meaningfully mitigated by the large diversification of the pool of assets that we put into the securitization."

As production is heavily weighted to the early years of unconventional wells—albeit with accompanying steep decline rates—the heavy cash flow early in the well life is used to make proportionately large contributions to amortization, noted Cook. In other words, the amortization schedule mirrors the profile of the cash flows in being heavily front-end weighted.

As regards potential parent-child well interference, the vast majority of wells in which Raisa holds interests have been pad developed, or will be pad developed, implying a limited impact from so-called frack hits from wells being drilled near or around a prescribed development area. In essence, the inner wells of the pad have minimal issues because they have typically already been co-developed.

The 'tip of the iceberg'?

In terms of growth prospects, Cook is optimistic about asset-backed securitization taking off in energy. "I can't think of a larger industry in the U.S. that has not tapped this form of financing," he said. "We think this deal is potentially the tip of the iceberg. Just consider the scale that this financing can bring to the market. Even if production is valued at a modest $30,000 per flowing barrel per day, if you do the rough mathematics, the potential market in the U.S. is massive."

The launching of asset-backed securitization in energy may also be highly timely in that "the shale business is transitioning from a venture-growth model to a manufacturing mode," observed Cook. In addition, asset-backed securitization is not subject to the sometimes volatile swings experienced in the semi-annual redeterminations of reserve-based lending, he added.

For Raisa, securitization of its nonoperated wellbore interests allows the company discretion over the use of the funds, making it possible to "give distributions back to our investors and also continue to grow its business over time," according to Cook. Proceeds from the offering are available to Raisa with limited restrictions, while Raisa also retains potential revenues generated from the tail-end of production once amortization of the debt is complete.

Mitigating single-basin risk

For Raisa, one possible avenue for expansion is combining assets with other producers, including private-equity (PE)-backed sponsors looking for an exit from a single basin.

"If you're a PE-backed operator or nonop in a single basin, being able to tap asset-backed securitization is probably more challenged, because of single-basin risk," said Cook. "We potentially have the ability to combine that type of production with our production and, being more diversified, offer more avenues for other E&Ps to access this market."

A near-term goal of Raisa is to issue asset-backed securities on a "systematic" basis, according to Cook.

"We'll probably have at least one or two additional securitizations that are planned for 2020," he said. "As groups of wells come online and mature and reach an appropriate scale and diversification, we're planning to continue to create SPVs, to continue to access the market and continue to effectively drop down these assets into what is a more efficient form of financing." □

THE GROWTH OF RAISA ENERGY

Raisa was founded in October of 2014 as an independent E&P based in Denver that creates value principally by owning nonoperated working interests in basins across North America. The company is led by CEO and founder Luis Rodriguez and has some 60 employees specializing in disciplines such as data science, software engineering, geology, mapping, land and accounting.

Originally from Venezuela, Rodriguez's career includes work at ExxonMobil Corp. and, later in the U.S., for Schlumberger Ltd. After earning an MBA from Stanford University, he joined Brigham Resources LLC, focusing on mineral activities. After founding Raisa, Rodriguez was joined by Ayman Kaheel, whose prior career experience includes work at Yahoo, Amazon, IBM and Microsoft.

An interesting element of Raisa is that its data science and software engineering department, with some 30 professionals, is based in Cairo, Egypt. The costs of an overseas office "are a lot lower, but the quality of the data scientists and software engineers is comparable to the U.S.," said Rodriguez. Importantly, the ability to process transactions across five basins is "very fast."

The underlying thesis for Raisa in its early days was that, if much of the core acreage had already been captured in key basins, an alternative strategy was to aggregate "fractionalized assets." Typically, these are nonoperated interests that can often be acquired. And, once such an interest is acquired, "you're able to gain all the information that you would as an operating partner," noted Rodriguez.

"If you're able to buy all these little pieces—so you're diversified across a variety of wells—then you can true up a diversified asset and, in turn, have a financial asset," said Rodriquez. "Then consider the data those assets can yield. With machine learning, I can grab all that data to give me a better understanding as to how I've invested in the past or how I can invest in the future," he continued.

"That was the crux of what Raisa was set up to do."

Others apparently liked the direction Raisa was taking. EnCap Investments LP made an unspecified equity commitment to Raisa in April of 2016, markedly accelerating the pace of its growth.

Raisa describes taking a "scalpel approach" in its search to find the best rock under the best operators.

As Raisa makes acquisitions of nonoperated interests, it gains proprietary data not generally available to public markets. The data goes into proprietary software and machine learning or artificial intelligence models, said Rodriguez, allowing Raisa to "better identify the next acquisition. Small pieces lead to more data and more wells for a better price. It creates a virtuous cycle."

In turn, for every dollar that is spent on leasing, Raisa typically may invest roughly $10 on drilling upon receipt of an authorization for expenditure (AFE) to participate in a new well. And with pad drilling often the norm, the AFE will increasingly call for participating in multiple wells rather than a single well.

"A well is drilled, completed, flows back, goes online and then is producing. And we start receiving checks," said Rodriguez. "We've effectively done that more than 700 times now."

COMPOSING THE BOARD OF THE FUTURE

Creating the right board of directors could give value investors the confidence to get capital flowing back into the industry.

ARTICLE BY
DAVID E. PRENG

When asked about the composition of energy boards and the challenges they will face in 2020 and beyond, I consulted with Allen Brooks, David Heikkinen, Maynard Holt, Ray Singletary, Art Smith, Jim Wicklund and a couple of my fellow National Association of Corporate Directors members. I call them the Brain Trust (BT). Their comments revealed a central theme—make sure you have the right board composition for today and tomorrow. It must be a board that understands the evolving energy market and your shareholder base, has the vision and creativity to make the right decisions for the future and is willing to champion and embrace change.

There are numerous writings on the shale revolution; greenhouse gases; alternative energy; environment, social and governance (ESG); and how the energy industry

is changing—even dying. Correspondingly, there is a myriad of papers depicting the right board composition. Although these are very thoughtful, there is no one size fits all. Each board has to ensure it has a vision and strategy to create and grow shareholder value for today.

Let's revisit a few fundamentals and develop key concepts for a great corporation run by a great board. Every public business has three primary constituencies: (1) employees who provide the goods and services that generate revenues and profits; (2) customers who are identified, studied, dissected and buy the goods and services; and (3) shareholders/investors who provide the needed capital.

It is this latter group that, unless an activist is involved, gets the least attention and is the least understood. Granted, public companies know their top 10 to 50 largest shareholders. They visit them. They hold analyst days for them. But do they truly know who they are today and what is driving them?

What investors see

The BT pointed out that the investor base has changed. The traditional growth investor who religiously followed energy is all but gone. He has heard two perspectives. On the one hand, energy has said we are in a shale revolution and have become a stable and steady industry, much like farming and manufacturing. On the other hand, he has heard about energy's demise with the advent of electric vehicles, renewables and the issues surrounding climate change, and has left energy for the FAANG stocks.

Thus, value investors have become the energy industry's primary source of capital, but they are having trouble buying into it. They see high-spending, over-levered companies when they are really searching for a return of capital, which is available in other industries. As evidenced at EnerCom's The Oil & Gas Conference and others, most of the energy industry has heard this and is creating dividend and buy-back programs and focusing on free cash flow. The energy industry is listening to the new investors and is headed in their direction, but they are not there yet.

So, what is needed to give the value investor the confidence to get capital flowing back into the industry? As the BT pointed out, debt is not bad if you are earning more than your cost of capital and returning the excess to shareholders.

The BT is adamant that having the right board is essential to achieving this goal. In our discussion, seven key points were highlighted:

1. **Boards must promote a strategy for the long term.** This is self-evident, but the BT believes that boards must constantly be revisiting and challenging the company's strategy as well as management. If they don't, an activist will.
2. **Boards need diversity of thought and experience,** especially with the cyclical nature of the energy business. They need to look at a lot of different things at the same time. An entrepreneurial expert who has a different perspective is a great addition to the board.
3. **Boards need to promote and embrace innovation and creativity.** This brought us the shale revolution, and it will take us into the future. Each board should ask how much technology expertise is needed on the board. They might consider bringing someone from outside the industry who has been with an innovative manufacturing company or in the semiconductor industry and looks at technology differently.
4. **Boards need to make sure they have the right metrics.** The BT said that we are not only competing for capital against every other energy company, but also against all global

Example List Of Board Competencies And Attributes

Here is a starter list of competencies and attributes, but each company needs to develop a comprehensive set that fits so they can do their fiduciary duty.

Attributes

- Accountable
- Cultural Fit/Compatible
- Ethical
- Financial Literacy
- Fully Engaged
- High Performance Standards
- Honest/Trustworthy
- Inclusive/Collaborative
- Independent & Creative Thinking
- Informed Judgment
- Mature Confidence
- Open
- Political & Cultural Awareness
- Principled
- Strong Conviction
- Transparent

Competencies/Skills

- Accounting/CPA Credentials
- Corporate Governance
- Crisis Response
- Cybersecurity/Data Protection
- Environmental, Social & Governance (ESG)
- Executive Compensation
- Financial Expertise
- Industry & Market Knowledge
- Legal/Compliance/Regulatory
- M&A
- Public Company Board/NEO
- Risk Assessment & Mitigation
- Shareholder Relations
- Strategy
- Talent Oversight
- Technology

Source: Preng & Associates

What is the best way to approach the competency/compensation dilemma? Take the board through a rigorous exercise that delineates which competencies the board should possess in total.

Make sure you have the right board composition for today and tomorrow. It must be a board that understands the evolving energy market and your shareholder base, has the vision and creativity to make the right decisions for the future and is willing to champion and embrace change.

companies. Someone is needed on the board who will bring that perspective and make sure that the company's metrics are right and provide a return above the cost of capital. Additionally, the BT believes that metrics should be built into compensation programs and seriously questioned whether a board should pay bonuses if the cost of capital is not achieved.

5. **Depending on the size of the company, the board needs to look at its committee** structure and create those beyond the mandated three that will add value—i.e., a finance committee, M&A committee and/or innovation committee. Boards need to be properly structured to help guide and be a partner/mentor to management.
6. **Consider the value of having one, two or three former CEOs on the board.** They know what it's like to be in the corner office, to be alone and make the tough decisions. They can be a sounding board for a CEO and help think things through.
7. **Most of all, boards need to consider their composition and competencies.** Some need to avoid the danger of a "group think." Many of these, even diverse ones, are comprised of energy experts/icons who have had successful careers but still think and operate the way the industry has always done things.

On the other hand, some lack sufficient technical expertise, and both miss opportunities and don't properly allocate capital. The answer? Boards need to take a step back and think about today's shareholder base and what they are looking for. This is not only in the area of capital but also with new issues such as ESG and cybersecurity. Make sure there are competencies on the board in these areas.

So, what might a starting framework look like at a small- to mid-cap oil company? Obviously, public boards need the three basic committees. If you start with the audit committee, the chairman should be someone from the industry; but at least one, if not two of the other independent members should be from outside the industry and have experience with the value investor.

Governance committees also need a blend of individuals from inside and outside the industry to help avoid the group think. The compensation committee can look the same, but it must be ready to challenge the metrics. If there is a technical committee, the members should have the specific competence needed. If there is no technical committee, there should be at least two technical experts on the board to support.

Overall, a balance of at least 40% of the board members should have operational experience and 40% should have finance and investment experience. The other 20% should be selected to fit the strategy of the company and the makeup of management.

So, what is the best way to approach the competency/compensation dilemma? One solution is to take the board through a rigorous exercise that delineates which competencies the board should possess in total. This process will also compare the current board's composition/skills against what they should possess.

Outlined here is what our firm has done for some of our clients:

1. Create a "competency committee" comprised of the chairman, CEO (if they are one and the same, then the lead director) and non-gov chair to develop the full list of competencies the board must have and create a matrix to evaluate each director's specific skills.
2. Ask the committee members to think, not as directors, but as investors (because they are) and have a brainstorming session to develop the initial competencies list. This session may take two to three hours but, at its conclusion, the committee will have a list of 15 or more competencies that, collectively, will protect and grow a shareholder's investment.
3. Send this initial list to the whole board asking these two questions: "Has the committee missed something that should be included?" and, "Is there something on the list which does not need to be there?"
4. Once the responses are collected and revised, the list is sent to all directors asking them to rate the competencies two ways—one is based on the company as it is today and the other assumes that the company will double in four or five years. In essence, challenge the board to think what would be needed at that time. The rating uses a scale of 1 to 5 (from "nice to have" to "absolutely critical").
5. Once this feedback is captured, a final list of competencies is put on a grid (competencies in the left-hand column and directors at the top).
6. The next step is for the team to meet each director and professionally interview and evaluate his/her skills/competencies.
7. Once done, complete the grid below that shows all the competencies and present the results to the committee. The final product is a document that not only shows any board weaknesses, but also becomes a working guide for the non-gov committee as they consider the future.

I hope the thoughts of the Brain Trust and the grid creation exercise will encourage you to think about your board's composition. ☐

David E. Preng founded Preng & Associates in 1980 and is president and CEO. Previously, he spent six years in the executive search industry with two international and one national search firm. He has worked on over 2,000 energy-related searches throughout the world ranging from board and senior executive to managerial and senior technical positions.

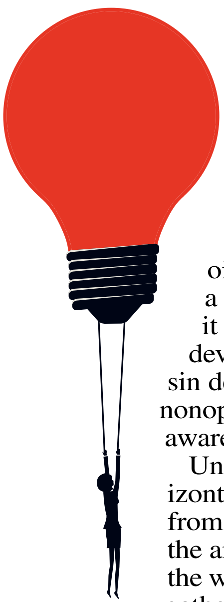
LEGAL ISSUES PERMIAN INVESTORS SHOULD KNOW

The Permian Basin remains one of the best opportunities for nonoperating investors in the world, particularly for those who go in with eyes wide open to these risks and a clear plan for mitigating them.

ARTICLE BY
JASON NEWMAN
AND
MEGHAN McELVY,
BAKER BOTTS

Five years have passed since commodity prices cratered and the energy industry faced an onslaught of producer bankruptcies. For almost as long, producers and midstream companies have squared off over whether dedications in gathering and processing agreements are real property interests—and therefore immune from the reach of the bankruptcy court—or executory contracts that may be shed by a debtor through the restructuring process.

The Permian Basin continues to be an attractive investment opportunity, thanks in no small part to its vast reserves of stacked, oil-bearing formations located within Texas—a state that has traditionally been pro-business and pro-development. Texas has also developed a body of statutory, regulatory and court-made oil and gas law giving investors and operators the certainty necessary to understand and account for the legal risks associated with oil and gas development.



However, even in the Permian Basin, oil and gas development has always been a risky venture, and that is as true today as it was during the heyday of conventional development, if not more so. Permian Basin development poses certain legal risks that nonoperating investors in particular should be aware of.

Unconventional development through horizontal drilling is different in many aspects from conventional development, including the amount of land required for development, the way that wells are drilled and the way that gathering and processing facilities are located and built. And even those basic aspects of oil and gas development that are largely the same for unconventional as for conventional development, such as oil and gas leases and joint operating arrangements (JOAs), can create new layers of legal risk based on the differences between the two types of development. All of these factors combined have created both new legal issues and new twists on established oil and gas legal principles that Texas courts have not yet addressed, adding a layer of complexity and developmental risk not always present in conventional exploration and development.

Nonoperating investors should be alert to these four legal issues:

- JOAs and the strong protection afforded operators under Texas law;
- Unsettled legal issues unique to horizontal drilling;
- Legal issues arising from potential development constraints; and
- Legal issues surrounding various exit strategies for nonoperating investors.

Key ways JOAs favor the operator

Much ink has been spilled on the subject of JOAs, particularly the American Association of Petroleum Landmen (AAPL) Model Form JOAs widely in use in the U.S. Nonoperating investors, however, should be especially alert to some of the provisions that give incumbent operators strong protection, particularly given the likelihood that any lease position acquired in the Permian Basin will be subject to one or more of these agreements.

For starters, nonoperating investors who are less than pleased with the current operator of their assets should know that JOAs and Texas case law generally place a high bar to operator removal.

The 1989 AAPL Model Form JOA, for example, requires a showing of "good cause," which need not be as high as gross negligence or willful misconduct (though those surely would count) but must still amount to a "material" breach or failure of obligation. What counts as "material" outside the gross negligence context is somewhat unclear because there are so few reported Texas cases on the subject.

In the *Tri-Star Petroleum Co. v. Tipperary Corp*. decision—arguably the best Texas case analyzing the level of conduct that might support removal for failure to carry out duties—a nonoperator satisfied the legal standard for removal by showing that the operator had: (1) improperly assessed charges against the joint account; (2) failed to supply reasonable information requested by the nonoperators; (3) commingled legal fees with other funds in the joint account; (4) classified and reclassified amounts billed to joint account, without explanation; (5) failed to provide timely and proper adjustments to the joint account; (6) double charged nonoperators on cash calls and subsequent billings; (7) allowed the premature loss of acreage to the government; and (8) was unable to sustain the deliverable quantities of gas under existing contracts.

While *Tri-Star* likely presents a more extreme scenario, the case provides a helpful roadmap for other operator removal disputes in terms of the quantity and quality of evidence required to replace an incumbent operator.

Additionally, insolvent operators may not always be subject to removal, even where the JOA provides for it. While it is commonplace for JOAs to provide that an operator may be removed based solely on insolvency or bankruptcy, Texas courts have held that such provisions are unenforceable under the Bankruptcy Code.

As one Texas bankruptcy court puts it in the *U.S. Energy Development Corp. v. WBH Energy Partners* case: "[N]otwithstanding a provision in an executory contract or unexpired lease, or in applicable law, an executory contract or unexpired lease of the debtor may not be terminated or modified, and any right or obligation under such contract or lease may not be terminated or modified, at any time after the commencement of the case solely because a provision in such contract or lease that is conditioned on … the insolvency or financial condition of the debtor at any time before the closing of the case. ..."

The *WBH Energy* decision clarified that a bankrupt or financially insolvent operator can still be removed, despite an *ipso facto* clause, but only where the party seeking removal demonstrates other factors, beyond the bankruptcy itself, that justify removal. In other words, high-bar factors like those listed above still would need to be established.

Even when operator removal is not being considered, nonoperating investors should be aware that JOAs, by design, give the operator sole control over administration of the joint account and typically establish pay now, complain later billing regimes. They provide nonoperators with limited ability to refuse payment of disputed charges.

For instance, the 2005 Accounting Procedure recommended by the Council of Petroleum Accountants Societies Inc. provides, with limited exceptions, that each party shall pay its proportionate share of all bills in full within 15 days of receipt. Those exceptions cover major discrepancies like being billed at an incorrect working interest that is higher than the nonoperator's actual working interest or being billed for a project or AFE that the nonoperator never approved.

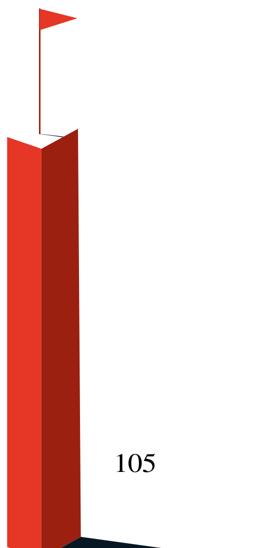
For most everything else, though, the nonoperator's only protection is that payment of any such bills does not prejudice its right to subsequently protest or question the correctness of the operator's bills. Typically, those types of protests are raised during the course of annual or periodic expenditure audits, but the typical audit provision gives the operator a generous period of time up to 15 months after an audit report is issued, which itself could take several months to prepare to resolve any audit exceptions before they may be submitted to litigation or other alternative dispute resolution. This means that nonoperating investors could be forced to carry their proportionate share of improper charges against the joint account for as long as one to two years.

All of this is to say that what the JOA giveth the operator, the JOA generally does not taketh away and neither do Texas courts. Therefore, nonoperating investors in the Permian Basin should be mindful on the front end and scrutinize not only the operator's *operating* experience, but also its *administration* experience and other back-office capabilities that are critical to the success of any multiparty oil and gas venture.

Unsettled legal issues related to horizontal drilling

Texas' developed body of oil and gas law is a product of the conventional, vertical drilling prevalent while most of it was created during the 20th century. As a result, some established legal principles apply equally to unconventional and conventional development and some do not, leaving gaps in the law that Texas courts have yet to fill.

