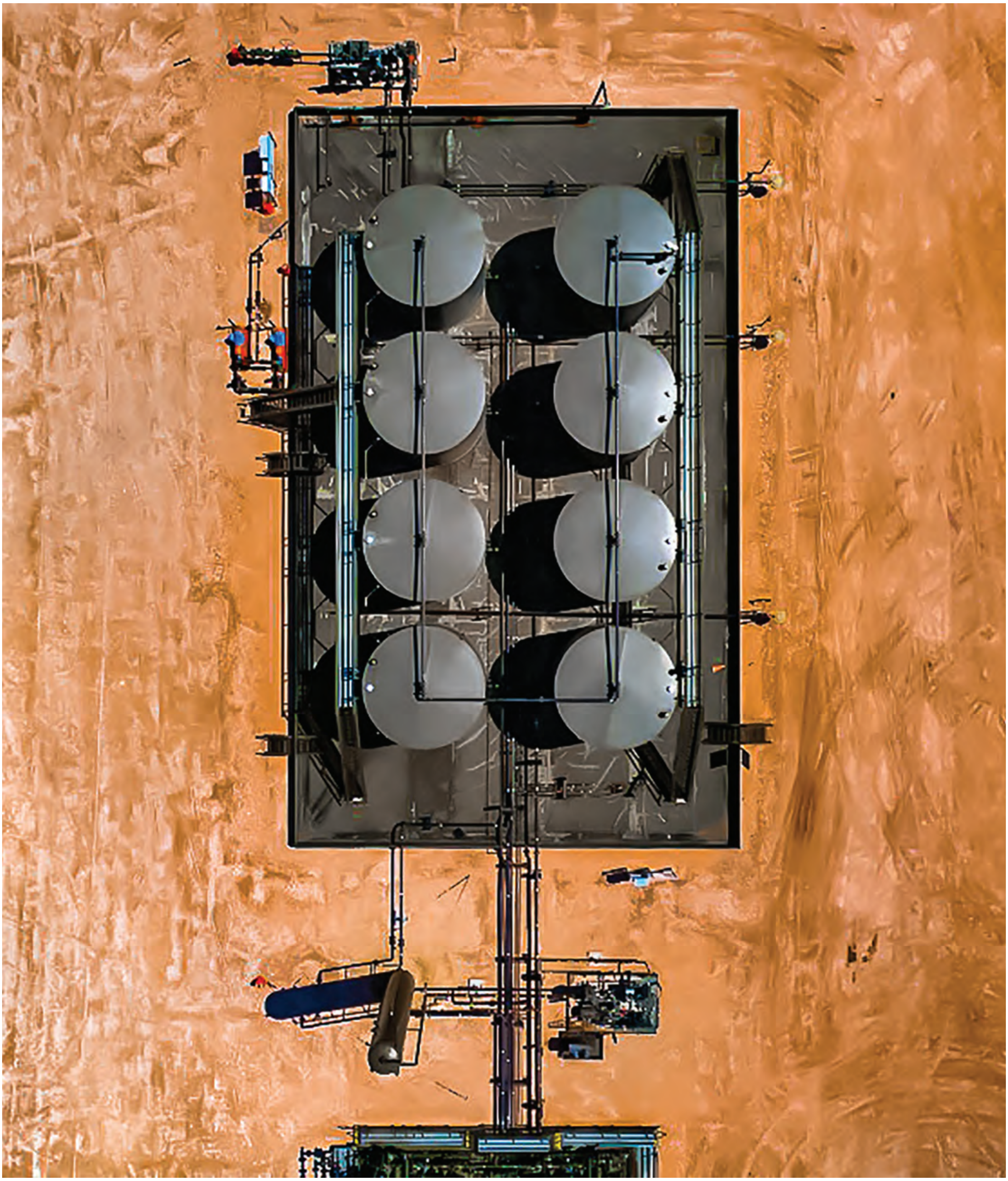
Oil and Gas Investor

JANUARY 2019



Investor takes a top-down view of the Top 50 most-valued independents.

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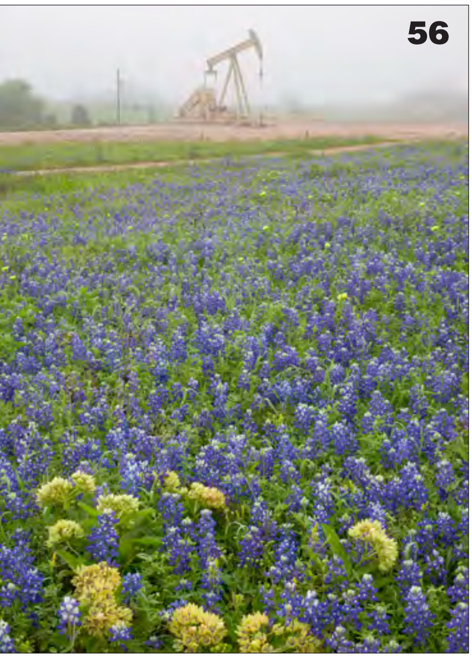


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COLUMNS

DEPARTMENTS

ABOUT THE COVER: With its vast global portfolio and focus on execution, ConocoPhillips ranks #1 in this issue's Top 50 most valued E&Ps. Here, a tank battery gathers produced oil and water at ConocoPhillips' Battle Axe WFI well site in the Delaware Basin. *Photo by Salvador Garza, courtesy of ConocoPhillips.*

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HARTENERGY

RE: 2019 Launch of HartEnergy.com

To: Our Readers

Throughout this past year we built the only single website that brings all perspectives of the energy community together through exclusive features, original content and relevant news, so you know what's happening, what it means and why it matters. This massive effort began with the consolidation of a decade's worth of award-winning, robust content, previously spread across four websites: OilandGasInvestor.com, EPMag.com, MidstreamBusiness.com and UGcenter.com.

HartEnergy.com's mission is to be the one site for daily deep dives for in-depth journalism and data with coverage that spans crude oil, natural gas, NGLs, refined products and renewables, from the upstream, midstream and downstream perspectives.

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LIVING THE NEW ORDER

STEVE TOON,
EDITOR-IN-CHIEF

What old habits of last year do we discard and which new ideas do we embrace? The upstream industry spent the whole of last year divesting its old grow-at-any-cost model for a new returns-and-cash-flow model. 2019 is when investors hold the industry accountable.

ConocoPhillips—not coincidentally the top-ranked company in our Top 50 E&P rankings in this issue—leads the paradigm shift. In December, the Houston producer announced its 2019 spending plan, which it held essentially flat year-over-year. The $6.1-billion capex projection provides for free-cash-flow generation with WTI at $40 and above, $3 billion in share repurchases and a target payout to shareholders of 30% cash from operations, with a modest 5% growth in production.

"We no longer think of our value proposition as merely disciplined; we view it as the new order," Ryan Lance, CEO, said in a news release. "We are running our business for sustained through-cycle financial returns, which is necessary for attracting investors back to the E&P sector."

Indeed, the E&P sector is undergoing a massive re-rating by Wall Street. David Deckelbaum, Cowen Inc. managing director of oil and gas equity research, said the evolution is real.

"E&Ps have re-rated from a growth sector to a value sector," he wrote in a Nov. 29 report, "which we believe is a byproduct of volatile commodity pricing, lack of investor sponsorship and ever-maturing inventory."

Deckelbaum noted that E&Ps underperformed the S&P by 98% during the previous five years, with shares lagging the broader market by 12% in 2018, "the fourth year in a row that the sector has earned the dubious distinction of being among the worst-performing investable sectors."

But now the E&P sector has the opportunity to be globally relevant, he added. "The move to free-cash neutrality is not insignificant as expectations for 2.7% free-cash yield, on average, for the sector stacks well against the 1.2% average for S&P sectors.

"… It is our view that E&Ps' shift in tone away from high production growth and NAV [net asset value] acceleration toward capital discipline, return on capital employed and debt-adjusted returns is resonating with Street analysts and could create the climate for a re-rating going forward."

Seaport Global Securities LLC has changed its own paradigm in how it rates E&Ps, materially altering its NAV-modeling approach. The sell-side research team now incents full-cycle returns and penalizes "companies that continue to live by Shale Version 1.0 standards," meaning "growth and pricey undeveloped acreage acquisitions sold on the merits of NAV upside," wrote Mike Kelly, lead analyst.

"We think our revised framework aligns with how Wall Street will assess U.S. E&P companies going forward."

Seaport's seven crucial elements to gauge E&Ps: returns, cash flow, growth, inventory, balance sheet, valuation and NAV upside. All of these can be summed up with management-team quality, which Kelly said has never meant more to investors than now and for which they are willing to pay up.

"As investors place more emphasis on corporate returns, excellence on the capital-efficiency front has become a must-have for many of the clients we speak with," he wrote. "We don't think this changes anytime soon in an E&P world where it seems easy to get smoked by potential parent-child type-curve revisions, [midstream/takeaway] tightness, misguided well-spacing assumptions, offset-frack hits, logistically complicated water-sourcing/disposal demands, etc., if you're not on top of your game.

"We think companies with good rock and a solid management team will increasingly garner a valuation premium and house long-term investors less interested in quarterly results/well-watching, thus taking some of the volatility out of a volatile space."

With OPEC's December decision to defend crude prices with production cuts, Kelly believes some of that volatility will level. "… The cartel has resigned itself to the passive role of oil-market balancer. This is outstanding for U.S. producers; the market share war is done and won by U.S. shale."

That means OPEC will defend an "almost concrete floor" on oil prices "not much lower than we are now" even while U.S. production hums along.

"We think the market dynamics have positively changed," he wrote, "which finally sets the stage for the outperformance of the E&P group. High-quality E&P companies capable of demonstrating above-average corporate returns and organic growth accompanied by free-cash-flow generation should perform well."

The battle on Wall Street is not yet done—the campaign to achieve scale, and whether that should be via organic growth or consolidation, remains to be fought. But the shift for E&Ps to look more like a typical S&P company is necessary and in progress. Valuations should follow.

"Despite positive results, the sector sits as cheap as ever," noted Bernstein Research analyst Bob Brackett in a Nov. 26 report.

Value is the new upside.

HARD TIMES IN ALGO LAND

CHRIS SHEEHAN, CFA
SENIOR FINANCIAL ANALYST

As of late November, crude prices had slid for seven consecutive weeks, and energy stocks had once again been taken to the woodshed. A key factor in the slide was the dramatic reversal in sentiment triggered in part by the unexpectedly generous waivers granted to purchasers of Iranian oil. But a reality of today's markets is that computer-driven models likely also exacerbated crude's slide.

In a Nov. 26 report, Goldman Sachs observed that the recent oil supply-demand outlook "simply doesn't explain the magnitude of the sell-off," even acknowledging recent pressure on Saudi Arabia to raise output and the U.S.' action to grant waivers for Iranian oil. The answer, according to Goldman, was "the lack of discretionary risk capital devoted to commodity markets."

This lack of discretionary risk capital has increased volatility as "systematic traders," relying on computer-driven programs, have grown to exert "an outsized influence on commodity prices," Goldman reported. "The key is that these systematic traders are based on rules that respond to price patterns or perceived risk premiums, which become more important than spot fundamentals."

The scarcity of discretionary money able to take the other side of a trade—given that "algorithmic system trading" is said to comprise about 80% of crude oil trading—can make commodities appear to price in "a more dire demand outlook," the report said. In turn, pricing can be "pushed below cost support"—below $55 per barrel (bbl) for WTI, an "unthinkable" level one month earlier.

With recent market conditions termed "unsustainable," Goldman recommended taking a long position in Brent. "Inventories are not elevated, demand growth is likely to beat low expectations, Iran exports will decline further and, ultimately, core OPEC will reduce output, in our view."

If crude prices are at risk of overshooting to the downside, energy equities have similarly followed a downward path.

"The oil-price correction has become a rout of historic proportions," said Jason Gammel, Jefferies Group LLC equity analyst covering the integrated-oil sector. "Energy equities have been decimated in the oil sell-off."

Gammel compared the severity of the crude-price collapse to that "in the aftermath of the November 2015 OPEC meeting, when the group decided not to act in the face of a very over-supplied market." The primary difference, he said, was "the lack of an obvious catalyst, although the Saudi decision to surge production has dramatically increased the market oversupply in a very short period."

Gammel said the integrated-oil stocks he covers were, on average, already pricing in a Brent price of $48/bbl. This compares with a January futures contract for Brent price of over $60/bbl for the same date, while the like WTI futures contract settled at just over $51.50/bbl.

Relative to prior corrections, the sector was in a much better position to weather the price downturn, Gammel added. The average breakeven price for stocks under coverage, where cash flow from operations covered capex plus dividends, was a Brent price of $51/bbl compared with $110/bbl in 2014.

But can a declining base of energy investors stung by recent losses step up again after recent drops in commodity and equity prices? How about the generalist investors?

"Capital discipline is still very much in evidence, and cash returns to investors have been prioritized. This is the performance that we would have expected to attract the generalist investor. Unfortunately, the oil price did not cooperate," Gammel said.

"We do not expect that the generalist investors will put money to work in the sector while oil prices are falling, but valuations are compelling and risk/reward is currently skewed to the upside with the stocks discounting $48 Brent."

Prior to OPEC's critical meetings on Dec. 6 and Dec. 7, Gammel warned that "a production cut of over 1 million barrels per day (MMbbl/d) with Russian cooperation seems the minimum response necessary for Brent to catch a bid. Anything less could be ugly from a price standpoint until the market rebalances."

(After the intra-OPEC meeting and a subsequent meeting that included Russia, the OPEC+ group agreed to a total cut of 1.2 MMbbl/d among them.)

Unfortunately, this was not before unsettled sentiment had taken its toll. In prior-day trading, crude prices crumbled and E&P stocks tumbled, with several stocks making 52-week lows—e.g. Apache Corp., Concho Resources Inc., Cimarex Energy Corp., Parsley Energy Inc. and Pioneer Natural Resources Co., to name just a few.

Indeed, an ugly outcome.

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FREE-MARKET FARCE

DARREN BARBEE,
SENIOR EDITOR

Welcome to 2019. Please keep a defibrillator charged and within reach.

Last year, the industry seemed to gingerly try the recovery on. Optimism returned despite an unhealthy diet of trade wars, oil price volatility and a tantrum-prone public market.

But an underlying arrhythmia has developed as international politics continue to take an outsized role in the price of a barrel of oil and the broader economy.

Upstream deal flow appeared to be just fine in 2018 as transaction values skyrocketed. But large, stock-heavy transactions obscured the infrequent asset sales, creating the highest values—yet lowest number of deals—since 2011—according to a November report by EnerCom Inc.

Investors, generally speaking, despised both kinds of deals.

First-quarter 2018 bankruptcies mirrored the transactions in first-quarter 2018. The number of bankruptcies fell from previous years, but debt was substantial. "The amount "almost equals the debt administered by filings during the entirety of 2017," Haynes and Boone LLP reported in March.

Despite higher commodity prices in mid-2018, companies faltered. Eagle Ford-focused Sanchez Energy Corp. appeared in real peril in December 2018.

Analysts don't usually write obituaries, but Capital One Securities Inc.'s Nov. 20 report on Sanchez came close. "Death spiral likely continues as Sanchez appears insolvent," the report began.

Sanchez's woes may serve to reinforce a cautionary tale: Rich deals don't necessarily equate to lucrative results. For much of 2018, Sanchez was on the defensive due to well-spacing and other challenges in its Comanche-area assets. In March 2017, Sanchez and partner Blackstone Energy Partners LP purchased the position from Anadarko Petroleum Corp. for some $2.3 billion.

In August 2018, Sanchez brought on a consultant to enhance its production and operating margins. On Dec. 4, with $550 million in liquidity, the company hired Moelis & Co. LLC to "explore strategic alternatives."

Weakness in the 2018 asset market complicated matters. For months, Sanchez marketed its Maverick position (among others). Analysts estimate Maverick is worth about $500 million. Despite generating interested parties and producing 347,000 barrels (bbl) of oil in the third quarter on little capex, the asset hasn't moved.

Erratic oil prices only served to justify the concerns of investors that turned away from oil and gas during the downturn. In October, the prompt-month CME contract for WTI was more than $70/bbl. In November, the prompt-month contract dropped to $50/bbl, according to EIA data.

By Thanksgiving, with the industry flailing, U.S. producers already haunted by November 2014 found themselves again watching Vienna, where OPEC would convene. However, a particularly powerful spoiler was at work: President Donald Trump.

S&P Global Platts tracked the prompt for Brent on CME and ICE and the president's related tweets—10 in all—from April through December.

In each, Trump aimed to keep oil prices low, likening them, in one case, to a tax cut.

"So great that oil prices are falling—thank you President T," @realDonaldTrump tweeted on Nov. 25. On Dec. 5, the president added, "Hopefully OPEC will be keeping oil flows as is, not restricted."

Despite pressure from Trump, OPEC, Russia and, a week earlier, Canada (yes, Canada) ultimately combined to curtail daily production by 1.5 million bbl (MMbbl). On Dec. 7, U.S. inventories continued to fall, with a draw triple the 2-MMbbl estimate by Tudor, Pickering, Holt & Co. (TPH).

"While we try to focus on fundamental and structural trends, it is undeniable that politics play a large role in the global market," TPH analysts reported. "The past few months have punctuated this fact.

"Whether it be government-mandated curtailments—Canada—an overt consolidation of power/influence—Saudi and Russia—or sweeping economic sanctions—U.S. and Iran—geopolitical relationships have a stranglehold on the current market."

Greater volatility should be expected.

"However, economics over the medium term will still rule the day as the majority of global growth resides in the hands of U.S. producers, who are beholden to their shareholders rather than a government entity."

But the economy is more politicized, Julian Emanuel, chief equity and derivatives strategist at BTIG LLC, told *The New York Times*. "The fact is that politics is driving the economy to an extent that is very atypical," he said.

And so 2019 begins much as last year did: with uncertainty—the great deal-killer—lurking ahead.

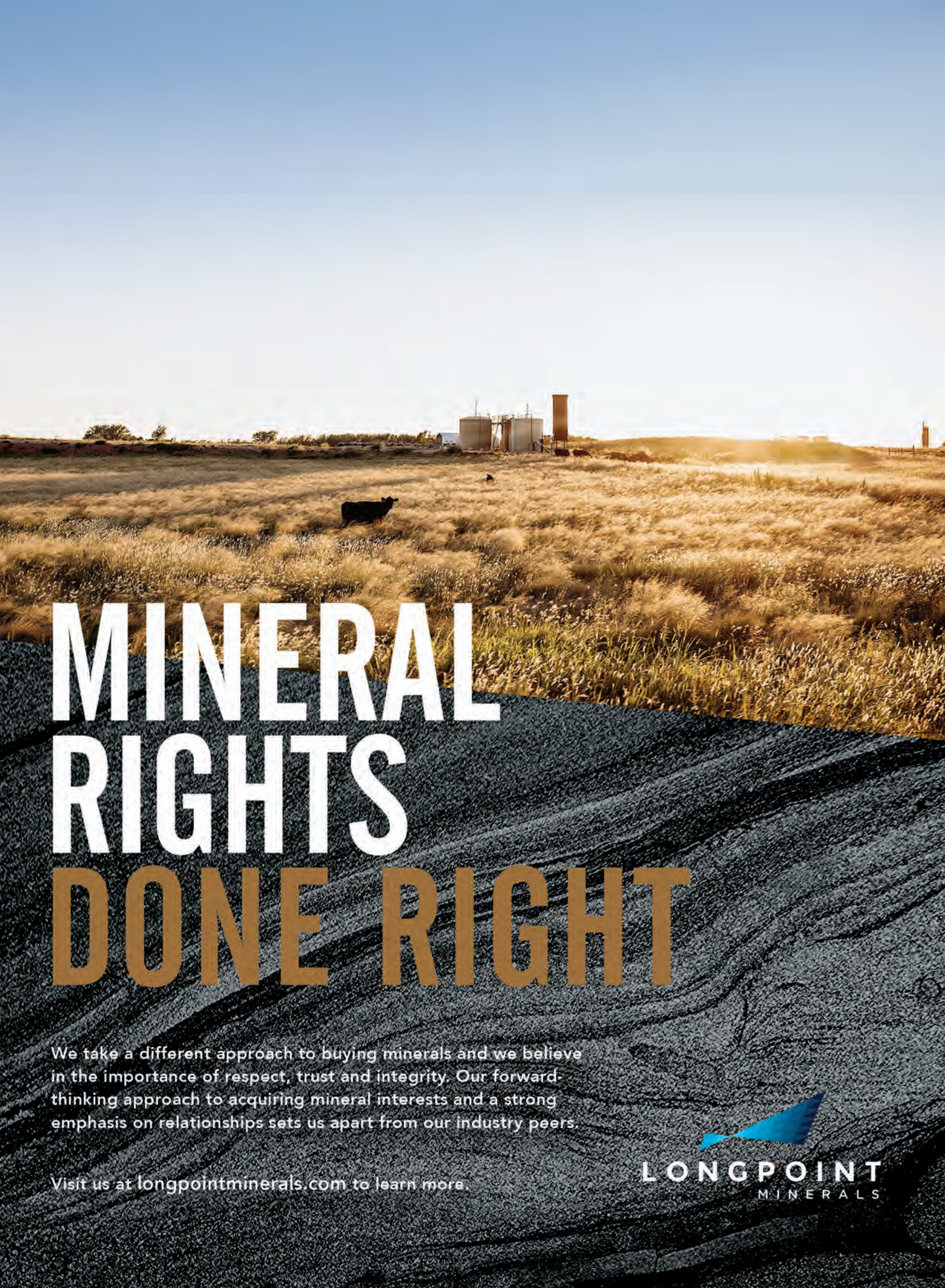
EVENTS CALENDAR

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

Event	Date	City	Venue	Contact
2019				
IPAA Private Capital Conference	Jan. 24	Houston	JW Marriott Houston Galleria	ipaa.org
SPE A&D Symposium	Jan. 31	Houston	Houston Petroleum Club	spegcs.org
NAPE Summit	Feb. 11-15	Houston	George R. Brown Conv. Center	napeexpo.com
Women in Energy Luncheon	**Feb. 12**	**Houston**	**Hilton Americas**	**women-in-energy.us**
DUG Haynesville	**Feb. 19-20**	**Shreveport, La.**	**Shreveport Convention Center**	**dughaynesville.com**
EnerCom Dallas	Feb. 27-28	Dallas	Tower Club	enercomdallas.com
Energy Capital Conference	**March 5**	**Dallas**	**Fairmont Hotel**	**energycapitalconference.com**
CERAWeek by IHS Markit	March 11-15	Houston	Hilton Americas	ceraweek.com
TAEP Expo & Annual Meeting	April 2-3	Irving, Texas	Irving Convention Center	texasalliance.org
OGIS New York	April 8-10	New York	Sheraton Times Square	ipaa.org
DUG Permian Basin	**April 15-17**	**Fort Worth, Texas**	**Fort Worth Convention Center**	**dugpermian.com**
Offshore Technology Conference	May 6-9	Houston	NRG Park	2019.otcnet.org
DUG Rockies	**May 14-15**	**Denver**	**Colorado Convention Center**	**dugrockies.com**
AAPG Annual Conv. & Exhibition	May 19-22	San Antonio	Henry B. Gonzalez Conv. Center	aapg.org
Midstream Texas	**June 5-6**	**Midland, Texas**	**Midland County Horseshoe Pavilion**	**midstreamtexas.com**
IPAA Midyear Meeting	June 24-26	Colorado Springs, Colo.	The Broadmoor	ipaa.org
DUG EAST	**June 18-20**	**Pittsburgh**	**David L. Lawrence Conv. Center**	**dugeast.com**
Unconventional Resources Tech. Con.	July 22-24	Denver	TBD	urtec.org/2019
EnerCom The Oil and Gas Conference	Aug. 11-14	Denver	Westin Denver Downtown	theoilandgasconference.com
The Energy Summit	Aug. 20-22	Denver	Colorado Convention Center	theenergysummit.org
Summer NAPE	Aug. 21-22	Houston	George R. Brown Conv. Center	napeexpo.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
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 OilandGasInvestor.com.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THE 'SHALE ON IT' GAME

STEPHEN G. BECK,
SENIOR DIRECTOR,
UPSTREAM

The beginning of a new year is a perfect time to reflect on the prior year. The stream of data is fresh and water-cooler contests are shaping up.

As such, Stratas Advisors decided to conduct our own year in review, of sorts. To keep it fun, let's kick everything off with a short game of "Shale On It," a game of trivia where readers get a chance to answer 10 questions on 2018 unconventional resources. Some will be easy; others, less so. Without further ado, let the questions begin.

Production is near and dear to any prospector's heart, so our questions start there. One note: While not all production numbers have been reported, enough data have been released to answer these.

1. *Of the three major shales in the Permian (Bone Spring, Midland Basin-Wolfcamp and Delaware Basin-Wolfcamp), which play saw the lowest oil-production growth by volume?*
2. *Which play saw the greatest increase in oil production by volume?*
3. *By what percentage did overall Permian oil volumes grow in 2018?*
4. *Traveling north to Oklahoma, what shale was a game-changer for the Scoop in 2018?*
5. *Turning elsewhere, Proposition 112 threatened to derail what unconventional play in 2018?*

This line of questions will focus on drilling and field activity. During 2018, a play highlighted in this column was said to be on track for 13% production growth in 2019 due to longer laterals and higher proppant loading.

6. *What is the name of this play?*
7. *What play covered in this column in 2018 gave attribution to higher rig counts for rising 2018 production?*
8. *What is the average drilling time cited in this column for the Wolfcamp Shale?*

Money is also near and dear to many a prospector. Hence, our remaining questions will query various economic areas.

9. *First up, what play was characterized in this column as having a majority of wells with breakeven prices below $50 per barrel (bbl)?*

Last one, Stratas projected total Rockies spending for 2018 in this column earlier in 2018.

10. *What was the amount of total capital spending given?*

Redirecting our attention to 2019, this seems an appropriate time to identify some early signposts for the year ahead. First up, compliance with the new round of production cuts.

Starting in January, a new agreement for production cuts takes effect. OPEC members, plus Russia, agreed to reductions totaling 1.2 million bbl per day until midyear. While Stratas expects these to largely comply, there are risks for noncompliance, especially if producers perceive their cuts are replaced by outsized shale production.

Second up, slowing growth in shale production, particularly slowing growth in the Permian. Swirling headwinds are expected to dampen the rate of growth in 2019. These headwinds include ongoing labor shortages, infrastructure constraints and flaring limits that are likely to continue through the first half of the year.

Labor shortages appear most problematic as there are no ready answers for particular skills in short supply. Infrastructure challenges should see reprieve around midyear. Flaring limits have become an issue in multiple areas due mostly to infrastructure bottlenecks. Stratas estimates the rate of growth in areas like the Permian could be halved compared with 2018.

Third, robust production growth in 2018 coupled with elevated demand risks led crude prices sharply lower in late-2018. Lower crude prices could further weigh on capital spending early in the year. Importantly, wells brought on in early 2019 carry a much greater weight on average annual production.

Each well added to production adds another layer to the production stack. Hence, the more wells added early, the thicker the total stack in the second half. The thicker the production stack in the second half, the greater the chances for a higher overall growth rate. Conversely, the thinner the stack, the slower the overall growth rate.

Fourth, breakthrough catalysts. Stratas is aware of and is monitoring several science projects that could extend the economic limits of select plays. At present, Stratas does not anticipate emerging technology to commercially alter the outlook for production in 2019. That said, breakthroughs can and do happen. Hence, it is prudent to keep tabs on the sciences.

Answers: 1. Bone Spring. 2. Delaware Basin Wolfcamp. 3. 43%. 4. Springer. 5. Wattenberg or Niobrara; each is a valid answer. 6. Haynesville. 7. Eagle Ford. 8. 22 to 26 days spud-to-spud. 9. Eagle Ford. 10. More than $12 billion.

25 INFLUENTIAL Women IN ENERGY

Join us to congratulate Oil and Gas Investor's The 2019 Honorees

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NAPE Where Deals Happen
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Gretchen Watkins, Shell Oil

Shell president: Collaboration extends Permian dominance

Shell Oil Co. incoming president Gretchen Watkins offered at Hart Energy's Executive Oil Conference in Midland a competing idea to competition itself: collaboration.

While competition will always drive the Permian Basin's performance, working together can also raise standards and improve safety in the basin, Watkins said. Early coalitions among Shell and independents have already started to improve road safety, where a fatality occurs every 29 hours, said Watkins.

The company is willing to share work site safety strategies "with anyone willing to learn.

"The fact is, as operators, we have a lot more to gain from collaborating than we do from going it alone," Watkins said.

Shell believes reducing greenhouse-gas emissions adds to the industry's social and material value, noting that flaring is a top source of the Permian's methane emissions. At new well pads, Shell has stopped installing flares.

"Reducing flaring is critical for our social and environmental license to operate, as well as our ability to generate revenue," she said. "We've been very encouraged to see substantial reduction in flaring that's happening just this year [in 2018]."

Shell is also testing the use of solar energy to power its Permian pads. "We can benefit by sharing best practices to reduce flaring and methane leaks that can cause us to lose vital product and actually undermine the case for gas as the molecule that can bridge us [in] the energy transition," she said.

Nevertheless, the fundamental driver of the Permian's "rise to a level of preeminence" has been unbridled competition, with independents leading the charge. Through competition, operators have "come to understand a very complex terrain here in the Permian Basin," she said.

The quest to grow leaner and more efficient has resulted in lowered costs and increased production. "As independents have competed with late-arriving oil majors, companies like Shell have had to become more nimble and more agile, and that has been good for us," she said, adding that she also sees "independents seizing on oil majors' scale and integration."

Shell now sees the Permian as much a part of its home turf as its deepwater assets, Watkins said, noting that other oil majors are taking a similar strategic outlook. Shell is now spending between $2- and $3 billion per year on its shale assets, including the Permian, Canada's Duvernay and Argentina's Vaca Muerta.

Since 2013, it has grown its Permian production to 125,000 barrels of oil equivalent per day (Mboe/d) from 25 Mboe/d. The operator now has interests in more than 1,300 operated and non-operated wells across 500,000 acres.

"We project we will reach 200,000 boe/d by 2020, and … 35% year-on-year production growth for the next five years," she said. The company is also planning to high-grade its Permian acreage through strategic swaps and small bolt-on acquisitions.

But Shell wants to be a community partner on a range of "important issues that all of us have a stake in" through partnerships. The goal is to build a basin that's safer, more stable and far more prosperous than ever before, she said.

"If you share this vision, let's work together to put the days of boom or bust behind us and let's move toward more collaboration."

—Darren Barbee

Weeping over Waha: Oil flows scuttle West Texas gas hub

Waha natural gas pricing falling to near zero in late November? Blame oil, says one analyst.

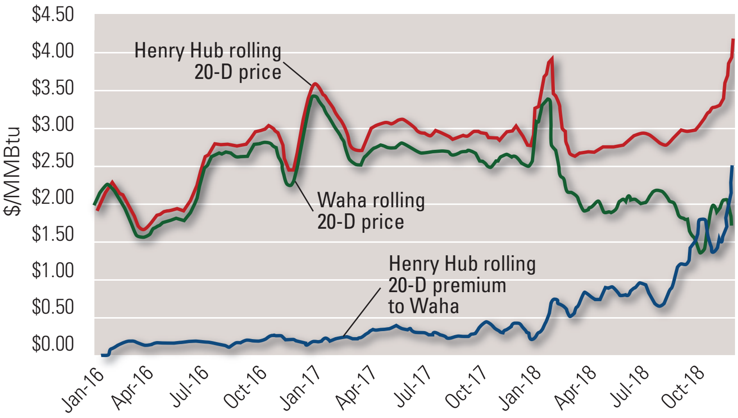
The culprit for the gas-hub blowout is in fact the commissioning of the Sunrise crude oil pipeline, which is a 500 Mboe/d West Texas-to-Cushing project owned by Plains All American Pipeline LP that was to help alleviate the bottleneck for Permian oil producers, according to Raymond James analyst J.R. Weston. How does that work? Through more associated gas, he said.

"This increase in volume strained a gas system that was already tight for infrastructure," Weston said in a Dec. 3 report. "It's hard for the system to handle this much gas all at once."

Acknowledging a self-described "bullish view" on global oil prices and U.S. oil production, Weston said it should come as no surprise that substantial Permian associated-gas production growth is also part of the story.

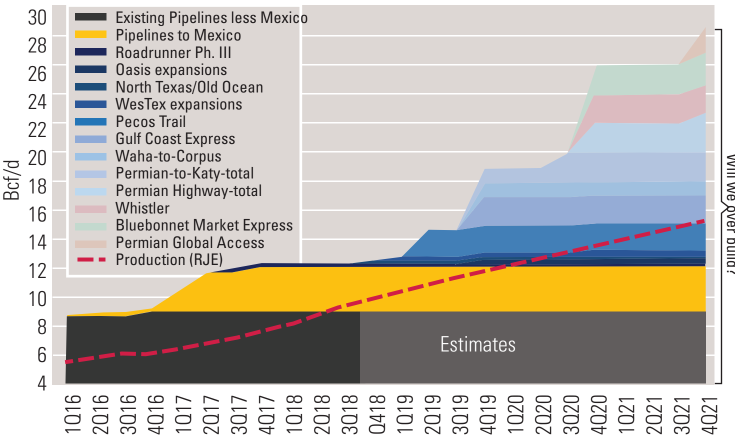
"As the Permian crude oil pipeline buildout has been pulled forward, associated-gas

Waha vs. Henry Hub 20-Day Rolling Average Prices



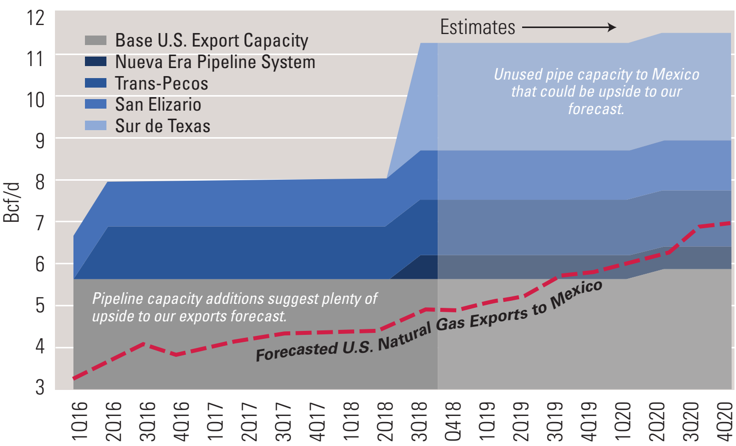
Source: Bloomberg, Raymond James research.

Permian Dry Gas Pipeline Takeaway



Source: EIA, company/partnership filings, Raymond James research.

Natural Gas Pipeline Capacity Additions Across the U.S.-Mexico Border



Source: EIA, Company presentations, Raymond James research

production is also arriving sooner rather than later. This was likely the impetus for the recent decline in Permian gas prices."

Weston warned that even more associated Permian gas is on the way as more oil pipelines are added. "We forecast as much as 6 Bcf/d [billion cubic feet per day] of Permian growth from 2017-2020, nearly doubling Permian production in three years." The growth has far surpassed corresponding pipeline additions, and Permian gas pricing is projected to remain lower for longer, he forecasts.

He noted with some irony, however, that current Permian gas-takeaway capacity of 12 Bcf/d "far exceeds" actual gas production of about 9 Bcf/d. Where's the rub? Too much of it goes to sub-optimal markets, such as Mexico, where utilization remains low, and to California and other destinations west, where the gas competes with renewables, and to the Midcontinent and Rockies, which are "not tremendous options for Permian E&Ps either."

And sub-optimal gas markets don't elevate regional pricing.

Short-term "bouts of extreme pricing pressure" should be expected in the Permian as pipe brownfield projects come online, creating up-and-down "zipper" pricing effects until Gulf Coast Express, a greenfield 2 Bcf/d Kinder Morgan Inc. project, was expected to come online by year-end 2019. Another 4 Bcf/d of combined capacity is due by late 2020.

Exports to Mexico remain a point of optimism for Permian gas producers, he said, and pipes are already in the ground and waiting for gas to flow. Current U.S. flows to Mexico average 4.5 Bcf/d. Three new pipes from the Permian to the Mexican border represent 3 Bcf/d of potential capacity.

"More U.S. export flows are possible if Mexican markets are ready for them," he said.

But export pipes to Mexico are not currently well utilized, as timing issues have delayed Mexico's readiness: south-of-the-border route disputes, and slow-to-commission gas-fired power plant buildouts.

"In the near term, this may not be the outlet valve the Permian E&P industry needs."

Weston expects that higher ethane recovery could lessen the burden on Permian gas pipes. Proximity to Gulf Coast demand centers and planned connectivity to Mont Belvieu, Texas, indicate ethane recovery should be stronger than in most plays, incrementally relieving gas pipelines.

Should Permian operators and investors be worried about basin gas constraints affecting oil production?"

Weston answered: Nope! "Our key industry contacts think Permian gas, while constrained, will be a non-event from a broader industry perspective due to several workarounds."

The brownfield and greenfield pipelines are coming, he said, and insiders expect flaring to be supplemented by waivers that could result in some 2 to 3 Bcf/d

of vented gas. "Texas regulators will show flexibility."

Also, the Permian's sizeable inventory of legacy gas wells could be shut-in to make way for the newer, liquids-rich production coming online. "It is unlikely that the Permian's natural gas takeaway constraints will bleed into the crude oil market," Weston concluded.

—Steve Toon

Voters prop Colorado industry, but future ballot battles likely

The oil and gas industry fended off two ballot challenges Nov. 6 in Colorado, but the margins of victory were less than resounding and could signal trouble in future election cycles.

"When it comes to Proposition 112 [in Colorado], what isn't surprising is that it lost," Ashley Petersen, senior oil-market analyst for Stratas Advisors, told Hart Energy. "What's surprising is how tight the margin was, given the disparity in resources between supporters and the opposition."

Colorado's Proposition 112, defeated 57% to 43%, would have prohibited oil and gas drilling within 2,500 feet of homes, schools or other occupied structures or "vulnerable areas." The ban would have made only 15% of the state's non-federal land available for drilling.

The industry-backed movement to defeat the measure spent about $36 million in its campaign, while supporters spent less than $1 million.

"The fact that, even in a traditionally oil- and gas-friendly state, this measure needed to be so vigorously fought against shows that sentiment in Colorado continues to shift away from extractive industries," Petersen said.

A study by the Colorado School of Mines estimated that horizontal drilling would give producers access to 42% of the non-federal land. However, the restricted area included sweet spots in the Denver-Julesburg Basin.

Meanwhile, in Washington state, voters rejected Initiative 1631, which would have allowed the state to charge companies for their emissions of CO_2 and other greenhouse gases. It followed rejection of a similar measure in 2016. The 2018 measure was opposed by 56.3% of voters, despite the full-throated support of Gov. Jay Inslee.

Under the initiative, fossil-fuel companies would have been required to pay $15 for every ton of CO_2 released into the atmosphere. The anticipated $1 billion-plus in revenue in five years would have been shifted to projects that would move the state away from fossil fuels, such as public transit, energy efficiency, wind and solar power.

"While in Colorado there are more obvious economic ties with the oil and gas industry, the tide here was turned by concerns that this would impact consumer wallets directly," Petersen said. "In large part, it was driven by


Rocky Mountain E&P Company of the Year
– 2018 Oil & Gas Awards

aggressive messaging from opposition parties."

Again, the oil and gas industry spent heavily—$31 million compared with proponents' $15.2 million. In Washington, though, the threat of higher fuel and utility bills convinced most voters.

"Clearly in Washington, economic concerns still handily outweigh environmental ones, regardless of how the fee is structured," she said.

Supporters of the initiative have promised to try again, she noted. "Chances might be better the third time around. In 2016, the measure was opposed by several social-justice groups and gained only 42% of the vote.

"This time around, I-1631 had broader support among social-justice groups and garnered 43.7% of the vote," she said.

Tom Pyle, president of the American Energy Alliance, issued a statement that "there is little doubt that those who authored the defeated initiatives will try again, but we hope they have finally learned their lesson.

"The voters have spoken. It's time to listen to them."

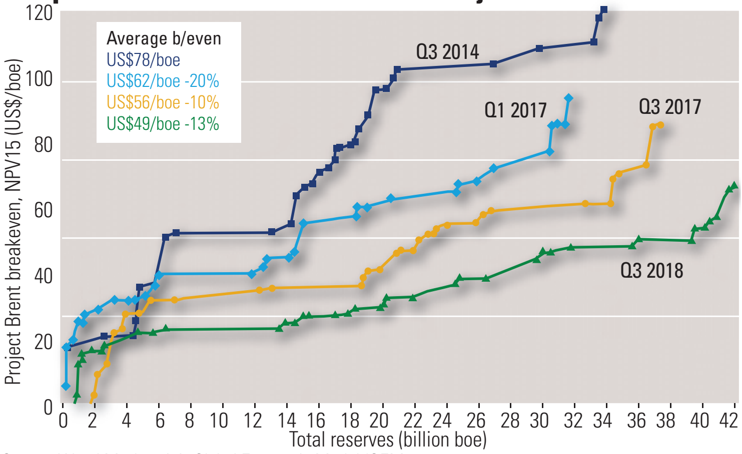
—Joseph Markman

Cost inflation threatens improvements in deepwater economics

Producers with the stamina needed to dive into deepwater projects and stay afloat have managed to slash breakeven costs in recent years. But analysts warn impending cyclical cost inflation could trigger a rise in such costs.

The average pre-final investment decision (FID) breakeven dropped to US$49 per barrel of oil equivalent (boe) in 2018 compared with $78/boe in 2014, Wood Mackenzie reported in late

Deepwater Cost Curve Of Pre-FID Projects Since 2014



Source: Wood Mackenzie's Global Economic Model (GEM

November. Carrying out lessons learned during the downturn, some operators have opted for fewer wells, more phases and tie-backs to existing infrastructure, while seeking lower rig day rates and supply-chain costs, drilling better wells and utilizing technology to control expenses.

BP Plc, for example, cut costs for the Mad Dog Phase 2 project in the deepwater Gulf of Mexico by more than half.

Focusing on value, industry solutions and collaboration with its partners BHP Billiton Ltd. and Chevron USA Inc. affiliate Union Oil Co. of California, the operator pared the massive 33-well, $20-billion development to $9 billion with up to 14 wells.

The project, which is set to begin oil production in late 2021, remains on budget and on schedule, Starlee Sykes, BP regional president, Gulf of Mexico and Canada, said in a news release.

"This project is key to delivering high-margin production from one of the largest fields in the Gulf of Mexico, and it will strengthen our position in the basin for years to come," Sykes said.

Similar stories have unfolded across the deepwater Gulf, where the number of subsea tiebacks has grown, and other parts of the world. Unit costs have fallen by more than 50% since 2013, WoodMac found. It added that improved project execution has resulted in the average deepwater project sanctioned between 2014 and 2016 starting up about 5% under budget, compared with the 10% to 15% overrun typically seen with projects between 2006 and 2013.

Improved project economics mean more deepwater investments could be on the horizon. WoodMac forecasts developments offshore Guyana, Brazil and Mozambique will drive higher deepwater capex, expected to hit nearly $60 billion by 2022 from about $50 billion in 2018.

But the cost-saving gains could be short-lived if companies fail to make the savings permanent. "The return of cyclical inflation could see this epic period of deepwater-cost reduction come to a close," reported Angus Rodger, WoodMac research director.

Cyclical inflation could affect costs in the areas of day rates, subsea equipment and services, and other areas. The speed of cyclical cost re-inflation will depend on how quickly operators drive a recovery and the supply chain's ability to meet their demand, WoodMac reported.

"The question now is how much of the 'structural' cost savings we have seen through the downturn will prove sustainable through the investment cycle and which are just short-term company adaptions," Rodger wrote.

Structural savings—considered more "resilient/sticky" by WoodMac—include drilling better wells faster and having quicker project lead times and phasing projects. WoodMac is skeptical that some of these "structural cost savings will stand the test of time in a sustained cyclical uptick."


Some horses are not
meant to be tamed

Such savings were viewed by the analysts as external environment-driven corporate behavior and project design changes.

"Those that 'stick' become cultural changes within the sector that can stand the test of time and price cycles, but, historically, the big players in [the] deepwater have been slow to change, based on their size, culture and limited risk tolerance in a challenging operating environment."

—Velda Addison

Permian's challenge: Above-ground vs. takeaway constraints

Activity in the Permian Basin has "absolutely" slowed down in what Joel Fry, a principal at private-equity firm Tailwater Capital LLC, called the periphery of the basin in Culberson County, Texas.

Fry, who took part in a panel discussing Permian takeaway at Hart Energy's Executive Oil Conference in Midland in November, said the slowdown is the result of the Permian-Gulf Coast basis differential.

Fellow panelist Steve Pruett, president and CEO of Elevation Resources LLC, said he "really hasn't seen a slowdown in drilling activity" in his area that is the result of takeaway constraint. Rather, he's seen a governor being investor pressure on operators to spend within cash flow—a mandate that took hold beginning in 2017.

Elevation, a producer in the heart of the basin, has paused activity due to changing what type of rig it will use in development, from a "skidding" rather than a "walking." Elevation's production moves to refining capacity in El Paso, Texas; the Permian Basin has some 500,000 barrels per day (Mbbl/d) of indigenous refining capacity.

Parsley Energy Inc. is also pausing activity, which Carrie Endorf, vice president of reservoir engineering and planning, said was "really related to capital discipline" and not due to constraint. The company is working on its 2019 budget, she added.

"At Parsley, we haven't seen any problems" with the ability to get its crude oil to market, Endorf said. "At this point, we're looking at 2020," but for 2019, "we're in good shape."

Pruett added that a great deal of demand capacity for Permian crude is the result of winning reversal in 2015 of the U.S. oil-export ban in 2015, which he attributed to the leadership of Scott Sheffield, chairman of Pioneer Natural Resources Co.

Analysts expect Permian on-pipe takeaway constraint to persist into the fourth quarter of 2019 and to possibly become a concern again in 2022. Production in the Permian is some 3.2 million barrels per day (MMbbl/d) currently; takeaway capacity is roughly the same.

Growth in Permian output "brought the oil-price collapse one year forward," said Reed Olmstead, IHS Market director of North American onshore

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research and business development. When visiting clients, Olmstead said, "I can't speak to any [country] without the first question being the Permian Basin."

Pruett said there are more immediate concerns to Permian producers. "The risk of NGL fractionating capacity is looming over us," he said.

Fry, whose firm has investments in oil and gas producers and in water-handlers, said, "Some folks are projecting 20 MMbbl/d of water[-handling] growth." Both the Midland Basin and, particularly, the Delaware Basin, produce more water than oil. "Houston, we have a problem," he said.

In addition to needing to dispose of produced water, producers need to source non-contaminated water for fracture stimulation. (Bio-contamination of in-formation hydrocarbons can create H_2S).

Pruett said Elevation's frack work was delayed in 2018 while the city of Odessa, Texas, needed more water for power generation. "Power supply is an [increasing issue]. We ended up having to do spot purchases of water at two times our normal rate," he said.

Elevation and other operators that have HBP'ed their acreage are switching to pad drilling, though, and this will mean they can begin recycling water, he added.

Labor issues are another concern. The city of Midland, Texas, has been unable to collect garbage at times for lack of drivers as a result of competitive oilfield demand for personnel, Pruett said. "It's chronic."

Olmstead said his room at the La Quinta the evening before cost more than his room at a hotel in Tokyo. "That just blew me away," he added.

The question Olmstead gets from clients is: "What's the limit to Permian production growth?" The issue isn't with the subsurface; operators know the rock well, he said. Rather, it's 'How many trucks you put on the road? How many hotel rooms? Where are we going to build the next McDonald's? It's congestion 'above ground.'

"Yeah, the basin can absorb another 250 rigs. How are you going to move them? What road is that going to go on? Who are you going to pay to do it? Where are you going to find the labor? It's all 'above ground.' It's the escalating cost of everything," he said.

—Nissa Darbonne

Oil price-swoon to test E&P capital discipline

Producers enjoyed a 2018 run-up of WTI pricing from near $55/bbl to $75/bbl, but the powers that giveth also taketh away: Beginning in October, spot pricing fell precipitously to near $50/bbl once again, wiping out a year of gains.

So, Barclays analyst Jeanine Wai asked in an analysis, at what price do E&Ps start reducing activity?

"Our sense is that generalist [investors] have progressed toward free-cash-flow (FCF) yield as the primary E&P metric," she said.

"However, the recent drop in strip pricing has a meaningful effect on 2019 FCF, even on a hedged basis. … If 2019 strip pricing of $52 [per bbl] holds, is there enough E&P FCF yield left for the sector to be attractive to this investor base?"

The recent correction in oil prices throws more attention on the E&P capital discipline narrative, Wai said. Where robust pricing in 2018 tested the sector's commitment to capital restraint in a higher-oil-price environment, "2019 could be the first test in a lower-price environment."

In a lower-price environment, the challenge will be to limit outspend and preserve the promised cash flow. And, while she predicts E&Ps will honor the call to be capital-disciplined, it's all in the timing.

"We think E&Ps will be slower to react to lower oil prices than the market, which could be disappointing to investors over the next few months."

The reason: Producers want to avoid "whipsawing" activity to preserve operational efficiencies. Many E&Ps, she said, have built-in buffers to smooth price swings—hedges to support cash flow and strong balance sheets to fund outspend.

Others might opportunistically capitalize on deflationary service costs with sustained or ramped activity.

During third-quarter 2018 earnings calls, $50 WTI was the "conservative" price deck for 2019 budgeting, she noted. "However, our sense is that, if oil prices remain sticky at around $45, ultimately E&Ps will capitulate and reduce activity.

"The devil is in the details for managing market expectations."

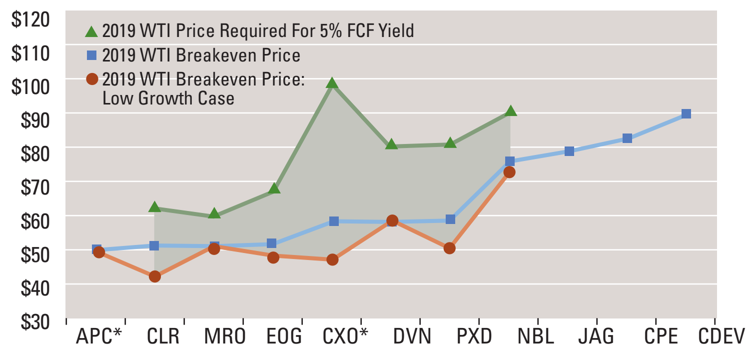
Breakeven price will be a driver of stock performance, she projected.

The winners will be those E&Ps that have the lowest breakevens combined with "the most robust and durable" 2019 capex/production outlooks.

"Based on our analysis, we think the pricing-pain threshold for generalists should be about $60 WTI."

—Steve Toon

2019 WTI Breakevens Comparison



Source: Barclays research; Analysis includes hedge gains/losses; FCF defined as Discretionary Cash Flow—Capex—Dividends; 2019 Breakeven defined as the WTI price at which 2019 Discretionary Cash Flow=Capex- Dividends; 2019 10% Growth Breakeven defined as the WTI price at which 2019 Discretionary Cash Flow=Capex-Dividends assuming 10% yoy adjusted production growth; *APC is Rating Suspended. Data is based on the 11/15/18 press release that indicates 2019 total production growth guidance is 8.3-10.2% yoy (divestiture adjusted) and the 2019 capital program is within cash flow in a $50 oil environment; *CXO's 2019 10% Growth Breakeven is ~$75 excluding hedges.

Shifting U.S. supply, demand to result in increased exports

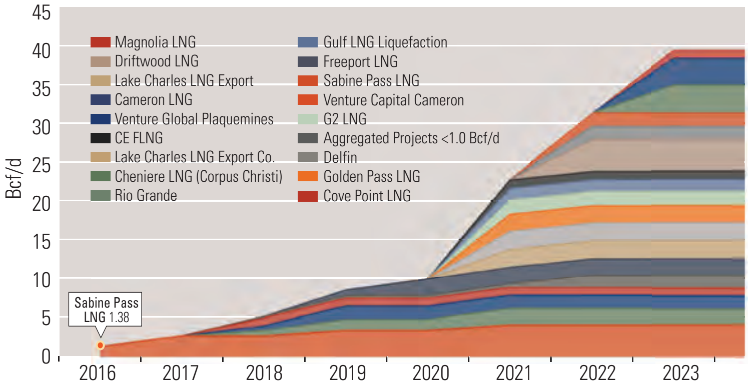
The U.S. is poised for multi-decade success as the global energy mix shifts, with supply growth underpinning ethane's growing role and the country's status as a net exporter by the mid-2020s, a midstream analyst said.

Greg Haas, director of integrated oil and gas at Stratas Advisors, told attendees at Hart Energy's recent Midstream Finance conference, "Energy transportation is an evolving sector and we also see increased regulatory risks and intensifying regulatory concerns affecting the industry."

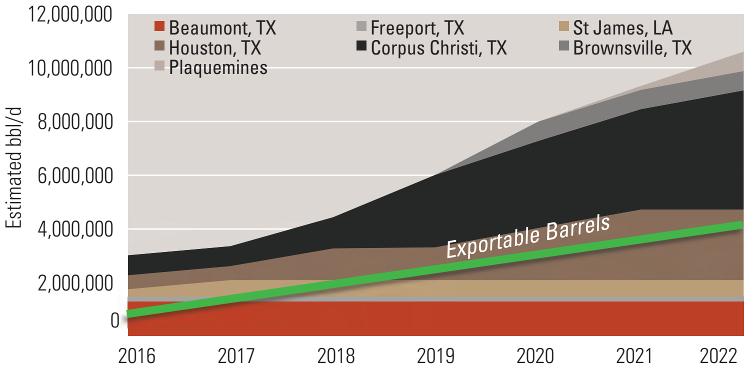
Haas pointed to California. The state primed for a potentially devastating earthquake is pondering a tectonic shift toward 100% renewable power. Haas also noted that the U.S. Strategic Petroleum Reserve is prepared to "right-size" itself.

"What we've seen in the

U.S. Gulf Coast LNG Export Capacity Forecast



U.S. Gulf Coast Crude Export Terminal Capacity



Source: Stratas Advisors North American Shale Infrastructure Service

upstream is great production-supply growth," he said. "Now the question is 'What will it be in the future?'"

Global daily oil consumption will rise at an annual average of 1.5 MMbbl, Haas said, with the U.S. taking over the top spot among producing countries. But growth in natural gas is an essential factor as well, he added.

With gas, "there's definitely supply growth in the U.S., which is now kind of the envy of the world; that's certainly why we have so many LNG facilities and pipelines feeding our near neighbors and also new industry- and utility demand."

Haas noted that refinery utilization was at 100% this past fall and was in the high 90s during the summer—a level not seen in about 20 years. "Refineries, of course, consume crude oil, but they also burn a lot of gas to boil that oil, which is the fundamental part of refining," he said.

"And they also produce propane and/or consume butane and condensates for blending with transportation fuels. So it's no wonder to us that we have such great utilization today."

Refinery projects have been announced in the Permian and the Bakken, and the Hovensa facility in the U.S. Virgin Islands is on track for a restart. That area is exempt from Jones Act restrictions on tankers.

When Haas' own career began, the issue was how to safely run refineries at very low levels of utilization. "It's been a total change," he said.

"We've got expansion—even planned by Exxon (Mobil Corp.) at Beaumont and other places around their network. So that's just thrilling to me, to sit on the sidelines from a vantage at Stratas Advisors to watch them.

"With these refineries running so high—and advantaged so well with low crude, low fuel and even low intermediate-feedstock costs like butane and condensate—you're seeing a lot of expansion in exports around the globe for finished refined products." In 2012, Haas attended a presentation in which a professor from the Massachusetts Institute of Technology predicted that, "someday," the U.S. would reach 25% net imports.

"And that 'someday' was predicated upon reducing demand, having higher costs to reduce demand, and some inclusion of Canada in the U.S. supply base. But because of what we have done in the shale industry … we're now in the low teens [imported] on a weekly run-rate basis.

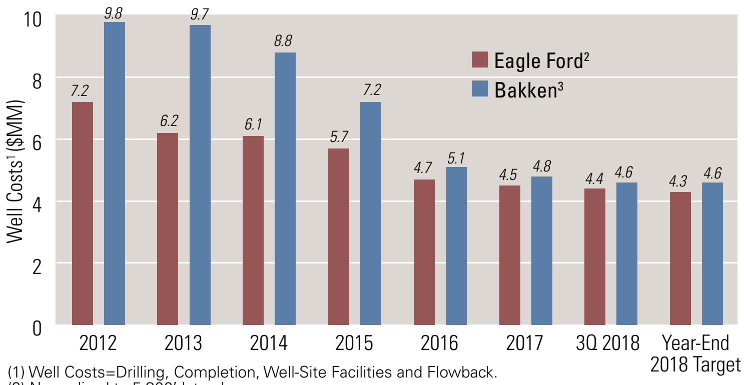
"And we think, within a couple of years, we'll be a net petroleum exporter—not even including natural gas; just on the liquids alone."