Two examples of established oil and gas principles that apply equally to conventional and unconventional development are the accommodation doctrine and the rule of capture. The accommodation doctrine in Texas gives the owner of the minerals, as the owner of the "dominant" mineral estate, access to the surface for operations to develop those minerals subject to an obligation to reasonably accommodated existing uses by the surface owner. The rule of capture, which allows the mineral owner to develop minerals under its tract without the risk of certain claims from adjacent tract owners, applies equally to unconventional development, as the Tex-



as Supreme Court held in *Coastal Oil & Gas Corp. v. Garza Energy Trust*.

Certain legal issues affecting unconventional development, however, have not yet been addressed by the courts. Among these issues are whether certain common law claims will apply to the allocation of production of different ownership when it is commingled in a horizontal wellbore or at a central facility. Another is the enforceability of provisions in oil and gas leases that purport to make the payment of royalty a lease condition, the breach of which supports termination.

Traditionally, the breach of a royalty provision in an oil and gas lease would support only a claim for damages but not lease termination. These new provisions found in more modern lease forms, if enforceable, substantially raise the legal risks associated with paying royalties. Until the Texas Supreme Court resolves these issues, they will continue to add a layer of legal risk that oil and gas investors should account for.

Legal issues involving land, infrastructure and drilling constraints

The old real estate adage "location! location! location!" also rings true when investing in oil and gas assets in Texas. There are remote areas of far West Texas where production may exist, but without access to gathering systems, pipelines and other necessary infrastructure, development remains uneconomic.

For example, to leverage capital expenditure during times of $45 to $55 per barrel oil, longer laterals are necessary to drill economic wells. To do this, operators must acquire large lease positions with enough contiguous acreage to drill economic wells. Investors should be aware of the complexity and legal issues involved in creating a large enough land position for long-lateral and mega-pad horizontal drilling.

Because much of the Permian Basin has been previously developed, many leases are encumbered by legacy agreements that may hinder or prevent the ability to enter land swaps or other arrangements necessary to create a large enough land position. Additionally, many older leases in the Permian Basin are HBP from older, shallow wells with marginal production, which may be challenged based on an alleged lack of production in paying quantities.

Moreover, operators also need large tracts of land to site facilities and other infrastructure, such as storage tanks and pipelines to move both fresh and produced water, to handle the production from the large number of wells necessary to develop shale plays. A lack of adequate leased acreage to site these facilities can also render horizontal development uneconomic.

The inability to economically dispose of produced water is another impediment to development in the Permian Basin. Horizontal wells in the Permian Basin produce large amounts of water, which must be disposed of, often through disposal wells. However, produced water could outpace disposal capacity in the near future, and operators are already facing high disposal fees or unequal bargaining power allowing companies that take and dispose of produced water to command long-term agreements with minimum commitments and acreage dedications.

Additionally, there continues to be insufficient pipeline capacity to move production from far West Texas to points of sale along the Texas Gulf Coast. Midstream companies attempting to build the necessary pipeline capacity have faced legal challenges when routing these pipelines. For example, some counties, cities, and even individual landowners have filed lawsuits challenging the routing, construction and future operation of the Permian Highway Pipeline on multiple grounds, including lack of due process, inadequate compensation and environmental claims.

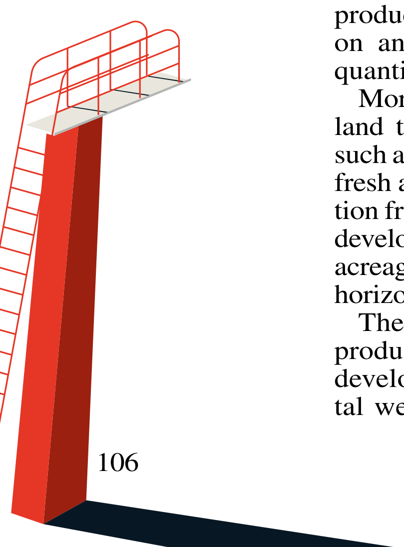
There also is a shortage of electrical infrastructure in parts of the Permian Basin (well-known for its remoteness) to provide reliable electrical service necessary to power the sophisticated equipment used to drill, complete and maintain production from oil and gas wells. This implicates a number of legal issues. First, if an operator cannot get access to electrical power, it may have no choice but to resort to using generators, which are not only more costly but also less environmentally friendly.

Additionally, where large well pad complexes straddle the service territories of more than one utility, this can lead to disputes between the operator and competing utilities over which utility has the right to serve the development field. Finally, rather than wait on a utility to build to them, some producers have opted to construct their own transmission lines to interconnect with utilities and self-serve, which avoids the need to go to the Public Utility Commission of Texas to obtain a certificate of convenience and necessity as utilities must do. Producers electing to go this route, however, must take care not to share costs of such construction with other producers (or, if they do, to properly structure their transactions) so as not to inadvertently become regulated electric utilities and/or run afoul of the Texas Utilities Code.

Legal issues surrounding various exit strategies

According to a July 2018 article by McKinsey & Co., "as the [private-equity] industry has matured, buyers are seeing fewer deals that are the first of their kind," and this has caused buyers to be "more sophisticated—and more demanding—than ever." That article was written about the private-equity industry writ large, but it applies just as aptly to the private-equity energy industry where commercial deal teams are well-versed in key performance indicators of success for energy assets, such as capital spend and cash flow.

It is telling, for example, that 9x to 10x EBITDA was market in 2016 and 2017, but, in 2018, private-equity sponsors are reportedly hoping



for 6x to 8x EBITDA for their energy portfolio investments yet only receiving offers from buyers in the 3x to 5x range.

As this firm previously noted in its May 2019 Energy Litigation Spotlight on Oil and Gas, one implication of this trend has been that private-equity energy firms have sought to more concretely demonstrate the value of their assets, for example, in the form of drilling numerous revenue-generating wells, before entering the marketplace to flip them. But this approach requires such firms to hold on to those assets for longer periods of time before exiting than initially desired.

For the operationally savvy (and lucky) private-equity energy firm this may work out, but for most others it exposes them to greater risks, including litigation with contractors, vendors, neighboring operators, surface owners and the underlying mineral rights' owners.

These disputes tend to have a life cycle of their own as a play itself matures. For example, in our experience it is not unusual in the early stages of an oil and gas play's development to see a greater frequency of personal injury matters associated with active drill sites or lien disputes as players spat over responsibility for unpaid bills. As infrastructure is built out, the focus can then shift toward environmental or other nuisance-type claims, such as impacts from flaring (driven in part by the lack of takeaway capacity on pipelines) or noise or other impacts from large, regional processing facilities.

Later in the development cycle, once wells come online and mineral rights owners begin to share in production proceeds in the form of royalties, it is not unusual to see more of a shift toward royalty-based disputes, whether those concern the propriety of certain post-production charges, the failure to timely remit proceeds under the Texas Natural Resources Code, or efforts to wash out overriding royalty interests.

Given their emphasis on freedom to exit and obligation to pay a preferred return on any capital calls back to investors, however, private-equity energy firms will be comparatively more incentivized to resolve such litigation than engage in protracted and costly court battles.

In addition to holding on to assets longer and/or further developing them, some private-equity energy firms have agreed to exits based on receipt of stock in the buyer, a model that historically has been disfavored by the industry due to the comparatively illiquid nature of the consideration as compared to cash.

It was much publicized, for instance, that NGP Energy Capital Management sold WildHorse Resource Development Corp. (one of its portfolio companies) to Chesapeake Energy Corp. for $3.98 billion, with the deal remuneration consisting of a combination of Chesapeake common stock and cash. Since that transaction closed in February 2019, Chesapeake's stock price has declined from $2.79 to 69 cents in November 2019 (a 25-year low), revealing the risks of this type of exit structure.

A new, more radical monetization model is emerging as of late (coinciding with 2018 and 2019's relatively mediocre and volatile crude oil prices). According to an article in The Wall Street Journal, shale companies seeking cash are courting investors with a new type of asset-backed security that involves bundling and securitizing oil and gas wells and selling bonds that will pay decent returns on the best quality wells but higher rates on riskier ones.

For example, the WSJ article reported that Raisa Energy LLC, which owns nonoperating interests domestically, privately offered its stakes in about 700 wells across the U.S., though few details were available on the offering, including how much it raised.

While this bonds-for-barrels approach is certainly creative, one cannot help but consider the parallels it bears to the mortgage-backed securities that sent the U.S. headlong into a recession in 2008. And given how imprecise oil and gas exploration can be, even with all of the advances of modern technology, these types of investments seem primed for legal risks.

For example, if the securitized wells do not end up performing as advertised (or at least close to it), there may be actions against underlying operator companies allegedly to blame or actions by sorely disappointed investors.

Overall, because this is such a new form of structured financial product, it remains to be seen whether this new approach to monetizing the oil and gas value chain will take hold on a widespread basis. Either way, this new investment strategy is sure to be closely watched, not only from a financial perspective but a legal one as well. □

Jason Newman is a partner at Baker Botts. He represents and advises energy clients on legal issues and disputes arising from horizontal development in all parts of Texas and throughout the U.S. Meghan McElvy is a partner at Baker Botts. She advises energy clients on most aspects of legal and operational issues arising from the development of shale plays and horizontal drilling throughout Texas.

Permian Basin development poses certain legal risks that nonoperating investors in particular should be aware of. Even when operator removal is not being considered, nonoperating investors should be aware that JOAs, by design, give the operator sole control over administration of the joint account and typically establish pay now, complain later billing regimes.


THE
CRITICAL
PIECE OF YOUR MIDSTREAM
PUZZLE

MIDSTREAM DEDICATIONS

The 2016 Sabine ruling seemed to absolve E&Ps in bankruptcy from their midstream agreements, but a new Colorado case levels the playing field. The moral: Language matters.

ARTICLE BY
JONATHAN HYMAN
AND
LYDIA WEBB,
GRAY REED


PHOTO COURTESY PIPELINE MACHINERY INTERNATIONAL

Five years have passed since commodity prices cratered and the energy industry faced an onslaught of producer bankruptcies. For almost as long, producers and midstream companies have squared off over whether dedications in gathering and processing agreements are real property interests—and therefore immune from the reach of the bankruptcy court—or executory contracts that may be shed by a debtor through the restructuring process.

Until recently, the only ruling on the characterization of these dedications, Sabine, came down in favor of producers. However, a recent opinion in Badlands Energy by a Colorado bankruptcy court may have evened the playing field, providing midstream companies leverage in their negotiations with producers.

The financial implications of the characterization of dedications in gathering and processing agreements are huge. Over the past two decades, midstream companies have collectively invested billions of dollars in pipeline infrastructure in response to the domestic shale boom. Transportation and related fees charged to producers are structured to provide midstream companies with a return of and on their investment over the life of the agreement. The dedications contained in these agreements were intended to act as security for midstream companies (and their financiers), with the understanding that such dedications are real property interests and, therefore, binding on successors to the mineral interests.

The bankruptcy courts provide a unique forum for energy companies duking it out over the characterization of midstream dedications. Bankruptcy courts are federal courts that apply the laws of the state where the property is located to determine the parties' relative rights. Given the popularity of Delaware and New York as "debtor friendly" filing venues, bankruptcy courts from these districts are often tasked with construing complicated and archaic property laws from states with significant oil and gas reserves, like Texas and North Dakota. These circumstances tend to favor producer-debtors over their midstream counter-parties.

The Sabine case, decided in 2016, is the prime example of how things can go wrong for a midstream company litigating the characterization of its dedications in bankruptcy court. Sabine sought to reject its gathering and processing contracts with Nordheim Eagle Ford Gathering and HPIP Gonzales Holdings in an attempt to make its assets more marketable and

The Badlands case arms midstream companies with additional arguments in the event their gathering and processing agreements face the prospect of rejection in bankruptcy.

thus, enhance its prospects for a successful restructuring. Nordheim and HPIP asserted the dedications in their agreements were covenants running with the land (a type of real property interest) under Texas law, were binding on any successor, and could not be rejected in bankruptcy. Because the dedication language referenced produced gas, a personal property interest, the Sabine court found the agreements were not real property interests. Rather, the Sabine court determined the agreements were nothing more than service contracts, and therefore, Sabine was able to jettison its gathering and processing agreements, saving as much as $115 million in future gathering fees and expenses.

Sabine has dominated the midstream characterization debate since it was decided three-plus years ago. At the time, the dedication language in the Nordheim and HPIP agreements was in large part standard across the industry. In subsequent producer bankruptcies, producers relied heavily on the Sabine decision to support their attempts to reject alleged "out of market" gathering and processing agreements. As a result, many midstream companies opted to enter into new gathering and processing agreements with lower rates rather than the roll the dice in bankruptcy court.

In September 2019, a Colorado bankruptcy court in the Badlands Energy case found that a gas gathering agreement and a salt water disposal agreement were both covenants running with the land under Utah law and therefore could not be rejected or otherwise stripped from the underlying assets by a bankruptcy sale. The Badlands opinion evens the score (so to speak) and provides midstream companies with compelling authority that agreements containing appropriate dedications of oil and gas reserves, and that otherwise meet the relevant legal requirements, should ride through bankruptcy unaffected.

Utah and Texas law on covenants running with the land are similar for the most part. The driver of the different result is the dedication language. In Badlands, the dedications in the agreements burdened the producer's interest in gas reserves "in and under" the subject acreage. The bankruptcy court found the dedication language sufficient to qualify the agreements as real property interests under Utah law.

From a midstream perspective, the Badlands decision supports drafting gathering and processing agreements to include a dedication of a producer's interests in oil and gas reserves, leases and related lands, rather than just the produced hydrocarbons.

Another significant distinction between Badlands and Sabine centered on grants of pipeline easements and rights of way. The Sabine court found that a grant of a pipeline easement or right of way in connection with entry into a gas gathering and processing agreement (a common occurrence in the industry) was insufficient to satisfy the requirements for a covenant to run with the land under Texas law. However, in Badlands, the bankruptcy court found that such a related conveyance was enough for a covenant to run with the land in Utah.

Because there is still such uncertainty surrounding the characterization of gathering and processing agreements, and the law can vary from state to state, midstream companies should obtain a pipeline easement or right of way from their producer when they enter into a new agreement.

The Badlands case arms midstream companies with additional arguments in the event their gathering and processing agreements face the prospect of rejection, or an attempted free and clear sale, in bankruptcy.

Given current commodity prices, and the recent spike of producer bankruptcies since May 2019, the characterization of midstream dedications will continue to play out in bankruptcy courts across the country for years to come. In fact, the issue is currently before a Texas bankruptcy court—for the first time—in the Alta Mesa bankruptcy. Given the level of oil and gas production in Texas, market participants should keep an eye on how a Texas court handles the characterization fight.

The moral of the story is that the language used in any gathering and processing agreement matters and will be the focal point of any dispute. It is critical that midstream companies revisit their existing dedications and ensure that future dedications are drafted to clearly implicate mineral interests in place and thus, insulate the agreement in question to the greatest extent possible from a subsequent attack in bankruptcy. □

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A Side-By-Side Comparison Of Sabine And Badlands

Sabine (2016)	Badlands (2019)
Applied Texas property law.	Applied Utah property law.
Decided by New York bankruptcy court, affirmed by New York district court and Second Circuit.	Decided by Colorado bankruptcy court, was not appealed.
Held midstream dedication did not constitute real property interest.	Held midstream dedications constituted real property interests.
Dedication language: Producer dedicates to gatherer all gas "produced and saved" from wells located within the dedication area.	Dedication language: Producer dedicates to gatherer "gas reserves in and under … and produced or delivered from" the leases within the dedication area.
Privity could only be satisfied if the dedication was created in a conveyance of real property.	Grant of pipeline easement and right of way through dedication area was sufficient to establish privity.

Source: Gray Reed

Three-Way Permian Merger Creates $1.5 Billion E&P

A BLANK-CHECK acquisition corporation will combine with **HighPeak Energy** and **Grenadier Energy Partners II** in what amounts to a shrewd workaround of the market's stonewalling of upstream IPOs.

HighPeak and the blank-check company buying it, **Pure Acquisition Corp.**, share board members and are both led by CEO Jack D. Hightower.

The Nov. 27 deal, expected to close in first-quarter 2020, would create the largest pure-play northern Midland Basin E&P with a 73,000-net-acre position. The company said pro forma production would accelerate from about 12,000 barrels of oil equivalent per day (boe/d) at the close of 2019 to double by the end of 2020. HighPeak said the transaction's enterprise value is $1.58 billion with a pro forma market cap of $1.85 billion.

Hightower, a veteran energy leader who previously led **Titan Exploration** and **Bluestem Energy Partners**, said the transaction creates an unlevered company with one of the best onshore domestic opportunities for cash-flow growth and single-well economics due to high-oil content.

"The HighPeak management team is confident in our ability to successfully implement the proposed development drilling program and achieve the anticipated growth profile of the company," he said.

In an interview, HighPeak's CFO Steven Tholen said that while the transaction partly involves related parties, the Pure Acquisition special purpose acquisition corporation "looked at a lot of different throughout the U.S.

"In the end, we were unable to bring any of those to completion," he said.

At the time Pure Acquisition was formed, the assets HighPeak had accumulated to that point also would not have justified a deal, he said.

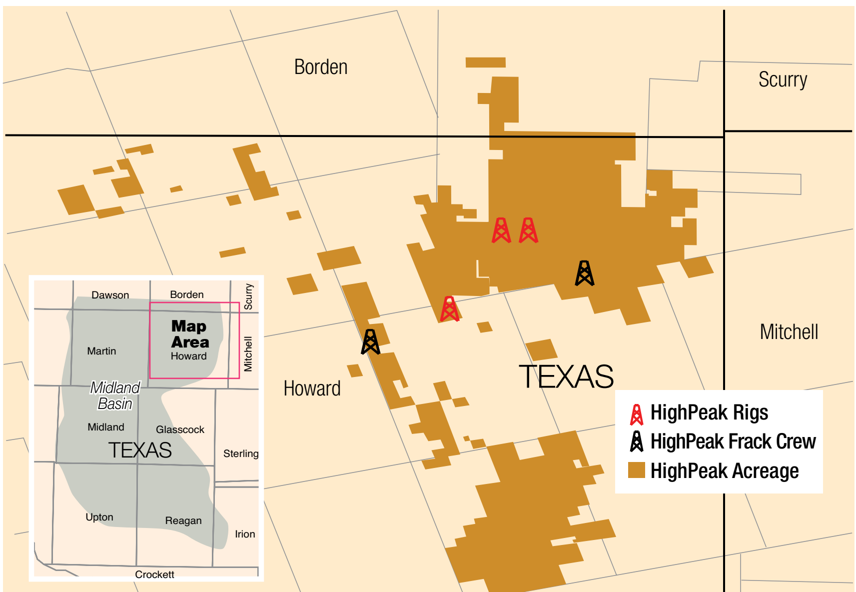
HighPeak Energy itself was created through the combination of two HighPeak entities backed by a combined $650 million from high-net worth individuals and management, Tholen said.

The companies estimated the combined entity will generate 2020 EBITDA of about $430 million and have no debt on its balance sheet at closing.

Over the past two years, HighPeak has assembled a 50,000-acre position, largely in Howard County, Texas. In April 2018, Pure Acquisition closed a $414 million upsized IPO.

Pure Acquisition was not barred from pursuing a combination with a business affiliated with board members. Its prospectus said that it did not have any specific business combination under consideration at the launch of its IPO, according to regulatory filings. Three of the board's six members were independent, and a committee of those members unanimously approved the transaction, which was then approved by the full board.

HighPeak Energy Acreage Position



Source: HighPeak Energy

HighPeak Energy Combination Company Type ($MM)

Metric	Total
Net Acres	73,000
Gross/Net Operated Locations	875/725
Net Production (boe/d)	12,000
2020E EBITDA	$430 million
2021E EBITDA	$935 million

Source: HighPeak Energy

As part of the combination, Grenadier will be acquired for nearly 16 million shares of HighPeak Energy common stock and $465 million in cash.

To fund working capital and a portion of the Grenadier purchase price, HighPeak said it is seeking to raise $200 million in the form of a private placement of shares. About $378 million in funding will come from Pure Acquisition.

"We are excited to reach this agreement with HighPeak Energy in the current market and help form a new strategic pure-play company focused on a key area of the Midland Basin," Grenadier CEO Patrick Noyes said. "Our Grenadier team has performed exceptionally well in both executing on our active drilling and completion program along with supporting this key transaction with HighPeak. As a significant shareholder going forward, we are excited about the continued growth and upside potential of this combined asset."

HighPeak said its inventory includes 7,254 net operated drilling locations.

A November 2019 HighPeak presentation said the company believes co-development of the lower Spraberry and Wolfcamp A is the optimal method for developing the asset. The company plans to begin pad development in 2020 with four operated rigs and projects it will produce 82% oil.

Jefferies LLC acted as financial adviser on the business combination agreement, and **Hunton Andrews Kurth LLP** acted as legal counsel to the special committee of the board of directors of Pure Acquisition. **Vinson & Elkins LLP** acted as legal counsel to the **HighPeak Funds**, and **Latham & Watkins LLP** acted as legal counsel to Jefferies LLC.

Jefferies also served as financial adviser for Grenadier transaction, and **Thompson & Knight LLP** acted as legal counsel to the HighPeak Funds. Vinson & Elkins acted as legal counsel to Grenadier.

—Darren Barbee

Jones Energy Agrees To $201 Million Buyout By Revolution

SIX MONTHS AFTER exiting bankruptcy, **Jones Energy II Inc.** said it agreed Dec. 6 to sell its assets and merge with **Revolution Resources**, an affiliate of **Mountain Capital Partners LP**, for $201.5 million in cash.

Jones Energy entered bankruptcy protection in April with secured and unsecured liabilities of more than $1 billion. The company, with assets in the Anadarko Basin in Oklahoma and Texas, emerged from reorganization after 33 days with a $225 million borrowing base agreement.

Jim Addison, Jones Energy's chairman of the board, said the agreement marks the successful completion of its strategic alternatives process underway since earlier this year.

"Throughout the course of our exhaustive review, we engaged in meaningful strategic dialog with a significant number of potential counterparties," he said. "Ultimately, the board unanimously determined that an all-cash transaction with Revolution is in the best interests of our shareholders and the company and will deliver the strongest economic value relative to the comprehensive range of alternatives we examined."

Prior to bankruptcy, Jones Energy targeted the eastern Anadarko Basin's liquids-rich Woodford Shale and Meramec Formation in the Merge area of the Stack/Scoop. In the western Anadarko, the company targeted the Cleveland, Marmaton, Granite Wash and Tonkawa formations.

In the Midcontinent and other areas, Jones Energy held about 185,000 net acres as of year-end 2018, including 10,708 undeveloped acres. About 94% of its leasehold was HBP. Additionally, the company's inventory included 597 net wells and 2,017 net locations.

Revolution Resources has previously taken advantage of distressed Midcontinent companies to make acquisitions. In January 2018, the company agreed to buy **Gastar Exploration Inc.**'s West Edmund Hunton Lime Unit (WEHLU) for $107.5 million.

Revolution II WI Holding Co. LLC is backed by a Houston-based Mountain Capital private-equity fund, which has about $1 billion of assets under management.

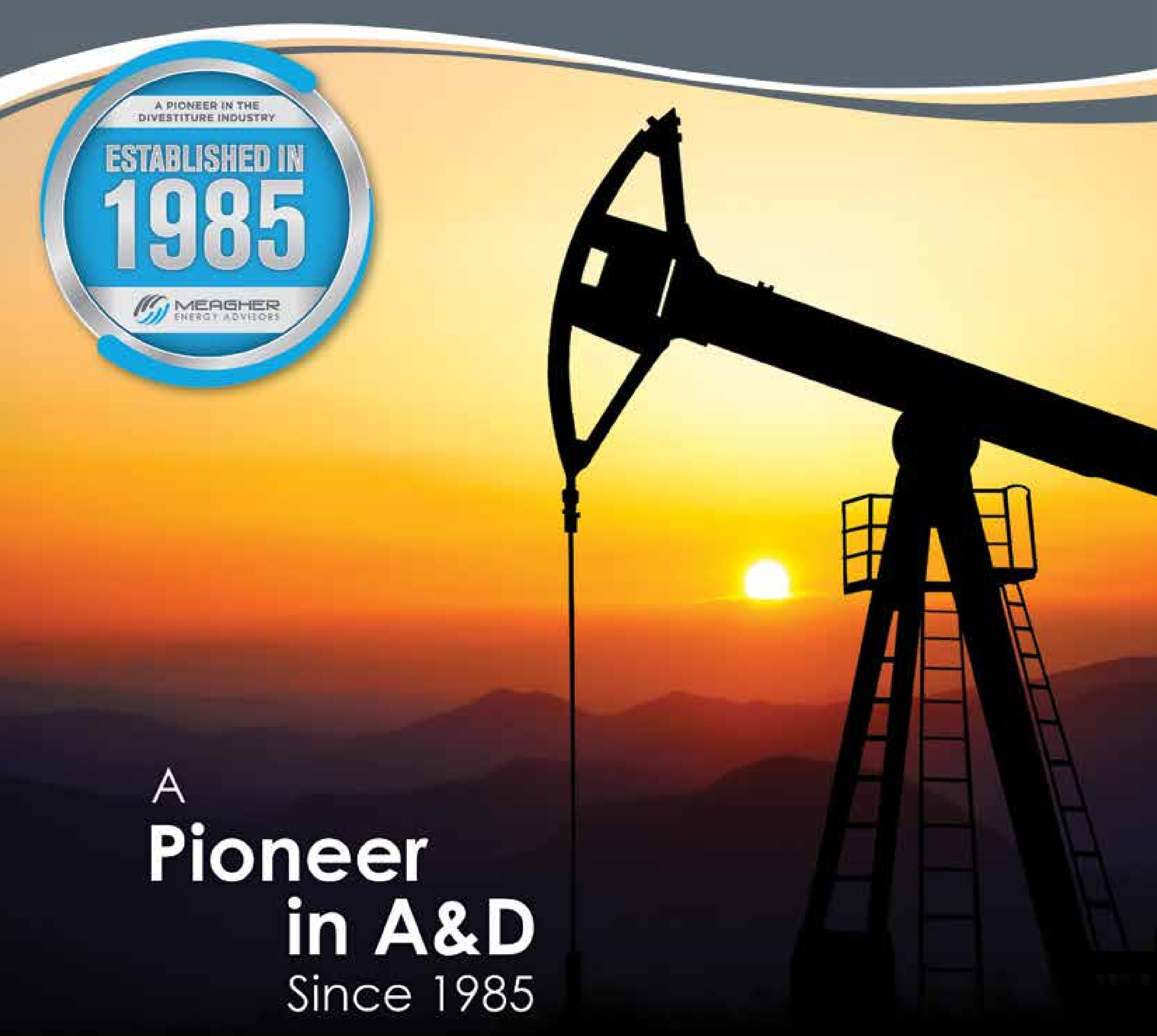
Evercore and **TD Securities (USA) LLC** are serving as financial advisers to Jones Energy, and **Baker Botts LLP** is serving as its legal counsel. **Kirkland & Ellis LLP** is Revolution Resources' legal counsel.

—Darren Barbee

Jones Energy Wells (December 2018)

Area	Net wells	Net locations
Western Anadarko	553	845
Eastern Anadarko	38	1,168
Other	6	4
All properties	597	2,017

Source: Jones Energy II Inc. regulatory filings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Laredo Petroleum Looks For Oil Growth With Permian Deal

LAREDO PETROLEUM INC. recently tacked on more Permian Basin acreage through a $130 million cash acquisition as the company's new CEO implements his strategic vision.

In its third-quarter earnings, Laredo revealed it had signed a purchase and sale agreement with **Cordero Energy Resources LLC** on Nov. 4 to acquire 7,360 net acres (96% operated) and 750 net royalty acres in Howard County, Texas. The largely undeveloped acreage is in an area of high oil productivity with offsetting wells indicating first-year production that is 80% oil, according to the company release.

Jason Pigott, who took over as Laredo's CEO last month, called the Howard County acreage acquisition Laredo's next strategic step to maximize and create additional value for its stakeholders.

The Tulsa, Okla.-based independent oil and gas company has worked to answer calls by investors to transform itself into a returns-focused company rather than one driven on net asset value accretion.

So far this year, the company has generated almost $40 million of free cash flow by high-grading its existing acreage and additional cost saving initiatives, which included a 20% reduction to its staff plus a total overhaul of its leadership team. Though on Nov. 5, Pigott said this is only the first step for Laredo.

"To implement the second pillar of our strategy, further improving our capital efficiency in corporate returns, we intend to opportunistically pursue transactions ... to target high-margin inventory that will move to the front of our development queue," Pigott said during the company earnings call, according to a Seeking Alpha transcript of the call.

Pigott joined Laredo in May, initially as its president, having previously worked at **Anadarko Petroleum Corp.** and, more recently, **Chesapeake Energy Corp.** He was eventually named as successor to Randy A. Foutch, Laredo's CEO, who had founded the company in 2006, effective Oct. 1.

According to Foutch, Pigott has made a "positive, profound impact" in a short period of time.

"Since joining Laredo as president in May, his focus on increasing oil productivity and minimizing risk has refocused the company on the Cline formation and improved our Wolfcamp development plan," Foutch said in a statement in late September.

The Howard County acreage acquisition, expected to close in December, will continue Laredo's pivot toward oil, said **Siebert Williams Shank & Co. LLC** senior equity analyst Gabriele Sorbara.

"We believe this is a pivotal transaction that shifts its production mix toward oil," Sorbara wrote in a research note on Nov. 6. He estimated Laredo is buying the acreage for about $16,000 per net acre. The company plans to finance through its senior secured credit facility.

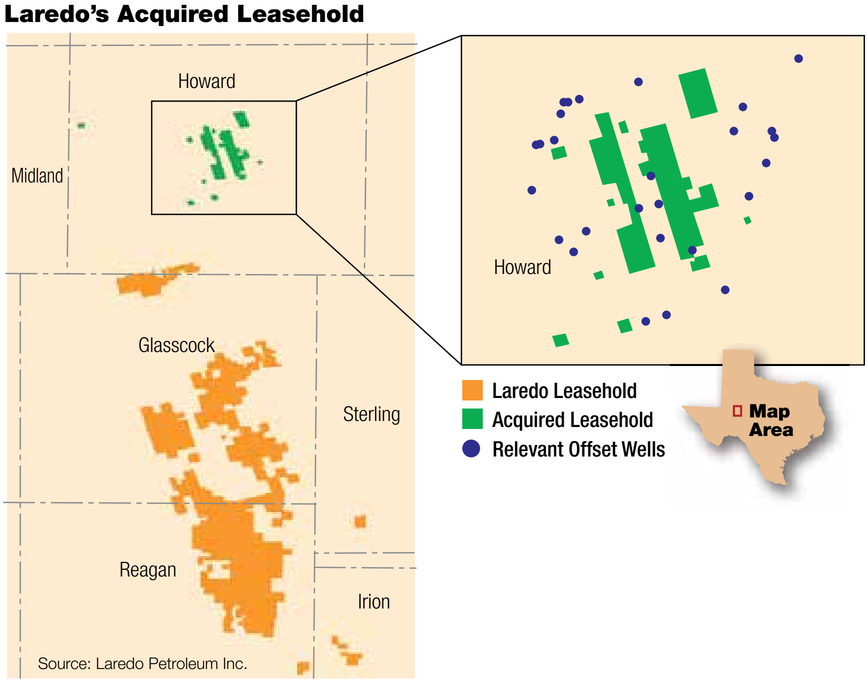
The transaction is expected to add 120 gross (100 net) primary locations in the lower Spraberry and upper and middle Wolfcamp formations, which Pigott said Laredo will begin drilling in first-quarter 2020.

"This is not acreage that is being acquired to languish our development queue as we expect to begin drilling our first package in the first quarter of 2020 and that the majority of our completions will be on this acreage in the 2020 to 2022 timeframe," he said on the earnings call.

He also added that Laredo currently expects to develop the locations in 16 well packages targeting primary zones to limit future parent/child interactions.

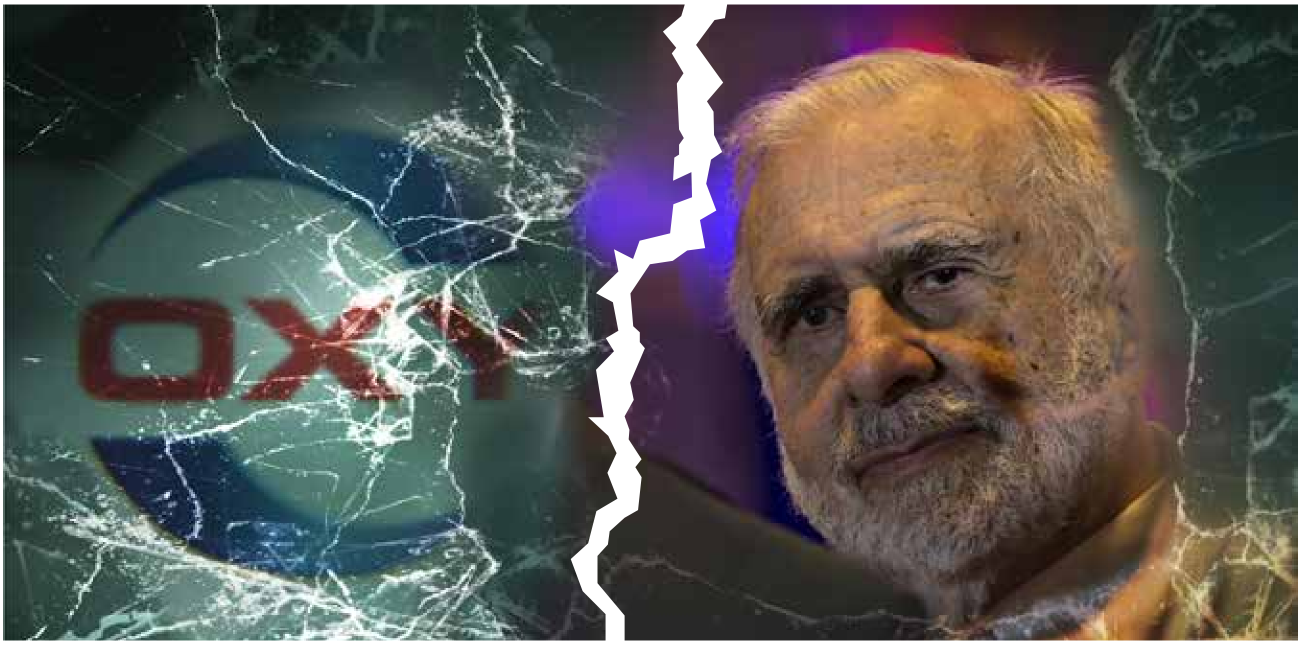
—Emily Patsy

Laredo's Acquired Leasehold



Source: Laredo Petroleum Inc.

Icahn Battles For Board After Occidental Deal



ACTIVIST INVESTOR CARL Icahn's proxy fight has mushroomed into a full-scale war against **Occidental Petroleum Inc.**, with Icahn reportedly intent on replacing the Houston-based company's entire board, including CEO Vicki Hollub, who is a director.

Icahn has hounded Occidental since it announced in May it would purchase **Anadarko Petroleum Corp.**, a deal he derided as the "OxyDarko disaster." While Icahn has been highly critical of Occidental's $55 billion Anadarko deal, in a Nov. 8 letter he appeared to be rankled by Hollub in particular, using the phrase "Hollub and her board" 14 times to describe company decisions and saying she would have been fired at a private company.

Icahn now intends to submit 10 replacement board members to stockholders by the company's Nov. 29 deadline for nominations, Bloomberg reported. The report echoes Delaware court documents filed on Nov. 14 that said Icahn was mounting a proxy fight to "replace members of Occidental's board of directors … with a new slate of directors they have proposed to Occidental's stockholders."

However, Icahn enters the new phase of his struggle with a reduced hold on Occidental and a legal setback. In November, Icahn said he cashed in millions of his shares because he was unwilling to risk money in Occidental "without changing the incumbent board and potentially the CEO."

And a Delaware court ruled that Icahn could not review Occidental records related to the Anadarko merger.

Icahn initially held an investment of $1.6 billion in Occidental and, as of September, owned about 2.9% of the company's outstanding shares, according to a November regulatory filing by **Icahn Enterprises LP**. Icahn now controls roughly 2.5% of the company's shares, worth about $900 million.

Icahn and his affiliates began buying Occidental stock on May 2, following the sale of preferred stock to Warren Buffett's **Berkshire Hathaway** for $10 billion. Icahn has criticized adding debt to buy Anadarko and financing part of the acquisition through stock, saying Hollub was fleeced by Buffett, who will receive an 8% cash dividend on his shares.

Occidental has argued that few if any lenders could have promptly agreed to provide the large block of financing without additional fees and loan syndication, according to court documents.

In late May, Icahn took his proxy fight to Delaware—where Occidental was incorporated—suing Occidental for access to documents related to the acquisition, financing and decision-making surrounding the Anadarko deal. In a bid to inspect board communications, Icahn cited a law allowing stockholders to inspect corporation documents if they can demonstrate a credible suspicion of mismanagement or wrongdoing.

Joseph R. Slights III, vice chancellor of the Delaware Court of Chancery, rejected the argument.

"Although they make a cursory argument about the need to investigate corporate wrongdoing or mismanagement, plaintiffs freely admit their primary purpose for demanding to inspect books and records is to aid them in their proxy contest," Slights wrote in a Nov. 14 decision.

Slights added that "whether a stockholder's desire to communicate with other stockholders is a proper purpose to justify inspection is, at best, murky."

Nevertheless, investor sentiment on Occidental remains mixed, **Goldman Sachs** analysts said in a Nov. 19 report.

The debate on the stock centers on these terms:

- Sustainability of dividends;
- Whether the company's ratio of enterprise value and debt-adjusted cash flow is too high;
- Timing of deleveraging; and
- Ability to see an upside without Brent prices moving above $60 per barrel.

"Investors indicated they will closely monitor leverage, and there was some improved sentiment based on management's statement that it expects to exceed the upper end of the $10 billion to $15 billion asset sale targets by mid-2020," Goldman Sachs analyst Brian Singer said.

On Nov. 13, Occidental said it expects proceeds from asset sales of "at least $15 billion" by mid-2020 and highlighted a $750 million Midland Basin joint venture and the sale of noncore assets for $200 million.

—Darren Barbee

Kimbell Royalty Partners Adds Eagle Ford Interests

KIMBELL ROYALTY PARTNERS LP added to its growing mineral and royalty position through an all-equity acquisition on Nov. 12 worth about $31.8 million.

The acquisition from privately held **Buckhorn Resources LLC** and its affiliates includes certain mineral and royalty assets with an oil-focused production mix and about 90% of the net royalty acres located in the core of the Eagle Ford Shale in La Salle and McMullen counties, Texas.

Kimbell is a publicly traded company based in Fort Worth, Texas. Since its IPO in 2017, the company has been a major player in the trend in recent years of consolidation within the oil and gas mineral and royalty space, completing over $700 million worth of transactions.

Not including the Buckhorn acquisition, Kimbell owns mineral and royalty interests in about 13 million gross acres in 28 states and in every major onshore U.S. basin.

Kimbell said the Buckhorn acquisition is expected to add roughly 86,000 gross (400 net) royalty acres. Production on a 6:1 basis is about 270 barrels of oil equivalent per day comprised of roughly 83% oil, 11% natural gas and 6% NGL.

The acquisition also includes 504 producing wells, 38 drilled but uncompleted wells and 519 additional upside drilling locations. Two rigs are also actively drilling on the acreage.

The top operator of the acquired assets by total PV-10 value is **EOG Resources Inc.**, according to the company release.

In the Eagle Ford, Kimbell's current Eagle Ford position covers roughly 532,100 gross (6,300 net) royalty acres and represents about 4% of the company's acreage portfolio. The position also has about 2,400 producing wells and four rigs operating, according to Kimbell's winter 2019 investor presentation published on Nov. 7.

The transaction, expected to have closed in late December, has a July 1 effective date, with Kimbell entitled to revenues from production on and after such date. As part of the all-stock agreement, Kimbell will issue about 2.2 million newly issue units to Buckhorn, a Houston-based company investing primarily in the Permian Basin and Eagle Ford Shale.