—Erin Pedigo

EOG targets lower costs as it improves inventory

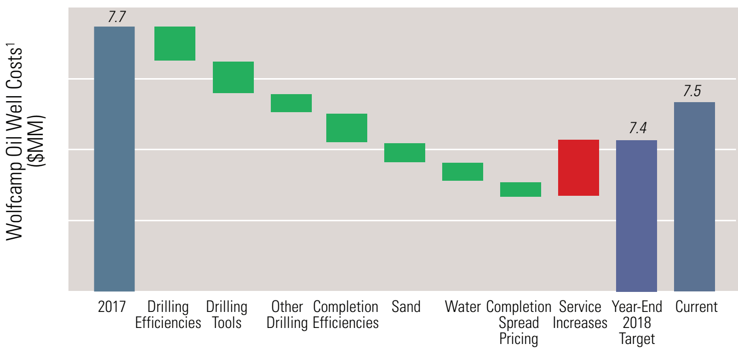
In U.S. shale plays, where increasing efficiency is among the unofficial mantras, EOG Resources Inc. is on a mission to

EOG Well Cost Reductions 2012-2018



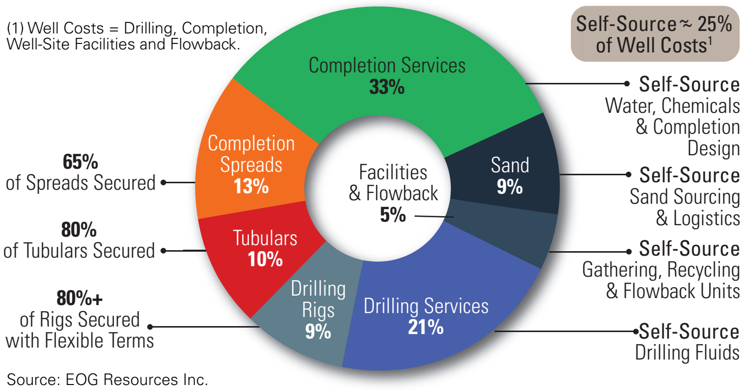
(1) Well Costs=Drilling, Completion, Well-Site Facilities and Flowback.
(2) Normalized to 5,300' lateral.
(3) Normalized to 8,400' lateral.

EOG Wolfcamp Well Cost Efficiencies



(1) Well Costs= Drilling, Completion, Well-Site Facilities and Flowback. Normalized to 7,000' lateral.

EOG 2019 Well Cost Pricing By Service



Source: EOG Resources Inc.

drive down costs as the company improves the quality of its growing inventory.

The Houston-based independent, which generated more than $500 million of free cash flow during third-quarter 2018 as part of more than $1 billion during the year, has already slashed well costs. In the Bakken, well costs are down by more than half, going from $9.8 million in 2012 to $4.6 million today. The company's Eagle Ford well costs also fell, dropping from $7.2 million to $4.4 million during the same timeframe.

"If you think about those times, we were going through times of high oil prices and times of low oil prices and we were still able to drive down well costs regardless of commodity price," Billy Helms, EOG COO, said at Bank of America Merrill Lynch's 2018 Global Energy Conference in November.

"We're well on our way to achieving our 5% cost reduction that we started out [in 2018]."

This includes a goal to bring down well costs to $7.4 million in the Delaware Basin's Wolfcamp. Costs are currently $7.5 million, but EOG is confident costs will fall further as it pulls levers, such as drilling and completion efficiencies, tools, sand and water.

Producers have been focused on lowering costs since the downturn. In response, many have gained fiscal discipline and have been more willing to try new technology and techniques, among other efforts.

Smarter ways of operating could hang around as companies exercise lessons learned. Many E&Ps are already starting to see higher cash flows from operations. EOG and peers, such as Pioneer Natural Resources Co. and Continental Resources Inc., are among them.

EOG, however, increased its 2018 spending budget to between $5.8- and $6 billion, up from between $5.4- and $5.8 billion, to retain high-performing service providers through year-end.

The company hadn't released details yet in December on its 2019 budget, which is likely to come in February.

"We've already secured about 65% of the anticipated typical well costs [drilling, completion and wellsite facilities and flowback] for [2019] at very competitive prices," Helms said during the conference, which was audio-streamed live at the company's website.

"We're trying to capture some of those prices that we're seeing today in the market."

EOG has locked in 65% of spreads, 80% of tubulars and more than 80% of the rigs needed in 2019 at what Helms described as favorable rates with flexibility. "We can flex our program up or down, depending on what the oil price is," he said.

Having flexibility also helps when trying out new concepts. In the Delaware Basin, for example, EOG ramped up to about 20 rigs in 2018 from 13 in 2017 as the company tested new spacing patterns and experimented with completion technology.

"That was all designed to try to understand a little bit more about the rock—having moved from a delineation mode into a development mode—and test some ideas to learn how to go forward on a full development mode," Helms said. The company's rig count has since dropped to 17.

But EOG, like other E&Ps, must still cope with rising service costs as the service sector continues to gain strength post-downturn.

"At the start of [2018], service costs were up pretty much across the board," Helms said, noting there's been a lot of softness on the completions side lately. "I expect, going into the [2019], there is still to be tightness on the drilling side."

The high-performing rigs EOG typically uses are in short supply, he added.

But "there's still quite a bit of frack equipment out there."

Much of this, Helms said, was never reactivated during the latest upturn. "Naturally, tubular products are going to be up mainly due to the tariffs," he added.

"We've tried to anticipate—and get ahead of—that as best we could. … By locking up a lot of these services going into 2019, we can help insulate ourselves from inflationary pressures that may happen [this year]."

Meanwhile, EOG continues to grow its premium drilling locations, which have increased to more than 9,500 from 3,200 in 2016.

"We're replacing this inventory at a rate of twice what we drill every year.

"So it's growing faster than we can actually drill it, but, more importantly, the quality of that inventory is improving," Helms said. "The average well now in that inventory has an EUR of about 970 Mboe."

A focus on premium wells—those that will generate a 30% rate of return or better at a $40 flat oil price—is something that remains at the core of EOG's growth strategy.

"With oil prices where they are today, these wells will generate 60% to 100% rates of return," Helms said.

"So we're pretty pleased with our inventory that we have, and we think that's going to continue to generate cash flow on a go-forward basis."

—Velda Addison

ExxonMobil turns to solar, wind to power Permian

Ørsted A/S has entered agreements with Exxon Mobil Corp. to provide 500 megawatts (MW) of wind and solar power in the Permian Basin, the Denmark-based company reported in November.

The two long-term power-purchase agreements are "a case study of where onshore renewables is heading," it added.

The Sage Draw wind farm, which is scheduled to be completed by first-quarter 2020, will provide half of the power ExxonMobil plans to purchase. The remaining 250 MW will come from Permian Solar, which is to be finished in second-quarter 2021.

ExxonMobil told Hart Energy that the 12-year deal with Lincoln Clean Energy LLC, an Ørsted subsidiary, will serve its operations in Texas. "We frequently evaluate opportunities to diversify our power supply and

ensure competitive costs," Julie King, an ExxonMobil spokeswoman, said.

Ørsted added there could be "further synergies possible in long-term operations and capex."

Several oil and gas players have been tapping renewables as the world turns toward cleaner sources of energy. Some are adding wind and solar energy assets to their portfolios, while others are utilizing such energy sources to reduce emissions or add new power sources for their operations, particularly in areas like the Permian where rising oil-related activity is straining the electricity grid.

Rising demand has prompted some companies, including Noble Energy Inc., to pursue electrification projects.

The Permian's Delaware Basin consumed the equivalent of 350 MW this summer, roughly the amount to power 280,000 U.S. homes, according to a Bloomberg report. The amount was triple the load of 2015, and demand is expected to continue rising as operators pump more.

Daily oil production in the Permian is forecast to grow by 63,000 barrels to about 3.7 million barrels per day in December, according to a U.S. Energy Information Administration forecast. Daily Permian gas production is set to increase by 251 million cubic feet to about 12.4 billion per day.

ExxonMobil is working to triple its Permian production by 2025. The company estimates its assets there hold 9 billion barrels (Bbbl), including more than 5 Bbbl in the northern Delaware Basin.

—Velda Addison

Safety remains major issue for industry

When a workplace accident occurs, particularly in the oil and gas industry, the inclination is for the company to terminate the person or people at fault and hire a replacement. But the perspective doesn't always deal with the internal breakdown that made the safety breach possible, according to Peter Katchmar, director of the U.S. Department of Transportation (USDOT).

Rather, it results in a new hire who is susceptible to the same mistakes. Katchmar calls it his "pickle juice theory."

"You are going to go hire another cucumber, put him in your jar of pickle juice and create a new pickle," Katchmar said in a midstream forum at Hart Energy's DUG Midcontinent conference in November.

"That's what you are going to do. You are going to throw this pickle out and you are going to go hire a new cucumber and throw him in that pickle jar. It's your pickle juice and he is just going to turn into that same pickle that you just got rid of."

While Katchmar's analogy drew much laughter, safety in the oil and gas industry—whether on rigs or pipelines—is a serious concern for all companies. Katchmar, who heads the Pipelines and Hazardous Materials Safety Administration Accident Investigation Division at USDOT, said safety is becoming even more of a concern because the oil and gas industry is becoming younger and less experienced as much of the workforce retires.

Less-experienced workers are more prone to make safety mistakes that could end catastrophically. "I've seen people die because they say, 'Yeah, I'm qualified,'" Katchmar said.

"The second question is, 'Do you use written procedures?' This gentleman had been trained for a year and he was on the job for six months at a big operator. [He] had never used written procedure ever—and he was trained with a guy who had been in the business for 40 years.

"I don't mean to put a damper or shadow over this whole thing, but I like taking warm showers in the morning. I like being able to fill up my gas tank at the local gas station. You guys do a wonderful job a lot of the time—most of the time."

The consensus among the four-member panel was that much is already being done, but even more is needed to ensure the safety of the industry's most valued asset: its employees.

Aubrey Harper, president and CEO of 4AM Midstream LLC, said 4AM's approach is to create an environment that goes beyond safety just in the workplace. For example, he said, employee discussions include how to properly use a ladder at home and how to prevent being mugged at a shopping center during Christmastime.

"It creates that culture where you are thinking about safety beyond just where we are," Harper said. "'What can we do to keep our company, family safe?'

"When you do that you create a culture where safety goes beyond the 8-to-5 or 7-to-6. It becomes a part of life for associates and our families. We feel like that's important and we push for that."

Mark Prewitt, senior director for safety and process safety management at DCP Midstream LP, said DCP decided a few years ago to make safety personal to elevate safe performance. Each year, DCP brings all of its 400 plant and field supervisors together for three concurrent weeklong sessions on safety.

In one, the company showed a video of an employee and his wife discussing a significant injury he suffered when a chain wheel operator fell off and struck him in the head. Fortunately, he was wearing a hard hat that prevented a much more serious injury.

"We had him do a video with his wife and had him talk through that day and, then, both of them kind of talked through the consequences of that and his recovery," Prewitt said. "We did that with three other significant events that we had where we had the employee and their loved ones talk about what happened in the video.

"We showed that to our

supervisors and had a two-hour discussion on that. And it really drove home the point that it is personal. An injury doesn't just affect you; it affects your co-workers, your family—really tried to drive that home."

Another issue that oil and gas companies face is holding independent contractors to the same standards. Sean Atkins, vice president for compliance at EnLink Midstream Partners LP, said it looks at contractors as partners, rather than just "hired help." EnLink holds safety summits with its contract workers to make sure they are all on the same page.

The idea is to let the contractors know they are valued and to make sure they have the same level of understanding and training when it comes to safety as do EnLink employees. "What it really boils down to is we don't treat them as a third-party independent contractor that is just there for the job," Atkins said.

"They have challenges as well, so we really want to help them succeed because, when they succeed, our projects succeed and, therefore, the company succeeds. So we take a look at it with a more hands-on approach."

DCP's Prewitt said it's also important to make sure short-term contractors are on the same page as well. DCP booked 6.5 million contract hours by the end of 2018.

The major concern isn't the contractors that work on a day-in-day-out basis, Prewitt said, but the ones who come in for a specific pipeline project and may not be well-versed on DCP's best safety practices.

"Those were the ones we found that their commitment to safety best practices kind of weren't aligned with us," Prewitt said. "So we made a big effort [in 2018] to scrutinize the contractors or the bidding process.

"We have selected several large contracts that were not the low bidder because we brought them with their executive team and talked to them about the safety culture and their view of safety didn't match up with ours.

"So even though they were the low bidder, we chose not to do business with them."

4AM's Harper said the lowest-bid contractor doesn't necessarily always get awarded the job. Rather, 4AM is willing to pay a little more on the front end for contractors who have proven to have safety practices in line with 4AM's safety policy.

He has found this approach is more effective in the long run, he added. "It has always been those contractors who supply the cheapest bid that you are going to have the biggest amount of issues with.

"You have to take the time to understand, 'Do they fit us? Are they going to be transparent enough with us?'

"The approach with us is I will pay a little bit more to know that I have a contractor that thinks like me, thinks of safety like us. He thinks of our culture and he fits in. I'm not going to pay a huge price for that, but I'm going to look at that as a strong point."

—Terrance Harris

Staff, supply shortages confront gas processors

What's the biggest challenge today in gas processing? It's not the gas itself or the technology used to clean it and extract the related NGL. Rather, it's the people—or lack of them—to do the work.

That was a major topic during a midstream forum that was part of Hart Energy's DUG Midcontinent Conference in November.

"The workforce is a tremendous challenge for us," said Geoff Hager, owner and general manager of Tulsa, Okla.-based Big Elk Energy Systems LLC.

Energy-business careers aren't considered by many high school and college students—even in energy-rich Oklahoma—he said.

"There's a perception that it's a dirty business. We've gone to high school students interested in both four-year and vocational degrees" to discuss career opportunities and the industry's comparatively good wages.

The potential for well-paying jobs usually gets students' attention, he said.

Arturo Puigbo, vice president, sales technology, for Linde North America Inc., seconded Hager's concerns. "We have to focus on the next generation. That's a challenge for any organization," he said, noting the average age of energy-industry employees is on the high side of 50.

Puigbo emphasized the need to assure the body of knowledge gained over the years by experienced personnel is not lost as they retire and younger employees take their places during the oil and gas industry's ongoing "big crew change."

In a related vein, gas processors face supply and manufacturing challenges nearly as severe as the staffing problem, the panelists agreed. Producers want new gas plants built on shorter cycles so they can put new wells on production quickly.

That's difficult, given parts shortages. The Trump administration's tariff rulings have exacerbated the problem for necessary valves and controls manufactured abroad, the panelists said.

"This is very difficult for us because we are in a business that's entirely built on relationships," Hager said. Customers want deadlines met at agreed-upon costs.

Gas-processing naturally has its technical issues as well, the panelists agreed. Companies that build NGL extraction plants, such as Linde, have done a remarkable job of improving gas-processing technology in recent years to the point that the latest-technology plants can extract nearly 100% of the liquids from a raw gas stream, Puigbo said.

However, plants with that impressive capability tend to be large—some with capacities of 300 million cubic feet per day (MMcf/d)—"and that benefits the larger midstreamers," Puigbo added.

The challenge now is to transfer that technology to smaller, less-expensive plants in range of 200 MMcf/d that are typically ordered by smaller midstream players.

Hager called for improvements to field-level gas chromatography systems that can verify the heat content of gas and NGL streams without time-consuming double checks from central laboratories.

"You want to get the exact dollar value for every cubic foot going through as well as the exact volume of every cubic foot," he said.

Improvements are necessary,

although "it's not practical to rip out" existing measurement systems. So ways must be found to improve the accuracy of equipment already in place.

Any technological and operating improvements "must be tied to the cash-register function, where you make your money," Hager added.

—Paul Hart

Despite lower oil prices, some E&Ps to gin up free cash flow

Crude oil was plunging from October highs and flirting with $50/bbl at press time, yet by all accounts, investors were still demanding free cash flow (FCF) from the oil and gas industry. "Free cash flow has never been a more prized commodity among investors," said Mike Kelly, partner, head of E&P research, at Seaport Global Securities LLC in a report.

Going into 2019, U.S. rig counts were reflecting greater caution among industry players.

In light of these volatile conditions and uncertainty, which E&P companies are poised to deliver free cash flow in 2019?

Kelly and team looked deeper into the prospects of 40 E&P companies in Seaport Global's coverage universe generating FCF in 2019, assuming a flat price of $55/bbl for West Texas Intermediate starting in the first quarter.

They further calculated FCF yield, defined as 2019 free cash flow divided by current enterprise value.

Based on this analysis, they concluded the top stocks for estimated FY2019 FCF yield are (in this order) W&T Offshore Inc. at 15%, Cabot Oil & Gas Corp. at 7%, Abraxas Petroleum Corp. at 6%, and Marathon Oil Corp. and Anadarko Petroleum Corp. each at 5%.

Northern Oil & Gas Inc. came in at a robust 12% (the latter being the only nonop-focused company in the group).

However, the average FCF yield projected for the group is a negative 5%, according to Seaport Global's calculations.

Larger E&P companies that are mostly oil and that generally receive more investor attention, such as Concho Resources Inc., Oasis Petroleum Inc. and Pioneer Natural Resources Co., had projected FCF yields of zero, near zero or a negative number.

The top six companies projected to show the best combination of debt-adjusted production growth and highest FCF yield were (in order): Abraxas, Continental Resources Inc., Cabot, Comstock Resources Corp., Diamondback Energy Inc. and HighPoint Resources Corp.

Looking ahead, the top stocks based on cumulative free cash flow yield through 2021 are estimated to be Northern Oil & Gas, W&T Offshore, Talos Energy Inc., Anadarko and Cabot.

Those companies that Seaport identifies with projected positive free cash flow yield combined with more than 20% production growth per adjusted share have outperformed E&Ps in the lower quartile of each category by some 24%, Kelly said.

—Leslie Haines

Analysts: OPEC deal good for global market, U.S. producers

Despite President Donald Trump's persistent calls for OPEC to not lower production, the 15-member oil cartel's decision to reduce supply on Dec. 7 will ultimately be good for U.S. oil production, a senior oil market analyst told Hart Energy.

OPEC ended two-days of intense talks in Vienna, Austria, with the expected decision to reduce oil supply by 1.2 million barrels per day (MMbbl/d) beginning in January. The OPEC producers agreed to cut supply by 800,000 bbl/d starting next month and the non-OPEC producers will reduce production by 400,000 bbl/d for six months beginning in January.

The immediate response was that oil prices jumped 5% as benchmark Brent rose $3.26 to a high of $63.32 early on Dec. 7 and U.S. light crude rose $2.62 to a high of $54.11 before slipping to around $53.90.

After oil plummeted 30% two months ago, OPEC and non-OPEC members came together in hopes of stabilizing the oil market.

"They kind of get the best of both worlds because the U.S. is not a member of OPEC, so U.S. producers produce at-will based on their budgets and individual company plans," said Stratas Advisors senior oil market analyst Ashley Petersen. "At the same time, they are going to benefit from price stability and price increases that come about from OPEC fighting off oversupply.

"That's really going to be the debate [in 2019] and moving forward—how long should OPEC be supporting these prices, at what point do price changes represent a change in global markets and does OPEC just need to accept lower prices, or is it something that OPEC should continue to manage around?"

There was uncertainty as to whether Russia and other non-OPEC members would go along with the supply reductions, but Russia agreed to cut its production by 200,000 barrels per day (bbl/d) so the market began to perk up. There was some uncertainty early Dec. 7 as sanction-laden Iran sought a waiver against supply cuts.

Once countries such as Iran and Venezuela were assured of waivers and Russia was fully onboard, OPEC was able to end a marathon two days of talks with an agreement that is closely in line with what most analysts predicted. There was speculation that the supply cut could have been as steep as 1.3 MMbbl/d, but the consensus seems to be that 1.2 MMbbl/d is a good landing spot for the next six months.

"This was a better than expected outcome," Petersen said. "They didn't give as many exemptions as people thought they would. They really only gave exemptions to countries that both need them and are needed to grow production next year. Venezuela is not turning that around. So the fact that they have an exemption isn't going to impact balances."

The consensus among most analysts seemed to be that OPEC's reductions were ultimately good because they prevent over supply of oil. The immediate shift in the markets seemed to support their beliefs.

"It's been an encouraging day for OPEC, with oil prices reacting positively to the outcomes of the conference," said Florian Thaler, an oil strategist at UK-based OilX. "OPEC's contemplated goal was to mitigate a 1.3 MMbbl/d over-supply, which has been achieved by the agreement of a 0.8 MMbbl/d OPEC and 0.4 bbl/d for non-OPEC allied nations, including Russia. Delegates also came to a consensus on the contentious issue of Iran—namely exemption of the country in the oil cuts, due to the current U.S. sanctions."

During a news conference on Dec. 7, OPEC said its main interest is to stabilize the market for both producers and consumers and to ensure the health and sustainability of the petroleum industry.

"Member countries remain committed to being dependable and reliable suppliers of crude and products to global markets," the cartel said in a released statement.

Petersen said the impact on the consumer won't be prohibitive and she says it could have a positive impact on the economy and jobs in the oil and gas industry.

"This isn't necessarily bad news for consumers because this isn't going to support $100 per barrel prices," Petersen said. "This is just kind of putting a floor to what we have been looking for. It adds to stability in prices, which is also important for consumers.

"While prices in some areas may go up a little bit or at least might stop falling it isn't going to directly hurt consumers' wallets. Then when you think about the economic impact of oil and gas operations for all it providing security to those jobs all throughout as well, that is good for consumers and future spending."

But Stratus Advisors director Greg Haas did add a cautionary note.

"If implemented, the announced OPEC cuts should incrementally put the market in a tighter supply position than previously thought," he said. "And if Alberta follows through on their unprecedented mandate to cut crude production by 325 Mbbl/d, then the willful removal of oil supply could top 1.5 MMbbl/d at the beginning of 2019. U.S. shale producers, still being chastised to keep spending within cash flow, likely cannot ramp production by similar barrels in a similar timeframe.

"The market outlook is clearly tighter today than it was yesterday. The new fashion for tight supply is arriving as the months and quarters ahead lead up to the implementation of big demand-side changes resulting from the sulfur-reducing rules known as IMO 2020."

With Trump staunchly against the production cuts, he could lessen the cost increase to consumers by releasing U.S. strategic reserves via an executive order, but Petersen does not believe that is the route Trump will take. The increases at the pump aren't expected to be that significant.

—Terrance Harris

TOP 50 E&Ps

From the biggest operators with multinational portfolios to basin-specific, smaller producers with motivation to grow, *Investor* showcases the 50 most-valued U.S independents.

ARTICLE BY
STEVE TOON,
DARREN BARBEE
AND LESLIE HAINES

For its inaugural list,* Investor *based 2017 company rankings on factors such as production, year-before market value adjusted for outstanding shares, and the relative position of now-defunct companies. Some executive comments were sourced from transcripts at SeekingAlpha.com.

PHOTO COURTESY NEWFIELD EXPLORATION CO.

Magnolia Oil & Gas Corp. didn't exist as an E&P a year ago. As a SPAC, TPG Pace Holdings Corp., at the time, Magnolia came to be this past summer via the acquisition of Eagle Ford Shale assets carved out of privately held EnerVest Ltd.

But CEO Steve Chazen knows something about achieving scale when it comes to investor buy-in. He previously led Top 5 E&P Occidental Petroleum Corp., taking it through a portfolio rationalization that would make an asset advisor's head spin, positioning that company with high-return, sustainable assets to weather future downturns.

"Oil and gas isn't all that popular in the investment community," he told *Investor* after closing the deal with EnerVest, "so I needed to find investors that invested in normal companies—cable or technology or industrial companies—where there are earnings from free cash flow and reasonable growth. I had to design a company that worked that way.

"We'll come out of the box with earnings per share—that's not immaterial. We have good runway to make decent returns for investors. If you make a story of reasonable growth, earnings per share, free cash flow, you can get investors to buy your stock."

Not a year old yet, Chazen's Magnolia has the assets and Wall Street confidence to crack the Top 50 public indies, leapfrogging dozens of other public producers in its debut.

It goes to show how quickly names can come—and go—on a list of top-valued E&Ps. The ebb and flow of market tides significantly affect valuations on any given day. And, with an equity-market downdraft across sectors this fall, oil and gas producers weren't spared. Add to that a dramatic pull-back in oil prices.

But a rising—or receding—tide lifts and drops all. Thus, *Oil and Gas Investor* valued all public E&Ps by market capitalization on Nov. 8, 2018. To be included, these producers must have production in the U.S., and E&P must be their primary endeavor. Integrated operators were excluded, as were producers for whom E&P is a secondary business. All production listed below is U.S. volumes only, unless otherwise noted.

Through 2018, E&Ps struggled with the choices of continuing with a growth-oriented trajectory per a traditional business model or shifting to a more value-driven model with slower growth and higher returns. The decision is not always obvious and a gamble either way.

The results of those strategies as determined by the investment community are represented below and ongoing. *Investor* presents this year's Top 50 Public E&Ps.

1 ConocoPhillips

HOUSTON
Market cap: $76.822 billion
Last year's rank: 1
Production: 579,000 boe/d
Key plays: Lower 48, Alaska, GOM

CONOCOPHILLIPS DESCRIBES itself as the world's largest independent E&P based on production and proved reserves—and it's the largest by market cap as well. The formerly integrated oil company still has an international E&P portfolio that would make any IOC do a double take. And for good reason: Its breadth encompasses European, North African and Asian conventional, Australian LNG, Canadian oil sands and, not the least, U.S and Canadian unconventionals. Its "Big 3" unconventional plays—the Eagle Ford, Delaware and Bakken—grew in output 43% year-over-year and are targeted to deliver 22% annualized growth through 2020. Those will add an additional $2 billion in net cash flow. Its North Slope, Alaska, project is on the rise as well. Globally, ConocoPhillips' production tops 1.2 MMboe/d. Going forward, it projects adding 90 MMboe/d over the next six years from international assets alone. After exposing itself to the raw edge of the downturn when separating from its mid- and downstream segments in 2012, the company carved out $16 billion in divestments through 2017, using much of that to pay down debt. Beyond the asset base, ConocoPhillips has won investor trust with a shareholder-friendly program that keeps on giving; notably, some $15 billion in planned buybacks that represents 20% of shares. "Our portfolio and efficiency efforts have boosted the underlying strength of our company and driven what we believe is a peer-leading sustaining price of less than $40 WTI," said Ryan Lance, CEO, in an earnings call. "We know it's a formula that works and we're sticking to it."

2 EOG Resources Inc.

HOUSTON
Market cap: $61.186 billion
Last year's rank: 2
Production: 700,448 boe/d
Key plays: Eagle Ford, Delaware, Powder River, D-J Basin, Bakken, Anadarko Basin

JUST LIKE "EVERYONE Loves Raymond," everyone—investors and operators alike—loves EOG. The perennial favorite is the E&P everyone wants to grow up to be. And iconoclastically opposite of many producers chasing investor sentiment to become single-basin-focused, EOG is digging dirt in a host of leading oily plays. Largely organically grown, EOG continues to add new plays to its "premier" portfolio—self-described as meeting a 30% rate of return hurdle as measured against a price deck of $40 oil and $2.50 natural gas, "no matter if commodity prices improve [in 2019]," per CEO Bill Thomas. Just this past year, it elevated both the Eastern Anadarko Woodford oil window and Powder River Basin to its class of assets worthy of receiving development capital. Production grew 25%. Thomas, in the company's second-quarter call, said, "The EOG machine is firing on all cylinders. … Our disciplined investments across a diverse array of premium plays are generating record rates of return." Those returns translate to free cash flow, and that excess cash is flowing back to investors with a 31% hike in its dividend in 2018.

3 Occidental Petroleum Corp.

HOUSTON
Market cap: $56.245 billion
Last year's rank: 3
Production: 315,000 boe/d
Key plays: Permian, Middle East, Colombia

GIVE OXY CREDIT for durability: The company celebrates its 99-year anniversary this year. While its diverse history has had the company invested in varied industries, today it focuses on oil and gas, midstream and marketing, and chemicals. In the upstream, Middle East operations represent nearly half its production; yet, within the U.S., the company is solely enamored with the Permian Basin. Oxy controls some 2.5 million acres there, split between its conventional EOR and unconventional-resource divisions, which account for 9% of all Permian oil produced, according to the company. But it's the unconventional side receiving all the buzz lately. Oxy brags on having 26 of the top 50 wells in the Permian during the past year. Two in particular are barn-burners, even for 24-hour IPs: A Greater Sand Dunes well peaked at more than 8,900 boe/d; one in the Greater Barilla Draw area topped 6,500 boe/d. Despite investor pushback, the company saw a window of opportunity and plowed an additional $1 billion of 2018 capex into the program with an estimated 50% production jump for the year. For 2019, it's targeting 35%. Oxy cleared an additional $5 billion in 2018 cash with the $2.5-billion sale of midstream assets along with another $2.5 billion gleaned from upsized oil prices—with all but the aforementioned $1 billion allocated to share buybacks. Company economics are designed to grow both production and the dividend at $50 oil.

4 Anadarko Petroleum Corp.

THE WOODLANDS, TX
Market cap: $29.354 billion
Last year's rank: 4
Production: 682,000 boe/d
Key plays: Delaware Basin, D-J Basin, Powder River Basin, GOM, Africa

ANADARKO CASTS A wide exploration footprint to diversify its value—from short-cycle U.S. onshore unconventional assets to high-margin conventional projects offshore Africa and in the Gulf of Mexico. Onshore the U.S., the operator is nearing completion of an infrastructure buildout in the Delaware Basin, where it's producing 120,000 bbl/d and had seven rigs running this past fall, a 20% increase quarter-over-quarter. CEO Al Walker emphasized to investors that more than half of its oil volumes receive waterborne pricing—a nod to the Brent uplift and including one cargo shipment per month out of Houston—and expects 70% to sail away when the Cactus II pipeline from West Texas to Corpus Christi is completed. Anadarko set the bar to be free-cash-flow positive above $50/bbl and is using the lagniappe to fund share buybacks to the tune of $5 billion, debt paydown of $2 billion and a measured ramp-up of its dividend by 30 cents per share. Also, it plans to determine FID on its Mozambique LNG project by mid-2019.