The transaction is one of several all-stock acquisitions made by publicly traded companies in the oil and gas mineral and royalty space so far this year. Others have included the closing of Kimbell's acquisition of **Phillips Energy Partners** from **EnCap Investments LP** and, more recently, **Viper Energy Partners LP**'s transaction with **Santa Elena Minerals LP**.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Petrobras May Divest Billions More Than Forecast

BRAZIL'S PETROBRAS could add several billion dollars of assets to its already ambitious five-year divestment plan, executives said on Dec. 4, underlining the state-run oil company's rush to reduce its hefty debt load.

In the company's 2020 to 2024 business plan released last week, Petrobras said it would look to sell $20- to $30 billion of assets during that period, including eight refineries spread around Brazil.

In a separate presentation Dec. 4, released during Petrobras' New York Investors' Day, the company said it may add its Bolivian assets to the divestment program, as well as its stake in petrochemical firm **Braskem SA**, legacy deepwater oil fields and its remaining stake in fuel distribution firm, **Petrobras Distribuidora SA**, commonly known as **BR Distribuidora**.

Talking to analysts and journalists, executives said they may sell parts of the Marlim oil field, one of Brazil's largest, as well as its majority stake in the smaller Papa-Terra Field.

CEO Roberto Castello Branco estimated a piece of Marlim could fetch about $2- to $4 billion, while CFO

Andrea Almeida said the potential sale of its Braskem stake could bring in $2- to $3 billion.

Petrobras has already failed previously, though, to sell its Braskem stake independently from controlling shareholder **Odebrecht**. Odebrecht and its creditor banks plan to keep the Braskem stake for at least two more years, Reuters reported earlier this week.

"The extra assets that are not included in the plan are BR Distribuidora, Braskem and other E&P assets," Almeida told journalists. "It adds to the $20- to $30 billion plan."

The comments indicate Petrobras is still laser-focused on selling off assets in a bid to reduce debt and sharpen its focus on Brazil's deepwater presalt area, a geological formation where billions of barrels of oil are trapped underneath a layer of salt beneath the ocean floor.

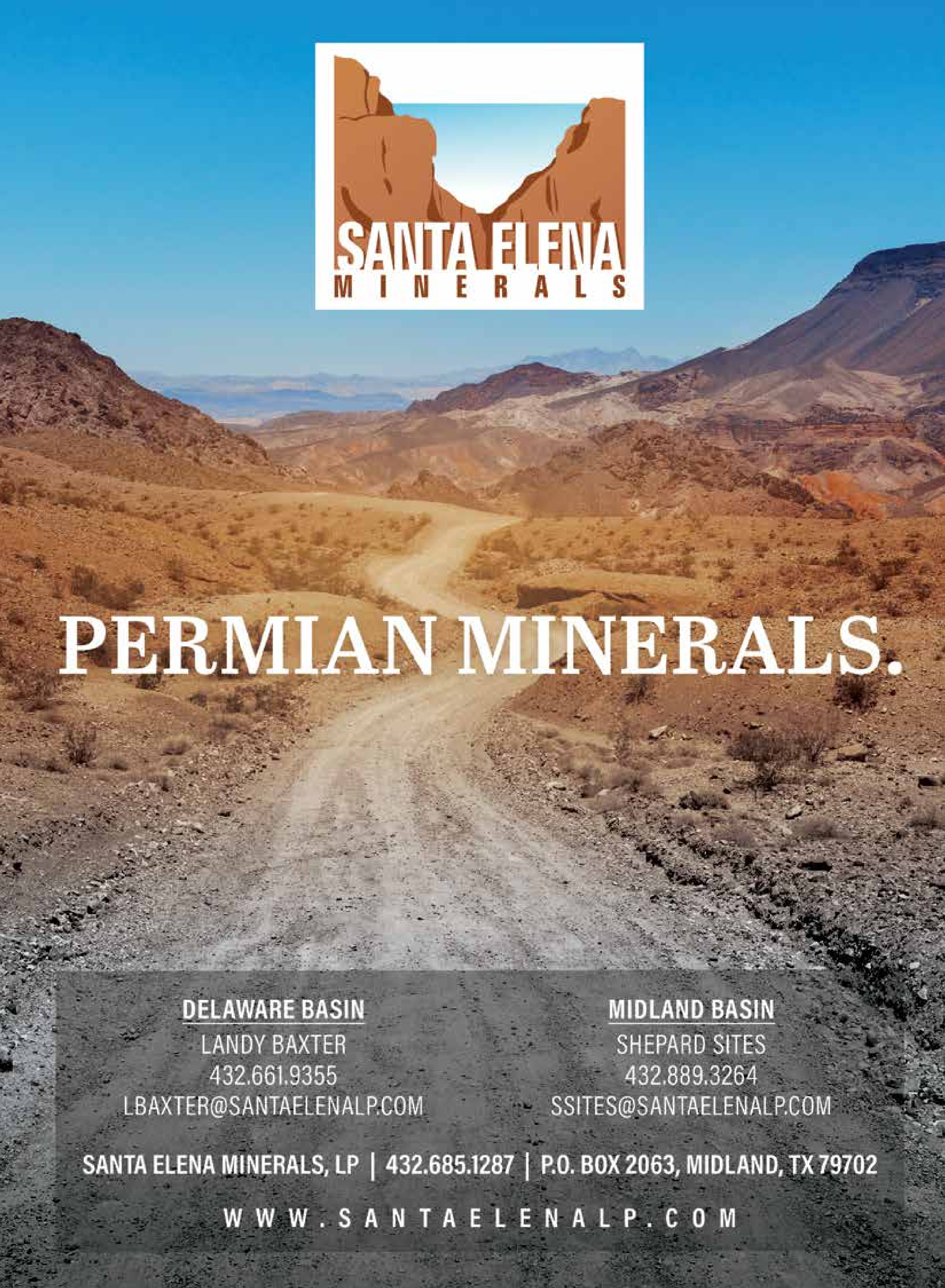
In the presentation, Petrobras estimated it would boost its equity value by roughly 45% by 2021.

Capex from 2020 to 2024 will be concentrated in the presalt, with a special emphasis on its Buzios Field, the company said.

Some 59% of $75 billion in forecast capex during the next five years will be geared toward the presalt formation. Around a quarter of total capex will go to Buzios, considered one of the world's most promising oil fields.

Petrobras also said it sees some $1 billion in "potential gains" in 2020 vs. 2018 via increased sales of bunker fuel, which is generally used to power ships. International regulators are lowering the maximum allowed sulfur content in bunker fuel, which is seen as favorable for Brazil, as the nation's crude is naturally low in sulfur.

Brazil-listed preferred shares in Petrobras closed up 1.6% on Dec. 4.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TRANSACTION HIGHLIGHTS

DALLAS

■ **Energy Transfer LP** and **SemGroup Corp.** closed their $5 billion merger on Dec. 5, resulting in the acquisition of Tulsa, Okla.-based SemGroup by Dallas-based Energy Transfer. Terms of the agreement were approved by the holders of a majority of SemGroup's outstanding voting stock at a special meeting of SemGroup stockholders on Dec. 4.

SemGroup has ceased to be a publicly traded company, and its common stock will discontinue trading on the New York Stock Exchange.

The combined operations of the two companies are expected to generate annual run-rate efficiencies of more than $170 million, consisting of commercial and operational synergies of $80 million, financial savings of $50 million and cost savings of $40 million, Energy Transfer said.

Energy Transfer's acquisition of SemGroup's Houston Fuel Oil Terminal (HFOTCO) strengthens its crude oil transportation, terminal and export capabilities, and provides Energy Transfer a strategic position on the Houston Ship Channel. HFOTCO is a world-class crude oil terminal with more than 18 million barrels of crude oil storage capacity, five deepwater ship docks and seven barge docks.

To provide shippers further access from the Houston Ship Channel to markets along the Gulf Coast, Energy Transfer is constructing the Ted Collins pipeline, a 75-mile crude line that will connect HFOTCO to Energy Transfer's Nederland terminal. The pipeline is expected to be in service in 2021 and will have an initial capacity of 500 million barrels per day.

This acquisition expands Energy Transfer's pipeline footprint by adding crude oil and NGL gathering systems and transmission lines in the Denver-Julesburg Basin in Colorado and the Anadarko Basin in Oklahoma and Kansas with connections to crude oil terminals in Cushing, Okla. The acquisition will also provide a significant natural gas gathering and processing presence in the Alberta Basin in western Canada.

NORWAY

■ Norwegian pipeline firm **Solveig Gas** has agreed to buy oil firm **Capricorn Norge** from **Cairn Energy** for $100 million, completing its transformation into a North Sea Field operator, Solveig's owner **HitecVision** said on Nov. 27.

The private-equity fund told Reuters earlier this year that it aimed to turn Solveig into an integrated E&P company, using the cash flow from its gas pipelines to fund expansion.

Cairn separately confirmed the deal, adding it will use the proceeds to fund its ongoing oil business in British waters.

Capricorn owns 10% in the **Wintershall Dea**-operated Nova Field in the North Sea, and it plans to drill two exploration wells in 2020, HitecVision said in a statement.

"The acquisition of Capricorn is expected to provide production of approximately 6,000 barrels of oil equivalent per day from the Nova Field when production commences in 2021 and will give Solveig the competence to act in the role as an operator for exploration licenses in Norway," it said.

Solveig Gas owns 15.56% of the Norwegian Gassled pipeline and terminal joint venture and is the second largest owner after government license holder **Petoro**, which owns 46.7%.

The company also 13.3% of the Polarled in the Norwegian Sea and 10% of the **Neptune Energy**-operated Duva Field in the North Sea.

HitecVision also owns a 30.4% stake in **Vaar Energy**, with Italy's **Eni** holding the rest. Vaar was formed last year by merging Eni's Norwegian operations with assets HitecVision had bought from **ExxonMobil Corp.**

CARIBBEAN

■ Colombian oil company **Hocol**, a subsidiary of state-run **Ecopetrol**, said on Nov. 26 it had agreed to buy **Chevron Corp.**'s participation in two gas production fields in the Caribbean.

Ecopetrol already owns 57% of Chuchupa and Ballena fields, while Hocol will take on the 43% that currently belongs to Chevron, Hocol said in a statement. Hocol will also take over operation of the fields.

The companies would not share the value of the sale, which is subject to approval by Colombian regulators, or the current production figures of the two camps.

Colombia had gas reserves equivalent to 9.8 years of consumption at the close of 2018, according to government figures.

SCOTLAND

■ **Coretrax,** a specialist well construction and intervention company, said Nov. 26 it acquired **Churchill Drilling Tools** as part of an ongoing growth and expansion strategy.

Aberdeen-headquartered Coretrax, which supports global well construction, completion and plug and abandonment operations, has bases in the U.K., Middle East and South East Asia and is planning entry into new regions.

It has acquired Churchill for an undisclosed sum and will integrate its extensive downhole product portfolio into a new group, with Churchill's employees joining the Coretrax team.

Churchill Drilling Tools launched in 2002 and is established as a high-quality and innovative global drilling tools business with operational bases in Aberdeen, Houston and Dubai. Its extensive product range covers drilling, completion and plugging and abandonment operations.

"Churchill's first-class technology, talented team and reputation for quality were a compelling draw for Coretrax as we push ahead with plans to widen our well construction and intervention offering and enter new global markets," Kenny Murray, CEO of Coretrax, said.

Coretrax secured a significant investment from private-equity firm **Buckthorn Partners** last year to prepare for growth. Now employing 200 people, the company continues to invest heavily in developing technology and expanding its service and engineering capabilities.

A group structure will be formed, which will include Coretrax, Churchill and expandable tubular well solutions specialist **Mohawk Energy**, following its acquisition by Buckthorn Partners earlier this year.

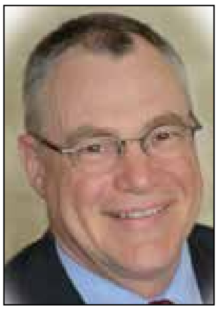
GOM

■ Talos Energy Inc. said on Dec. 10 it will expand its portfolio in the U.S. Gulf of Mexico (GoM) in a series of acquisitions totaling $640 million.

The Houston-based company signed agreements with **ILX Holdings LLC**, **Castex Energy LLC** and **Venari Resources LLC** to acquire assets that include at least 40 identified exploration prospects in a total acreage footprint of roughly 700,000 gross acres. The assets' production during the third quarter averaged about 19,000 boe/d, consisting of 65% oil and over 70% liquids.

Talos Energy said the acquisitions will not only strengthen its position in the GoM, but also provide increased scale and free cash flow (FCF) including about $150 million of FCF for the remainder of 2019. Production is also expected to increase to 72,000 boe/d based on third-quarter results.

TRUE CYCLE TIME



RICHARD MASON,
CHIEF TECHNICAL
DIRECTOR

After a half decade of confusing metrics on well intensity, it is time to embrace a new approach for evaluating E&P performance.

Seems like only yesterday that E&Ps adopted language that incorporated variations on barrels of oil equivalent (boe) per 1,000 foot of lateral, or IP-24 hour, IP-30 day, or 180-day cum's, or capital efficiency measurements anchored to drilling day reductions, or completed stages per day. And let's not forget type curves, the arbitrary designation where every headline well's estimated ultimate recovery is better than average.

Such metrics were proffered to the financial community as a Rosetta Stone to decipher the mishmash of results that populated E&P press releases and quarterly earning calls.

E&Ps touted technical expertise at every investor conference. The irony is that each operator sought to differentiate itself by highlighting metrics like lateral length, proppant intensity and spacing, both for individual laterals (stages per well) and wells per drilling spacing unit.

One can forgive generalist investors for the frustration involved in trying to determine whether an average 200- or 500-foot variance in lateral length, or 200- to 800-pound range in proppant per lateral foot actually separated any individual E&P from its peers. Indeed, the way E&Ps differentiated themselves to the investor class was by revealing that they were all range-bound when it came to well intensity.

Meanwhile, all of this was obscured by the fact that aggregate industry production rose impressively in tight formation plays over the past eight years even as a cohort of 36 publicly held E&Ps produced aggregate negative cash flow per boe every single year during that period, according to McKinsey & Co. Such was the zeitgeist that reflected the production volume growth phase of shale development.

Lately, analysts have been sifting through the proliferation of mass data presented by firms such as Enverus, Wood Mackenzie, Rystad, IHS Markit and RS Energy Group. That winnowing reveals production per well in most basins peaked a couple years ago and has declined since, even as completion intensity grew.

This decline reflects the growing percentage of infill wells as basins mature combined with aggressive spacing assumptions. Stages too closely spaced cannibalize production along the lateral, while laterals too closely spaced between each other cannibalize well productivity from 25% to 35%.

Now that the oil and gas industry has embarked on a new business model in which E&Ps operate like a standard business emphasizing profitability vs. the old model of growth at any cost, focus is narrowing to metrics that impact financial performance. In the cash constrained new era of energy, metrics that matter most involve a "show-me-the-money" measurement that reveals sustainable positive net cash flow at the bottom line.

And that leads to the evolving way analysts use to examine the industry. The emphasis is on a holistic approach to operations, moving beyond rig count, fracture stimulation crews or other traditional tracking metrics. Chief among these new metrics is true cycle time. And, no, true cycle time is not just about reduced drilling days, or the total number of stages pumped per day, or the number of wells per quarter turned in line. Rather, true cycle time is about how quickly an operator generates a dollar of revenue after the well has been spud.

E&Ps understate the true amount of time it takes to convert an invested dollar into revenue.

A Guggenheim Partners review of 15 E&Ps found true cycle time ranged from 160 days to 450 days per well, with more than half exceeding 300 days. True cycle times varied by basin from 11 to 14 months, with the Anadarko and Permian basins at five to seven months and the large pad and extended lateral dry gas plays in Appalachia at the long end.

Furthermore, true cycle time varied by E&P class. The integrated companies take longer, while basin-specific independents turn wells to sales the fastest.

With E&Ps bumping into technical limitations on drill days or completion times, efforts to eliminate the empty space in scheduling all field operations become a key to reducing true cycle time and thus revenue acceleration.

The takeaway is significant opportunity exists for further capital efficiency improvements. At sub-$60 oil, capturing those gains is essential.

EASTERN U.S.

1 In White County, Ill., ***Campbell Energy*** completed a Phillipstown Consolidated Field well in Section 1-4s-10e. The #5 Willard was drilled to 4,130 ft and tested flowing 20 bbl of oil and 150 bbl of water per day. Production is from commingled perforations in Salem Limestone at 3,842-3,987 ft and Warsaw at 4,004-4,128 ft. It was drilled to 4,220 ft and was tested after acidizing. Campbell's headquarters are in Carmi, Ill.

2 IHS Markit reported that ***Ventex Operating Corp.*** has staked a Smackover test along the southeastern edge of Alabama's Brooklyn Field. The #1 Pate 13-15 is permitted to 12,500 ft and will be directionally drilled from a Conecuh County surface location in Section 13-3n-13e. Nearby production is within 1 mile to the northwest at Ventex's #1 Cedar Creek Land & Timber 13-5, a Brooklyn Field producer completed in mid-2019. The 12,214-ft well was tested flowing 743 bbl of crude from Smackover perforations at 11,915-11,920 ft. The Dallas-based company's completion has not yet been brought online.

3 ***Ascent Resources*** announced results from a Utica Shale completion in Guernsey County, Ohio. The #3H Black Racer is in Section 16, Londonderry Township. It was drilled to 21,193 ft, 7,528 ft true vertical, in Canton Consolidated Field. The well was tested flowing 770 bbl of oil, 7.391 MMcf of gas and 95 bbl of water per day. Production is from perforations at 8,252-21,053 ft. Additional information is not available. Ascent Resources is based in Oklahoma City.

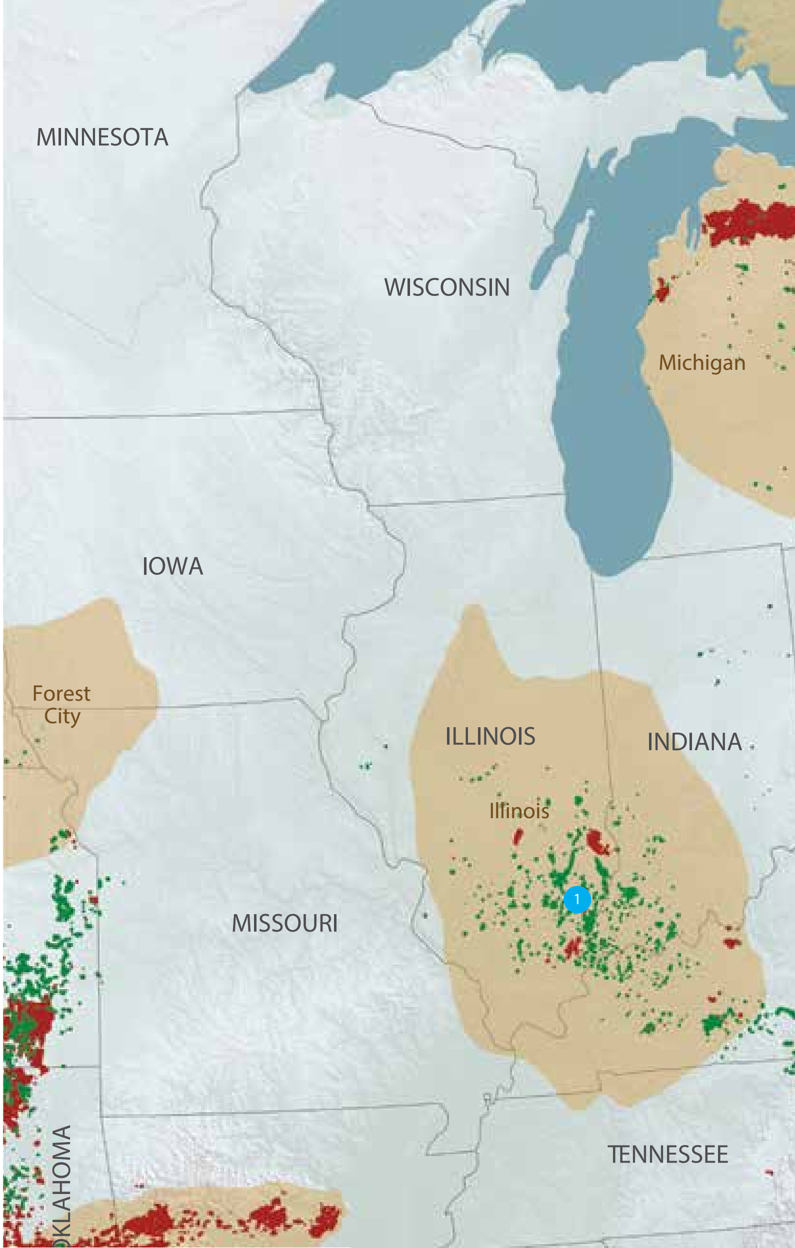
4 ***Gulfport Energy Corp***. completed two Utica Shale discoveries from a pad in Section 30-5n-4w in Belmont County, Ohio. The #1D Watkins 210085 was tested flowing 13.714 MMcf of gas and 310 bbl of water per day after fracturing. The Anderson Run venture was drilled to 17,391 ft, 9,773 ft true vertical, and production is from perforations at 10,526-17,199 ft. The #2C Watkins 210085 produced 13.688 MMcf of gas and 192 bbl of water per day. It was drilled to 16,955 ft with a true vertical depth of 9,780 ft. Production is from fractured perforations at 10,165-16,869 ft.

5 A Belmont County, Ohio, Utica Shale well was tested flowing 19.539 MMcf of gas and 465 bbl of water per day. ***Ascent Resources***' #4H Seabright CLR BL is in irregular Section 12-6n-3w. The Pultney Field well was drilled to 19,112 ft, 10,138 ft true vertical, and bottomed in Section 5. Production is from fractured perforations at 10,204-18,933 ft.

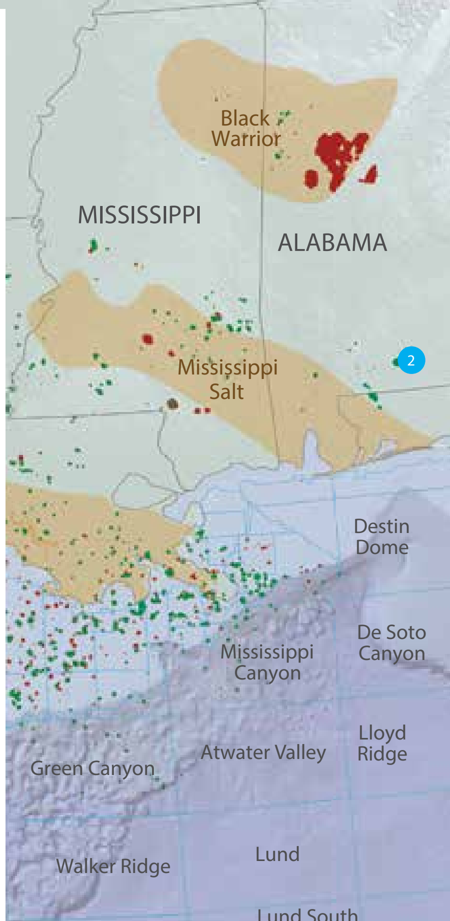
6 Houston-based ***EAP Ohio LLC*** announced results from two Utica Shale completions in Jefferson County, Ohio. The discoveries were drilled from a pad in Section 12-10n-3w. The #1H Williamson 12-10-3 produced 31.78 MMcf of gas and 1.049 Mbbl of water per day from fractured perforations at 9,170-21,285 ft. It was drilled to 21,579 ft, 8,773 ft true vertical. The #5H Williamson 12-10-3 flowed 30.182 MMcf of gas and 1.023 Mbbl of water per day. It was drilled to 21,435 ft with a true vertical depth of 8,772 ft. Production is from perforations at 9,170-21,285 ft.

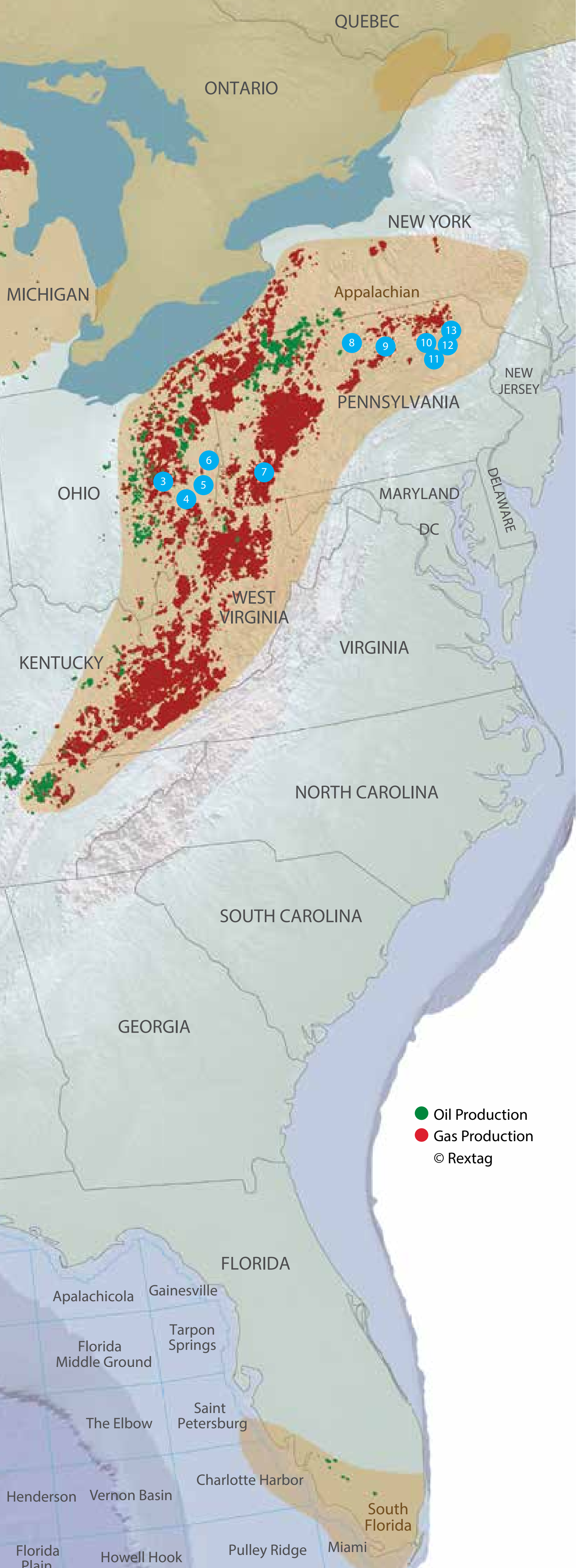
7 In Pennsylvania's Washington County, ***Range Resources Corp.*** completed a Marcellus Shale well in Linden Field. The #3H Mizia James 11676 Unit is in Section 2, Hackett 7.5 Quad, Nottingham Township, and was drilled to 23,340 ft, 7,162 ft true vertical. It initially flowed 19.01 MMcf of gas per day with a shut-in casing pressure of 1,050 psi. Production is from perforations at 7,607-23,267 ft. Range Resources is based in Fort Worth, Texas.

8 In Tioga County, Pa., ***Southwestern Energy Co.*** reported results from two Marcellus Shale-Wellsboto Field completions that were drilled from a single pad in Section 3, Tiadaghton 7.5 Quad, Shippen Township. The #433-3H Houck was tested flowing 10.357 MMcf of gas per day from perforations at 6,242-18,355 ft. It was drilled to the southeast to 18,513 ft, 5,617 ft true vertical. The #433-7H Houck produced 10.735 MMcf of gas per day at 6,478-18,649 ft. It was drilled to the southwest to 18,752 ft with a true vertical depth of 5,588 ft. Southwestern's headquarters are in Spring, Texas.



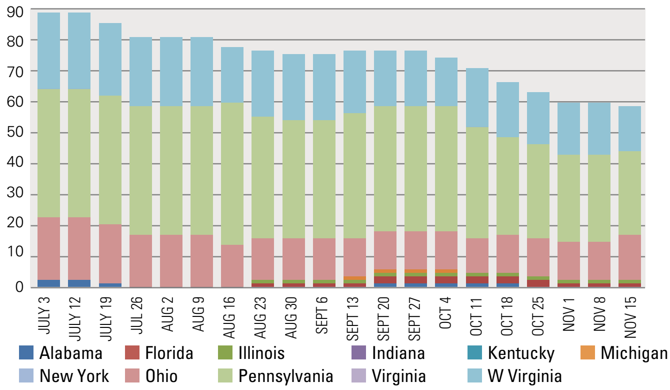
9 Two Marcellus Shale ventures were completed at a drillpad by Dallas-based ***Chief Oil & Gas*** in Bradford County, Pa. The Bailey Corners Field wells are in Section 7, Leroy 7.5 Quad, Leroy Township. The #3H SGL-12 J South Unit was drilled to 17,140 ft, 8,561 ft true vertical, and flowed 10.736 MMcf of gas per day from perforations at 8,933-16,894 ft. It was tested on an unreported choke size with a shut-in casing pressure of 2,771 psi. The #4H SGL-12 North Unit was drilled to 13,903 ft, 9,070 ft true vertical. It initially flowed 13.118 MMcf of gas per day. The 13,903-ft well has a true vertical depth of 9,070 ft, and it was tested on an unreported choke size with a shut-in casing pressure of 3,216 psi. Production is from perforations at 9,019-13,853 ft.





Eastern U.S. Rig Count

July 3, 2019-Nov. 15, 2019



Data compiled from Baker Hughes

10 In Pennsylvania's Bradford County, ***Chesapeake Operating Inc.*** announced results from three Herrick Field-Marcellus Shale completions. The discoveries were drilled from a pad in Section 8, Laceyville 7.5 Quad, Tuscarora Township. The #2HC Deremer flowed 81.773 MMcf of gas per day. It was drilled to 20,870 ft, 20,692 ft true vertical. Production is from perforations at 8,524-20,692 ft, and it was tested after 62-stage fracturing. The #4HC Deremer produced 32.716 MMcf of gas per day from perforations at 7,332-17,131 ft. It was tested following 39-stage fracturing and was drilled to 17,267 ft with a true vertical depth of 7,293 ft. The #5HC Deremer produced 25.996 MMcf of gas per day. It was drilled to 17,239 ft, 7,238 ft true vertical, and was fractured in 39 stages. Production is from perforations at 7,495-17,099 ft. Chesapeake's headquarters are in Oklahoma City.

11 ***Chesapeake Operating Inc.*** completed two Marcellus Shale wells from a Dimock Field pad in Section 4, Meshoppen 7.5 Quad, Mehoopany Township, in Wyoming County, Pa. The #2H Cappucci flowed 31.083 MMcf of gas per day from perforations at 8,606-14,950 ft. It was drilled to 14,998 ft with a true vertical depth of 7,962 ft and was fractured in 26 stages. The #1H Cappucci N flowed 16.42 MMcf of gas per day from perforations at 8,321-14,368 ft. It was drilled to a true vertical depth of 7,926 ft and was fractured in 25 stages between 8,321 and 14,368 ft.

12 ***Chesapeake Operating Inc.*** completed two wildcat Marcellus Shale wells at a pad in Section 8 Auburn Center 7.5 Quad, Meshoppen Township, in Wyoming County, Pa. The #2HC AMCOR was drilled to 1,097 ft, 7,333 ft true vertical. It was tested flowing 84.269 MMcf of gas per day, with no reported water, after 90-stage fracturing between 7,587 and 20,957 ft. About 50 ft to the west, #3HC AMCOR was drilled to 20,553 ft, 7,286 ft true vertical. It was tested flowing 64.305 MMcf of gas per day after 53-stage fracturing from perforations at 7,442-20,415 ft.

13 In the Mehoopany Field portion of Wyoming County, Pa., ***Chesapeake Operating Inc***. completed two Marcellus Shale wells drilled from a drill pad in Section 9, Auburn Centre 7.5 Quad, Meshoppen Township. The #1HC Ruth was drilled to 19,873 ft with a true vertical depth of 7,408 ft. According to IHS Markit, it was tested initially flowing 63.271 MMcf of gas per day from perforations at 7,932-19,691 ft after 48-stage fracturing. The #2HC Ruth flowed 71.717 MMcf of gas per day. Production is from perforations at 7,743-19,774 ft after 80-stage fracturing.

GULF COAST

1 In Karnes County (RRC Dist. 2), Texas, ***Marathon Oil Corp.*** announced results from an Eagleville Field-Eagle Ford Shale discovery. The Houston-based company's #3H Spahn-Mikkelson Unit was tested flowing 2.574 Mbbl of oil, 2.196 MMcf of gas and 859 bbl of water per day. The well is in Francisco Ruiz Survey, A-9, and was drilled to 17,866 ft, 12,131 ft true vertical. Gauged on a 24/64-in. choke, the flowing casing pressure was 3,882 psi. Production is from perforations at 11,885-17,737 ft.

2 A Gonzales County (RRC Dist.1), Texas, Eagle Ford discovery by ***EOG Resources Inc.*** was tested flowing 3.319 Mbbl of 43-degree-gravity oil, 4.408 MMcf of gas and 2.049 Mbbl of water per day. The #1H Vespucci A is in James Jones Survey, A-301, and is in Eagleville Field. It was drilled to 22,201 ft, 11,941 ft true vertical, and bottomed in Francisco Gonzales Survey, A-233. It was tested on a 64/64-in. choke, and the flowing tubing pressure was 1,309 psi. The flowing casing pressure was 864 psi. Production is from fractured perforations at 11,970-22,201 ft. EOG is based in Houston.

3 Two DeWitt County (RRC Dist. 2), Texas, Eagle Ford discoveries in Eagleville Field were reported by IHS Markit. The ***EOG Resources Inc.*** wells were drilled from a pad in Isaac Baker Survey, A-89. The #20H McCollum A Unit was drilled to 15,800 ft, 11,885 ft true vertical, and produced 3.728 Mbbl of oil, 3.56 MMcf of gas and 1.482 Mbbl of water per day. Production is from perforations at 12,382-15,661 ft. The #21H McCollum A Unit was drilled to the south to 15,720 ft, 11,853 ft true vertical, and initially flowed 2.635 Mbbl of oil, 2.751 MMcf of gas and 1.419 Mbbl of water per day. Production is from perforations at 12,339-15,567 ft.

4 ***Shell Oil Co.*** has added a new Lower Tertiary development test to the company's program at the Perdido spar facility on Block 857. The #7GB OCS G17571 will be drilled in the southwestern corner of Alaminos Canyon Block 857 and will bottom to the south in Block 901. Water depth in the area is 8,100 ft. The Perdido area is made up of numerous Lower Tertiary wells in Great White (Block 857), Tobago (Block 859) and Silvertip (Block 815) fields. Shell's wells produce through perforations at 14,000-18,900 ft, and first production from the floating facility was reported in 2010.

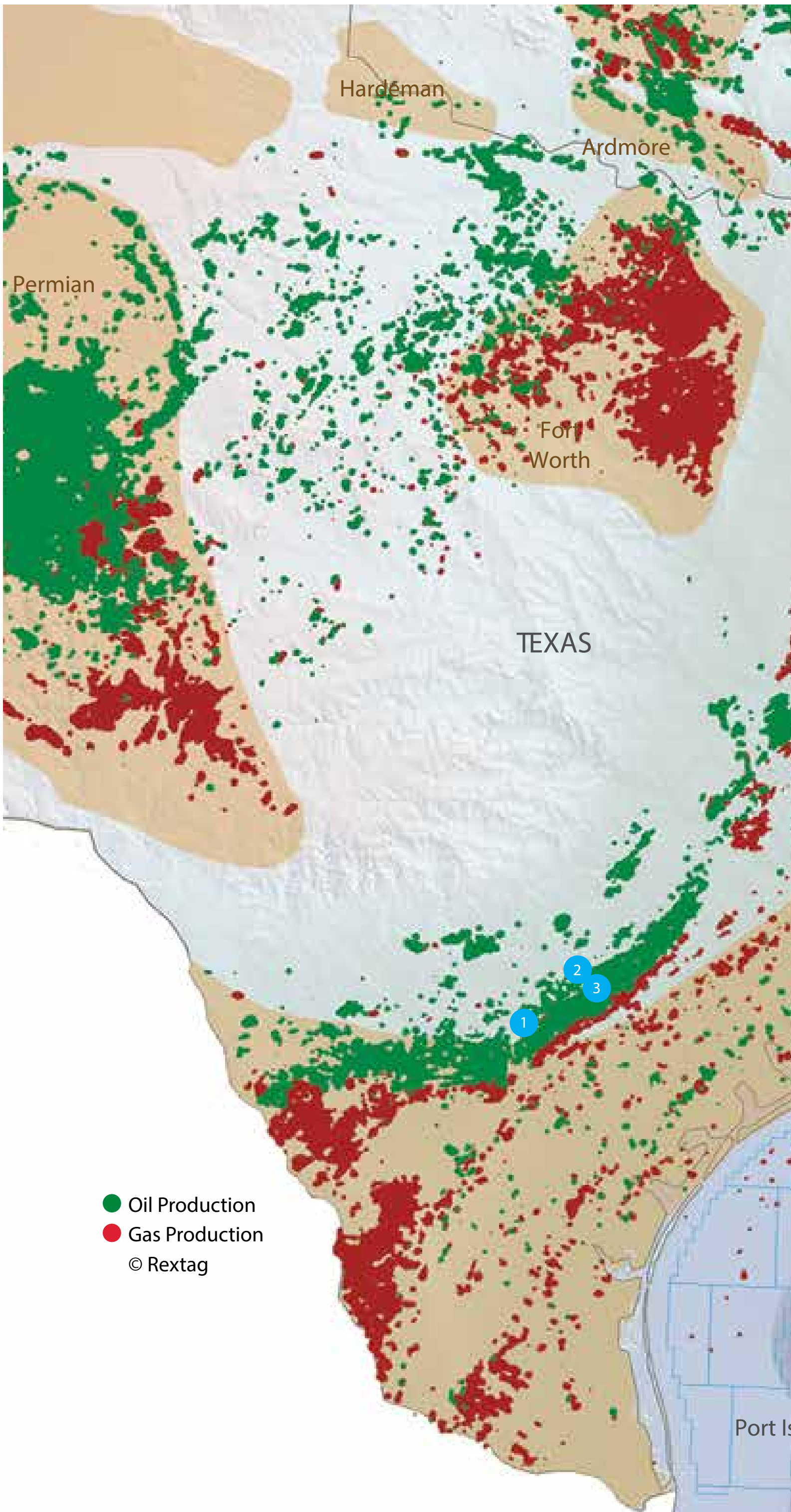
5 ***Sabine Oil & Gas*** announced results from a Carthage Field-Haynesville Shale completion in Panola County (RRC Dist. 6), Texas. The #2H Hudson GO is in John Beck Survey, A-51, and it was drilled to 20,862 ft, 11,161 ft true vertical. The venture flowed 21.632 MMcf of gas and 11,822 bbl of water per day from perforations at 11,526-20,576 ft. It was tested on a 29/64-in. choke with a flowing casing pressure of 6,202 psi and a shut-in casing pressure of 6,758 psi.

6 ***Covey Park Gas*** completed a Hayneville Shale well in the Bethany Longstreet Field portion of DeSoto Parish, La. The #4-Alt Miller Land Company 10-3 HC was tested flowing 30.662 MMcf of gas and 1.133 Mbbl of water per day. It was drilled to 21,588 ft, 11,676 ft true vertical, in Section 10-13n-16w and bottomed in Section 3. Tested on a 36/64-in. choke, the flowing casing pressure was 6,083 psi, and production is from perforations at 11,953-21,473 ft. Covey Park is based in Dallas.

7 In Bossier Parish, La., ***Covey Park Gas*** completed two Haynesville Shale wells in Swan Lake Field. The wells were drilled from a drillpad in Section 23-15n-11w. The #1-Alt Martin 23-14 HC was tested flowing 25.765 MMcf of gas and 229 bbl of water per day. Tested on a 26/64-in. choke, the flowing casing pressure was 7,544 psi, and it was drilled to 22,800 ft, 12,220 ft true vertical. Production is from perforations at 12,165-20,083 ft. The #2-Alt Martin 23-14 HC was drilled to 21,884 ft, 11,607 ft true vertical, and produced 30.94 MMcf of gas and 271 bbl of water per day. It bottomed in Section 14. Gauged on a 28/64-in. choke, the flowing casing pressure was 7,898 psi, and production is from perforations at 12,118-21,733 ft.