5 Pioneer Natural Resources Co.

IRVING, TX
Market cap: $27.233 billion
Last year's rank: 5
Production: 320,659 boe/d
Key plays: Midland Basin, Eagle Ford

TEN YEARS AGO, *Investor* featured Pioneer in, "Coming Home," a story about operators paring their international portfolios to focus on the U.S. Today, one could say Pioneer's "home" is the Permian Basin as the company guided that it would be a Permian pure-player before year-end 2018, expecting to announce a sale of its final non-Permian-holding—the Eagle Ford Shale. But what a mansion: The company has more than a full table to feast on with 785,000 acres—that's 1,226 square miles—and 20,000 drilling locations in the heart of the Midland Basin. And, as other operators gnashed their teeth over depressed pricing these past few months, the Permian prince receives Gulf Coast pricing, thus avoiding the pesky Mid-Cush differentials. CEO Tim Dove, in the latest earnings call, declared that Pioneer is now "essentially a Brent-priced company." The company has 24 rigs running with growth plans exceeding 20%.

6 Concho Resources Inc.

MIDLAND, TX
Market cap: $27.151 billion
Last year's rank: 6
Production: 287,000 boe/d
Key plays: Permian Basin

THE ORIGINAL PERMIAN pure-player, Concho wielded Thor's hammer to make a statement with its $9.5-billion takeout of RSP Permian Inc. last July. The all-stock deal points to the value and trust in Concho's value base. Following the combination and with RSP's 55,000 boe/d, Midland's home team touts itself as the largest oil and gas producer in the Permian, running 34 rigs across 640,000 acres in West Texas. "Those assets and that fit with our existing portfolio really create a lot of powerful economies," Tim Leach, CEO, said. Concho brags on free-cash-flow generation in 12 out of the prior 13 quarters with a 1.2x debt-to-EBITDA. It plans 2019 capex in the neighborhood of $3.5 billion, based on $55 to $60 oil. "We clearly have two very important priorities," Leach said on the third-quarter call. "One is to demonstrate that we can grow our oil production and deliver free cash flow and a return of capital to our shareholders—and do all that in a very efficient way as we mechanically mine this asset that we have."

7 Continental Resources Inc.

OKLAHOMA CITY
Market cap: $18.870 billion
Last year's rank: 8
Production: 296,900 boe/d
Key plays: Bakken, Scoop/Stack

WITH OIL PRICES SOARING and with a completely unhedged oil portfolio, Continental CEO Harold Hamm saw a bird in the hand this past summer and juked when others jived, accelerating growth in his two big plays in contrast to all the other big guys stoically exhibiting capital discipline. Will the move pay off? The company was to bring on 70 new Bakken wells in the fourth quarter—40% of the annual basin total—and another 18 in Oklahoma, potentially boosting year-over-year production by up to 24%. "While we remain a highly disciplined company with a primary focus on capital-efficient growth and corporate returns, it was an appropriate time to increase our production growth rate," Hamm said. Even with the capex bump, free cash flow was projected to approach $1 billion through 2018. Due to its unhedged-on-oil nature, and if oil prices hold strong, the company's $6 billion of debt and 1.5x leverage ratio stand to plummet.

9 Devon Energy Corp.

OKLAHOMA CITY
Market cap: $16.795 billion
Last year's rank: 7
Production: 418,000 boe/d
Key plays: Delaware, Stack, Powder River, Canadian oil sands

ALAS, DENSITY MATTERS. Devon is lowering expectations around its Stack oil play, which it upsized in late 2015 with a nearly $2-billion acquisition of Felix Energy LLC, the premium value predicated around an expected eight to 12 wells per unit. Subsequent, testing proved otherwise: Four to eight are more realistic. In 2019, Devon intends to stack its chips on its Delaware Basin asset with nearly $1 billion in capex, girded by the knowledge that "we have secured the supply chain, infrastructure and takeaway capacity

8 Hess Corp.

NEW YORK CITY
Market cap: $17.726 billion
Last year's rank: 10
Production: 128,000 boe/d
Key plays: Bakken, Gulf of Mexico, Guyana, Malaysia, offshore Canada

CAN YOU SAY GUYANA? Hess does—a lot. Despite having a global portfolio, the multinational explorer is high on its prospect offshore South America. And why not? In the third quarter, Hess revealed a ninth discovery on its Stabroek Block in a year. Together, these discoveries are estimated to contain some 4 Bboe of gross recoverable resources, with up to five FPSOs producing 750,000 bbl/d by 2025. Exxon Mobil Corp. is the operator, with Hess holding 30%. A second drillship is being deployed to further test prospects. Guyana and its other favorite play—the Bakken—consumed 75% of its

$2.1-billion operational budget for 2018, and that's likely to continue, per John Hess, CEO. In third-quarter comments, he indicated the 2019 spend would blossom to $3 billion. "All that incremental spend between 2018 and 2019 will be targeted to the highest-return investments in the E&P business, and that's our Bakken and Guyana assets." The portfolio should be "cash generative" post-2020, he added.

ConocoPhillips' Alpine Field on Alaska's western North Slope is one of the largest onshore oil fields discovered in North America in the past 20 years. The Alpine West CD5 drill site achieved first production in 2015 and has capacity for up to 43 wells.

Photo courtesy of ConocoPhillips.

Apache Corp.'s discovery in far West Texas dubbed Alpine High in southwestern Reeves County opened up a region in the southern Delaware Basin believed to be too geologically complicated to produce at scale.

Photo courtesy of Apache Corp.

10 Marathon Oil Corp.

HOUSTON
Market cap: $15.238 billion
Last year's rank: 12
Production: 304,000 boe/d
Key plays: Eagle Ford, Bakken, Scoop/Stack, Delaware, Equatorial Guinea

WHEN MARATHON DIVESTED its Canadian oil sands assets for $2.5 billion in 2017 and simultaneously added nearly $2 billion in Delaware Basin acquisitions, it set the tone for 2018's program: funnel 90% of its $2.3-billion global operational capex into U.S. resource plays. And it intended to do that with production growth of between 10% and 14%, targeting 30% returns at $50 WTI. It did that and more, raising production targets quarterly, without raising capex. And, while its Eagle Ford and Bakken positions make up the lion's share of the budget—and production—the less-mature Scoop/Stack and Delaware Basin assets garner the bulk of investor infatuation. But the ongoing Eagle Ford core extension is achieving "outstanding results," said CEO Lee Tillman in the most recent earnings call, and the Bakken deserves awe. "We've gotten a little bit spoiled and jaded in the Bakken," he said, where a recent well realized 4,800 boe/d IP30. "These wells are incredible, world-class wells and certainly some of the best that have ever been completed in the North American unconventional space…. And, all of a sudden, that's not even headline-grabbing anymore, which is shocking to me." What to watch for: Marathon spud its first exploration well in the emerging Louisiana Austin Chalk play during the third quarter.

to execute on our development plans," said Dave Hager, CEO. That's not to mention some 4,000 boe/d Wolfcamp wells. A doubling of rigs in the rising Powder will fill the Stack EUR gap. Still, Devon hopes to woo investors with other perks: By year-end, it was approaching its $5-billion divestiture goal, including shedding its half-interest in EnLink Midstream LLC for $3.1 billion. Much of that surplus was reinvested into an aggressive $4-billion share buyback program, the industry's largest when measured by market cap; $2.7 billion had been deployed through the third quarter. An additional $4 billion of excess cash flow was driven into debt reduction.

11 Apache Corp.

HOUSTON
Market cap: $14.073 billion
Last year's rank: 9
Production: 272,000 boe/d
Key plays: Permian, Egypt, North Sea

WHILE ITS WEST Texas Alpine High discovery dominated headlines in 2017, Apache is also diligently at work running 16 rigs throughout its 1.6-million-acre Permian position spanning the Midland and Delaware basins and even the Central Basin Platform. But Apache is still high on Alpine High, touting it as a world-class discovery with 5,000 locations to tap 3 Bbbl and 75 Tcf of resource in place. In 2018, midstream was foremost on Apache's mind: It commissioned the 2 Bcf/d Permian Highway Pipeline Project with Kinder Morgan Inc., EagleClaw Midstream Ventures LLC and Blackstone Energy Partners LP; agreed to be an anchor tenant on the EPIC crude pipeline; and dropped its Alpine High midstream assets into the publicly traded Altus Midstream LP with a $3.5-billion valuation. For 2019, Apache plans a $3-billion capital program (a slight downtrend from 2018) to maintain current levels of activity, projecting 15% production growth in the U.S. and 10% overall. Elsewhere, Apache made its fourth discovery on the U.K. North Sea Garten Block with 700 feet of pay and 10 MMbbl of expected recoverable resource.

12 Noble Energy Inc.

HOUSTON
Market cap: $12.677 billion
Last year's rank: 11
Production: 249,000 boe/d
Key plays: D-J Basin, Delaware, Eagle Ford, Israel

NOBLE'S 2017 ACQUISITION of Clayton Williams Energy Inc. nearly tripled its acreage in the southern Delaware, and, in 2018, the company cashed in on that bet, doubling its production from the region year-over-year. Yet it tempered completions and new drilling in the latter part of 2018 and in plans for at least the early part of 2019, acquiescing to basis differentials and moderating new production to basin-pipeline additions. Capex is being redeployed mostly to the D-J. With the Colorado setback scare in the past for now, Noble is pushing forward with its Mustang comprehensive drilling plan there: a 100-square-mile, state-approved plan built around infrastructure and manufacturing efficiencies. Some 800 locations are included. Elsewhere, Israel is trending up, with Noble's big offshore Leviathan project due to produce first sales by year-end 2019 as is West Africa, with its 3 Tcf potential Alba Field anticipated to be sanctioned in early 2019. Trending down: Eagle Ford. Gone: Gulf of Mexico, Appalachia. Exploration remains a Noble priority. On the horizon: Newfoundland, Gabon, the Eastern Mediterranean.

13 Diamondback Energy Inc.

MIDLAND, TX
Market cap: $11.234 billion
Last year's rank: 17
Production: 123,000 boe/d
Key plays: Midland Basin

DIAMONDBACK SHOUTED TO the industry and to Wall Street that it is positioning itself to be an operator of scale in the Permian with the purchase of both Energen Corp. and Ajax Resources LLC for a combined $10 billion. Both deals were set to have closed by year-end, and Diamondback's market cap and production do not reflect pro forma numbers, poising the company for a move up in the 2020 ranking. It also grabbed an additional 3,600 acres with 3,500 boe/d from ExL Petroleum LP and EnergyQuest LLC in October in the northern Midland Basin, shoring up its position. The combined company will feature 394,000 net acres across the Midland and Delaware basins with 7,200 locations and 14 rigs in motion pre-Energen, which also had 10 running. "Diamondback will continue to look for assets complementary to our existing asset base that compete for capital right away," said Travis Stice, CEO, in the third-quarter call. The producer grew production 45% year/year and within cash flow. Additionally and above its $1.5-billion capex, it joined with The Carlyle Group LP to drill outlier acreage in Pecos County, Texas. And not to forget: Diamondback started its big buying spree in 2017 with the $2.5-billion Brigham Resources LLC deal.

14 Cabot Oil & Gas Corp.

HOUSTON
Market cap: $11.043 billion
Last year's rank: 13
Production: 2,029 MMcfe/d
Key plays: Marcellus

A PREMIER APPALACHIAN player, Cabot has patiently waited for pipes—and for the better part of five years. Amazingly though, and despite sometimes wide basis differentials and challenged natural gas pricing, the company maintained positive free cash flow for nine of 10 consecutive quarters. The feat exhibits Cabot's drive to be the lowest-cost producer in the northeastern Pennsylvania Marcellus. And Cabot's pipe dreams came true in October, with the oft-delayed Atlantic Sunrise finally in service, absorbing 850 MMcf/d of Cabot's 2 Bcf/d production. With pipeline constraints in the rearview mirror, the producer foresees production growth of between 20% and 25% through 2019, up from 8% in 2018.

15 EQT Corp.

PITTSBURGH
Market cap: $9.134 billion
Last year's rank: 16
Production: 4,068 MMcfe/d
Key plays: Marcellus, Utica

IN 2017, THE Marcellus-Utica power player scooped up Rice Energy Inc. in an $8.2-billion blockbuster that slingshot it to the front of the pack of gas producers in the U.S. Despite some turbulence in the CEO seat in 2018 and a shuffling of upper management, the producer finds itself generating some 4 Bcfe/d. However, a late-year bump up in capex and bump down in production guidance dinged the stock, as investors took a wait-and-see approach to the transition. One challenge: The Rice acquisition gave opportunity to extend average lateral lengths from 8,000 feet to 14,000, with many capable of 18,000 or more. "In hindsight, we probably tried to drill too many of those ultra-long laterals in 2018," said new CEO Robert McNally in the 3Q call, adding to learning curve costs. 2019 will feature "a more measured pace." In late November, EQT spun out its midstream assets into Equitrans Midstream Corp., setting itself up as a streamlined E&P going forward.

In the third-quarter call, though, Dan Dinges, CEO, assured "our focus, first and foremost, is on maximizing returns and free cash flow with production growth simply being a result of disciplined capital allocation to high-quality assets." Cabot commits 50% of free-cash-flow generation to dividends and buybacks.

16 Cimarex Energy Co.

DENVER
Market cap: $8.613 billion
Last year's rank: 15
Production: 218,600 boe/d
Key plays: Permian, Midcontinent

CIMAREX HOPPED ON the merger bandwagon in late 2018, announcing the $1.2-billion acquisition of Resolute Energy Corp., bolstering its Delaware Basin position by a third. Pro forma, production will be 253,000 boe/d. CEO Tom Jorden pounds the table on the mantra "returns over production-ramp," with the company moving to a large-scale, multi-year development plan based on flat pricing of $55 oil for the next three years. But the operator is also focused on squeezing every ounce of value out of its Permian and Midcon assets as well with "a deeper understanding of optimum development" that does not overdrill or underdrill, he said. One challenge to full-out development: "We're still getting surprised to the upside with some of these new landing zones, a number of which we haven't discussed and aren't ready to discuss," Jorden said.

17 Encana Corp.

CALGARY
Market cap: $8.419 billion
Last year's rank: 14
Production: 137,000 boe/d
Key plays: Midland Basin, Eagle Ford

ENCANA SURPRISED THE market once again in November when it revealed a near-$8 billion planned combination with Newfield Exploration Co., establishing itself in Oklahoma's Scoop/Stack and stocking up on an additional 3 Bboe of liquids reserves. In 2014, Encana bought Athlon Energy Inc. for $7 billion to get a foothold in the Permian. The Canadian company also holds Eagle Ford, Williston and Uinta assets in the U.S.; in Canada, in the Montney and Duvernay. Pro forma total production will be 577,000 boe/d, which the company touts as second-best in North American unconventional resources. The deal is expected to close in this quarter. Encana anticipates transferring its Midland Basin cube-development strategy to the Scoop/Stack. "Having multiple core positions gives us a tremendous advantage when it comes to managing risks related to market access and infrastructure," said CEO Doug Suttles in the third-quarter call.

18 Parsley Energy Inc.

AUSTIN, TX
Market cap: $7.752 billion
Last year's rank: 18
Production: 116,200 boe/d
Key plays: Permian

Following a period of acquisitiveness and an aggressive development pace during the down-cycle to build scale, Parsley spent 2018 concentrating on "operational continuity" in search of better efficiencies. Its goal: achieve free-cash-flow status by year-end 2019. Following a year of 56% production gains from its 200,000-acre positions in the Midland and Delaware basins, Parsley leveled drilling activity and set about creating margins. "We've now established a line of sight to significant and sustainable free cash flow," incoming CEO Matt Gallagher said to investors. "The idea is to get there and stay there at a meaningful scale." Founder and previous CEO Bryan Sheffield stays on as chairman in 2019.

19 Energen Corp.

BIRMINGHAM, AL
Market cap: $7,123 billion
Last year's rank: 23
Production: 103,100 boe/d
Key plays: Permian

Energen is the glowing bride to Diamondback's groom in one of the largest deals of the year. Valued at $9.2 billion to be paid in stock, Diamondback stands to gain 179,000 net acres and 90,000 boe/d in the Midland and Delaware basins. The deal, which was to have closed by year-end, adds some 3,900 horizontal locations, a 120% boost to Diamondback's inventory.

20 WPX Energy Inc.

TULSA, OK
Market cap: $6.531 billion
Last year's rank: 26
Production: 123,800 boe/d
Key plays: Delaware, Bakken

WPX is on an upward trajectory. With its portfolio transformation largely complete, accented by the sale of its San Juan Basin assets in 2018, the company is primarily an oil-producer today. Anchored in the burgeoning Delaware Basin since its 2015 entry, WPX has sought to control its destiny for its ramping production vs. infrastructure constraints via its own midstream buildouts and partnerships. It receives 98% of WTI pricing. A delay in a self-owned processing-plant completion in the third quarter, however, exacerbated gas and NGL constraints that were alleviated before year-end. In 2019, WPX plans to generate free cash flow at strip while growing oil volumes 25% to 30% with a flat rig count.

21 Murphy Oil Corp.

EL DORADO, AR
Market cap: $5.363 billion
Last year's rank: 25
Production: 169,000 boe/d
Key plays: Gulf of Mexico, Eagle Ford, Duvernay/Montney, offshore Canada, Malaysia, Brunei

This diverse E&P-oriented operator is committed to delivering free cash flow and continuing to pay its longstanding dividend while growing oil production. It has successfully delineated the Samurai find in the Green Canyon of the Gulf of Mexico, raising its discovered resource there to 90 MMboe, so plans for 2019 are underway. In October, Murphy expanded its exploration in the Gulf by inking an accretive, oil-weighted JV with Brazil's Petrobras, paying $900 million to Petrobras. CEO Roger Jenkins touted the deal, which was well received by the market, as a transaction "directly tied to our long-term strategy." Earlier in the year, the company boasted of about $2 billion of liquidity with no borrowings on its credit facility. By the third quarter, it had beat on operated cash flow and reported free cash flow of $141 million year to date—it returned 12% of that to shareholders through its longstanding dividend.

22 Antero Resources Corp.

DENVER
Market cap: $4.979 billion
Last year's rank: 21
Production: 2,718 MMcfe/d
Key plays: Marcellus

Antero's mantra in 2018 was to "keep it simple." The company announced its two affiliated midstream entities will merge and convert to a C corp, owned 31% by the parent, a move chairman, president and CEO Paul Rady said on a conference call is "a win-win-win across the Antero family." A Marcellus leader, Antero recently surpassed 3 Bcfe/d of production and its growing liquids output now makes up 43% of the total.

23 Centennial Resource Development Inc.

DENVER
Market cap: $4.891 billion
Last year's rank: 24
Production: 62,930 boe/d
Key plays: Delaware Basin

If reputation is everything, that goes a long way with this relatively new company, whose chairman and CEO Mark Papa made hay at his former post, EOG Resources Inc. He's chasing industry-leading performance once again, which is on its way to 65,000 bbl/d by 2020 from the northern Delaware Basin, while reporting top-notch wells there. Its longest lateral yet went 12,000 feet in Upper Wolfcamp. Investors were encouraged recently with its first test of the First Bone Spring in New Mexico, which management said on a conference call a third to a half of its acreage is feasible for developing this new zone. In addition, it plans to test two additional zones in 2019—the Second Bone Spring and a 2-mile Third

Marathon Oil stands out as a Top 10 independent operator because of the breadth and execution of its portfolio, and the Bakken Shale stands tall within its holdings. The company holds some 255,000 net acres in the heart of the Williston Basin.

Photo courtesy Marathon Oil

Hess Corp. balances its portfolio with global offshore exploration, highlighted by its participation in discoveries in Guyana, as well as U.S. shale. Here, the Baldplate production facility in the deepwater Gulf of Mexico represents Hess' first discovery in the GoM in 1991, with current production from seven primary fields.

Photo courtesy of Hess Corp.

Bone Spring carbonate. Papa assured investors he's locked in takeaway for 100% of the gas and 70% of the gross oil output, so no flaring will be needed. He said M&A is too pricey, so he prefers to grow production organically by drilling—and maybe a few bolt-ons.

24 Range Resources Corp.

FORT WORTH
Market cap: $4,335 billion
Last year's rank: 27
Production: 2,267 MMcfe/d
Key plays: Marcellus, Louisiana Terryville

HAVING DISCOVERED THE mighty Marcellus, Range has now drilled more than 1,000 such wells, and it just completed the longest lateral in the play yet at 18,556 feet, located in southwestern Pennsylvania. CEO Jeff Ventura vows to keep whittling away at the company's debt while maximizing output from its peer-leading Marcellus inventory. "We have great confidence in our long-range plan," he told investors, adding that he believes the company has the best gas assets in North America based on quantity, quality and liquids optionality. The company already ranks as a Top 10 gas producer at 2.3 Bcfe/d and, what's more, it's been riding the wave of increased NGL prices, being among the top three NGL producers in the U.S. and the first to export ethane to Europe. Liquids production contributes 47% of total product revenues. It stubbed its toe with the pricey Louisiana purchase, but recently sold a 1% override in Washington County, Pa., for $300 million as part of its debt-reduction effort.

25 Newfield Exploration Co.

HOUSTON
Market cap: 4,324 billion
Last year's rank: 20
Production: 202,000 boe/d
Key plays: Scoop/Stack

THIS SCOOP/STACK PIONEER will soon be scooped up by Encana Corp. for $5.5 billion in stock plus assumption of $2.2 billion of net debt for total deal value of almost $7.7 billion. Meanwhile, it beat production in the third quarter, with better-than-expected well results in the Anadarko Basin. Its production there averaged 143 MBoe/d, up 11% vs. the second quarter. Encana has to like what's ahead for the assets it's buying: Newfield recently issued targets of between 14% and 18% total production CAGR from 2018 through 2020.

26 Southwestern Energy Co.

SPRING, TX
Market cap: $3,291 billion
Last year's rank: 30
Production: 2,800 MMcfe/d
Key plays: Marcellus

SOUTHWESTERN MADE A huge pivot in 2018 by selling its legacy Fayetteville Shale, which it discovered early in the shale revolution, for $1.86 billion. With renewed focus in Pennsylvania, it aims to ramp up liquids output and will look harder at Upper Devonian, where its first test was so good that the company thinks it's comparable to the economics of the rich-gas Marcellus. CEO Bill Way told investors, "We're on a mission to achieve both a sustainable, 2x leverage ratio and free cash flow neutrality by the end of 2020." Strong NGL prices have led it (and all its Appalachian peers) to pursue more liquids output; in fact, liquids are a third of its local production. A strong third-quarter beat on cash flow (up 40% year/year) was due to increased NGL performance and cost savings from its expanded water projects in the basin. It will deliver water by pipe to all wells in 2019, saving $500,000 per. A share repurchase program was initiated in September; cash flow positive will be reached in 2021.

27 Whiting Petroleum Corp.

DENVER
Market cap: $3.283 billion
Last year's rank: 39
Production: 128,680 boe/d
Key plays: Bakken, Niobrara

NOW ON GEN 4 designs in the Bakken's Sanish area, Whiting looks rock solid. Its enhanced completions there have been outperforming prior wells by a stunning 80%. This is one of the few mid-cap E&Ps to generate free cash flow, all while adding inventory in Mackenzie County, N.D., to the tune of 100 more locations on newly acquired acreage, answering investors' call for

28 Chesapeake Energy Corp.

OKLAHOMA CITY
Market cap: $3,262 billion
Last year's rank: 28
Production: 537,000 boe/d
Key plays: Eagle Ford, Anadarko Basin, Powder River Basin, Marcellus

CHESAPEAKE WOWED THE market in October by unveiling its proposed acquisition of WildHorse Resource Development Corp. for $4 billion primarily in stock to increase its Eagle Ford position. The announcement was the morning after Chesapeake closed on the $2-billion cash sale of its Utica-Ohio assets to Encino Acquisition Partners LLC. WildHorse's northeastern Eagle Ford is a cash flow machine. It's another milestone in Chesapeake's grand transition from being one of the country's biggest gas producers for many years to being oilier and continuing to bulk up higher-margin assets. Its fast-developing Turner Formation in the Powder River Basin is another step in this process, where it's targeting 80% of future drilling. The biggest hurdle to more investor love is its $9 billion-plus of debt that CEO Doug Lawler continues to address through a series of refinancing deals and divestments.

more line-of-sight growth. Further, CEO Brad Holley said the new completions can unlock potential in what he calls "halo plays" on the Bakken's edges, moving them from Tier 2 into the Tier 1 column. The company may have dodged a bullet on the Colorado referendum in November. But, on the other hand, it pulled its Red Tail asset from the market, failing to get the price it wanted.

29 CNX Resources Corp.

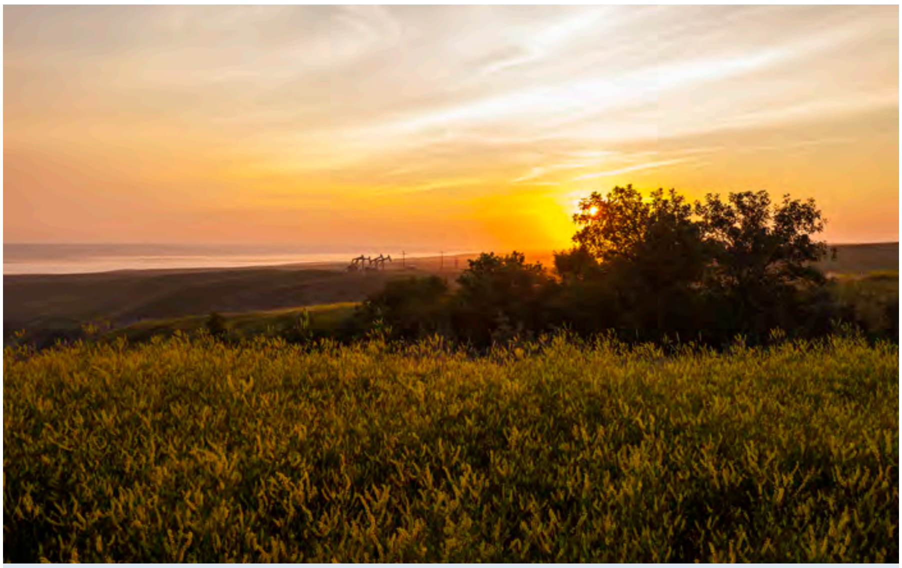
CANONSBURG, PA
Market cap: $3.168 billion
Last year's rank: 29
Production: 1,293 MMcfe/d

One of the largest and longest-legacy Appalachian Basin gas producers—and now set free from an affiliated coal operation—CNX has turned its attention to greater well results, share repurchases and lower debt. To that end, it sold its Ohio wet-gas assets that were in a JV with Hess Corp. to Ascent Resources-Utica LLC for $400 million cash. President and CEO Nick DeIuliis said this accretive deal "brings forward the value of assets that were simply outranked by other options in CNX's opportunity set." This past summer, CNX reported it was the first producer to commit to using a 100% electric frack fleet in the basin, partnering with Evolution Well Services LLC. Lessons from the company's central Pennsylvania operation are being applied southwest, with development of Marcellus and Utica stacked payzones on the same pad.

30 Matador Resources Co.

DALLAS
Market cap: $3.090 billion
Last year's rank: 34
Production: 54,600 boe/d
Key plays: Delaware Wolfcamp, Eagle Ford, Haynesville

A Delaware success story that keeps growing, Matador stepped up big time and made headlines at the recent New Mexico BLM lease sale, paying up for core-of-the-core acreage. It looks like it was worth it: The company added 8,400 acres in the prolific Stateline area (southern Eddy and northern Loving counties). Now some 88% of company production is in New Mexico and it will add an eighth rig there in 2019. It's producing from seven intervals and recently drilled its first operated 2-mile lateral. In the Antelope Breaks area, it drilled the best well in company history. A plus: Matador announced a gas-gathering and -processing agreement through its midstream unit, San Mateo Midstream LLC, with an E&P on its Eddy County acreage. With this deal and saltwater-gathering and -disposal agreements that San Mateo has, Matador's run-rate goes up and analysts expect 20% growth out of the midstream business in 2019.



31 Oasis Petroleum Inc.

HOUSTON
Market cap: $2.976 billion
Last year's rank: 37
Production: 85,400 boe/d
Key plays: Bakken, Delaware

While a recent Permian entrant, Oasis remains a solidly Williston company, with about 87% of its E&P capex devoted to the Bakken. And the company can't buy a break: Its stock was crushed 34% between Oct. 1 and Nov. 9, yet the company has been a model of what investors say they want. For three consecutive years, Oasis has been a fiscal disciplinarian, with discretionary cash flow exceeding its capex. Oasis was on track to do it again in 2018. The company also continues to build out its Delaware Basin assets with the purchase in February of Forge Energy LLC assets for $946 million, or about $38,200 per acre.