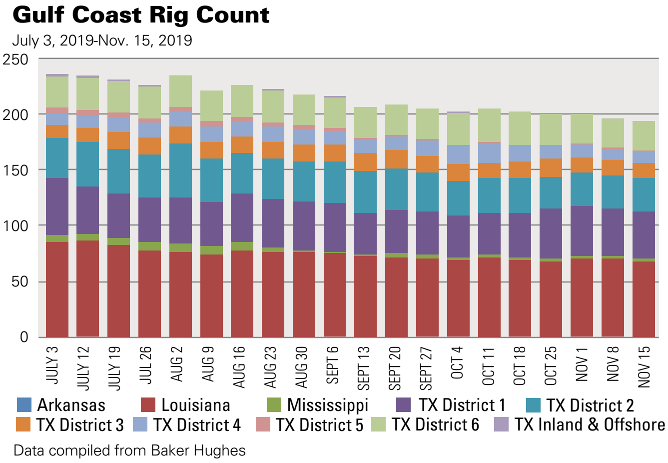
8 IHS Markit announced that Houston-based ***Rockcliff Operating LA LLC*** has completed the first horizontal well in North Louisiana's Lucky Field. The Bienville Parish completion, #1 Petro-Hunt 35H, flowed 432 Mcf of gas through acidized and fracture-stimulated perforations in Hosston at 11,348-14,668 ft. It was tested on a 24/64-in. choke, and the flowing tubing pressure was 846 psi. The new producer was drilled about 1 mile to the north to 14,791 ft (11,160 ft true vertical) and is in Section 35-16n-7w. Lucky Field was opened in 1957.

9 In Garden Banks Block 426, ***Shell Oil Co.*** reported a discovery at #01A8S4B2 OCS G08241 ST04BP02. The well was drilled to 21,614 ft, and the true vertical depth is 19,765 ft. It is producing 4.564 Mbbl of condensate and 19.45 MMcf of gas per day. Gauged on a 48/64-in. choke, the flowing tubing pressure was 6,992 psi, and the shut-in tubing pressure was 7,800 psi. Production is from an unreported formation at 21,027-21,226 ft.



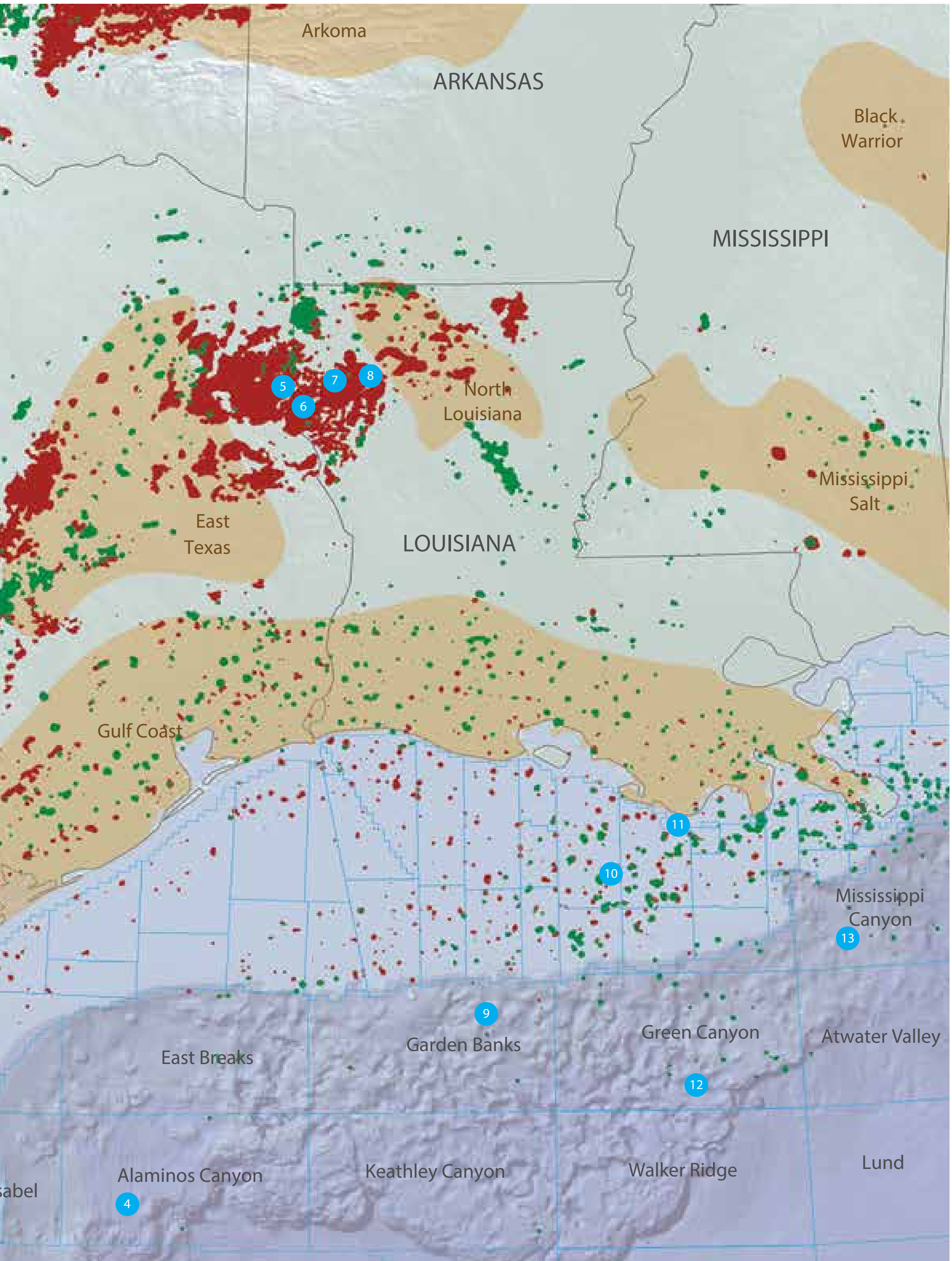
10 ***Arena Offshore***, based in The Woodlands, Texas, has filed a plan to drill up to 13 development tests in offshore Louisiana's Eugene Island Block 238 Field. According to development plan submitted to the Bureau of Ocean Energy Management, the tests will be drilled from the existing K platform in the southern portion of Eugene Island Block 237. Eight tests are expected to bottom beneath Block 237 (OCS G00981), and another three tests will bottom beneath Block 253 (OCS G10741). Both of the tracts have been producing oil and gas since 1964 as part of Block 238 field. Two of the company's new tests have a planned bottomhole location in Block 254 (OCS G36207) to the southeast. Last production under a previous Block 254 lease was reported in May 2015.

11 In Ship Shoal Block 34-21S-13E, ***Castex Energy Inc.*** completed #1 SL 21615 DISC 12 RA SUA in Bayou Goreau Field. The Louisiana state waters well was tested flowing 1.030 Mbbl of oil, 12.044 MMcf of gas and 16 bbl of water per day. Production is from Discorbis perforations at 16,474-16,534 ft. It was tested on an 11/64-in. choke with a flowing tubing pressure of 4,688 psi and a shut-in tubing pressure of 4,980 psi. Castex is based in Houston.



12 ***BP Plc*** has spud the first test on its Puma West prospect in Green Canyon Block 821, 12 miles west of the company's Mad Dog development. The #2 OCS G3456 is in the northeastern portion of the block, and area water depth is 4,000 ft. According to the London-based company's exploration plan, as many as four tests could be drilled on Block 821. The Puma West prospect is owned by BP (75%) and ***Talos Energy Inc.*** (25%).

13 ***Hess Corp.***, according to IHS Markit, announced a deepwater Gulf of Mexico discovery that will be tied back to its Tubular Bells facilities. The #1-Esox, apparently a re-entry of #3 OCS G24101, is in 4,600 ft of water in Mississippi Canyon Block 726. According to the company, the discovery encountered approximately 191 net ft of high-quality, oil-bearing Miocene reservoirs. The well was originally drilled to 8,369 ft in 2012 before being temporarily abandoned by the New York City-based operator. True vertical depth was 8,358 ft. Hess operates the discovery with a 57.14% interest. Project partner ***Chevron Corp.*** owns the remaining 42.86% interest.



MIDCONTINENT & PERMIAN BASIN

1 IHS Markit reported that Golden, Colo.-based ***Tap Rock Operating LLC*** has completed a horizontal Delaware Basin producer in Eddy County, N.M. The #168H Miso State was tested flowing 1.079 Mbbl of crude, 1.994 MMcf of gas and 2.38 Mbbl of water per day from fracture-treated Wolfcamp perforations at 8,412-12,976 ft. The Purple Sage Field well was tested on a 42/64-in. choke, and the flowing casing pressure was 948 psi. It was drilled to 13,245 ft (8,849 ft true vertical) and is in Section 2-26s-25e. The horizontal lateral bottomed within 1 mile to the north.

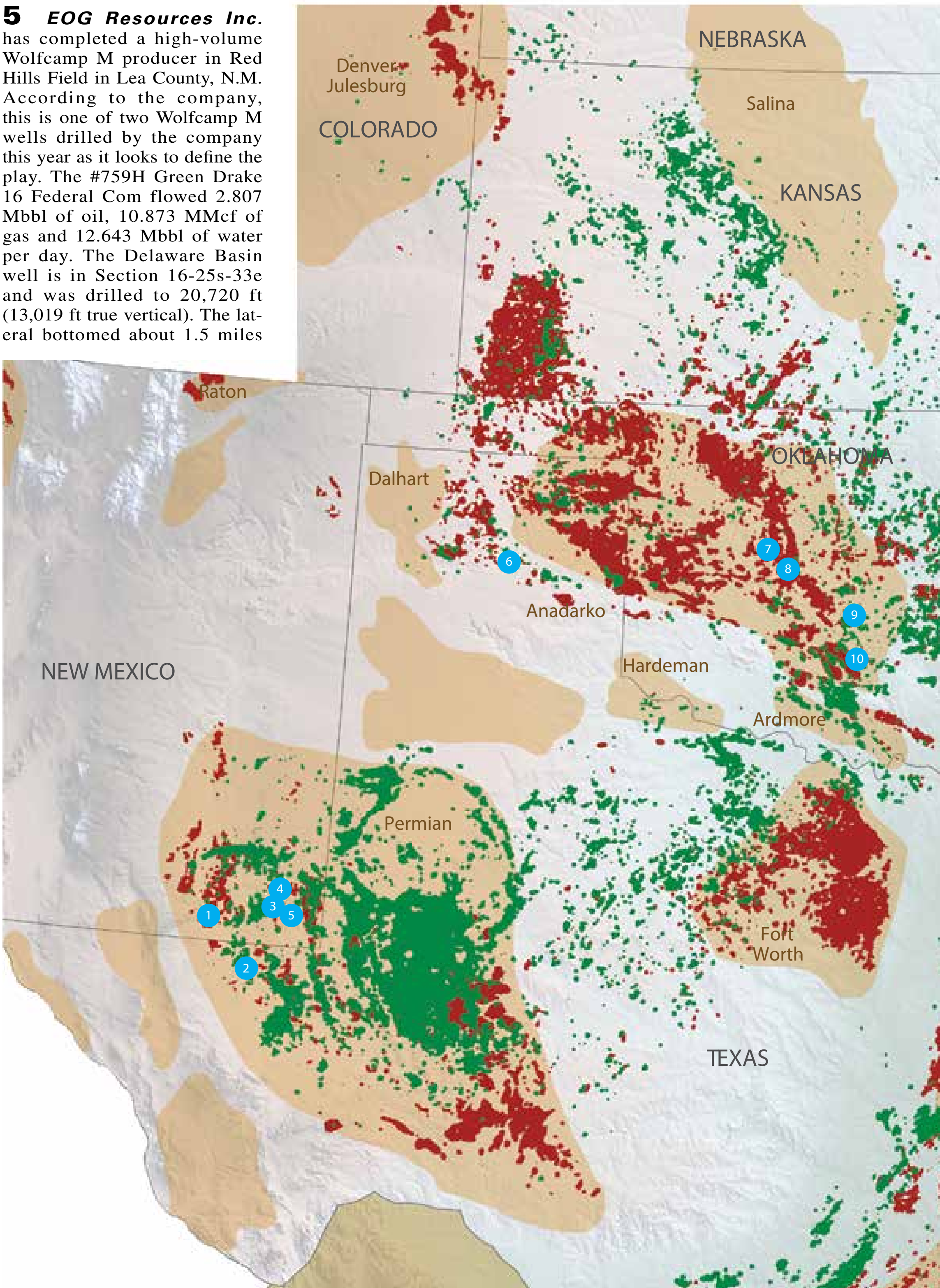
2 In the Phantom Field portion of Reeves County (RRC Dist. 8), Texas, ***PDC Energy Co.'s*** #4H C Liam State 53-12 was tested flowing 220 bbl of condensate, 10.687 MMcf of gas and 4.737 Mbbl of water per day from Wolfcamp. The discovery is in Section 12, Block 53, PSL Survey, A-3237. It was drilled to 20,468 ft, and the true vertical depth is 10,204 ft. Production is from perforations at 10,374-20,381 ft and was tested on a 64/64-in. choke after fracturing. PDC's is based in Denver.

3 In Section 2-25s-32e in Lea County, N.M., Houston-based ***EOG Resources Inc.*** completed a Lower Bone Spring well that initially flowed 4.84 Mbbl of oil, 6.959 MMcf of gas and 6.292 Mbbl of water per day. The #505Y Savage 2 State Com is in an unnamed field and was drilled to 15,506 ft with a true vertical depth of 10,595 ft. It was tested on a 98/64-in. choke with a flowing casing pressure of 621 psi. Production is from perforations at 10,835-15,462 ft.

4 Three Wolfcamp discoveries were announced by ***EOG Resources Inc.*** According to IHS Markit, the wells were drilled from a pad in Section 36-24s-32e Lea County, N.M. The #703H Python 36 State Com was drilled to 17,373 ft, 12,412 ft true vertical, and produced 2.82 Mbbl of oil, 8.373 MMcf of gas and 6.024 Mbbl of water per day. It was tested on a 64/64-in. choke, and the flowing casing pressure was 1.857 psi. Production is from perforations at 12,600-17,331 ft. The #705H Python 36 State was drilled to 17,345 ft, 12,420 ft true vertical, and flowed 4.199 Mbbl of oil, 11.822 MMcf of gas and 4.885 Mbbl of water per day. It was drilled to 17,345 ft, 12,420 ft true vertical, and production is from perforations at 12,600-17,288 ft. Gauged on a 64/64-in. choke, the flowing casing pressure was 2,307 psi. The #706H Python 36 State flowed 3.084 Mbbl of oil, 7.999 MMcf of gas and 4.906 Mbbl of water per day. It was drilled to 17,344 ft, 12,420 ft true vertical, and production is from perforations at 12,600-17,256 ft. Tested on a 64/64-in. choke the flowing casing pressure was 1,831 psi.

5 ***EOG Resources Inc.*** has completed a high-volume Wolfcamp M producer in Red Hills Field in Lea County, N.M. According to the company, this is one of two Wolfcamp M wells drilled by the company this year as it looks to define the play. The #759H Green Drake 16 Federal Com flowed 2.807 Mbbl of oil, 10.873 MMcf of gas and 12.643 Mbbl of water per day. The Delaware Basin well is in Section 16-25s-33e and was drilled to 20,720 ft (13,019 ft true vertical). The lateral bottomed about 1.5 miles to the southwest in Section 16-25s-33e and was fractured in 32 stages. Perforations are at 13,477-20,686 ft. Tested on a 1-in. choke, the shut-in casing pressure was 3,139 psi. EOG recently completed a Wolfcamp M well in Reeves County (RRC Dist. 8), Texas, #3H State Correa Unit, that produced oil, gas and condensate. EOG has identified 855 net premium drilling locations in the Wolfcamp M, with estimated net resource potential of 1 Bboe across a 193,000-net-acre position. The company reported that these wells produce roughly equal amounts of oil, NGL and gas.

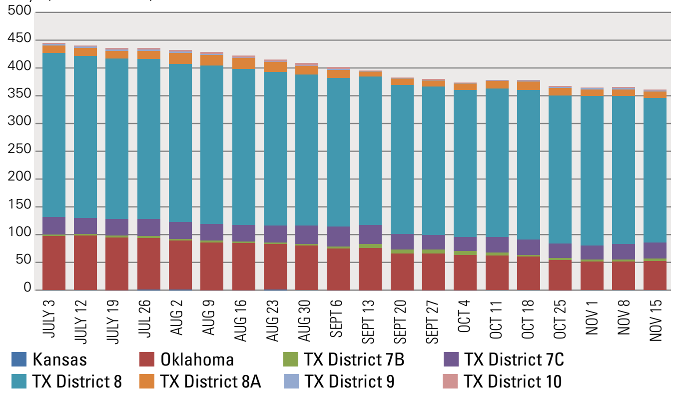
6 ***Le Norman Operating LLC*** announced results from a Canyon Lime completion in Section 52, Block 1, BS&F Survey, A-1123, in Potter County (RRC Dist. 10), Texas. The #1H Bivins 52-17 East was tested producing 391 bbl of 42-degree-gravity oil, 151 Mcf of gas and 158 bbl of water per day. The discovery was tested on a 64/64-in. choke with a flowing tubing pressure of 3,800 psi. The Amarillo North Field prospect was drilled northward to 15,309 ft, 7,194 ft true vertical, and bottomed in Section 17, Block M-3, G&M Survey, A-454. Le Norman's headquarters are in Oklahoma City.



7 According to IHS Markit, Oklahoma City-based ***Continental Resources Inc.*** completed the two highest producing Meramec wells reported to date in the Stack play in Blaine County, Okla. The wells were drilled from a pad in Section 13-15n-11w. The #7-13-24XHM Reba Jo flowed 4.168 Mbbl of oil, 11.9 MMcf of gas and 2.638 Mbbl of water per day. It was acidized and fractured at 11,026-21,174 ft and was tested on a 46/64-in. choke with flowing tubing pressure of 3,005 psi. Drilled to 21,347 ft, 11,221 ft true vertical, it bottomed in Section 24-15n-11w. About one-third of a mile to the west, #5-13-24XHM Reba Jo produced 3.615 Mbbl of oil, 10.4 MMcf of gas and 2.579 Mbbl of water per day. Production is from acidized and fractured perforations in a parallel lateral between 10,998 and 21,050 ft. The 21,223-ft Watonga-Chickasha Trend well has a true vertical depth of 11,113 ft, and it bottomed in Section 24-15n-11w. The completion was tested on a 46/64-in. choke, and the flowing tubing pressure was 2,611 psi.

Midcontinent & Permian Basin Rig Count

July 3, 2019-Nov. 15, 2019

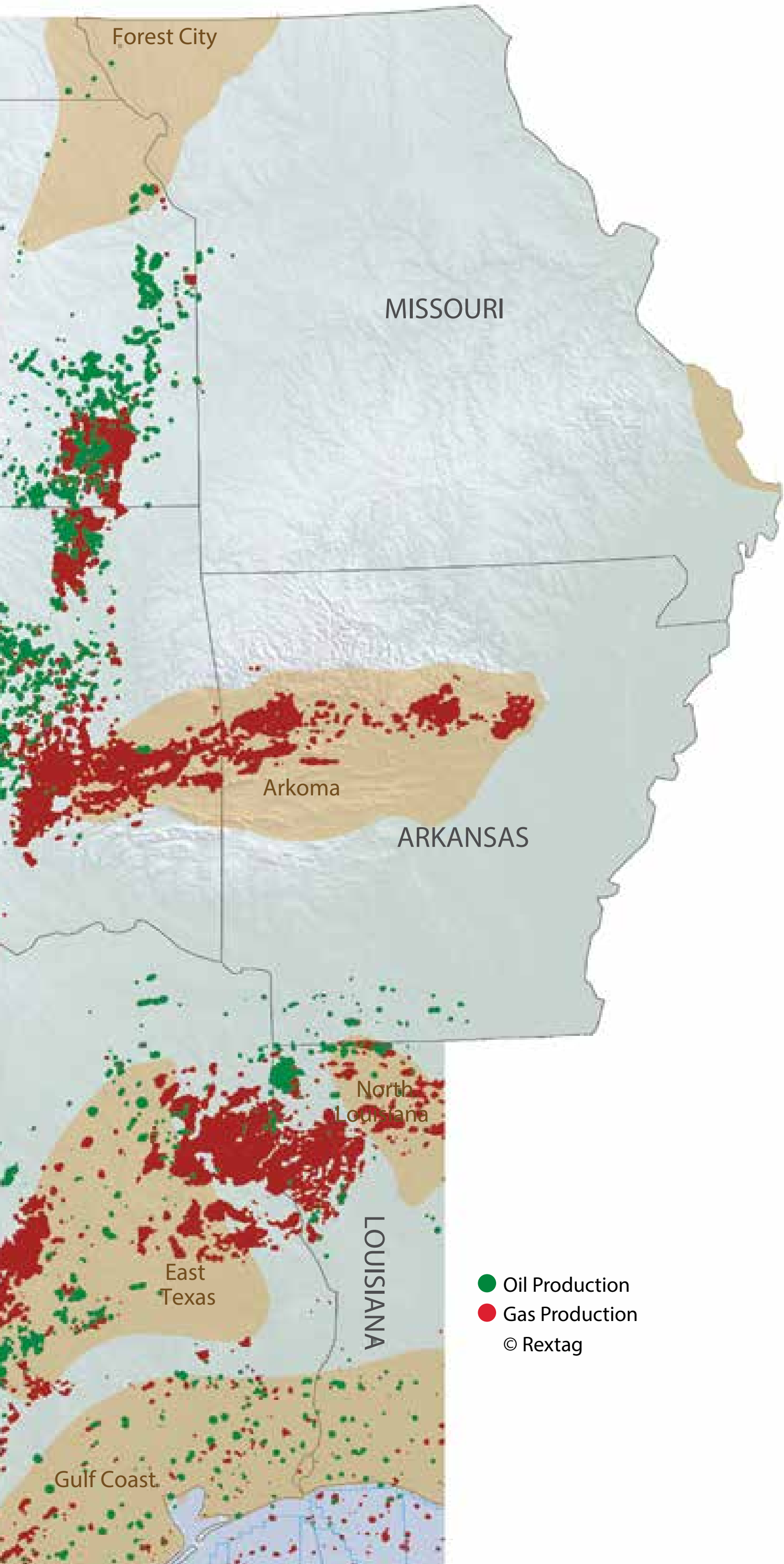


Data compiled from Baker Hughes

8 In Kingfisher County, Okla., Houston-based ***Marathon Oil Corp.*** completed three Altona Field-Mississippi Solid ventures. The wells were drilled from a pad in Section 33-15n-9w. The #1-28-33MXH Mike Stroud BIA 1509 was drilled to 20,269 ft, 9,857 ft true vertical, and flowed 1.086 Mbbl of oil, 7.311 MMcf of gas and 1.708 Mbbl of water per day. It was tested on a 20/64-in. choke, and production is from perforations at 10,291-20,110 ft. It bottomed in Section 28. The #2-28-33MXH Mike Stroud BIA 1509 was drilled to 20,720 ft, 10,171 ft true vertical, and was tested flowing 1.797 Mbbl of condensate, 9.211 MMcf of gas and 1.285 Mbbl of water per day. It was tested on a 20/64-in. choke, and production is from an unreported interval. The #3-28-33MXH Mike Stroud BIA 1509 was drilled to 20,720 ft, 10,171 ft true vertical, and was tested flowing 908 bbl of oil, 7.094 MMcf of gas and 857 bbl of water per day. It was tested on a 20/64-in. choke, and production is from perforations at 10,714-20,567 ft.

9 Two horizontal Woodford producers were completed at a drillpad in Section 7-9n-4w in McClain County, Okla., by ***EOG Resources Inc.*** The #4H Nighthawk 0718 flowed 1.001 Mbbl of 40-degree-gravity oil, 1.1 MMcf of gas and 6.625 Mbbl of water per day. It was tested on a 128/64-in. choke following acidizing and fracturing at 9,600-19,714 ft. The well was drilled to the south to 19,812 ft, 9,386 ft true vertical, and the respective shut-in and flowing tubing pressures were 1,200 psi and 490 psi. About 20 ft south, #3H Nighthawk 0718 produced 863 bbl of oil, 960 Mcf of gas and 6.533 Mbbl of water daily. Production is from treated perforations between 9,515 and 19,676 ft. Gauged on a 128/64-in. choke, the flowing tubing pressure was 424 psi, and the shut-in tubing pressure was 1,300 psi.

10 A Springer Shale well by ***Marathon Oil Corp.***, from a multiwell pad flowed 1.288 Mbbl of oil, 1.73 MMcf of gas and 1.194 Mbbl of water per day. The #3-18SH Newby 0304 is in Section 18-3n-4w of Garvin County, Okla. It was tested on a 22/64-in. choke, and production is from acidized and fracture-stimulated perforations between 13,523 and 18,452 ft. It was drilled northward to 18,560 ft, 13,059 ft true vertical, and additional details are not yet available.



WESTERN U.S.

1 A horizontal Pinedale Anticline discovery was tested flowing 25.863 MMcf of gas, with 441 bbl of oil/condensate and 4.241 Mbbl of water per day. The extended-reach well, #8-25-A-1H Warbonnet, was drilled by ***Ultra Petroleum Corp.*** and is in Section 25-30n-108w, Sublette County, Wyo. Production is from a horizontal lateral in Lower Lance extending from 11,803 ft eastward to 21,615 ft, 11,325 ft true vertical. The discovery bottomed in Section 29-30n-107w. It was tested on an open choke after 35-stage fracturing between 11,200 and 20,354 ft. Ultra's headquarters are in Denver.

2 IHS Markit reported that ***Southland Royalty*** completed a Lewis Sand well that initially flowed 3.722 MMcf of gas and 373 bbl of oil/condensate per day in Sweetwater County, Wyo. The #5H-15-4H Monument Lake is in Section 15-22n-93w, and production is from a lateral extending from 11,565 ft northward to 16,456 ft. The true vertical depth is 11,578 ft. It was tested on a 26/64-in. choke after 18-stage fracturing between 11,565 and 16,456 ft. Southland Royalty's headquarters are in Dallas.

3 ***DJR Operating LLC*** announced results from a horizontal Gallup producer on the North Alamito Unit in the San Juan Basin. The #232H North Alamito Unit is in Section 28-23n-7w of Sandoval County, N.M. It initially flowed 745 bbl of oil, 1.296 MMcf of gas and 528 bbl of water per day. Production is from a northwest lateral extending from 5,485 ft to a total depth of 11,350 ft. It bottomed in Section 21-23n-7w, and the true vertical depth is 5,272 ft. It was tested on a 28/64-in. choke after 28-stage fracturing between 5,704 and 11,276 ft. DJR is based in Denver.

4 A Campbell County, Wyo., completion was announced by ***Peak Powder River Resources LLC.*** The Night Creek Field-Turner Sand well is in Section 23-43n-74w. The #1-23TH Roush Federal was drilled to 15,776 ft, 11,083 ft true vertical. It was tested flowing 1.358 Mbbl of oil, 816 Mcf of gas and 3.05 Mbbl of water per day. Production is from acidized and fractured perforations at 11,572-15,592 ft. Peak Powder River is based in Englewood, Colo.

5 ***Peak Powder River Resources*** completed a Converse County, Wyo., Turner Sand well in Section 28-42n-72. The #1-28TH Stoddard Fed produced 1.4 Mbbl of oil, 6.517 MMcf of gas and 1.583 Mbbl of water per day. The discovery was drilled to 14,860 ft with a true vertical depth of 10,399 ft. Tested on an unreported choke size, the flowing tubing pressure was 2,125 psi. Production is from acidized and fractured perforations at 10,642-14,688 ft.

6 In Converse County, Wyo., Oklahoma City-based ***Devon Energy Corp.*** completed a Powder River Basin-Niobrara well producing 2.353 Mbbl of oil, 1.854 MMcf of gas and 1.493 Mbbl of water per day. According to IHS Markit, #18-193771-1XNH SDU Tillard-Federal is in Scott Field and was drilled to the south in Section 7-37n-71w to 21,596 ft, 11,243 ft true vertical, and bottomed in Section 19. It was tested on a 30/64-in. choke following 32-stage fracturing between 11,600 and 21,281 ft, and the flowing tubing pressure was 1,850 psi.

7 A Niobrara producer and a Turner Sand producer were completed from a drillpad by ***Devon Energy Corp.*** in Section 25-37n-71w in Converse County, Wyo. The #25-363771-1XNH South Tillard flowed 1.956 Mbbl of oil, 1.389 MMcf of gas and 1.56 Mbbl of water per day from Niobrara. It was tested on a 20/64-in. choke, and the flowing tubing pressure was 1,032 psi. Drilled to 20,520 ft, 10,868 ft true vertical, production is from perforations at 11,145-20,364 ft and bottomed in Section 36. About 30 ft to the south, #4XTH SDU Tillard Fed 25-363771 produced 1.669 Mbbl of oil, 1.292 Mcf of gas and 1.839 Mbbl of water per day from Turner Sand. It was drilled to 20,520 ft, 10,868 ft true vertical, and bottomed in Section 36. Gauged on an 18/64-in. choke, the flowing tubing pressure was 977 psi, and production is from perforations at 11,706-21,086 ft.

8 In Converse County, Wyo., ***Anadarko Petroleum Corp.*** announced results from a Turner Sand venture that produced 1.616 Mbbl of 43-degree-gravity oil, 5.369 Mcf of gas and 337 bbl of water per day. The #3469-12-T4XH EH Fed Radler is in Section 36-35n-59w in Well Draw Field. Gauged on a 26/64-in. choke, the shut-in tubing pressure was 2,937 psi, and the shut-in casing pressure was 3,135 psi. It was drilled to 18,079 ft with a true vertical depth of 10,239 ft, and it is producing from perforations at 10,738-17,973 ft. Anadarko is based in The Woodlands, Texas.

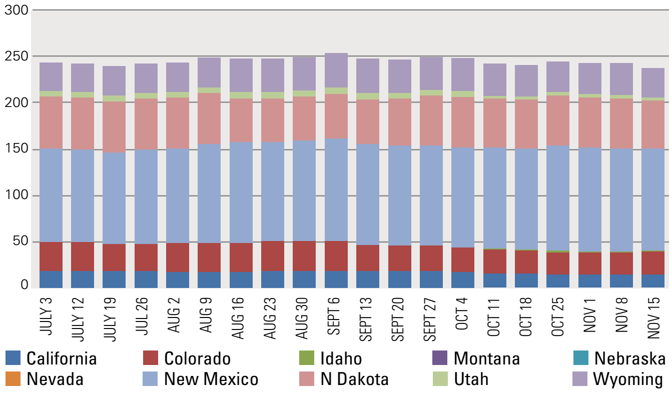
9 ***Great Western Oil & Gas Co.,*** based in Denver, announced results from a Wattenberg Field well in Weld County, Colo. The #18-3-11HC Anderson is in Section 18-1S-66W and was drilled to 12,101 ft with a true vertical depth of 7,700 ft. It initially flowed 582 bbl of oil, 627 Mcf of gas and 321 bbl of water per day from comingled zones in Codell (8,140-12,455 ft), Fort Hays (8,627-12,461 ft), Carlile (10,416-10,820 ft) and Niobrara (11,748-11,891). The completion was tested on a 16/64-in. choke, and the flowing tubing pressure was 1,590 psi. The flowing casing pressure was 1,960 psi.

10 Oklahoma City-based ***Continental Resources Inc.*** reported a Williams County, N.D., Middle Bakken discovery that was tested flowing 2.077 Mbbl of oil, 1.319 MMcf of gas and 2.218 Mbbl of water per day. The #11-25HSL Putnam is in Section 25-156n-100w in East Fork Field, and it bottomed in Section 16. The well was drilled to 21,361 ft, 10,814 ft true vertical, and was tested on a 38/64-in. choke with a flowing tubing pressure of 831 psi and a flowing casing pressure of 346 psi. Production is from perforations at 11,129-21,362 ft.

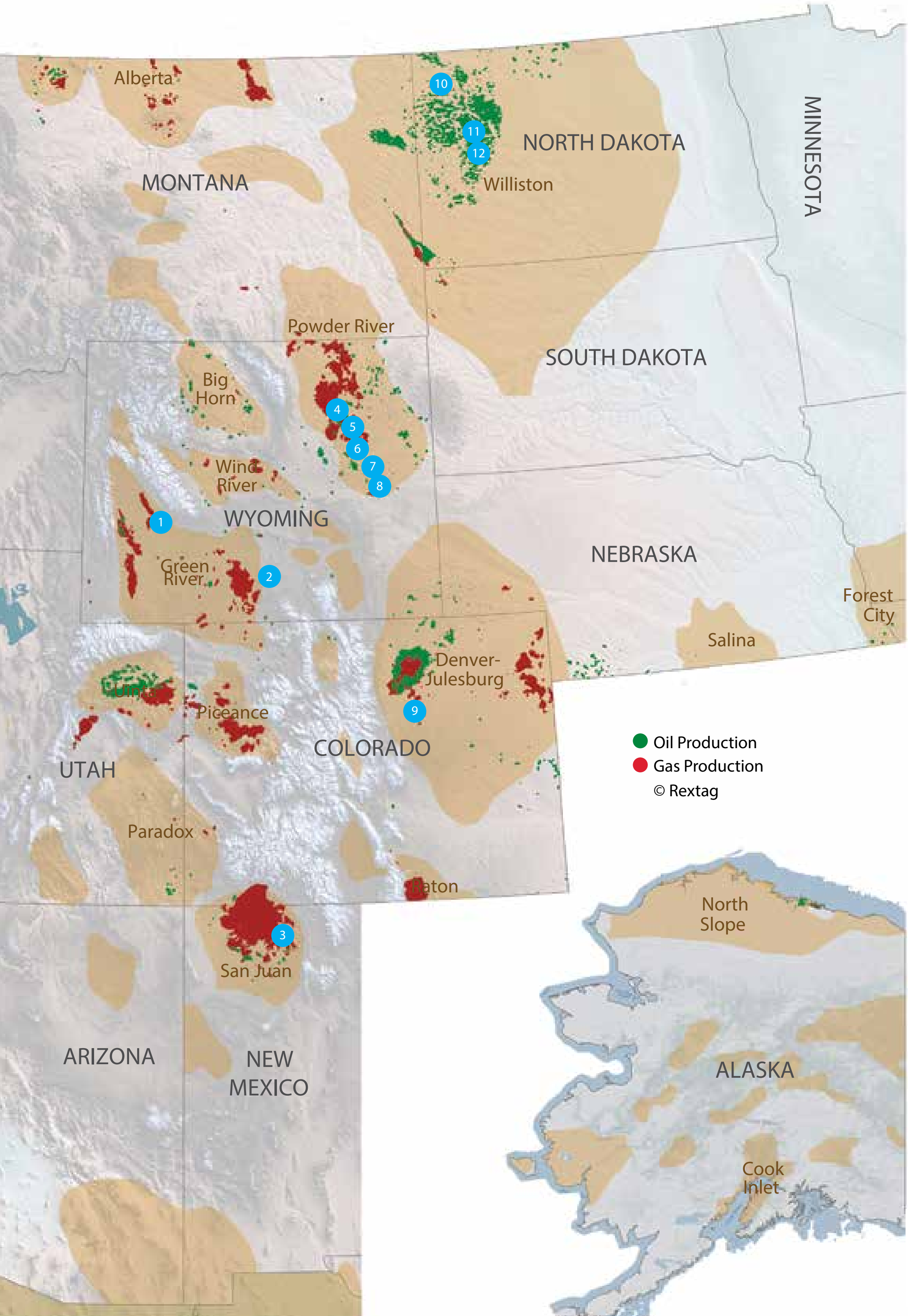
11 A Middle Bakken completion in Dunn County, N.D., was tested flowing 4.318 Mbbl of oil, 4.519 MMcf of gas and 4.976 Mbbl of water per day. ***Marathon Oil Corp.***'s #44-11H Dasha USA is in Section 13-146n-95w and is in Chimney Butte Field. It was tested on an open choke, and the flowing casing pressure was 1,025 psi. Drilled to 21,548 ft, 10,831 ft true vertical, production is from perforations at 11,405-21,088 ft.

Western U.S. Rig Count

JuLY 3, 2019-Nov. 15, 2019



Data compiled from Baker Hughes



12 Four Dunn County, N.D., completions were announced by ***Marathon Oil Corp.*** The Killdeer Field discoveries were drilled from a pad in Section 36-146n-95w. According to IHS Markit, #24-36H Eggert-State produced 5.02 Mbbl of oil, 3.57 MMcf of gas and 6.838 Mbbl of water daily from Middle Bakken. It was drilled to the north to 21,423 ft, 10,864 ft true vertical, and bottomed in Section 25. It was tested on a 1-in. choke following 45-stage fracturing between 11,342 and 21,287 ft with a flowing casing pressure of 1,290 psi. The #34-36TFH Elias-State produced 3.848 Mbbl of oil, 3.17 MMcf of gas and 5.727 Mbbl of water per day. Production is from a lateral in Upper Three Forks. It was drilled to the north to 21,378 ft, 10,952 ft true vertical, and also bottomed in Section 25. It was tested on a 52/64-in. choke after 45-stage fracturing between 11,258 and 21,243 ft, and the flowing casing pressure was 1,325 psi. The #34-36TFH Eileen-State flowed 3.452 Mbbl of oil, 2.445 MMcf of gas and 9.996 Mbbl of water per day from Middle Bakken. It was drilled to 21,323 ft, 10,967 ft true vertical, and bottomed in Section 25. It was tested on a 64/64-in. choke, and the flowing casing pressure was 900 psi with production from Upper Three Forks at 11,247-21,190 ft. The #44-36H Etta-State was tested flowing 5.429 Mbbl of oil, 4.457 MMcf of gas and 7.899 Mbbl of water per day from Middle Bakken perforations at 11,234-21,178 ft. It was drilled to 21,313 ft, 10,875 ft true vertical, and bottomed in Section 25. Gauged on a 56/54-in. choke, the flowing casing pressure was 1,300 psi.

INTERNATIONAL HIGHLIGHTS

According to the International Energy Agency's (IEA) annual World Energy Outlook (WEO) 2019, there are deep disparities that define the energy world, including the clash between well-supplied oil markets, growing geopolitical tensions and uncertainties, insufficient policies to curb greenhouse gas emissions to reach safe climate targets and a gap in electricity access for 850 million people around the world.

The WEO describes a pathway that enables the world to meet those needs while maintaining a strong focus on the reliability and affordability of energy for a growing global population.

Governmental decisions on climate and energy access are critical for the future of the energy system. The WEO scenarios map out different routes the world could follow over the coming decades, depending on the policies, investments, technologies and other choices that decision-makers pursue today.

The Stated Policies Scenario incorporates today's policy intentions and targets in addition to existing measures to show how today's plans and their consequences are off track for a safe, sustainable and secure energy future. The Sustainable Development Scenario indicates what needs to be done differently to fully achieve climate and other energy access goals aligned with the Paris Agreement.

Alongside emissions management and energy access, energy security remains paramount for governments and must address new hazards such as cybersecurity and extreme weather.

—Larry Prado

1 *Argentina*

Echo Energy is planning to drill the first well, #1-x CLM, in a four-well exploration program in Argentina's Tapi Aike Block in the Santa Cruz Austral Basin. The location is in Chiripia Oeste in the eastern part of the Tapi Aike 3-D survey area in which ***CGG*** recently surveyed. The well will be targeting a stratigraphic trap in Magallanes (Magallanes 20). A secondary horizon will be in Anita (D3). A shallower secondary interval (Magallanes 60) will also be tested. The well will be drilled in two vertical sections and has a planned depth of approximately 2,600 m. Cores will be cut and collected over the primary target, and well logs will be run over all intervals of interest. Echo Energy's headquarters are in London.