32 PDC Energy Inc.

DENVER
Market cap: $2.973 billion
Last year's rank: 31
Production: 110,000 boe/d
Key plays: D-J, Delaware

PDC, like other Colorado producers on this list, could take a step back after the defeat of Proposition 112 in November. But, and this is key, the company wasn't required to do so. PDC and other E&Ps spent millions to fight the initiative that called for well setbacks within a half-mile of occupied structures and "vulnerable areas." In Weld County, Colo., alone, 85% of non-federal lands would have been off limits to new oil and gas production. The company has 1,950 gross Wattenberg and Delaware locations and the Permian continues to exceed company expectations. Management also anticipated exiting 2018 with 125,000 boe/d. In its third-quarter call, CEO Bart Brookman noted pro forma liquidity of $1.23 billion and free cash flow, along with a sale of its Delaware midstream assets, giving flexibility heading into 2019. It also has a backlog of about 100 Wattenberg DUCs that "we'll be looking at … depending on what's happening with prices," He added, "We'll never take our eye off that free-cash-flow goal."

33 Magnolia Oil & Gas Corp.

HOUSTON
Market cap: $2.860 billion
Last year's rank: NEW
Production: 49,600 boe/d
Key plays: Eagle Ford, Austin Chalk

Magnolia is a youthful E&P headed by the no-nonsense Steve Chazen, the former Occidental Petroleum Corp. CEO. In September, at Hart Energy's DUG Eagle Ford conference, Chazen counted his small G&A bill among his advantages, adding, "One of the problems I had with Oxy is I had too many employees." Chazen's company, then sitting at about $3.5 billion in market value, also foresaw a "$10-billion-market-cap business is not out of the question." Magnolia continues to up production, averaging 55,200 boe/d in third-quarter 2018, up 1% from the second quarter. The company also added 114,000 net acres from Harvest Oil & Gas Corp. in a deal worth about $190 million. Chazen is still scouting for acquisitions but also sees a business that "will double on its own in five years."

34 Jagged Peak Energy Inc.

DENVER
Market cap: $2.686 billion
Last year's rank: 33
Production: 36,100 boe/d
Key plays: Delaware Basin

At the close of 2016, conventional wisdom held that Jagged's 60,875 net acres and large inventory of wells would tempt a buyer for the Delaware Basin E&P. Whether a proposal was ever made, Jagged instead completed an underperforming IPO in early 2017 with production then averaging about 6,500 boe/d, of which 82% was oil. Largely under the radar, it has since increased its leasehold by about 30% to 78,900 net acres and blown the doors off production with a 5.5x increase in less than two years, while keeping oil at a comfortable 76% of production. The operator, as described by a Seaport Global Securities LLC report, has built an "execution machine" with third-quarter EBITDAX up 12% and a beat and raise on production.

35 Kosmos Energy Ltd.

DALLAS
Market cap: $2.556 billion
Last year's rank: 32
Production: 130,200 boe/d
Key plays: Gulf of Mexico

For landlubbers, Kosmos' recent squall in the markets might be read as investors balking over a $1.23-billion deal to acquire Deep Gulf Energy Cos. In reality, from the deal's announcement in August, the news was well received well past its September close, with shares up 18%. The real culprit appears to be the dry hole it drilled. In October, the company confirmed that its $13-million exploration well offshore Suriname discovered a pocket of subterranean water but no hydrocarbons. Kosmos isn't giving up, of course. Andy Inglis, chairman and CEO, said it's early days yet for exploring the Suriname-Guyana Basin. "Our current plan is to test the next prospect in 2020."

THE CONTENDERS

With Energen Corp., Newfield Exploration Co. and WildHorse Resource Development Corp. exiting the Top 50 via mergers, who's next up to take their places? Penn Virginia, in the No. 51 spot, would be a candidate, but it's also being absorbed via a merger. Next in line to claim Top 50 status in the 2020 ranking:

HighPoint Resources Corp.	$951MM
W&T Offshore Inc.	$883MM
Comstock Resources Inc.	$879MM

36 SM Energy Co.

DENVER
Market cap: $2.387 billion
Last year's rank: 40
Production: 130,200 boe/d
Key plays: Midland, Eagle Ford

In "Gladiator", protagonist Maximus shocks a bloodthirsty arena with his quick and efficient slaughter of enemies before turning to spectators and asking, "Are you not entertained?" SM is setting up for some oil-letting of its own with the anticipated 2019 kickoff of its 25-well Merlin Maximus pad development project in the Midland Basin. Meanwhile, it was tidying house in 2018, selling assets in the Bakken, West Texas and the Powder River Basin for a combined $792 million, while reducing debt by $345 million. SM runs six rigs in the Midland on 82,500 net acres and has drilled more than 80 wells as of third-quarter 2018. It also runs a single rig on 164,500 Eagle Ford acres. 2019 looks to be more thumbs up than down from the market crowd.

37 Enerplus Corp.

CALGARY
Market cap: $2.387 billion
Last year's rank: 42
Production: 82,500 boe/d
Key plays: Williston, Marcellus, D-J Basin, Canada

Canada, land of the Maple Leaf flag, gravy-covered fries and milk sold by the bag, does things differently. Enerplus perhaps doubly so. The company has an enviable balance sheet, starting with a remarkably low leverage rate of 0.4x. For 2018, it estimated a 17% return on capital employed, a 5% free cash flow yield and projected liquids production growth of 22%. While the company faces some headwinds in the Bakken, where differentials are creeping up, Enerplus has added fixed contracts to hold price differences steady in 2019. In the D-J Basin, four new wells are on track to produce 100,000 bbl/d in their first year.

38 Callon Petroleum Co.

NATCHEZ, MS
Market cap: $2.369 billion
Last year's rank: 41
Production: 34,900 boe/d
Key plays: Permian

Callon made just one mistake in 2018—adding Delaware inventory in a deal with Cimarex Energy Co. for $570 million. Within two weeks, Callon's share value had plunged 16%; it only recovered in early October, six months after the deal was announced. Otherwise, it made strides in production—up 55% since 2017—and generated $41.22 per boe, up 27%, it reported in November. Simultaneous rig operations on its Monarch mega-pads have exceeded production by legacy pads by 16% and a second mega-pad is online. With 2018 transition to full asset development, Callon CEO Joe Gatto said 2019 will see it "entering a new phase of growth with the maturing of the company and our production base, a phase that provides optionality for delivering shareholder value."

39 WildHorse Resource Development Corp.

HOUSTON
Market cap: $2.209 billion
Last year's rank: 46
Production: 49,000 boe/d
Key plays: Eagle Ford

Chesapeake Energy Corp. is buying WildHorse for about $4 billion, mostly in stock. WildHorse's third-quarter oil realizations netted 104% of WTI prices, thanks to low differentials and favorable Gulf Coast pricing. And it brought online nearly 26 net wells in the Eagle Ford, along with three net wells in the Austin Chalk. The company also reported net income of $11.5 million, a reversal from third-quarter 2017 when it posted a net loss of $10.8 million.

Magnolia Oil & Gas makes its debut as a new public company, birthed out of a SPAC, with a focus on the Eagle Ford Shale. Its acquired assets include a massive upside position in the Austin Chalk Formation.

Photo courtesy Magnolia Oil & Gas

40 QEP Resources Inc.

DENVER
Market cap: $2.152 billion
Last year's rank: 43
Production: 156,500 boe/d
Key plays: Permian, Haynesville, Williston, Pinedale, Uinta

PLANS CHANGE. QEP Resources hatched a strategy in February to become a Permian Basin pure-play operator, essentially changing the fabric of the company. That meant peeling off its Cotton Valley and Haynesville assets for $735 million, its silky Williston Basin assets for $1.7 billion and an assortment of Uinta Basin acreage for $155 million. Pro forma divestitures, QEP will work a 50,700-net-acre position in the Permian that averaged roughly 55,000 boe/d in third-quarter 2018. And, despite divesting $2.6 billion in assets, it hasn't lost its shirt. Its market value remained in November roughly the same as at that time in 2017.

41 SRC Energy Inc.

DENVER
Market cap: $1.805 billion
Last year's rank: 44
Production: 49,703 boe/d
Key plays: D-J Basin

LIKE OTHER COLORADO producers, SRC battled the overhang of the state's Prop 112 ballot initiative, which ultimately failed at the polls. But, also like other Colorado producers, SRC continues to battle takeaway constraints out of the D-J Basin. A planned addition of 300 MMcf/d capacity by a third-party processor in the first quarter should ease the pain. Still, the company delivered 45% growth year/year despite the constrictions. The company formerly known as Synergy Resources expects to keep its activity flat at two rigs and achieve free cash flow this year.

42 Carrizo Oil & Gas Inc.

HOUSTON
Market cap: $1.743 billion
Last year's rank: 45
Production: 64,627 boe/d
Key plays: Delaware, Eagle Ford

FACED WITH TAKEAWAY constraints and widening differentials in West Texas, Carrizo pivoted its activity focus to the Eagle Ford Shale, where it now has four of its six rigs running. It expects to hold here until second-half 2019. The Eagle Ford will drive its production-growth targets this year. During the lull in the Delaware, it will test additional layers and multi-layer cube concepts. Carrizo added 10,000 Delaware acres from Devon Energy Corp. after these rankings were locked.

TOP 50 U.S. PRODUCERS

Comparing companies by a volume of production would seem an easy feat, but oil to gas equivalents can be like apples to oranges—they both taste good, but they still taste different, particularly when valued by investors. Thus we find that gas producers can be quite prolific and rise to the top of our rankings when measured on an equivalency basis. For those operators reporting equivalent volumes in MCFE, *Investor* converted at 1 bbl of oil to 5,800 cubic feet of gas. All volumes are U.S. net production only unless noted. All public producers reporting net volumes were included, including majors and those with production as secondary business units.

	Company	Net BOE/d
1	Exxon Mobil Corp.	994,483
2	Chevron Corp.	831,000
3	Royal Dutch Shell Plc	825,034*
4	BP Plc	736,000
5	EQT Corp.	709,050
6	EOG Resources Inc.	700,448
7	Anadarko Petroleum Corp.	682,000
8	ConocoPhillips	579,000
9	Chesapeake Energy Corp.	537,000
10	Southwestern Energy Co.	482,758
11	Antero Resources Corp.	468,620
12	Devon Energy Corp.	418,000
13	Range Resources Corp.	390,862
14	Cabot Oil & Gas Corp.	349,827
15	Occidental Petroleum Corp.	347,000
16	Pioneer Natural Resources Co.	327,704
17	Marathon Oil Corp.	298,000
18	Continental Resources Inc.	296,900
19	Concho Resources Inc.	287,000
20	Apache Corp.	272,000
21	Noble Energy Inc.	249,000
22	Gulfport Energy Corp.	246,121
23	CNX Resources Corp.	222,931
24	Cimarex Energy Co.	211,400
25	Newfield Exploration Co.	202,000
26	QEP Resources Inc.	155,000
27	Kinder Morgan Inc.	144,340
28	Encana Corp.	137,000
29	California Resources Corp.	136,000
30	SM Energy Co.	130,200
31	Whiting Petroleum Corp.	128,680
32	Hess Corp.	128,000
33	Ultra Petroleum Corp.	126,551
34	WPX Energy Inc.	123,800
35	Parsley Energy Inc.	116,200
36	Diamondback Energy Inc.	112,600
37	PDC Energy Inc.	103,000
38	Energen Corp.	97,400
39	Enerplus Corp.	92,883
40	National Fuel Gas Co. (Seneca)	89,687
41	Penn Virginia Corp.	84,000
42	EP Energy Corp.	82,500
43	Oasis Petroleum Inc.	79,400
44	Sanchez Energy Corp.	75,750
45	Extraction Oil & Gas Inc.	75,700
46	Murphy Oil Corp.	71,000
47	Laredo Petroleum Inc.	67,206
48	Denbury Resources Inc.	61,994
49	Eclipse Resources Corp.	59,720
50	Centennial Resource Development Inc.	57,528

* Shell reports North American production volumes.

43 Gulfport Energy Corp.

OKLAHOMA CITY
Market cap: $1.672 billion
Last year's rank: 38
Production: 1,427 MMcfe/d
Key plays: Utica, Midcontinent, South Louisiana

INDUSTRY VETERAN DONNIE MOORE took the interim CEO post in the fourth quarter from his COO position, following the sudden departure of Mike Moore. The company generated 19% growth year/year as of 3Q. The early-entrant Utica Shale player rigged down there late in the year, while 55 wells await completion. Two rigs are working the Scoop in Oklahoma.

44 Extraction Oil & Gas Inc.

DENVER
Market cap: $1.478 billion
Last year's rank: 35
Production: 75,700 boe/d
Key plays: D-J Basin

A California pure play, California Resources Corp. boasts it is the largest producer by gross operated production with activity in all four major basins across the state. CRC operated an average of 10 drilling rigs during the third quarter 2018.

Photo courtesy of California Resources.

Talos Energy gained public status via reverse merger in 2018 and it's on a tear to capture opportunity—and assets—in the Gulf of Mexico, both on the U.S. and Mexico sides. Here, Talos' Zama discovery offshore Mexico, where it spud an appraisal well in November, promises some 2 billion boe in recoverable resource.

Photo courtesy of Talos Energy.

Extraction is beginning to feel as if its Ferrari is being throttled back. Just when the Denver producer received relief on DCP Midstream LP's Plant 10 in August with 220 MMcf/d throughput, the midstreamer imposed a production allocation, effectively dialing back the E&P's production 35%. A new plant is expected mid-2019 but will likely have its own allocations. In the meantime, Extraction is jazzed by results from its Broomfield project, a 12,000-acre test area with little previous production. And Broomfield takeaway will be serviced by its own Elevation Midstream LLC.

45 California Resources Corp.

LOS ANGELES
Market cap: $1.344 billion
Last year's rank: 55
Production: 136,000 boe/d
Key plays: California

After having "drastically cut" capital allocation during the downturn, the California pure-player ramped up investment during 2018 and made several strategic moves. It joined with Benefit Street Partners LLC in a $250-million drillco in the Los Angeles and San Joaquin basins, and with Macquarie in a $300-million JV to drill four fields in the San Joaquin Basin. It has three rigs running in the Los Angeles Basin and seven in the San Joaquin. In April, it acquired Chevron's nonop interest in the 47,000-acre Elk Hills Field for about $500 million to realize 100% working interest.

THOSE THAT WERE

The only thing for certain is change, so they say, and taking a look back to the Top 50 independents from 25 years ago illustrates that concept. *Oil and Gas Investor* ranked independent E&Ps by market cap on June 30, 1993. Maybe proving some longevity, three of the top five are still around, in some form, albeit two under different names.

	Company	Market Cap ($000)		Company	Market Cap ($000)
1	Burlington Resources Inc.	6,260,000	26	Plains Petroleum Co.	260,792
2	Enron Oil & Gas Co.	3,260,000	27	Box Energy Corp.	260,038
3	Sun Energy Partners LP	2,991,024	28	HS Resources Inc.	254,366
4	Anadarko Petroleum Corp.	2,224,899	29	Mesa Inc.	241,069
5	Oryx Energy Co.	2,048,340	30	Gerrity Oil & Gas Corp.	207,781
6	Louisiana Land & Exploration Co.	1,615,213	31	Alta Energy Corp.	203,821
7	Apache Corp.	1,302,474	32	Nuevo Energy Co.	200,698
8	Maxus Energy Corp.	1,200,879	33	Oakridge Energy Inc.	191,646
9	Noble Affiliates Inc.	1,076,144	34	Sabine Royalty Trust	191,349
10	Santa Fe Energy Resources Inc.	939,750	35	Permian Basin Royalty Trust	186,436
11	Enserch Exploration Partners Ltd.	871,250	36	Dorchester Hugoton Ltd.	173,247
12	Parker & Parsley Petroleum Co.	761,936	37	Dekalb Energy Co.	159,783
13	BP Prudhoe Bay Royalty Trust	628,625	38	Phoenix Resources Cos. Inc.	152,784
14	Petrol Industries Inc.	598,965	39	Wiser Oil Co.	147,477
15	Pogo Producing Co.	581,885	40	St. Mary Land & Exploration Co.	138,049
16	Devon Energy Co.	557,199	41	Benton Oil and Gas Co.	135,168
17	Cabot Oil & Gas Corp.	496,276	42	Barrett Resources Corp.	125,515
18	Diamond Shamrock Offshore Partners	470,646	43	Plains Resources Inc.	123,332
19	Snyder Oil Corp.	448,902	44	Wainoco Oil Corp.	115,826
20	San Juan Basin Royalty Trust	431,133	45	Basin Exploration Inc.	115,200
21	Vintage Petroleum Inc.	346,281	46	Tom Brown Inc.	100,170
22	Kelley Oil Corp.	327,320	47	LL&E Royalty Trust	97,329
23	Kelley Oil & Gas Partners Ltd.	322,664	48	American Exploration Co.	90,816
24	Berry Petroleum Co.	292,792	49	Coho Resources Inc.	88,853
25	Santa Fe Energy Partners LP	285,584	50	Hadson Energy Resources Corp.	87,324

46 Denbury Resources Inc.

PLANO, TX
Market cap: $1.338 billion
Last year's rank: 52
Production: 59,181 boe/d
Key plays: Gulf Coast, Rockies

The CO_2-flood specialist caught a few off guard in October when it announced plans to buy Eagle Ford Shale producer Penn Virginia Corp. for $1.7 billion in stock and cash. The motivation: to bring Denbury's EOR expertise to Penn's 87,000-acre oil-rich unconventional portfolio. Denbury currently operates CO_2 floods along the Texas Coast in proximity to Penn's position. It sees potential for 60 to 140 MMbbl recoverable. And, while EOR is upside, the purchase more than likely represents a shift to shorter-cycle projects based on Penn's three-rig drilling program.

47 Laredo Petroleum Inc.

TULSA, OK
Market cap: $1.292 billion
Last year's rank: 36
Production: 71,382 boe/d
Key plays: Midland Basin

Wanting to find the upper limits of its Wolfcamp acreage's capacity to produce, Laredo in 2018 tested high-density drilling. It drilled six packages of wells designed to co-develop multiple landing points in the Upper and Middle Wolfcamp formations at a density of 24 to 32 wells per drilling spacing unit. The good news: These packages demonstrated that this development plan increases the total value of the leasehold. The bad news: It's at a lower per-well value than lower-density development. Said simply, the wells declined a lot faster than wells more spread out. The high-density units are also capital-intensive. Combined with a will to operate within cash flow in 2019, Laredo is gearing down to a lower-density development going forward.

48 Talos Energy Inc.

HOUSTON
Market cap: $1.235 billion
Last year's rank: NEW
Production: 54,900 boe/d
Key plays: Gulf of Mexico

Permian pure-play powerhouse Concho Resources got bigger with the giant acquisition of RSP Permian last year. It now holds some 640,000 net acres across West Texas and New Mexico, with production exceeding 287 Mboe/d.

Photo courtesy of Concho Resourses.

TALOS MADE ITS debut in the public realm in 2018 via a reverse merger with Stone Energy Corp. And the Gulf of Mexico pure-player has not broken stride. It signed a two-well commitment to drill two deepwater wells in the Phoenix complex—Tornado #3 and Boris #3—that are expected to be in production by 2H19. On the shelf, it successfully drilled a well in Ewing Bank Block 306 and two in Main Pass Block 72. Following its 2-Bbbl Zama discovery offshore Mexico, Talos spud the first appraisal well, Zama-2, in late November. Also, it acquired Whistler Energy II LLC, comprised of 14,500 acres in Green Canyon and was the high bidder on six deepwater and eight shallow water blocks at the most recent Gulf lease sale.

49 Northern Oil & Gas Inc.

MINNETONKA, MN

Market cap: $1.166 billion
Last year's rank: 63
Production: 26,708 boe/d
Key plays: Bakken

NOTEWORTHY FOR ITS nonop strategy, Northern cracks the Top 50 most valued producers nonetheless. Maybe that's because of its other strategy: Partner with top producers in the resurging Bakken Shale play. The company recently added two deals to its repertoire: a $292-million, 10,600-acre acquisition of W Energy Partners LLC and a $151-million, 4,100-bbl/d purchase of Pivotal Petroleum Partners LP. Northern now holds some 152,000 net Bakken acres.

50 Baytex Energy Corp.

CALGARY

Market cap: $1.092 billion
Last year's rank: 51
Production: 37,198 boe/d
Key plays: Eagle Ford

BAYTEX'S BIG NEWS this past year was its combination with Raging River Exploration Inc., a Duvernay producer that expanded its reach into the Canadian light-oil play. But it's also an Eagle Ford player, having entered the play in 2014 with the acquisition of Aurora Oil & Gas Ltd. With a little over 20,000 net acres in Karnes and Atascosa counties, the Eagle Ford represents 37% of Baytex total production.

A CENTURY OF SUCCESS

At 100 years old, "Big Red" oilfield-services company Halliburton has weathered the industry's ups and downs, ultimately conquering the world in its reach. At the top of its game, it's positioning for another 100.

ARTICLE BY
STEVE TOON
AND
JENNIFER PRESLEY

Halliburton Co. president and CEO Jeff Miller carries a country charm that subtly contrasts with his dapper gray business suit and "Halliburton red" tie—and with his position as the head of one of the largest oilfield-services providers in the world.

Halliburton president and CEO Jeff Miller said only a handful of companies in the Fortune 500 have reached 100 years in business. "We're excited to be one of them."

It may be no surprise, then, that Miller once competed as a professional cowboy in rodeos before taking off his cowboy hat and ropers for a CPA job that would ultimately land him with Big Red, having a $28-billion market cap.

He sits at the helm of the Houston-based company at a momentous point in its history: Halliburton celebrates its 100th anniversary this year, solving oil and gas field problems. In 1919, founder Erle P. Halliburton started an oil-well cementing business in Duncan, Okla., with a borrowed wagon, a team of mules and a pump. The rest is history, albeit a storied one.

Today, Halliburton serves E&P operations around the world with 60,000 employees in 80-some countries. "The biggest bets we make are on our people," Miller told Investor. *"The business has changed many times over, but our company doesn't thrive for 100 years without fantastic people."*

Miller holds an agriculture and business degree from McNeese State University in Louisiana and an MBA from Texas A&M University. He first joined Halliburton in 1997, working his way through various leadership roles until assuming the president post in 2014 and the CEO seat in June 2017. He took the reins during one of the worst downturns in the industry's history.

Investor *chatted with Miller at the company's headquarters in Houston.*

Investor Would Erle P. Halliburton be more impressed by the fact that Halliburton has reached $20-plus billion in revenue or 100 years in age?

Miller I think Erle P. would be more excited about the $20 billion in revenue. Earl P. was an absolute competitor and it came through in everything he did, going back to the beginning with the jet cementer pulled by mules.

He invented a lot of other things as well; he was an innovator at heart. With what the industry has done and what Halliburton has done, he'd be fascinated by it. He'd want to be a part of it.

He'd be excited about the 100 years too, because that's quite a legacy, and there aren't many companies that have done that. He would be impressed to see 60,000 employees go into the market, the R&D that we've done and the kind of technology that we deliver every day.

Investor How significant is it to be in business and even a sector leader for a century?

Miller It's a really big deal. There aren't many companies—say 12—that log 100 years and are still in the Fortune 500. We're excited to be one of them. That kind of staying power says we're a company that reinvents itself, that delivers new ideas and stays relevant. It's one thing to be 100 years old; it's another to be at 100 years and still leading in our field. That, to me, is what's most fantastic.

Investor What's the secret to that longevity?

Miller When I think about Halliburton, I think about our value proposition: We collaborate and engineer solutions to maximize asset value for our customers. That sounds like a mouthful, but, the fact is, that absolutely captures the DNA at Halliburton. We work closely with our customers, we're constantly developing new technologies, and we're always driving toward our customers' goal of the lowest cost per barrel of oil equivalent (boe). That's a theme that resonates with customers.

I met with Curtis Mewbourne, a customer, the other day. He's the 83-year-old gentleman who founded Mewbourne Oil Co., a strong oil company. His first discovery in West Texas was in 1968, I believe. And he told me the story about his first discovery well. They discovered oil, and it's blowing out the way wells did when they made a discovery back then.

Everyone went home except for him and the Halliburton engineer. He and the Halliburton engineer worked all night long, got some choke on the well and, then, shook hands and the Halliburton guy went home.

He remembers that 50 years later, and that is the essence of Halliburton executing work. We're there on location, doing the work, committed to our customers.

Investor Halliburton has a long history of being a technology innovator and a disruptor in the industry. How do you know when to shake things up?

Miller Great companies are always willing to challenge and disrupt things, and we like to disrupt. But I think at the core of disruption is honesty, and by that I mean the willingness to look at the market, understand the technology and, when the time is right, be willing to disrupt things that may have worked for a very long time.

But it's also done because we know we want to deliver the lowest cost per boe for our customers. And that's going to involve disruption.

We've got a lot of things we're working on today that are likely disruptive. We'll bring those to the market when we think the market is ready for them.

Investor Such as?

Miller There are things we're doing in hydraulic fracturing today that are driving a lot of speed in terms of fracturing. There are things we are doing in formation evaluation, looking through multiple casing strings. All of these things have the ability to disrupt. What we're doing around lifting chemicals is also exciting.

Investor How would you say the landscape has changed for service providers during the past few years?

Miller It's more competitive. We've come through the worst downturn in the history of the industry, just in the last few years. Any time we're at the bottom of a cycle, it tests value propositions, and I think our value proposition clearly withstands the test of time.

Investor How has the R&D focus changed over time?

Miller We're more focused than we've ever been on those things that create lower cost or increase production. And it sounds like an oversimplification, but it's an important one. That's the screen that I use when we think about how we invest our R&D dollars. And because of that, we're more effective than we have ever been delivering technology.

"Cementing done by Halliburton Oil Well Cementing Co." A Halliburton cementing crew circa 1920s.
All photographs courtesy of Halliburton.

We were 44th in the world in terms of patent grants in 2017. And we're the only oilfield-services company in the Top 50. We're excited about that because it means we're more efficient than we've ever been, even when working through a very tough cycle.

Investor What technologies do you foresee as having the most impact in the coming years?

Miller Digital is clearly going to have an impact, though I'm very pragmatic around how it's going to impact our businesses. An open architecture is critical for it to be adopted. But it will drive down costs and make us more efficient. At the same time, I don't have a utopian view that is oversimplified. Over time it will be impactful.

Investor How are data analytics or artificial intelligence changing how we explore?

Miller We're still in the early days for both. My view is that oil and gas has really been the first big adopter of big data. We were consuming petabytes of data back before anybody else knew what petabytes of data were. We were processing huge seismic libraries and things of that nature.

Our industry is very pragmatic, and I think, in many cases, the key will be "How do we put these technologies to work, so we are collectively making a return?"

At the moment, artificial intelligence (AI) is having more of an impact in the learning and advising sphere than it is in operations. There's a lot of risk associated with what we do, and my view, at least today, is that AI is contributing to better decision-making by people and network-learning from algorithms to give us better visibility of what risks may lie ahead. We still have a lot of human intervention, and I think the human intervention, at this point, is the right thing to have.

Investor How effective might AI and data analytics be toward improving well economics?

Miller The value of digital will evolve over time in our business the same as it has in our personal lives—with respect to smartphones and all the things that are automated in our life. There's still real work that has to be done to deliver oil and gas wells. I am always cautioning that these things have to create value sooner rather than later as we develop them.

I do believe it's an evolution, because I think the road is littered with overspending on technology that wasn't pragmatically tied to a solution.

Investor Is your EarthStar LWD tool an example of how data will be gathered in the field?

Miller EarthStar generates the data that might drive artificial intelligence at some point, but it is a fantastic tool and a tool of choice in many markets today, partly because it reads out so far into the reservoir—200 feet. That data is recovered and the resolution on that data is fantastic; it allows them to really look in real time and understand the reservoir. So that has quite an impact.

We're developing what those products or what that data can do over time. That's a story that's still evolving.

A Halliburton team prepares the company's Earthstar ultra-deep resistivity tool, which can measure 200 feet from the wellbore.

Investor Similarly, is your Prodigi AB fracturing service a look at how AI is leading to "push-button fracking?"

Miller Prodigi allows us to, in effect, automate the act of how we control the pumps on location. We use reservoir information as we're doing the work, and algorithms and artificial intelligence ultimately drive the outcome. And because of that, we've got more consistency in how fractures are created, and, at the same time, the pumping is customized to the rock.

That combination creates a much better outcome for our customers, and means less wear and tear on our equipment because the pressures are more controlled and smooth.

The key here is the algorithms. They take what we know about the reservoir and convert that into making a better decision, rather than the artisan frack operator deciding.

Investor How much will the industry be able to improve recoveries during the next five or so years?

Miller I'm going to stay away from the prediction, but I know it will be better. Twenty years ago, we drilled through the shale and threw that stuff away because it had no value at all, and look at it today; it gets bids of up to $60,000 an acre in some cases.

There is a lot of oil in place, and I always bet on our industry, our customers and on Halliburton to solve those problems and find new ways to increase production.

Investor Has the oilfield-services sector recovered from the downturn, or is it still ongoing?

"At the moment, AI is having more of an impact in the learning and advising sphere than it is in operations ... and I think the human intervention, at this point, is the right thing to have."

Miller Oilfield services are in a better place certainly than we were in the downturn, but it's clear that we haven't recovered to the level we were at prior to the downturn. And, so, there's still more recovery to come. We approached where we were in the last cycle in the second quarter of this year, for example, in North America. It's a story that's unfolding now.

Customer-spending behavior is a component of recovery. I also think that oil price has been a component of it and the pace at which money gets spent. All of those things have had an impact on recovery.

But worldwide, the industry is still recovering. Internationally, we didn't find the trough until the middle of last year. There's a lot of capacity left from the prior cycle that's yet to be consumed, and, as that is consumed, then we'll see more tightness and, I expect, more recovery. That is a story to be told as we get into 2019 and 2020 and beyond.

Investor What do you think the time line is for deepwater recovery?

Miller It's going to be longer. It's been "a couple years out" for four or five years now, so I'm careful with the time line. But it feels like it's a 2020-2021 event.

There are a lot of alternatives to deepwater in the world today to invest in, and I think you see a lot of capital going into those markets. Deepwater, in my view, is an important part of the energy complex in the future, so it does recover.

But clearly, it recovers more slowly, and, as I look around the world, I think we'll see some deepwater activity picking up. But meaningful recovery still feels a couple years out.

Investor FIDs (final investment decisions) for deepwater projects have been essentially nonexistent for a few years. Do you think that's going to affect global supply?

Miller It can't help but have an impact. If we look at the decline in international capex, it stepped down 50% in 2015, another 50% in 2016 and maybe a little bit more in 2017. That's one of the only times in history we've had three consecutive years of less spending—and substantially less spending.

It picked up a little bit [in 2018], by maybe 5%. It's a modest recovery. And these are things with a seven- to 10-year duration in terms of going from discovery to new barrels in the tank. So, yes, it is having an impact, and it will have a more pronounced impact over time.

Investor Do you believe shale technology is able to achieve scale in countries beyond North America?

Miller There are great opportunities in other parts of the world, but getting to scale involves a lot of other things—like access to capital and markets and pipeline capacity. We almost take for granted the interstate pipeline investment in the U.S. that's made shale so successful. That's what allows a lot of it to get to scale. But good rocks are the place to start, and from there we can scale up.

We're invested in the unconventional business here and around the world—from a technology standpoint and an execution standpoint. We're very excited about the work we won with Saudi Aramco. Our expectation is to bring the efficiencies and technologies that we've delivered in the U.S. to the Middle East.

Similarly, in Argentina quite a number of operators are working in the Vaca Muerta Shale. We work for many of them. And, again, that same Halliburton execution and collaborating in engineering solutions to maximize asset value for our customers is alive and well.

Investor Has investor sentiment changed toward service companies?

Miller Our metric is always going to be returns; returns are always in vogue, and we've had leading returns over almost any period we measure.

About investor sentiment, both generalist and energy-specific, it's tough to call where that is on any given day. Clearly, there's less energy investment than there was five years ago and certainly less than there was 10 years ago.

But I know oil and gas is supremely important to economies and our way of life. It's an important part of GDP—not just in the U.S. but practically every country in the world. So the demand for what we do remains high, and I have a lot of confidence that the best days are ahead of us.

Investor What was your biggest challenge when you became CEO?

Miller The entire industry was challenged by the downturn of the past four years, and we were in the middle of that. As we move into recovery, I'm excited about looking more to the future in terms of how we put great technology to work and construct better wells for our customers.

Investor What are the headwinds and tailwinds that you foresee in North America for 2019?

Miller There are clearly headwinds in the marketplace with respect to takeaway capacity. In certain basins, there'll be all sorts of labor shortages and things to wrestle with as the market picks up, but those are things we manage every day. And I expect that, as we get into 2019, many of those disruptions are resolved.

But what's most important is where the macro is on supply and demand for oil. And, right now, it's in the best place that it's been in probably four years in terms of both supply—being largely constrained or at least known—and a strong demand for oil. I expect 2019 overall will be very positive for the industry.

Investor If you had to do it all over again, would you have remained a professional rodeo cowboy?

Miller Absolutely not! It was great at the time, but I can promise you the good was out of it by the time I let it go. But I wouldn't trade those days for anything because I learned a whole lot about life and a whole lot about competing while getting to do it. I remember those days very fondly.

Business afforded me the ability to compete in a lot of the same ways I did when I was rodeoing. But I've never looked back. I've never looked back at all. □

SOUTH LOUISIANA VERTICAL

Old-time conventional E&P is yielding big profits in South Louisiana for these operators familiar with bypassed potential.

ARTICLE BY GREGORY DL MORRIS

The fracked, horizontal, unconventional-resource bonanza seems ubiquitous across the Lower 48. It is not.

Vertical development of conventional resources is not only alive and well on Louisiana's Gulf Coast, proponents make a powerful case for its profitability over horizontal drilling and fracking—albeit while the sweet spots aren't thousands of square miles in size.

Wells can cost 10% of those in shale. Leases can cost as little as 1%. And prices for crude are higher on the Gulf Coast. Louisiana Light Sweet (LLS) usually fetches a price near that of Brent and usually at a substantial premium over West Texas Intermediate (WTI).

It's old school, but it makes money, according to niche conventional-trap operators like Metairie, La.-based Upstream Exploration LLC, which has almost doubled its production in a year. "We took our production from about 2,200 barrels of oil equivalent a day (boe/d) to about 5,300 in about a year's time," said Michael Willis, president.

PHOTO COURTESY UPSTREAM EXPLORATION

Baywater Atchafalaya drilling rig, operating for Upstream Exploration, drilled the Palmetto D prospect in the East Cox Bay Field in Plaquemines Parish, Louisiana. The company has drilled four wells so far.

Michael Willis, president, Upstream Exploration LLC, said production had almost doubled in a year, to 5,300 boe/d. "We drilled a good well, but we also had some improvements to our infrastructure."

James Mertz, president of Mertz Energy LLC, says the company is busy with a re-drilling and turnkey project in Iberia Parish, La. "We can't give this up because we have low-hanging fruit on a brand new 3-D survey."

"We drilled a good well, but we also had some improvements to our infrastructure that have enabled us to increase production overall."

Of the four wells it's drilled so far, three are in Louisiana waters up to 25 feet deep. It has 100% working interest in those, which produce from Middle Miocene. It also has a 50% interest in a well in East Texas.

"Overall our production is split about evenly between gas and oil," Willis said. "Even the gas wells flow with high condensate—about 50 to 100 barrels (bbl) per million cubic feet (MMcf). We are driven by seismic, some of which is proprietary. We are on our fifth iteration of reprocessing."

The primary area of exploration is the toe of the Louisiana "boot" in Breton Sound and East Cox Bay where the Mississippi River meets the Gulf. Success has been about 70%.

Its most recent well—in East Cox Bay Field in Plaquemines Parish—encountered 59 feet of net condensate pay with no apparent water from a 75-foot-gross interval in a geopressured Middle Miocene sand at some 12,000 feet. It flowed some 675 bbl/d and 4.9 MMcf/d on choke.

The company has 100% working interest in some 4,100 acres in the field. Privately held, Upstream Exploration is owned by HighBridge Principal Strategies (HPS) and is working with assets acquired in the 2016 restructuring of RAAM Global Energy Co., of which HPS was a creditor.

Another well came online Aug. 15, flowing some 1,700 bbl/d and 13 MMcf/d. It was paid for from cash flow. From the start, gas was moved through existing pipe in the area, "but oil was something of a challenge," Willis said.

"From our first discovery, we used barges to get the oil out. But, more recently, we have tied into a sales line. That has allowed us to increase our production rate and improve our economics."

Upstream Exploration is getting Heavy Louisiana Sweet (HLS) pricing, which closely tracks LLS. Lifting costs are between $5 and $6 per boe and the operator's G&A is some $4 to $5 per boe.

"We generate a lot of free cash that we are reinvesting in operations. We pay about $250 an acre for leases, so we are putting our money into drilling, not into leases."

Willis isn't seeing competition for leasehold. "There is a high barrier to entry, especially in the state waters. This is a different environment, and we have the technical expertise."

There are other, mostly private, operators along the Louisiana coast—some small; some, not so small. "The majors have a large P&A (plug and abandonment) situation in this area," Willis said, "and we are looking for some acquisitions. But we are not getting into the P&A game."

'The hits are big'

For Houston-based Mertz Energy LLC, the main focus is a Miocene Lower Planulina gas-trend prospect it plans to drill in Iberia Parish, southeast of Lafayette, La. The company just sold the bulk of its existing production. Details were not disclosed, but it left Mertz this past fall with just five wells and production in the 100s of bbl/d.

"Our main focus is to re-drill our existing prospect with new partners and a new surface location, so we can use a turnkey contract and drill a vertical well," said James Mertz, president. "The original effort was an extreme-angle well to try to reduce some surface costs, but ended up being more expensive.

"Resource potential in place is very large for a single-well prospect: 88 billion cubic feet (Bcf) of gas and 5- to 6 million barrels (MMbbl) of oil. We can't give this up because we have the low-hanging fruit on a brand-new 3-D survey: AVO, very strong amplitude perfectly conforming to structure, and rolling over into a fault with pressured shales up-thrown.

"We hope to spud within nine months from finalizing our working-interest arrangements. We are doing that now, and it's about two-thirds complete."

The target depth is 16,500 feet. "Rig availability has been an issue," Mertz added. "There are still some available, but fewer, and day rates have increased."

In addition to his oil and gas business, Mertz is active in real estate and venture capital. Informed by that perspective from outside the oil patch, he is clear about the outlook for vertical wells.

"The conventional markets are contracting," he said. "There are some incredible opportunities, but the marginal developments are simply not viable."

However, Mertz added, "I like conventional development. The outcomes are binary; there are hits and misses. But the hits are big, just like in my venture-capital business.

"In the resource plays, it's easier to deploy large amounts of capital in a short time. That is why the big private-equity houses are attracted to the shale plays. Those have a risk profile more like bonds. The risk profile in conventional development is more like equity, and the bond market is many times larger than the equity market."

Close to shore

Prospects that Houston-based Blue Moon Exploration Co. LLC has generated currently produce some 10 MMcf/d and about 1,000 bbl/d from about a dozen wells in South Louisiana and Southeast Texas. Most are in South Louisiana, on- and offshore.

Offshore waters can be anywhere from two to 2,000 feet, but Michel Bechtel, president, said he stays close to shore. "I have worked in the federal Outer Continental Shelf, but we are not currently there. We now stay in state waters and inland. Our high ground is a few miles north or south of Interstate 10," Bechtel said.

If conventional production with vertical wells harkens back to an earlier era in the oil patch, then Bechtel could be one of the colorful characters of those times as well. In

Upstream Exploration's Palmetto production barge—including storage tanks—in the East Cox Bay Field in Plaquemines Parish, Louisiana. Upstream almost doubled its production in just a year from about 2,200 boe/d to about 5,300 boe/d.

Forrest Hise, manager of business development at Hise Exploration Partners LLC, is raising capital for the company's third program. "Investors in the Gulf Coast have to have a contrarian mindset compared with investors who want to pay top dollar for leases and drill a few PUDs in the shale plays."

Energy Drilling Co. Rig No. 14 drilled J.J. Burdin Well No. 1 in Section 28 Field of St. Martin Parish, Louisiana. Blue Moon Exploration Co. LLC generated the prospect and Interstate Exploration Co. is operator. Oil discovery was completed in 2016 and it is currently producing.

addition to his post at Blue Moon, he is mayor of Morgan's Point, Texas—population, 339—alongside the Houston Ship Channel.

"I've been in this business 48 years," Bechtel said, "and had my own company since 1983. My business partner, Tom McWhorter, and I have been in the oil patch together forever."

The headquarters for Blue Moon is in a 1920s-era building the company bought and restored in the historic Heights neighborhood of Houston.

"We are probably one of the more active and successful prospect-generators in the South Louisiana area," Bechtel said. "We're producing mostly from the Miocene and Frio sands and currently exploring Lower Tuscaloosa objectives.

"We are looking for working-interest partners to drill and evaluate major potential in East Baton Rouge Parish. That area was a giant trend in the 1970s and '80s for the majors."

When the arrangements are made, Blue Moon plans to drill four to five wells. "We generate the prospects, lease the acreage and put together the play," he said. "Then we go to the industry for working-interest partners."

There is a smile in his voice when he mentions acreage costs. "Leases are in the range of $250 to $300 an acre in South Louisiana. That is a mere 1% of rates in the Permian Basin."

Stacked pay

With multiple sands in a prospect, "we can book more reserves under an acreage block than for most unconventional plays," Bechtel said. "So, for a few hundred acres, we can look at prospects with 40 Bcf of gas and 5 MMbbl of oil in place. We don't have to maintain a huge lease block."

"Leases are in the range of $250 to $300 an acre in South Louisiana. That is a mere 1% of rates in the Permian Basin."

Michel Bechtel,
Blue Moon Exploration Co. LLC

Neither are lease terms onerous. "We actually make money producing hydrocarbons. In the horizontal plays, they seem to make most of their money flipping acres.

"We are privately owned and make money selling oil and gas over the long term. We take wells to depletion. Our economics are fantastic compared with the unconventional stuff."

Bechtel is "amazed" that there isn't more interest in conventional production. "If you want to make money, go to conventional. The economics are better."

He has several theories on why the sector continues to be overlooked. "There are lots of young people in the industry and in finance who have never known anything but unconventional.

"They are just clueless about conventional. As a result, Wall Street only pays attention to shale. The players on the financial side are very young. They just don't know."

One other factor may be the legacy complications that beset some operators when they tried to recomplete fields that had been first developed by the majors. There were both legal and environmental issues. Those have mostly been sorted out, but it gave the area a bit of a reputation for a while.

Over at LLOX Onshore Exploration, Covington, La.-based Taylor Butterworth, chief geologist, said, "We have an active drilling program with two rigs—one land and one inland barge. We will operate three to four additional wells by the end of 2018. For 2019, we have about 15 wells that we expect to operate."

LLOX's prospects are "probably 80% step-out wildcats and 20% development. Also, to note, our working interest ranges from 50% to 100% with the average around 75%."

Rig day rates have increased "due to shale plays' demand," he added. "Also, we sometimes struggle to find services because people and equipment are shipped to unconventional basins."

Meanwhile, though, ongoing demand for services in the Gulf of Mexico "keeps some services in the nearby area."

A career in land, 3-D

Matt G. Chiasson, president and CEO of Lafayette-based Orbit Energy Inc., said oilfield-service costs in South Louisiana "are reasonable, and we've been lucky in our ability to find rigs.

"If I need a rig I can usually get one in 30 to 90 days because there is a suite of rigs available that work specifically in this region. We've seen activity levels rise in the area," Chiasson said.

"We have also seen some increase in capital coming in—some from independent companies, some from high-net-worth individuals. Those are savvy investors who are eager to make money—not just book proven reserves."

Chiasson believes that "the shale plays are really just about proving reserves. It's a treadmill. You have to prove reserves to get capital, but you need to spend money to prove reserves. Some of the areas work well, but it's very expensive."

Orbit is mainly producing from Frio north of Interstate 10 in southwestern Louisiana. "We are using 3-D seismic we shot ourselves or have licensed," he said.

"We are drilling on a large in-house-generated prospect portfolio, where we drilled 155 wells with a success ratio of approximately 75%—mostly in that non-pressured Frio regime."

All of Orbit's wells are on land. They cost $1.2- to $1.6 million completed; dry holes, less than $1 million. "Our honey hole is that Frio objective.

We are also drilling shallower, Miocene targets and some deeper objectives, such as the Cockfield, which is equivalent to the Yegua in Texas."

PHOTO COURTESY BLUE MOON EXPLORATION

Matt Chiasson, president and CEO of Orbit Energy Inc., said rig availability for southwestern Louisiana projects is good. "If I need a rig, I can usually get one in 30 to 90 days."

The oil zones can be a little gassy, and gas zones typically have high condensate yields. From a prospect with 200,000 bbl of net reserves and low drilling costs, wells are paying out in six to nine months.

Production is less than 1,000 boe/d; the oil is transported by truck. "Gas is a little trickier," Chiasson said, "but we are in and around known basins and areas of production, so there is usually a pipeline tap within a mile or so."

The oil gets LLS pricing. "The beauty of the Gulf Coast—and especially South Louisiana—is that we are getting that Louisiana Light Sweet price. We are getting the premium, while many of the other active areas, like West Texas, are taking a hickey."

Orbit has very little debt. "We raise capital in a couple of ways," said Chiasson, who is the majority owner, and is also sole owner of Planet Operating LLC.

"We just finished a small equity-capital-raise and also go to the industry for working-interest partners. We have a large portfolio of prospects and 1,500 square miles of 3-D seismic data."

While Chiasson is not adverse to a big pile of capital from private-equity investors, he is circumspect. "To have $50- to $100 million at your disposal would be huge in this Gulf Coast region," he said. "No doubt some good things can come of that kind of capital infusion, but you also lose some control.

"When they say it's time to sell, it's time to sell."

Meanwhile, Chiasson recalled, "a boutique PE firm came to us several years ago and stayed with us for quite a while. It was a good experience. The key is to have a well-planned model and be upfront and deliver on the business plan."

In the industry for 30 years, he's run his own company for 25. "I'm a landman by schooling and trade," Chiasson said. "I started college in 1984 when everyone in this business was heading for the hills. It was not the best of times.

"However, I became an independent landman in 1989 and started managing large onshore projects in 1994 at the beginning of the Gulf Coast 3-D-seismic phase. Orbit was founded in 1999 as a result of that 3-D-seismic experience."

Tuscaloosa Trend

Lafayette-based Hise Exploration Partners LLC is the latest manifestation of the legacy Hise companies founded in 1968. The drilling program that's just starting is the third for this set of Hise entities.

The first ran from 2000 to 2008 and drilled 13 Tuscaloosa Trend gas wells to 20,000 feet in Pointe Coupee, East Baton Rouge and West Baton Rouge parishes.

That achieved a 200% return on investment. Cumulative production has been 90 Bcf and 1.5 MMbbl of condensate. Several of the wells are still producing.

The second program ran from 2014 to 2015 in Pointe Coupee, East Baton Rouge, Allen and Vermillion parishes. Those wells targeted shallower formations. Cumulative production to date is some 2.5 Bcf and some 650,000 bbl of oil.

Forrest Hise, manager, business development, is raising capital for the third program, dubbed "Black Bear."

"It is custom-packaged based on the private investor," he said. "Each drilling program reflects the current and long-term trend of the commodity price. Program I was drilled, targeting the deep sourcerock of the Tuscaloosa because gas prices could support the capex budget.

"In the Black Bear program, Portfolio 1 targets shallower, oil-bearing formations using non-pipe-setting wells."

HEP was planning at press time to spud the first well in the Black Bear program, said Richard Hise, CEO. "Target depth is near 13,800 feet. The wells in this program will be vertical and target oil-bearing reservoirs.

"These wells should flow naturally from partial water drive, which is consistent with other our operations in the area."

The four prospects for Black Bear are 10,500 to 13,800 feet in depth. Rigs are available, said Richard Hise. "The barge market is typically more available, but they can be hard to move."

Forest Hise said Black Bear has had "a whirlwind of activity. The major players in private equity have not seen the enormous potential in the Gulf Coast, which is a big advantage in terms of our lease efforts for each project.

"However, the risk profile seen in Gulf Coast prospects is different than for prospects in the resource plays. For example, the returns are greater and the land costs are not as enormous as those in West Texas."

He added that "investors in the Gulf Coast have to have a contrarian mindset compared with investors who want to pay top dollar for leases and drill a few PUDs in the shale plays.

"Our investors see the opportunity in Louisiana and have felt firsthand the positive results when the log comes into the office, showing large pay zones from water-drive reservoirs."

Publicly held operators have very little presence in South Louisiana; their nearest activity mostly consists of horizontal Austin Chalk development. Transportation is by truck or barge for oil.

"There is a tremendous number of pipelines for gas," said Richard Hise. "We start early in our planning to get the resource out, working through a marketer."

It also helps that the Hise companies have been active in the area for decades. "We have a 30-year track record of success and an asset team with 244 years of combined experience.

"We are based in Lafayette and are dealing with local landowners, vendors and operators. We are even on good terms with regulators, having had them out to our operations to see that we do a good job." □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COULD MEZZANINE BE RE-EMERGING?

The intermediate financing tool is getting investors' attention in "log-jammed" A&D and equity markets.

ARTICLE BY
CHRIS SHEEHAN,
CFA

In lieu of issuing dilutive public equity or increasing debt, "asset-level mezzanine or another type of structured solution is really the only way to go," said David Albert, co-head of Carlyle Energy Mezzanine Opportunities Fund II LP.

When capital markets are challenging and none of the traditional instruments in the financial toolbox look attractive, investors tend to rediscover mezzanine finance. And, after the turmoil throughout world markets in October, the flexibility of mezzanine may make it particularly appealing to investors.

For users, mezzanine capital is not designed to be a permanent source of capital; rather, it is an intermediate financing tool, typically for a specific project. Terms usually consist of an interest-bearing component, coupled with an element of upside for the capital provider. Historically, the latter "equity kicker" has taken the form of warrants, net-profits interest, overriding royalty interest and other instruments.

Funding growth projects can be tough in today's energy sector, in which E&Ps are at risk of criticism for raising debt above certain levels or for issuing equity to fund capex projects in excess of cash flow. Mezzanine financing's focus on a particular project means leverage is generally for a limited period, while equity dilution, if incurred, tends to be temporary rather than permanent.

A leader in the sector, like The Carlyle Group LP, has recently financed projects from $75 million to $1 billion or more. Other providers focus on a narrower range of projects. Prudential Capital Energy Partners LP makes investments ranging from $10 million to $50 million in its new mezzanine fund. Macquarie Bank Ltd.'s investments typically range from $25 million to $100 million.

"There's a particularly attractive dynamic in the market right now," said David Albert, co-head of Carlyle Energy Mezzanine Opportunities Fund II LP. "The demand for capital is significant because of what's happening in the equity-capital markets. Equity shareholders generally want companies in the energy sector to live within their cash flow.

"That being the case, if a company needs to grow and they don't want to do it by raising debt or having it be dilutive by issuing equity, then asset-level mezzanine or another type of structured solution is really the only way to go to increase your growth without running afoul of some of the other sensitivities out there in the marketplace."

Promising deals

Carlyle has joined with two large-cap E&Ps to help accelerate production growth and, in turn, pull forward net asset value that otherwise may not have been fully realized.

In September, it and Diamondback Energy Inc. entered an agreement to fund development of Diamondback's assets in the San Pedro area of Pecos County, Texas, in the southern Delaware Basin. Of the estimated $620 million cost, Carlyle is funding up to 85% of the development in a five-year period.

In 2017, Carlyle and EOG Resources Inc. struck a joint-venture (JV) drilling agreement covering EOG's assets in the Marmaton play of Ellis County, Okla. In this, Carlyle is providing $400 million in a four-year program. In both cases, after certain performance hurdles are achieved, Carlyle's working interests will largely revert to the two E&Ps.

"Diamondback and EOG were both in the position of having more attractive acreage and inventory than they can actually pursue at the moment," Albert said. "You could decide not to develop it and just hold onto it for later. But the further you push that out into the future, the less you're getting any credit for it in your stock price.

"They're going to choose their own best projects first. Some of their wells generate IRRs [internal rates of return] of 50% to 60%, for example, and others, 30%. For Diamondback and EOG, a 30% IRR well may not make the cut. But, for us to be able to partner with a blue-chip operator in acreage that is attractive, that's a win-win for everyone."

Factors common to the transactions are "they're both deals where we're funding the drillbit; they're both deals where we're not paying for acreage; and they're both deals where there are reversionary working interests. So our equity participation steps down after we get a minimum threshold return.

"But they both have tails, so we keep some of the upside."

Comparing the two transactions, the EOG deal was "a little bit later-stage" so that, "to a large degree, we had a pretty well-delineated play from the early days," Albert said. Conversely, the Diamondback assets were "in a slightly earlier stage of development," so "we had more protections for ourselves.

"What's different about our approach is that it's not formulaic," said Randall Kob, managing principal, Prudential Capital Energy Partners.

"We needed to make sure the wells were going to perform as expected before accelerating the rate of development."

But the attraction for Carlyle's partners is that "the bulk of the upside goes back to them after we hit a certain threshold, no matter what the return is," he noted.

Development, not wildcatting

Does the structure bear some resemblance to a DrillCo JV? "It is like a DrillCo, but the main difference is the amount of reversionary interest," Albert said.

"Most investors in a DrillCo are excited about the equity upside and are less concerned about having downside protection with some equity-kicker. It's a subtle difference, but it drives how you structure the deal. The key question is 'Does the asset and the structure have enough stability to give us comfort on the downside?'"

Here, the risk profile of the play—for example, a manufacturing-style play vs. wildcatting—is a major factor.

"To the degree the play has been fairly well-delineated and you have protections in place, like caps on drilling costs, then you actually can get comfortable that your downside is in a manageable position," he said. "You're not taking full equity risk, because you have two forms of an embedded cushion.

"One, you haven't paid for acreage. Two, you can be selective as to participating in specific fields based on, for example, results from analog wells in the area."

Overall, Carlyle targets returns in the mid-teens, although specific risk factors, such as a play's stage of development, etc., can move the threshold up to the higher teens, according to Albert.

Having the scale to do larger deals has helped Carlyle, as "there's less competition for bigger deals of $500 million and up, and there's less competition for deals with hair on them," he said. "You have to decide which areas you want to focus on. We want to deploy capital in areas that have more attractive risk-adjusted returns, which means you have to be more creative." E&Ps are reluctant to rely too heavily on the banks, Albert said.

E&Ps are reluctant to draw down large bank facilities if they can avoid it," Albert said. "People don't want to come close to the edge and load up on bank debt, given how fickle the banks have been and the risk of getting squeezed in a downturn in pricing. That's why our capital has such appeal—because they know that, even if commodity prices go south, they still have runway."

Similar to unitranche

Prudential closed fund-raising on its Prudential Capital Energy Partners Fund I LP at $343 million in September. The PCEP fund continues a history of mezzanine financing previously conducted by Prudential Capital Group, the $81-billion private-capital arm of PGIM, the investment management affiliate of Prudential Financial Inc.

"Our fund is targeting the middle market," said Randall Kob, managing principal, Prudential Capital Energy Partners. "We look to deploy $10 million to $50 million in individual transactions. We're typically the sole capital provider in a company's balance sheet. From time to time, we'll provide both senior debt and junior capital from the fund, similar to a unitranche financing."

As of June 30, the fund had invested in four companies. Two were acquisitions made with the goal of using the junior capital to accelerate production and to subsequently refinance the mezzanine by increasing the operators' reserve-based borrowing base.

One, Prairie Provident Resources Inc., is based in Calgary, where the retrenchment by middle-market banks has created particular opportunities. "We suspect there may be a size bias on the part of capital providers," Kob said.

"We've seen some very solid underwriting opportunities in certain markets that are less efficient, such as those serving smaller enterprises with 1,000 to 2,000 bbl/d of production."

In certain cases, an enterprise can be formed specifically to buy a package of properties using mezzanine capital. In this instance, Kob said, the incoming team is not only in control, but typically contributes meaningful equity or assets to support the leverage. This is in contrast to an investment by a private-equity-backed team, where management has less control and a lower ownership interest.

Not formulaic

"What's different about our approach is that it's not formulaic," Kob said. "Deal terms are a function of the profile of the assets and the capability of the team. And we have the ability to design structures for the circumstances as they present themselves.

"Our typical investment is $25 million, but, with co-investments, we can go above $50 million for the right transaction."

The PCEP fund is targeting IRRs of between 16% and 18%. Where the risk profile is viewed as being fairly modest, a contractual return is used, combining an interest rate, a payment-in-kind feature and certain fees. If more meaningful drilling risk is involved, a coupon of between 9% and 10% may be coupled with a net-profits interest—and potentially a warrant—to offer appropriate upside participation.

The fund may also offer an "advancing mezzanine facility," based on a proved, producing asset that funds further development drilling, with cash flows sent to a depositary account pending well results and establishment of funding for a next tranche of wells.

"That's probably the highest-risk form of financing we do, and our return would include a net-profits interest, warrant or common equity," Kob said.

"We're providing a higher level of outstanding debt than what's available in the conforming-bank-loan market. Typically, it's more than what can be achieved in a unitranche or a first- and second-lien format.

"And the advancing mezzanine facility is funding drilling based on a very detailed analysis of the drilling inventory and also the existing asset base."

The investments' expected duration may vary. In the U.S., investments are likely to be made predominantly in private companies. In Canada, however, the fund is invested with publicly held Prairie, and Kob said further such investments may occur.

PDP vs. PUD weighting

For Macquarie Bank, the focus of mezzanine finance continues to be mainly on private operators, often those "a little off the radar," according to Drew Allen, senior vice president in its energy-capital group.

The sweet spot for investments is $50 million, but can range from $25 million to $100 million for "a single hold." Macquarie can also participate with other capital providers in larger "club" deals.

Key drivers for private operators turning to mezzanine are threefold, Allen said. One, a soft A&D market for less-delineated assets; two, increased investor focus on free cash flow vs. growing inventory, as witnessed in 2016 and early 2017; and, ultimately, three, the "need to drill more wells to get to a monetization event."

Similarly, for public companies, mezzanine continues playing a key role in financing specific projects at more attractive costs of capital than in equity markets, Allen said. "Frankly, it may not make sense to issue equity if the assets being developed are no longer considered an 'equity' level of risk."

However, in recent years, he noted, mezzanine finance has experienced increased competition from new capital providers primarily offering DrillCo structures.