2 *Mauritania*

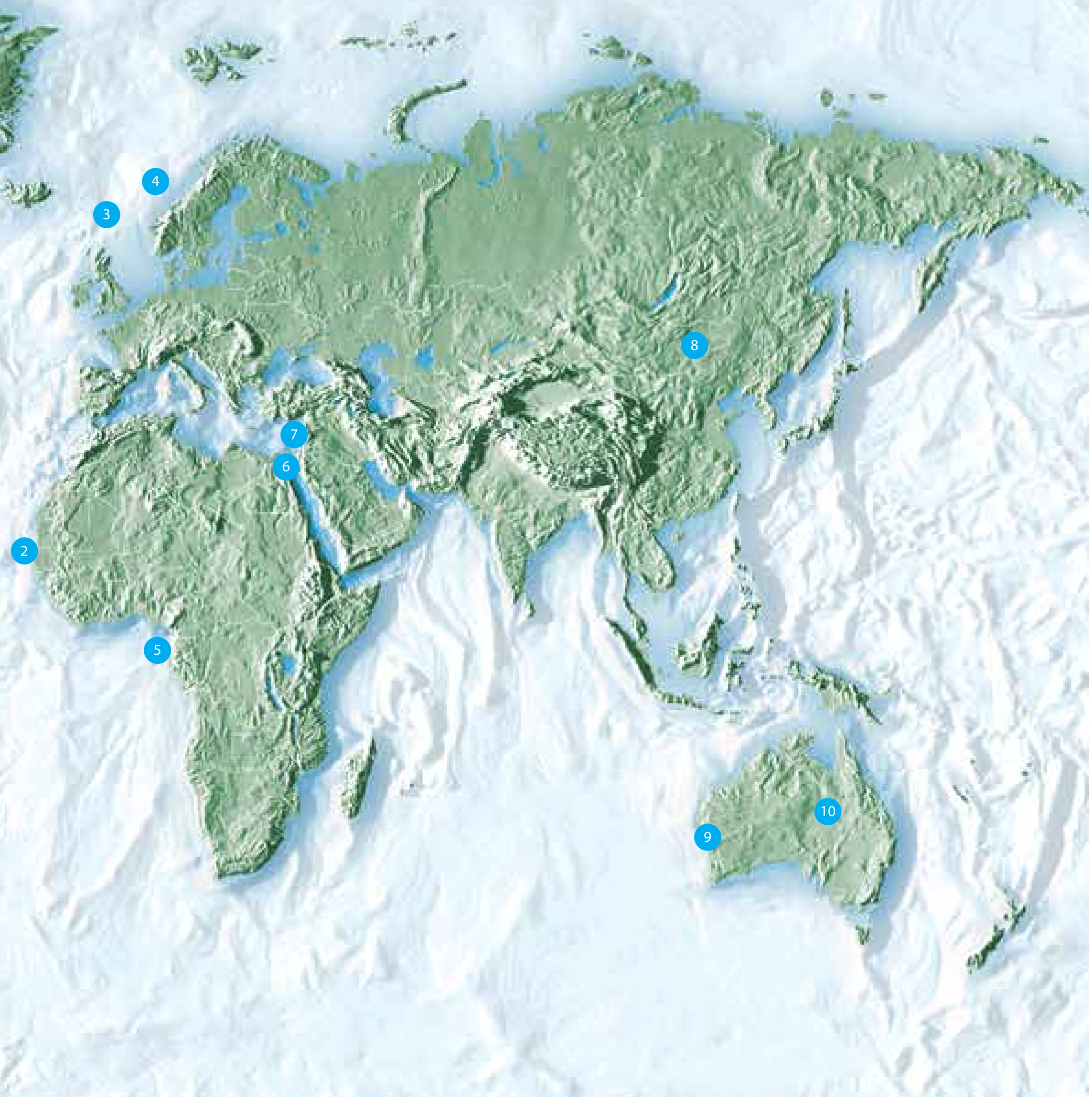
Kosmos Energy has announced a gas discovery in the offshore Mauritania-BirAllah area at exploration well #1-Orca. The 5,266-m exploratory well targeted a previously untested Albian play and encountered 36 m of net gas pay in excellent quality reservoirs. The well also extended the Cenomanian play fairway and confirmed 11 m of net gas pay in a down-structure position relative to the discovery well, #1-Marsouin, which was drilled on the crest of the anticline. According to the company, #1-Orca and #1-Marsouin have de-risked up to 50 Tcf of gas-in-place from the Cenomanian and Albian plays in the BirAllah area. In addition, a deeper but untested Aptian play has also been identified within the area and surrounding structures. Project partners include ***SMHPM*** and ***BP***.

3 *Norway*

Equinor, based in Stavanger, completed Fram Field exploration well #35/11-23 Echino South in the North Sea. Recoverable resources are estimated at 38-100 MMbbl of oil equivalent. It was drilled to 2.947 m, and area water depth is 350 m. The well is about 3 km southwest of the field, and the primary exploration target was to prove petroleum in the Upper Jurassic reservoir in Sognefjord. The secondary exploration target in the well was to prove petroleum rocks of the Middle Jurassic period (Brent group). Hydrocarbons were proven in both exploration targets. A sidetrack (#35/11-23 A) is being drilled to delineate the discovery in Sognefjord. The discovery will be tied back to existing infrastructure. Partners in the prospect are ***ExxonMobil Corp.*** and ***Neptune Energy***.

4 *Norway*

OMV Norge, operator of production license PL 644, has completed appraisal well #6506/11-11 S on the #6506/11-10 (Iris) gas/condensate discovery. The well encountered a 70-m gas column in Garn with about 50 m of sandstone with reservoir properties varying from poor-to-good with no gas/water contact. Multiple sandstone layers totaling about 55 m were encountered with moderate-to-good reservoir quality. The primary objective was to delineate the gas/condensate discovery in Garn toward the southwest and determine if there is petroleum in reservoir rocks in the underlying Middle Jurassic Ile. During the Garn test, the well had a maximum flow rate of 1.6 MMcm of gas and 883 cu m of condensate. Preliminary estimates indicate that Garn holds 4-12 MMcm of recoverable oil equivalents. The appraisal was drilled to 4,433 m and was terminated in Ror in the Lower-to-Middle Jurassic. Area water depth is 382 m. OMV is based in Vienna.



5 *Gabon*

Vaalco Energy announced results of an offshore oil discovery at appraisal well #9P-Etame in Gabon's Etame Field. The venture was targeting the subcropped Dentale reservoir. The well was drilled to 3,127 m and encountered both Gamba and Dentale oil sands. The shallower section will be plugged back to drill the #9H-Etame horizontal development well section in the Gamba reservoir. The completion verifies the presence of a Dentale oil column, and it hit approximately 35 ft of good quality Dentale oil sands with 27% porosity and 3,000 mD of permeability. The gross recoverable oil resources are now estimated at 2.5-10.5 MMbbl of oil. Houston-based Vaalco is the operator of Etame Marin Block and its fields.

6 *Egypt*

Rome-based ***Eni*** reported the discovery of new resources in the Abu Rudeis Sidri Concession in the Egyptian sector of the Gulf of Suez. The #36-Sidri appraisal well was drilled to assess the field continuity westward and encountered a 200-m hydrocarbon column in the clastic sequences of Nubia. It was tested flowing approximately 5 Mbbl of oil per day and will be completed and put into production. The Sidri South discovery is estimated to contain about 200 MMbbl of oil in place, and the field will be reassessed following these new results.

7 *Lebanon*

Total SA is scheduling oil and gas exploration in offshore Lebanon's territorial waters in Block 4. The Paris-based company plans to use exploration at Block 4 to test the northward extension of Oligocene and Miocene sandstones (Tamar Sands) found in offshore Israel's Leviathan and Tamar fields. Block 9 also has possible reserves in its carbonate limestone formations, similar in geology to offshore Egypt's Zohr Field and Cyprus's Calypso prospect. Total was awarded 40% interest and operatorship of Block 4 in 2018 in partnership with ***Eni***, with 40%, and ***Novatek,*** with the remaining 20%.

8 *Mongolia*

Petro Matad announced the results of well testing operations at #1-Heron oil discovery in the north of Block XX in the Tamsag Basin in Mongolia. During a drillstem test, the well initially flowed 821 bbl of 46-degree-gravity oil, an unreported amount of gas and no water per day from a 12-m interval at 2,834 m in the upper portion of Lower Tsagaantsav. It was tested on a 19/64-in. choke. The well has now been shut in. The pre-drill resource estimated for the Heron structure is 165 MMbbl of oil-in-place, with 25 MMbbl (P50) of recoverable resource. Petro Matad is based in Ulaanbaatar, Mongolia.

9 *Australia*

Operator ***Strike Energy*** reported results from a flow test at #2-West Erregulla in EP469 in Western Australia. The well flowed 69 MMcf of gas per day from Kingia Sandstone. The test program for the Perth Basin venture was to determine well deliverability from the reservoir in West Erregulla Field. Three 48-m intervals were tested between 4,799 m and 4,851 m. It was tested on a 2-in. choke, and the well head pressure was 700 psi. Data from the flow test will be analyzed and used to update models to determine the contingent resources. The joint venture partners in EP 469 are ***Warrego Energy,*** 50%, and Thebarton, South Australia-based Strike Energy, 50%.

10 *Australia*

Beach Energy has announced a 10-well appraisal program by the PEL 92 joint venture in the South Australia portion of the Cooper Basin. The first well in the program has been spud at #22-Callawonga, and it is the first of four appraisal wells to be drilled in the Callawonga oil field. The #22-Callawonga is about 500 m north of a previous discovery, #3-Callawonga, and it will test a possible field extension to the north. The planned depth is 1,497 m. The other wells in the program are #19-Callawonga (planned depth, 1,381 m), #20-Callawonga (no planned depth reported), #4-Callawonga (planned depth, 1,540 m) and #21-Callawonga (planned depth, 1,476 m). The Callawonga wells will be deviated from two surface locations and will be targeting Namur Sandstone. The overlying McKinlay Sands are a secondary objective. Four additional wells are planned in Butlers oil field and two are planned in the Rincon oil field. Adelaide, South Australia-based operator Beach Energy holds a 75% interest with partner ***Cooper Energy***, which holds a 25% interest in the joint venture.


THE SITUATION WAS TOUGH.
BUT OUR REPUTATION WAS STRONGER.
Only the Strong Survive.
Setting industry standards for delivering superior accuracy in the most professional and reliable way earned us a reputation in land services that kept us going when others simply couldn't. We continue to put experienced, professional crews on the ground within days. We work at top speed to negotiate fair and reasonable terms that let you move just as quickly. We search out and solve snags before they become problems, with an obsession for accuracy that's second to none. No wonder oil and gas companies continue to turn to us. After all, in uncertain times, it's nice to know what to expect.
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ANOTHER ASSET-BACKED FINANCING ANNOUNCED

A further instance of asset-based securitization has arisen, with Diversified Gas & Oil Plc announcing the securitization of operated upstream assets. Both Fitch and Morningstar gave the $200 million securitized financing by Diversified an investment grade rating of BBB-. The 10-year amortizing notes, with a 17-year final maturity, carry a 5% coupon.

Diversified Gas & Oil, whose stock trades on the London Stock Exchange's AIM market, operates wells and midstream assets in the Appalachian Basin. To facilitate the financing, it created a special purpose vehicle to issue the notes, which were collateralized by a 21.6% working interest in the existing upstream proved developed producing assets of Diversified.

"The BBB- investment grade notes provide a superior PV10 advance rate (present value at 10% discount factor) compared to Diversified's existing revolving credit facility and create $60 million of additional liquidity," the company said. "The structure also protects the company's liquidity with no semi-annual borrowing base redeterminations."

To provide stable cash flows, 10-year hedging has been put in place on 85% of the production volumes of the collateralized assets, according to the company. Munich Re Reserve Risk Financing Inc. said it facilitated funding of the entire transaction, including the commodity price hedges.

"As an acquisitive growth company, the ability to fix attractive rates for a 10-plus year period on a portion of our debt—while freeing capacity on our revolving credit facility—is paramount to our continued success and demonstrates to sellers of assets our ability to transact," commented Diversified CEO Rusty Hutson Jr.

—Chris Sheehan, CFA

DEBT

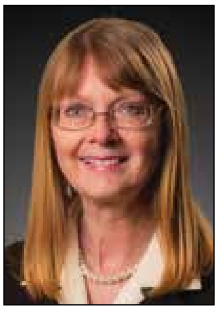
Company	Exchange/ Symbol	Headquarters	Amount	Comments
Diamondback Energy Inc.	NYSE: FANG	Midland, Texas	$3 billion	Priced an offering of $1 billion of 2.875% senior notes that will mature on Dec. 1, 2024, $800 million of 3.25% senior notes that will mature on Dec. 1, 2026, and $1.2 billion of 3.5% senior notes that will mature on Dec. 1, 2029. The prices to the public for the 2024 notes, the 2026 notes and the 2029 notes are 99.959%, 99.858% and 99.741% of the principal amounts, respectively. Diamondback intends to use the net proceeds from the offering (i) to repay a portion of the outstanding borrowings under its revolving credit facility, (ii) to redeem all of the outstanding $1.25 billion aggregate principal amount of its 4.75% senior notes at an aggregate purchase price of approximately $1.3 billion, including the redemption premium and accrued and unpaid interest to the date of the redemption and (iii) for general corporate purposes. **BofA Securities, Inc.**, **J.P. Morgan Securities LLC**, **Wells Fargo Securities LLC**, **Citigroup Global Markets Inc.**, **Credit Suisse Securities (USA) LLC** and **Goldman Sachs & Co. LLC** served as joint book-running managers for the offering.
Targa Resources Corp.	NYSE: TGRP	Houston	$1 billion	**Targa Resources Partners LP**, a subsidiary of **Targa Resources Corp.**, and the partnership's subsidiary, **Targa Resources Partners Finance Corp.**, announced the pricing of an upsized offering of $1 billion aggregate principal amount of senior unsecured notes due 2030. The notes will accrue interest at a rate of 5.5% per annum, will mature on March 1, 2030, and were priced at par.
Hess Midstream Partners LP	NYSE: HESM	Houston	$550 million	Announced that it has upsized and priced $550 million in aggregate principal amount of 5.125% senior notes due 2028 at par in a private offering. **Hess Midstream** intends to use the net proceeds from the offering to finance the acquisition of **Hess Infrastructure Partners LP** (HIP), including to repay borrowings under HIP's credit facilities, partially fund the distribution to HIP's sponsors and pay related fees and expenses.
Murphy Oil Corp.	NYSE: MUR	El Dorado, Ark.	$550 million	Priced an offering of $550 million of 5.875% senior notes due 2027. The company expects to use the net proceeds from the offering, plus cash on hand, to (i) fund the previously announced cash tender offers to purchase up to $550 million aggregate principal amount of its outstanding 4% senior notes due 2022 and 3.7% senior notes due 2022 pursuant to terms and conditions set forth in the offer to purchase for the tender offers; and (ii) pay any related premiums, penalties, fees and expenses in connection with the foregoing. **J.P. Morgan**, **BofA Securities** and **MUFG** are acting as physical joint book-running managers for the offering.

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Endeavor Energy Resources LP	N/A	Midland, Texas	$500 million	Its wholly owned subsidiary, EER Finance Inc., priced a private placement of $500 million in aggregate principal amount of 5.75% senior unsecured notes due 2028. The 2028 notes mature on Jan. 30, 2028, pay interest at the rate of 5.75% per year and were priced at 104% of par, resulting in a yield to worst of 4.991%. The issuers previously issued $500 million in aggregate principal amount of 2028 notes on Dec. 7, 2017. The notes being offered will have identical terms, other than the issue price and the issue date, as the existing 2028 notes, and the notes being offered and the existing 2028 notes will be treated as a single class of securities under the indenture governing the 2028 notes. Endeavor intends to use the net proceeds from this offering to repay amounts outstanding under its revolving credit facility and any remaining net proceeds for general partnership purposes.
Diversified Gas & Oil PLC	London AIM: DGOC	Birmingham, Ala.	$200 million	Announced it closed its inaugural BBB- investment grade-rated securitized financing arrangement with a coupon of 5%. The notes have a 10-year scheduled maturity, though provide for a longer 17-year final legal maturity. To facilitate the arrangement DGO created a wholly owned and fully consolidated (for accounting purposes) special purpose vehicle, Diversified ABS LLC, to issue $200 million (approximately $190 million net) of nonrecourse asset-backed securities, collateralized by a ~21.6% working interest in the company's existing upstream proved developed producing asset portfolio (collateral). Importantly, the notes allow DGO to retain 100% ownership and operational control of the collateral, and the collateral excludes the company's midstream assets and its recently acquired upstream EdgeMarc assets due to timing of the EdgeMarc acquisition close. The BBB- investment grade notes provide a superior PV10 advance rate compared to DGO's existing revolving credit facility and create approximately $60 million of additional liquidity. The structure also protects the company's liquidity with no semiannual borrowing base redeterminations and provides for flexible and limited financial covenants tied only to the performance of the securitized assets. DGO used the net proceeds after establishing a required ~$7 million reserve account from the notes to reduce its borrowings on its RBL by approximately $183 million. Going forward, DGO will use the hedge-protected cash flows generated by the LLC's working interests to satisfy the payment of principal and interest on the notes, with any excess cash flows distributed upstream to the parent on a monthly basis and available to further pay down the RBL.

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.

SO WHAT IS NEW?



LESLIE HAINES,
EXECUTIVE EDITOR-AT-LARGE

In preparing the special report that comes with this issue, "The Permian at 100: The Play That's Changing Everything," I had occasion to search through some back issues of *Oil and Gas Investor*. Sometimes it seemed they were written yesterday.

"Given the oil and gas industry's history of returns vs. other industries, and the fact that many investors may now see more downside than upside in commodity prices, the appetite of investors for holding E&P equities isn't all that strong now, nor is the high-yield market for smaller operators."

No doubt you've assumed this is a typical and familiar comment ripped from the pages of analyst reports seen in the past few weeks and months? No. This observation was made 20 years ago, in the April 2000 issue! It came from energy banker James Mercurio of Bank of America (before the merger with Merrill Lynch), who spoke to *Investor* for a cover story on capital trends. The more things change, the more they remain the same.

At the time, bankers were anticipating that oil prices would average in the mid-$20s per barrel (bbl) through the year 2000, with natural gas trading around $2.50 per thousand cubic feet.

Today, WTI is trading around $59/bbl, three times more than in 2000, but natural gas prices are no better. Sadly, investor sentiment has not improved either—not after two decades of progress in the form of enhanced well completions, the shale revolution, artificial intelligence, data analytics, a focus on returns as much as growth, and on and on. It appears that oilfield history is repeating itself, and each new generation of E&P managers and investors has to relearn the old lessons.

The whole industry certainly enjoyed a great run in the middle of those 20 years though. Optimism surged, peak oil was forgotten, money poured in and each new shale play was greeted with exuberant press releases. These were followed by more drilling rigs going to work, which in turn led to astonishing results as costs fell and EURs rose.

But back in that April 2000 issue of *Investor*, two analysts from Petrie Parkman & Co. wrote an article for us in which they argued that "amid profound investor disenchantment, time was running out for independents to get back to basics, that is, to generate a return on capital rather than a return of capital." They focused on free cash flow as a key metric, saying if E&Ps can deliver free cash flow, they will differentiate themselves from their peers.

So, here we are again, at the start of another year and a new decade, still searching for cash-flow-positive companies.

But some things have changed. U.S. oil production is forecast to rise by as much as 930,000 bbl/d to an all-time high of 13.18 MMbbl/d this year, although that number gets revised every month by the Energy Information Administration.

Another big change from 20 years ago is that the industry is not just saying it will move into manufacturing mode, it's doing it. At the same time, more companies have managed to reduce greenhouse gas emissions to their lowest level in a generation.

Now, companies are tasked with slowing down the completions pace in order to deliver a higher return and at the same time, improve safer operations to ensure fewer methane leaks and less natural gas flaring.

Maybe slowing down is good for the goose, but not for the gander. Permian Basin production started 2019 at 3.8 MMbbl/d, according to IHS Markit, and ended above 4.4 MMbbl/d. But the base production decline rate is getting faster, and was expected to be approximately 1.5 MMbbl/d by the end of 2019—a staggering 40% base decline rate in one year, the firm said, adding that E&Ps should now consider what they must spend to keep production flat.

Most of the key themes companies have set forth for 2020 are the same ones that were being touted five years ago. After attending the Howard Weil energy investor conference in 2014, our colleague, Richard Mason, reported that the themes then, for 150 presenting companies, were these: efficiency, execution (doin' it factory-style), optionality for gassy assets as gas prices neared $4.50, weather, and most telling: "turning the corner from putting money into the ground to getting money out of the ground."

What did we just say about change? The biggest difference now is that the whole U.S. gas picture has been upended, what with the surge in the Marcellus, Utica and Permian plays. Last year TC Energy (TransCanada) completed the Mountaineer Xpress and Gulf Xpress pipeline expansions, hiking takeaway capacity from the Northeast to the Gulf Coast by nearly 900 MMcf/d. At press time, the new LNG export plant near Savannah, Ga., was about to ship off its first cargo. And further, the Grey Oak line was about to start up.

So, the race is on now for 2020—production surplus is dueling with the drilling pace and making money.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