"We think of our form of capital as acceleration capital for a project that essentially already works and is economic at today's prices," he said. "But you can only get so far with a borrowing base, so we provide the additional capital to accelerate the development plan at a cheaper cost of capital than equity.

"We work with companies and their private-equity sponsors who want to continue developing their assets in preparation for a monetization event down the road at a better valuation, and we provide them the capital to get there."

Most financings by Macquarie involve "non-equity levels of risk, where hydrocarbons are clearly in the ground, and operators have shown those hydrocarbons can be extracted economically," Allen said.

These financings can involve projects that are more heavily weighted with PDP [proved developed producing] assets to ones that are more weighted to PUD [proved undeveloped] assets, according to Allen. The PDP vs. PUD weighting, as well as the amount of capital being sought, are factors determining Macquarie's cost of capital, along with other structural items, such as hedging and covenants.

Projected returns targeted by Macquarie, assuming no equity-kicker, can vary from 8% to 15% "all-in." In addition to an upfront fee, variables include a floating interest rate tied to Libor depending on the perceived risk of the deal and a possible pre-payment penalty. If risk levels warrant inclusion of an equity-kicker, "we'd want to be up in the 15% to 20% range for our all-in return," Allen said.

In terms of E&Ps that may find mezzanine attractive, he pointed to "small private companies that are a little off the radar because they either haven't drilled that many wells or they're under-served because they don't have a large acreage position.

"It's fairly rare that you see a capital provider finance a company with only 5,000 to 15,000 acres. That's where we can carve out a niche."

Macquarie is willing to downscale in terms of acreage size in light of its in-house technical staff—four engineers and a geologist—who can evaluate assets very closely and come up with an educated view of the project's future cash flow, Allen said. If everything goes to plan, "these are three- to four-year deals that we expect to be refinanced in 18 to 24 months."

"We provide the additional capital to accelerate the development plan at a cheaper cost of capital than equity," said Drew Allen, senior vice president in Macquarie Bank's energy-capital group.

Capital competition

Allen is candid about other sources of private capital providing increased competition in the space. "The reality is that it's become harder to find a good [mezzanine] deal right now with equity upside," he said. "Private equity has just ballooned because the flexibility they provide makes it easier for companies to execute on their business plans.

"The other factor is the re-emergence of DrillCo joint ventures. Some companies and sponsors are less inclined to take on leverage or want to lay off some risk, and they view DrillCos as a potential way to do that and bring in more capital.

"Historically, when we'd do mezzanine deals, they were with operators that were either so-called 'mom and pops' or small private operators that already owned an asset. They may have had some other type of capital behind them, but it wasn't private equity.

"We were typically the primary capital provider in those deals. Now we're a secondary source of capital, working with private equity, as opposed to competing with them on occasion. And that's where we want to be and plan to be in the future."

Nonetheless, deal flow is termed "healthy" because of the apparent logjam in A&D and equity markets—not despite it.

"We've seen a lot of activity in the last 12 months; deal flow has been healthy," Allen said. "I keep coming back to a saturated A&D market and a highly cautious equity market.

"The smaller E&Ps have to grow up more—to be more mature in the life cycle of a business—to attract a buyer. By necessity, you have to find capital elsewhere to continue drilling wells." □

THE GREENER GREEN GAS

E&Ps are voluntarily banding together to rein in methane losses along the value chain. They're hitting remarkable targets—and far earlier than anticipated.

ARTICLE BY
DARREN BARBEE

"Any methane that's leaked is methane that's not sold. So it just makes sense from a bottom-line perspective [to capture it]," said Jennifer Stewart, Southwestern Energy Co. senior vice president, government and regulatory affairs.

"We're really changing the world." The thought hit Jennifer Stewart, Southwestern Energy Co.'s senior vice president, government and regulatory affairs, in Washington, D.C., while presenting at the World Gas Conference last June.

Stewart participated in two panel discussions on the importance and role of methane-emissions mitigation and strategies to improve companies' environmental footprint. As the fourth-largest U.S. natural gas provider, Southwestern's clean-burning fuel is being exported worldwide.

But her thought was tempered by realization that "climate benefits are only going to be realized if the industry as a whole addresses methane emissions," she said.

"It's not just the right thing to do for the environment. It's a risk-management approach, a differentiation approach, and it's also a value approach. Any methane that's leaked is methane that's not sold. So it just makes sense from a bottom-line perspective."

For Southwestern and other producers—as well as midstream and downstream companies—efforts to reduce methane emissions have been long-term. Their goal was to reduce their cumulative methane emissions to 1% by 2025.

In November, after a four-year effort, a group of 16 energy companies called Our Nation's Energy Future (ONE Future) released its first report detailing how it's fared in achieving its aggressive 1% goal. In 2012, the overall gas industry's methane intensity—the ratio of net emissions to throughput volumes—was 1.44%, federal data show.

ONE Future participants surpassed their 2025 goal eight years early: The group's combined methane intensity was 0.55% in 2017.

ONE Future's numbers are not fanciful or puffery. For years, the group laid the groundwork for its efforts, working with the U.S. Environmental Protection Agency (EPA), the Obama Administration and environmental groups to ensure its results would be seen as legitimate.

Its protocols were developed in partnership with the U.S. Department of Energy and its results independently reviewed by the National Energy Technology Laboratory and by Innovative Environmental studies.

The ONE Future participants collectively account for 10% of U.S. gas production, 32% of gas-transmission miles and 9% of distribution. Other companies, including oil and gas majors, have joined similar groups to increase profitability and to demonstrate their stewardship of the environment.

Efforts by ONE Future have largely gone unnoticed outside of the industry. And investors and consumers are increasingly concerned about using fuel perceived as harmful to the environment.

"What ONE Future's report validates is that targeted investment in abatement technologies can significantly reduce methane emissions across the natural gas supply chain," said ONE Future executive director Richard Hyde.

"We are demonstrating that natural gas can indeed meet the growing energy needs of our country in a sustainable manner, and, as our coalition continues to grow, we look forward to helping new members across the country achieve their methane-reduction goals."

The coalition's members operate in 11 of 19 U.S. basins and in additional regions of the country. Its members include Antero Resources Corp., Apache Corp., Berkshire Hathaway's BHE Pipeline Group, BHP Plc, Dominion Energy Inc., Equinor ASA, EQT Corp., Hess Corp., Jonah Energy LLC, Kinder Morgan Inc., National Grid Plc, Noble Energy Inc., Southern Co.'s Southern Company Gas business, Southwestern Energy, Summit Utilities Inc. and TransCanada Corp.

Southwestern, a founding member, surpassed its methane leak/loss-rate goal of 0.36% of gross production with a 0.22% methane intensity. Its efforts have proven profitable beyond just sparing gas from escaping, including signing up a utility that wants more "responsibly produced" gas.

'War stories'

During a span of about four weeks in 2015, a turbocharged Mooney TLS Bravo M20M flew over the gas operations in Arkansas' Fayetteville Shale. The purpose was to conduct a series of top-down emissions measurements—and solve a scientific riddle. Readings on the ground and in the air didn't match.

PHOTO COURTESY SOUTHWESTERN ENERGY CO.

Southwestern Energy Co. personnel survey a Marcellus site for emissions, using infrared optical gas imaging.

"The realization was you had methane emissions and, if you're a producer, that's basically just money going up in the air," said ONE Future executive director Richard Hyde.

Colorado State University, the National Oceanic and Atmospheric Administration (NOAA), the Colorado School of Mines and others teamed up for the study. But capturing the precise measurements required E&Ps to open up their sites to scientists.

The sponsors included Southwestern as well as XTO Energy Inc., Equinor, Chevron Corp. and the American Gas Association.

The genesis of ONE Future began with Southwestern setting a goal of achieving methane leakage below 1%, Stewart said. Initially, seven other companies joined. To make it work required cooperation among all the companies, as well as the EPA, the White House, universities and researchers, and environmental groups.

ONE Future participants have invested in reducing emissions since 2014, upgrading and replacing pipeline infrastructure as well as actively seeking and repairing system leaks.

Southwestern has gone to great lengths to create an engineering philosophy in which it tries to build facilities and use equipment that loses as little methane as possible. "As much as we can, we 'design out' the loss of methane," said Clay Murral, who oversees Southwestern's air-quality program.

The coalition advocated for technologies that complied with—but weren't mandated by—the state or federal level. For the industry operators, emitting less means increased profitability. But the organization worked out differences with EPA-approved reporting protocols to demonstrate "credible and measurable results," ONE Future reported.

As a group, participants also learned from one another. "One of the benefits of having a coalition like this is you're able to share war stories, so to speak, and best practices," Hyde said.

"As we started talking through this, we found additional ways that companies could deploy technologies or use an existing technology maybe in a more cost-effective way."

ONE Future pushed a policy framework that incorporated science-based performance targets, giving operators across the value chain the flexibility to deploy their capital and resources as they saw fit.

Capitalist enterprises need goals, not processes. ONE Future wanted outcome-based measures "rather than a one-size-fits-all process for every producer, pipeline company or gathering company across the U.S., no matter the size or geography," Stewart said.

Southwestern sees a responsibility to mitigate venting methane into the atmosphere, she said. The role of natural gas as a low-carbon fuel could be offset by uncontrolled methane emissions. But it also is cost effective.

"You can't look at one side of the equation," she said. "You have to look at both sides."

And while environmental stewardship is important to the company, its efforts were not a reaction to outside activists or other pressures. "It's not a defensive posture. It's more of a proactive posture," she said.

"We recognize that natural gas is a low-carbon fuel, clearly. It's a much cleaner fuel than coal—or oil, for that matter. But it's primarily methane, which we know is a greenhouse gas due to its heat-trapping ability."

Before ONE Future, Southwestern already had a robust leak-detection and -repair program, Murral said. "At that stage in the game it was a voluntarily program, which we continue to this day," he said. "We survey all of our facilities, regardless of regulatory requirements."

Southwestern's efforts to work with regulators have given it flexibility to test new technologies and methods as they were developed, providing feedback to developers even when some ideas weren't accepted by existing regulations.

The company's partnership with Colorado State University's Methane Emissions Technology Evaluation Center has also enabled research space to conduct studies in a semi-controlled environment that mimics actual facilities.

"CSU is able to operate this facility, coordinate studies and have industry, technology companies and regulatory agencies test existing and emerging technologies," Murral said. "It's been an extremely successful operation that they have there."

"They narrowed down where that difference came from, and it had to do with timing of the measurements," Murral said. "It was a seminal study that has basically solved this conundrum that had been going on for a while between these two different methodologies.

"And it validated them both. They're both correct and quite accurate. It's just the timing—relative to activity—and what can be deduced from each that provides the best sort of answer."

Another study is evaluating the efficacy of leak detection and repair conducted with optical gas-imaging and the human factor. "It had been assumed for the longest time that [optical technology] would reveal 100% of the leaks," Murral said.

"What they're finding is that's not truly the case. What this research does is provide a basis upon which emerging technologies can be evaluated in the leak-detection realm that I think is going to lead us to that step-change, the next major improvement in that field."

Under pressure

In October 2017, scientists at Stockholm University warned of "strong emitters" in the Baltic Sea that were responsible for an estimated 9.5% of the area's greenhouse-gas emissions. The culprits: seaworms and *Limecola balthica*, the latter better known at dinner tables as the clam.

The macrofauna help produce an unhealthy share of gas—the worms by disturbing the seabed; the clams, in the usual, digestive way—according to research published in the journal *Scientific Reports*.

While not all sources of emission may be as clear cut, oil and gas industry-led groups have banded together, as with ONE Future, to plug the leaks. The motives vary. CEOs at major oil companies have thrown support behind addressing climate change; others feel more pressing concerns from investors and activists.

"The investor community has really pushed for how companies are going to behave in a sustainable way with a lot of issues—methane being one of those," ONE Future's Hyde said.

In 2018, investor groups, including As You Sow, an environmental-protection and -conservation nonprofit, led a charge against several companies in an attempt to force oil and gas producers to disclose more about their methane emissions, policies and procurement.

Along with other groups, Anadarko Petroleum Corp., Chevron, Devon, Dominion, Kinder Morgan, Energen Corp., EQT and Range Resources Corp. all faced shareholder initiatives. Miller/Howard Investments Inc. filed several measures, as well, though they were withdrawn after Devon, EQT, Energen and Anadarko agreed to improve disclosure.

In May, Range held a vote on the matter after a measure was introduced for the E&P's annual meeting. Shareholders narrowly defeated the measure, coming within one-half of a percent of approving it.

Other companies are voluntarily moving to share more with the public for multiple reasons. The American Petroleum Institute's The Environmental Partnership and the voluntary, CEO-led Oil and Gas Climate Initiative (OGCI) have pledged to reduce emissions.

The OGCI members represent about 30% of global oil and gas production. Royal Dutch Shell Plc, an OGCI member, has targeted methane-emission intensity below 0.2% by 2025. The target covers all oil and gas assets Shell operates.

Occidental Petroleum Corp. is a member of both organizations. "Industry innovation and collaboration have a critical role to play in addressing climate change," said Richard Jackson, Occidental senior vice president, operations support.

"The OGCI can be a catalyst for change and Occidental will be working with the other members to contribute to a collective goal of achieving significant reductions in methane emissions by 2025."

The OGCI aims to collectively decrease emissions by stepping up the speed and scale of the initiatives individual companies are taking. The details of how that work will progress is still taking shape, but Occidental will look to identify and develop emission-reduction opportunities across the value chain.

"We are still very early in our engagement with OGCI," Jackson said, "but look forward to transparently sharing emission-reduction techniques and technology."

Occidental has already joined efforts to be more open about how it's trying to limit emissions. It voluntarily participates in the EPA's Natural Gas STAR Program. It was also one of the first companies to join API's The Environmental Partnership in 2017.

However, it committed to going beyond the partnership's requirements by saying it would "report our progress in implementing initiatives annually on our website," Jackson said.

Since 1990, Occidental has implemented a broad range of projects to reduce methane emissions, resulting in preventing 17.2 billion cubic feet reaching the atmosphere through year-end 2016. However, the continued advancement in technology will be key in identifying and quantifying emissions.

"Occidental is advancing carbon capture, utilization and sequestration (CCUS)—with specific focus on CO_2 EOR where we are an industry leader," Jackson said. "This technology has the potential to help achieve global goals for reducing emissions with the benefits of doing so in a relatively short timeframe."

A steady advancement in the breadth and sophistication of technology for identifying and quantifying emissions is helping. Occidental uses forward-looking infrared cameras to identify possible emissions leaks on equipment and components, such as pneumatic valves, plunger lift systems, storage tanks, compressors and glycol dehydrators.

Kinder Morgan Inc. already quietly ran a methane-emissions plan, said Tom Hutchins, vice president, environmental health and safety, Kinder Morgan Natural Gas Pipelines. "We were pretty quiet, staying under the radar screen."

Occidental's Methane-Emissions Curtailment Efforts

Valves, flanges, pump seals	Adopted lower-emission thresholds to identify and minimize leaks.
Green completions	Wellhead-gas capture during completion; surveyed 2,500 leaks between 2016 and 2017.
Pneumatic controls, instrumentation	Adopting low-bleed or no-bleed pneumatic valves or transitioning to compressed air instead.
Vapor-recovery units (VRU)	Capture and recover gas from certain equipment, rather than venting.
Infrared cameras	Help in identifying and eliminating leaks.

Source: Occidental Petroleum Corp.

"I trust, as an industry, we recognize that the drive to reduce greenhouse-gas emissions has both social and material value," said Gretchen Watkins, Shell Oil Co. president.

OGCI, through its $1-billion Climate Investments fund, is also supporting promising technologies and seeking additional collaboration opportunities. "Looking ahead, scientists are working to advance aerial-survey and satellite techniques from the laboratory to commercial ventures and Occidental is one of the member companies helping to facilitate this process," Jackson said.

The operator continues to explore other innovation for its processing facilities and infrastructure where it can better consolidate, monitor and proactively manage maintenance, while ensuring a high operating efficiency and enhanced environmental performance.

Plans are to unveil its new emissions targets in 2019. The company's direct-emissions reduction plan will include a 2030 emissions target with shorter-term milestones and actions it will take at the asset level.

A subsidiary, Oxy Low Carbon Ventures LLC (OLCV), is capitalizing on its parent's EOR leadership by developing CCUS projects that source man-made CO_2. The company is also promoting other complementary innovative technologies that help advance its business while reducing emissions.

In November, OLCV announced an investment agreement, subject to regulatory approval, in NET Power LLC's development of a low-cost gas/electric power system that generates no atmospheric emissions. The power system captures all CO_2 and produces no nitrogen oxide (NOx).

The progressives

The initial eight companies that formed ONE Future in 2014—and the members that have since joined—are what Hyde calls "progressive" in that they "want to find solutions as opposed to the 'just say no' crowd."

The companies, including Southern Company Gas, where Hyde was formerly in a government-relations role, came to the conclusion that methane emissions were an issue—though, from a climate-change perspective, "whether it's man-made or not was not part of the argument."

"The realization was you had methane emissions and, if you're a producer, that's basically just money going up in the air," he said. "It makes good business sense to reduce your emissions."

In competition, natural gas becomes a formidable player when methane intensity across the value chain falls below 1.3%, particularly when going head to head with coal, Hyde said.

ONE Future's founders also saw the Obama Administration eyeing regulations of methane "under the traditional command-and-control type regulations," he said. Instead, the companies came together to design a toolbox of technologies that could fit differing needs—"because not everybody is created equal," Hyde said.

Within the industry, few thought that the EPA's approach would work because it didn't account for how each company's operations varied. In 2014, ONE Future engaged directly with the White House and EPA, working with them "to support a voluntary, performance-based program," he said.

The coalition also worked to get federal approval of ONE Future's estimation methods for methane. "That was the result of Southwestern Energy leadership going to the White House on numerous occasions under President Obama's administration and working with the EPA," Murral said.

With the ground rules established, the companies could then implement their reduction strategies. Direct engagement also gave companies a way to minimize redundancies systemic in the EPA's command-and-control process. ONE Future believes each member is best positioned to determine the most effective ways to reduce methane emissions.

"As we looked at those three stakeholder groups-employees, investors and customers—there's a huge motivation to say, 'We need to address methane emissions and be intentional about how we're addressing and reducing those emissions,'" Hyde said.

Stewart sees independent producers as the first-movers in methane-emission reduction, though, in some cases, reluctant ones. "Companies put time, effort and dollars into creating a framework for tamping down leaks," she said.

Company leaders, to varying degrees, were skeptical about investing capital in aggressive emission-reductions goals. The balance-sheet implications weren't promising either.

"Using ONE Future's actual data, the cost of reducing emissions per Mcf (thousand cubic feet) was $3.35 in 2016," Hyde said. "The price of natural gas, at less than $3 per Mcf, meant deficit-spending."

From a safety perspective, less leakage meant less danger to employees and neighborhoods. Investors were interested in how to maximize profit for a business that lives and dies on margins.

"ONE Future also had to get nongovernmental organizations (NGOs) on board—or at least to the point of mutual respect," Stewart said.

ONE Future member Kinder Morgan Inc. similarly raised a few eyebrows internally. However, Kinder Morgan already quietly ran a methane-emissions plan before it was brought into the open following its $21.1-billion acquisition of El Paso Corp., said Tom Hutchins, vice president of environmental health and safety for Kinder Morgan Natural Gas Pipelines.

"There were some within the organization that I would say were surprised," said Hutchins, former chairman of The INGAA Foundation Inc., a nonprofit that provides support to pipeline operators. "We were pretty quiet, staying under the radar screen."

However, significant opposition because of methane emissions led the company to join ONE Future.

As for Hyde, his involvement in ONE Future began while he worked for AGL Resources Inc., which was later purchased by Southern

Co. AGL Resources' corporate culture had fully backed methane reduction.

Southern is an electricity provider and producer and there was a question about the efforts because the company uses coal as a fuel source, he said. However, Southern underwent a culture shift, with management eventually becoming a "huge proponent" of curbing emissions. Ultimately the calculations added other elements.

"When it comes to employee safety and customers, you can't put a price on that," he said. "Some within the industry generally assumed that the cost of reducing emissions didn't make economic sense and, a few years ago, I may have agreed. But ONE Future members have actually demonstrated that it does make good business sense."

Stewart said its methods are now paying benefits. "It's no longer a novel way of doing things. Now it's just embedded in how we do business."

Green and gas

In September, Southwestern's emissions efforts paid off in an unexpected way, thanks largely to how consumers on the East Coast think about energy. The company entered a contract to sell gas to New Jersey Resources Corp., a distribution company serving more than a half-million customers throughout the state.

The utility agreed to pay a premium for gas to local indices because it is sourced from wells that are independently certified as responsibly produced under measures that include methane-emission intensity, wellbore integrity and water use.

"That premium is derived from Southwestern's reputation and operational excellence," Stewart said. "You're starting to see our approach to methane emissions manifest that way. We have a couple of other utilities that are talking to us about similar contracts."

Even some that aren't willing to pay a premium are talking to the company about how it's reducing emissions, using water or wellbore integrity. "You're seeing the demand side—especially with utilities that are accountable regarding sustainability to the citizens they serve—becoming much more demanding on methane-intensity-reduction efforts," she said.

Early success by ONE Future doesn't mean member companies will be coasting from now until 2025. Stewart said Southwestern was "beyond proud" of its early success.

"It was celebratory," she said. "We need more people to get onboard."

The industry has a long road ahead in getting other operators to participate, while also countering more-outspoken environmental groups that have urged institutional investors to divest from oil and gas holdings.

"To do that," Stewart said, "requires hammering home the data: The U.S. CO_2 levels are at 1990 levels."

Energy-related CO_2 emissions fell by 42 million tonnes in 2017 and were 1% lower than in 2016. "Methane is a greenhouse gas, so the industry must focus on reducing fugitive emissions.

"But we certainly can't ignore the climate benefits of the increased use of clean-burning natural gas for power generation," she said.

At Kinder Morgan, the company has worked for more than 20 years to reduce emissions as part of the EPA's Natural Gas Star program. Among a multitude of steps, the company has replaced high-bleed pneumatic devices with low- or no-bleed pneumatic devices, installed turbines or electric compression instead of reciprocating engines, and conducted leak surveys to identify and fix leaks.

With more than 84,000 miles of gas pipelines, its goal was to reduce emissions intensity to 0.3% or less. The results from the first ONE Future report show the transmission and storage sector, where Kinder Morgan resides, has already surpassed its goal, with its methane intensity in 2017 at just 0.12%.

"Having already met the goal, we will not rest on our laurels," Kinder Morgan's Hutchins said. "We will continue to look for technologies and best practices that will allow us to continue managing and minimizing methane emissions."

The company wants to take part in reducing emissions because it manages the methane molecule longer than any other segment of the natural gas value chain, he said. Other companies are also showing a growing commitment to emissions practice that is not just good for business but also for the environment.

"I hear that from the folks who are glad we're doing this: 'It's something I really want to do,'" he said.

At Hart Energy's Executive Oil Conference in Midland, Texas, this fall, Shell Oil Co. incoming president Gretchen Watkins said Shell is no longer installing flares at new-well production pads in the Permian Basin.

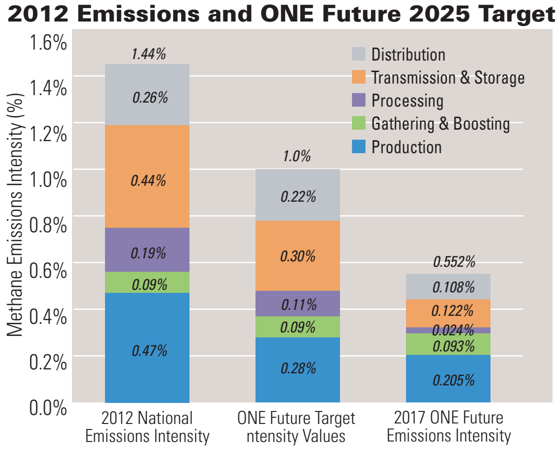
The company has phased out greenhouse-intensive technology, such as high-bleed pneumatically operated controllers, and is also using solar energy to power its wellpads. It's also part of the OGCI initiative.

"I trust, as an industry, we recognize that the drive to reduce greenhouse-gas emissions has both social and material value," Watkins said. □

"Industry innovation and collaboration have a critical role to play in addressing climate change."

–Richard Jackson, Occidental Petroleum Corp.

2012 Emissions and ONE Future 2025 Target



Source: ONE Future. Data for two new-member companies is not reflected.

Through the combined efforts of ONE Future's upstream, downstream and midstream companies, the coalition of natural gas companies surpassed its targets set for 2025 in its first year of reporting.

A PLAY ON THE YESO

A start-up in early 2016, Percussion Petroleum LLC has found success with horizontal pay from New Mexico's Yeso.

ARTICLE BY
TRAVIS E. POLING

PHOTO COURTESY PERCUSSION PETROLEUM LLC

Percussion Petroleum LLC's founders began their hunt for a platform asset in early 2016 as WTI was heading to less than $27 a barrel. From left to right, Lupe Carrillo, COO; John Campbell III, CEO; and Brian Zwart, chief technical officer.

In January 2016, three E&P executives met at a Panera Bread in Houston and contemplated what had brought them to this point. John Campbell III, Brian Zwart and Lupe Carrillo had just departed Rockcliff Energy LLC as the operator closed out its first phase and moved onto Rockcliff II.

The triumvirate formed Percussion Petroleum LLC to take advantage of market bargains and ready private-equity cash available to snag those assets. "We quit our jobs and, then, looked at each other during the lowest oil price that I had personally seen in my career. We wondered if we had made the right decision," said Campbell, CEO.

"We're calculated. Two of us are engineers and Lupe has a very deep background in oil fields, so he's seen the ups and downs in oil price before. We're pretty risk-averse, so it was a pretty big leap for us."

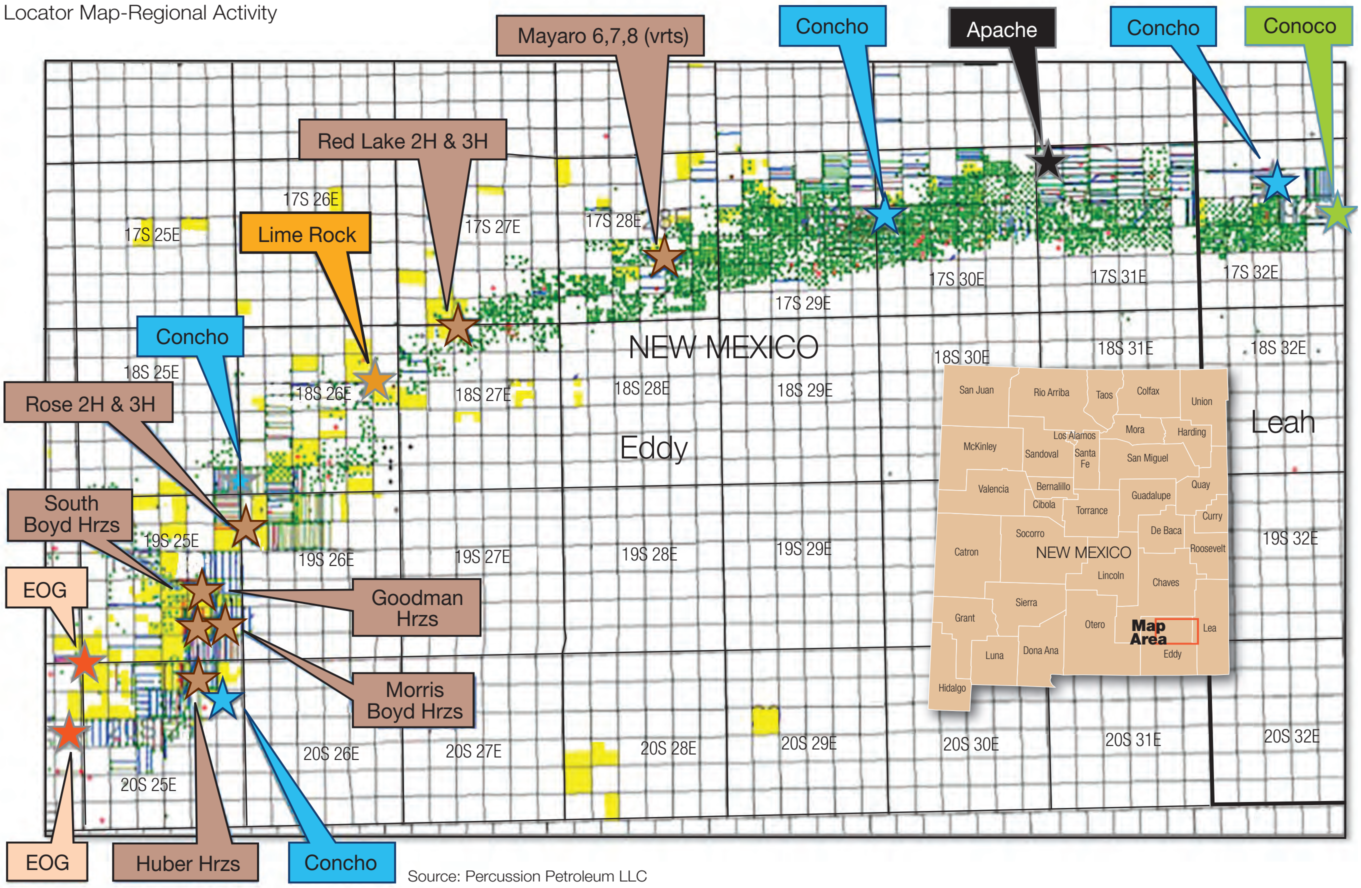
Confidence to go out on their own came from discovering they had developed complementary skills after years of working together. Meanwhile, low oil prices were creating buying opportunities. Most of all, "capital from private-equity firms was accessible to a younger team like us for the first time," Campbell said.

They best knew the ArkLaTex region and the Permian Basin, so they focused their efforts there, eventually settling on putting together acreage in the thick dolomite of the Yeso Formation of the Permian Basin in New Mexico's Lea and Eddy counties.

They weren't the first to use horizontal drilling in the Yeso to take advantage of what had been exploited with vertical drilling for decades. Concho Resources Inc. had begun drilling horizontal Yeso wells in 2016—making 40 wells of these that year—after a decade that produced 1,300 Yeso verticals for it on the Northwest Shelf.

Percussion's Capital Program

Locator Map-Regional Activity



Source: Percussion Petroleum LLC

The Percussion team has zeroed in on Eddy County in the Permian's Northwest Shelf as the platform for their first E&P.

Other E&Ps that started to work the Yeso horizontally include Apache Corp., ConocoPhillips, EOG Resources Inc. and Occidental Petroleum Corp. Part of the allure of the formation is that it is relatively shallow at 2,500 to 3,500 feet when compared with producing formations elsewhere in the Permian and in other basins. Completed wells may cost $4 million or less. Breakeven can be at $30 WTI or less.

For a somewhat risk-averse startup such as Percussion, it was irresistible.

In just two years, through numerous acquisitions, Percussion amassed 16,500 acres of Yeso on the Shelf, making it the biggest player in the western portion. Concho is the largest player on the other half of the Shelf.

The company has 46 employees, operates 220 wellbores, is drilling a new well every nine days and has identified 1,200 horizontal locations, while it adds more acreage. As of late October, production was 9,000 net barrels of oil equivalent per day.

Starting with PE

The team's start came in February 2016 as Carnelian Energy Capital LP announced Percussion as its second investment from its inaugural $400-million fund. The Houston-based investment firm typically starts with commitments of less than $100 million. Carnelian closed its second fund at $600 million in mid-2017.

Campbell said he was introduced to the Carnelian partners by a friend and found a good fit. Carnelian partner Daniel Goodman recalled those first meetings and how well their goals aligned.

"I could instantly see that John's work ethic, technical acumen and network were top tier," Goodman said. "We spent time in and out of the office with John, Lupe and Brian making sure the relationship was strong before we partnered.

"We were drawn to their keen sense of value creation and the cohesiveness they demonstrated after having worked together at [Rockcliff and Quantum Resources Management LLC]. Just as with any relationship or partnership, fit is really important, and we all felt like we viewed the world the same way and were all committed to helping each other succeed."

The team's experience and skills were key in the deal-evaluation and -acquisition phase and in the current operations and expansion stage. Campbell and Zwart, both in their early 30s, grew up with family connections to the oil and gas industry in Houston before pursuing petroleum engineering degrees at the University of Texas. Carrillo, COO, grew up in Hobbs, N.M., where his father worked in the oil field off and on in the oil-price cycles, before going to the University of Houston for a degree in geology.

Campbell brings the downhole and business-development expertise to the team; he began his career in the E&P group at El Paso Corp. that was spun out as EP Energy Corp. Zwart, chief technical officer, specializes in subsurface geology and reservoir management; he began his career at Devon Energy Corp.

Carrillo, the eldest of the three at 45, is the Swiss Army knife of the group, with decades of experience handling accounting, finance, risk management and marketing, and managing field operations and lift costs. His career includes XTO Energy Inc. and Schlumberger Ltd.

The early days for the Percussion partners were initially in Zwart's living room—the only one without children yet—and, then, in a rundown Houston office building where they rented a small space. The office had rusted metal, no security, some questionable tenants, a bad parking garage, infrequent elevator service and was in need of a paint job, recalled Zwart.

"We were doing everything from geologic mapping and economic modeling to taking out the trash and hooking up printers" after leaving the comfort of the established Rockcliff, Zwart said. "When we left, people thought we were crazy."

They moved to offices a step up a few months later, but didn't dip deeper into their equity commitment for a classier space until after they closed their first acquisition. Getting to that first deal took about seven months after looking at more than 200, evaluating 30, bidding on 15, negotiating on four and, then, closing on one.

Campbell said, "We worked every holiday that year. We didn't see the light of day in 2016."

Zwart said, "At first, we were trying to work it as fast as possible to disprove each deal. You can't out-engineer, can't exploit an asset you overpaid for. If we worked it for anywhere from a day to two weeks and it still checked all the boxes, then it would go to the third stage."

What they were looking for was non-core assets from distressed companies that might want to sell to avert bankruptcy as oil dropped below $27. While some deals looked promising, most sellers decided to hang on to their positions in the Permian and elsewhere, even if that meant Chapter 11 in the hope that the assets would eventually lead them back to profitability. As deals fell through, it was on to the next and more grueling days of work.

What they ultimately found was a North Texas oilman ready to retire from the business and willing to sell in the Yeso. As part of the agreement, there was no press release about the acquisition from Nearburg Producing Co., but public data show the change in operator.

The Nearburg acquisition in Eddy County, N.M., included 6,000 net acres, 700 boe/d net production, 75 operated wells--and a significantly undercapitalized program.

The closing was cause for celebration. Carrillo said that, before the deal was closed, "I sent my wife on a mission to find a great bottle of champagne." Time passed, "but, as soon as we got back from the lawyers' offices, we popped that bottle then and there."

Fatigue quickly set in. "We were too tired to celebrate too much," Zwart said. "Our world is more like a chess game or a golf game with a fist pump for small victories along the way." By the time bottle of the bubbly was gone, the mindset was already turning to the uphill road of hiring, integration and operations in New Mexico.

Things moved quickly then. "From an evaluation standpoint, [the deals] got easier because we were getting more familiar with the area," Zwart said. While sometimes more complex, the larger acquisitions came together more quickly than smaller—yet crucial bolt-on—buys because the large-operator sellers didn't have small-money sales high on their priority list.

In all, Percussion made more than 30 acquisitions in 2017.

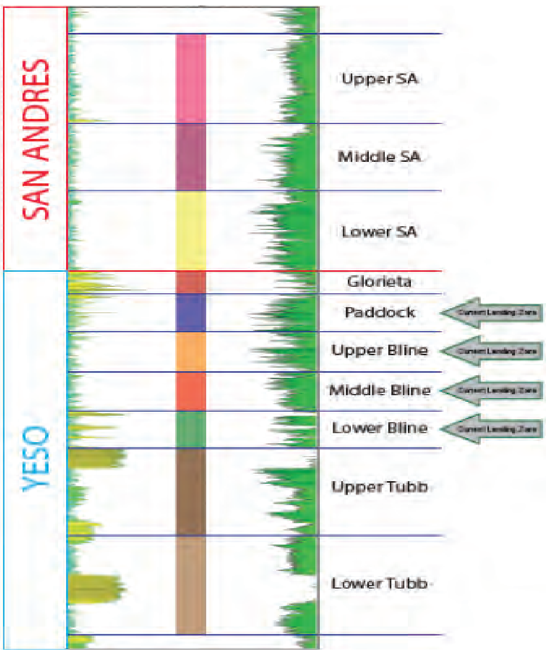
The attention the horizontal Yeso play is getting lately has tended to drive up acreage prices, but there are a few large positions left in their core operating area, Zwart said. Campbell said the leasehold could grow from 16,500 acres to 20,000 in the months ahead. Meanwhile, Percussion is in the process of selling much of its roughly 6,000 acres of non-core assets outside the Yeso.

"The wells are demonstrating that our high oil IPs and increased EURs are repeatable across our position, yielding some of the best economics in the Lower 48."
–John Campbell III, CEO

A third the cost

In April last year, Percussion completed four wells in Eddy County that included the highest reported 30-day IP for any of the more than 400 horizontal Yeso wells. The Goodman 22-4H flowed 1,208 boe/d on a three-stream basis (92% liquids; 89% oil), 1,440 boe/d on a 24-hour IP rate. The lateral measured 4,835 feet and the four wells cost between $3- and $4 million each.

The four wells together averaged 4,915 feet of productive lateral at just under 3,000 feet TVD. Average 30-day IP for the group was 1,080 boe/d on a three-stream basis.



The Yeso Formation on the Delaware Basin Northwest Shelf in Eddy County, N.M., is 2,000 feet thick with multiple benches.

"You can't out-engineer, can't exploit an asset you overpaid for."

— Brian Zwart

ROBERT D. FLAHERTY/COURTESY PERCUSSION PETROLEUM

The results are enhanced by very brittle rock ("like hitting a car windshield with a hammer") and by pushing the completions. The Goodman wells were stimulated with more than 1,000 pounds of proppant and 2,500 gallons of water per foot of lateral length.

"As we apply new completion technology across the multiple benches of the 2,000 foot-thick Yeso, we have seen the results continue to improve," Campbell said. "The wells are demonstrating that our high oil IPs and increased EURs are repeatable across our position, yielding some of the best economics in the Lower 48."

The team estimates Percussion has about 10 to 20 years of drilling inventory. In the field at year-end was one rig to prove up as many reserves as Percussion can. With 9,000 barrels per day there is enough cash to keep things going without tapping the Carnelian equity.

"Well costs are about a third of the Delaware, yet EURs are the same," said Tomas Ackerman, a Carnelian partner. "It is really the gift that keeps on giving, and the Percussion team has just scratched the surface in terms of developing the multiple zones on their acreage."

It is drilling a new well every eight or nine days with the one rig. It's planning to add a second by mid-2019; possibly, a third by year-end.

Much of the drilling is on federal land. Due to the Shelf's long history of production, a lot of infrastructure already exists in the area.

In addition, trucking the oil is possible: The main roads have undergone repair and reconstruction in recent years and Holly-Frontier Corp.'s 100,000 bbl/d Navajo refinery in Artesia, N.M., is just 10 miles from the heart of Percussion's production.

Percussion recently installed lease automatic custody transfer units with pumps for quicker tanker-truck fills as opposed to using only gravity.

The company is working now on frack- and produced-water infrastructure in the area. The team sees a lot of upside in having strong water assets and rights. Campbell said Percussion spent a significant amount on water assets in 2017 and will aggressively do more this year as drilling intensifies. As part of its program, the company owns and operates a large-scale saltwater disposal system with 90,000 barrels of water per day capacity. It also owns a high-rate water transfer line from a third-party source well to Percussion-owned frack ponds with 600,000 bbl capacity, and has secured a long-term source water contract for 110,000 bbl water per day refresh rate.

While Carnelian doesn't need to put any more money into Percussion for development, it stands ready to back possible acquisitions as they become available, Goodman said. "This specific asset is now cash flow positive, and we can fund drilling organically.

"That said, we continue to look for accretive acquisitions and expect some of the larger companies in the area to put their legacy Yeso assets on the market as they continue to refocus their companies on being single-basin pure-plays."

Campbell said Percussion "is getting to the point of critical mass," thanks to the number of wells drilled and proof of decades of drilling potential. Like most companies backed by private equity, selling is likely in the cards at some point. For now, the company is staying private and doesn't need an IPO to continue its buying-and-development streak.

Ackerman said, "They have turned that play into one of the most economic oil plays in the country. They have also used their Rolodex and sheer hustle to grow their initial anchor asset through more than 50 bolt-on transactions. It has been really fun to watch the success that they've had."

Campbell said there is a certain amount of hype that has arisen around the Yeso since Percussion started producing significant results in an area few were paying attention to, but he thinks it is well deserved.

"We made it shiny again." □

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SMALL, STRATEGIC CAPITAL

These private-equity firms fund both conventional- and unconventional-resource ideas and teams needing less than $200 million to make their plays.

ARTICLE BY
ELLEN CHANG

Some public companies' stock prices are depressed, so issuing more stock is not the solution. And fewer privately held producers are completing IPOs as potential shareholders remain cautious on commodity prices.

For example, Dallas-based Berry Petroleum Corp. that was spun out of Linn Energy Inc. aimed this past summer to raise $367 million from its IPO for itself and for selling shareholders. The deal priced at $14 a share rather than the $15-to-$17 estimate and 13 million shares were sold rather than 21.6 million.

For producers seeking other capital, private-equity investors remain. These three firms seek deals of less than $200 million and tend to focus on less-popular basins that still have a large amount of reserves remaining.

Expertise in their regions

Based in Houston and Calgary and formed in 2007, Arcadius Capital Partners Inc. targets smaller, regional operators with lower-risk strategies. "We are focused on the underserved, lower middle market and companies that can deliver out-sized returns," said Tym Tombar, managing director.

"Our firm wants to leverage competitive strengths and build out a portfolio in the upstream business to take advantage of inefficiencies in the micro-cap space."

Arcadius' strategy is to partner profitably with seasoned managers to build businesses with strong returns by investing in basins in the U.S. and Canada that are highly fragmented and under-exploited, he said.

The firm has made investments in operators with assets in South Louisiana, the Powder River Basin in Montana and Wyoming, the conventional areas of the Permian Basin and in Central Alberta in Canada.

Tym Tombar, managing director, Arcadius Capital Partners Inc., says it focuses on only a few counties or parishes per asset position.

It invests mainly in conventional "cost-competitive asset positions and, in many cases, have some unconventional upside to them," Tombar said.

These portfolio companies are led by management teams that demonstrate insight into, and expertise in, their regions. "We partner with the management teams to build out their asset positions, usually with a narrow two- to three-county or -parish focus," he said.

The assets are well-positioned on the cost curve, Tombar said. "Whether oil is $45 or $75 a barrel, we have to find a way to make money and we look for companies that are always in plays that are most cost-effective."

By not solely focusing on the shale regions, Arcadius has sought opportunities in basins where oil was discovered and exploited in the 1940s through the 1980s and still have the ability to produce more. "While these assets are not as large as the shale plays, we can deploy incremental capital that is typically $30- to $35 million and seek to triple our investment," Tombar said. Compared with those of larger public companies, these assets do not move the needle as much.

The firm likes the resources in South Louisiana that were discovered in the 1940s. One investment is in Sugar Land, Texas-based Premience Energy LLC, which is focusing on three of 20 producing zones in a South Louisiana oil field.

"These three zones are very prolific and the previous company was unable to commingle a number of zones," Tombar said. "The management team was able to unitize the field in such a way that they can now commingle zones from 6,500 to 9,700 feet effectively."

Newer technology has enabled many operators with better methods of produced-water disposal, he added. The position Premience has put together has the potential to produce an additional 10- to 20 million barrels (MMbbl) of oil.

"We do take advantage of the advances in technology and are also relying on people who have expertise working in larger, integrated oil companies or large independents and are rede-

Marceau Schlumberger, co-founder and managing partner, Coral Reef Capital LLC, said it seeks undercapitalized assets to turn around.

ploying their talent and expertise on assets that have been undercapitalized and undermanaged," Tombar said.

At Arcadius, investments have generally been below $200 million, while the firm's sweet spot is between $25- and $45 million. "We don't like the large, single-well event risks that might leave us and the company more exposed," he said. "We are investing in plays that are cost-effective—i.e., spending less than $700,000 to drill a well in the eastern shelf of the Permian."

He added that "our end of the market is less competitive. We are looking at opportunities to capture attractive assets with substantial discounts to market metrics, and we tend to have a better profile of assets often with relatively much more low-hanging fruit."

During the past two to three years, E&P-focused private-equity firms have worked to distinguish themselves to generate outsized returns, he said. When oil dipped to $45 a barrel, the industry was forced to think more critically and find the right basins.

"It's been painful from an investor-sentiment standpoint, while it has created opportunities for people who are committed to investing for the longer term," he said.

The firm's last exits were in 2014—two portfolio companies that were sold in their entirety and two that were sold in parts. These had assets in the Eagle Ford, the Wattenberg Field, Southeast Texas and Central Oklahoma.

Since those sales, the firm has been waiting for the right opportunity. "We might be selling a company [operating] in the Powder River Basin sometime in 2019," Tombar said.

Applying tech advancement

Formed in 2008, New York-based Coral Reef Capital LLC targets smaller E&Ps whose management teams have proven operator records of creating shareholder value for buy-and-build growth strategies in upstream North American energy assets, said Marceau Schlumberger, co-founder and managing partner. Its latest fund, CRC Energy Fund LP, has made two platform investments.

"We focus on acquiring and developing neglected, mismanaged, undercapitalized assets and backing management teams to unlock the embedded value of those assets through operations improvement or by applying recent advances made in drilling and completion," Schlumberger said.

One area the firm focuses on is regional consolidations in the U.S. and Canada. In a short period of time, its portfolio companies have grown eight to 10 times in size by making add-on acquisitions that provide synergies and growth opportunities.

Management teams leverage their industry experience and knowledge of a basin to manage assets better. Schlumberger added, "Upstream E&P is blocking and tackling, but also a high-tech business." Data-driven decisions lead to proper risk management and better business outcomes.

"We are fortunate to work every day with industry leaders that can apply their art and science to build companies that now all have more than 10,000 acres of leased land with lots of drilling-growth opportunities and that can grow organically and sustainably with their own generated cash flow," he said.

"Having well-capitalized, low-leverage balance sheets and low all-in costs of operations of $20 to $30 per barrel allows our companies to take on the risks and make decisions that are necessary to make money."

The Illinois Basin, which was a leading U.S. producer in the early 20th century, is the focus of portfolio company Shawnee Oil Co. LLC, based in Carmi, Ill. It holds 12,000 acres and 155 producing wells.

"The reservoirs are shallower, and, therefore, costs and risk are lower," Schlumberger said. "Only a handful of operators in this basin understand slickwater fracking. The innovations that have worked elsewhere in the last 10 years in Texas and Oklahoma are only just starting to be applied successfully across the U.S."

In Illinois, each well drilled during the past two years is generating two to five times cash-on-cash returns. "The short paybacks on wells allow us to fuel our growth," he said.

Meanwhile, on the Gulf Coast, secondary recovery techniques, such as dump floods, as well data advances, can be matched with skilled engineering to recover more oil at a low cost. One of Coral Reef's Gulf Coast-region investments is Mesa Gulf Coast LLC, which is led by a team from Stone Energy Corp. and Chevron Corp. that pioneered dump floods.

It is applying this high-rate waterflood technique to Valentine Field onshore Lafourche Parish, La., that has historically produced 1 trillion cubic feet of gas and 15 MMbbl of oil.

Another investment is Covington, La.-based Krewe Energy LLC, which is also focused on South Louisiana conventional resources. It's grown production from 500 net equivalent bbl/d to 4,000 in under two years.

Coral Reef typically invests $20- to $40 million in each deal from the CRC Energy Fund. If the firm needs to make a larger investment, it can flex up with its institutional co-investors and limited partners.

"We like to work with people we have gotten to know over a period of time to become custodians of our capital and deploy it," Schlumberger said. "Not only are we picking management teams, but also the assets to execute with the management teams. They're running the show and we are the co-pilot."

The U.S. and Canada are major energy markets endowed with large energy deposits. "More importantly, the real value is the people who are at the cutting edge of significant technological advancements," he said.

"It is very exciting to work with our management teams to roll out this know-how across basins."

Overlooked resources

Founded in 2016, Outfitter Energy Capital LLC invests upstream and midstream. Its principals were founding members and managers of TPH Partners LLC, the legacy private-equity business of energy investment bank Tudor, Pickering, Holt & Co., and Outfitters continues to manage the two predecessor TPH Partners funds.

After multiple monetizations during the past few years, the remaining combined portfolio includes five active companies, including three investments first made in 2013: Elk Meadows Resources LLC, Elm Grove Resources LLC and Principle Petroleum Partners LLC.

Denver-based Elk Meadows exploits resources on the Permian Basin's Central Basin Platform, primarily targeting the prolific San Andres with horizontal development. Houston-based Elm Grove is currently pursuing horizontal exploitation of the Lower Cotton Valley in East Texas and North Louisiana. Dallas-based Principle Petroleum exploits conventional assets in the Bighorn Basin of Wyoming.

In the Appalachian Basin in 2014, Outfitter joined in forming Pittsburgh-based Laurel Mountain Energy LLC, whose management team has more than 35 years of basin experience and is focused on the Marcellus, Upper Devonian and Utica with some 28,000 acres.

And the firm's most recent investment, Oklahoma City-based Antioch Energy LLC, holds a roughly 24,000-acre core position in the red-hot Arkoma Basin unconventional-resource Stack play in southeastern Oklahoma.

Outfitter focuses on the lower-middle-market space, typically investing $20- to $100 million per company and with a focus onshore the Lower 48, said George McCormick, co-founder and managing partner. One benefit of smaller deals is that there are simply fewer dollars chasing this space, resulting in less pricing pressure on the initial acquisition.

"We get access to high-quality resources that maybe were overlooked by larger players for no reason other than size," he said. "While there are more lower-middle-market private-equity managers today than there were when we entered this market 10 years ago, we haven't felt crowded yet. It's a big industry that has a big appetite for capital, and we still firmly believe in the opportunity set."

Portfolio companies grow their assets to an exit size. "By the time we've put $50- to $100 million to work in a portfolio company, the resulting asset base is still small enough to take advantage of a very large pool of potential acquirers, including larger privates and

George McCormick, co-founder and managing partner, Outfitter Energy Capital LLC, said the end goal is to create companies with wide exit appeal.

private-equity-backed companies as well as public ones," McCormick said.

"We always start with the end goal in mind, which is to build quality companies that will appeal to a wide audience at exit time. This approach gives us multiple paths to achieve liquidity, which is a real benefit to our strategy, since our job is to drive the best risk-adjusted returns for our [limited partners]."

Outfitter is allocating more money and time to the traditional acquire-and-exploit strategy by buying existing proved reserves "without having to pay for the upside and applying technology and expertise to improve production and reserves to set them up for sale," he said.

"There are multiple places to play that have these benefits where we can avoid the big-dollar competition and drive attractive returns."

The firm is currently focused more on liquids—crude oil and NGL—and believes it can make a better bull case from a supply-and-demand perspective for those commodities rather than gas. Also, it likes plays where management teams can apply unconventional technology—horizontal wells, hydraulic fracturing—to proven, oily reservoirs.

"There are lots of opportunities to materially improve the extraction economics in historically produced oil reservoirs," McCormick said. "We want to be partnered with teams who are best positioned to find and execute on these opportunities, and often that means they are really working in their own backyard."

One example is the ArkLaTex area, which has a long history of production and is near Henry Hub and LLS pricing. "To be successful, we have to partner with really smart, driven people in the business and help them make money," he said.

"That's how we compete. We come to work every day thinking about ways to support our teams, and we demonstrate that dedication with our actions throughout the life of that investment."

The firm's role is to help the companies—not simply to provide capital—McCormick said. "This might include making key industry connections or helping to find interesting assets," he said.

"We spend quite a bit of time on the strategic side, focused on how to position the company's assets to achieve the best possible exit outcome. We're trying to help them create value in their company." □

FROZEN OUT: M&A IN THE ICE AGE

Publicly held E&Ps are settling in for a long cold spell, lest they be burned. Forego deals for fear of shareholder reprisal? Or press ahead despite market backlash?

ARTICLE BY
DARREN BARBEE

PHOTO COURTESY OF DELOITTE

From left, Citi's Steve Trauber, Kirkland & Ellis' Andrew Calder and Blackstone's Angelo Acconcia discussed E&Ps' capital access, investor sentiment, deal-making and more at Deloitte's Oil & Gas Conference in Houston this fall.

Denbury Resources Inc. and hedge fund Mangrove Partners Master Fund Ltd. agree that Penn Virginia Corp. is a compelling investment. But, according to Mangrove, it's a compelling investment if not merged with Denbury.

"Denbury Resources and [Penn], as a combined entity, is not of interest to Mangrove Partners," Nathaniel August, a Mangrove director, reported in a Nov. 14 SEC filing after meeting with the two E&Ps' management on the matter.

Penn announced on Oct. 28 that it would merge with Denbury for $1.7 billion in stock, cash and debt assumption.

August added in his filing that "other [Penn] shareholders have reached out to Mangrove to express their dissatisfaction" as well. And Denbury shareholders didn't appear to like the deal either, he wrote, "driving Denbury's shares down over 40% in the 12 trading days since its announcement."

He stated he wouldn't vote for it; Mangrove held 9.5% of Penn's outstanding shares at the time.

He followed up on this in a Nov. 28 filing, having picked up more shares for a total of 10.7% of outstanding. He wrote that he had called on Penn in a Nov. 26 meeting "to work with Denbury … to terminate the proposed transaction."

Also, he asked for shareholder records to commence communications with them. Meanwhile, Strategic Value Partners LLC, an owner of 10.2% of Penn shares, stated it supported the merger and had signed an agreement with Denbury to vote its shares in favor.

Cold shoulder

The Denbury-Penn Virginia drama represents the challenges E&Ps face today in the M&A market, a topic of discussion at Deloitte's Oil & Gas Conference in Houston two days after the announcement. Industry transactioneers there said the public equity markets have entered a straint on companies to grow organically and inorganically."

The larger message is, "We're not coming back until you change."

"Why are there more SPACs coming? Because there's dysfunctionality among the equity markets," said Steve Trauber, vice chairman and global head of energy for Citi. "A SPAC invests the greatest capital—more capital than you're likely to get doing an IPO."

mini-Ice Age since the downturn.

"Even the largest companies right now are very nervous about doing [a] large transaction because they're scared their stock is going to get absolutely hammered," said Andrew Calder, a Houston-based partner in law firm Kirkland & Ellis LLP.

Angelo Acconcia, senior managing director with investor The Blackstone Group LP, said he's been stunned by the market response to an oil price that has rebounded from less than $27 a barrel. Had he been told in 2015 that "the general equity indices of the upstream sector would be largely unchanged [upon rebounding to $70], I would have laughed."

Yet, "that's what's happening."

The market's cold shoulder reflects the paradigm shift that now dogs every E&P at quarterly earnings time. "I think this risk-focus in the market has manifested itself in a 'show me, prove it to me' mentality," he said. "And the easiest way to do that is with free cash flow and dividends."

Steve Trauber, Citi vice chairman and global head of energy, said public-equity markets are closed to the energy sector as generalist investors figure out whether oil and gas will be competitive, on a return basis, with other sectors.

"Today, the S&P 500 is probably about 6% energy," he said. "There is no generalist investor who's going to outperform his peers by investing [in] energy."

Investors are waiting to see whether upstream, midstream and service companies can actually generate economic returns greater than their cost of capital. "There's not a lot of capital today coming into the energy sector, which remains a problem," Trauber said.

Oil and gas producers and others are stuck—unable to access capital to grow and punished by markets for transactions that bring scale. "Where we are today," Acconcia said, "is the market is saying [companies] need to generate free cash flow, which is putting a constraint on companies to grow organically and inorganically."

The larger message is, "We're not coming back until you change."

The 'panel of judges'

Calder has seen firsthand the turmoil of the disconnect, particularly among investors without a history in the oil and gas business. "We've been involved in deals that have fallen apart as a result of the stock-market reaction."

While he didn't mention any specific deals, his clients have included Bonanza Creek Energy Inc. In 2017, SandRidge Energy Inc. offered $746 million in cash and stock for Bonanza, which had no debt; the transaction was crushed under pressure from SandRidge activist investors that included Carl Icahn. (Mangrove, a Bonanza investor, had supported the deal.)

Volatility in the oil and gas sector hasn't been limited just to market caps and oil-price swings. That's changed what Acconcia called the market's "panel of judges."

"A lot of the investors are shortsighted," he said, adding that management teams know their costs, inventory and strategic M&A needs better than anyone else. "You're being held accountable to those people, which can create a misalignment."

Nevertheless, management teams continue to make deals. "They realize they aren't necessarily going to get appreciated by the public markets today. But they have more information than the markets about their business, and they're going to make the right decisions," Acconcia said.

"That accountability [to shareholders], while negative today, will prove up to be a winning strategy."

The morning of the conference, Chesapeake Energy Corp. reported plans to buy WildHorse Resource Development Corp. for nearly $4 billion in stock, cash and debt assumption.

Acconcia applauded it and said Denbury was due congratulations too.

Mangrove's August reported that day that Penn—an Eagle Ford pure-player as is WildHorse—should command a higher premium than Denbury offered. He followed up two weeks later that there appeared to be a dislike for the Denbury deal "beyond the typical arbitrage pressures following the announcement of a stock-for-stock transaction."

Rather, the reaction, as reflected in the decline in Denbury's share price, seemingly "reflects a rebuke of the transaction itself."

Going to school

Penn's impasse with Mangrove hasn't been an isolated phenomenon. In July, Concho Resources Inc. closed its all-stock deal to buy RSP Permian Inc. after initially losing 9% of its value following the $9.5-billion transaction, including debt assumption, news in March.

Diamondback Energy Inc.'s shares were tapped by about 10% after it announced in August plans to buy Energen Corp. for $9.2 billion in stock and debt assumption.

As public equity markets have closed their doors to E&Ps, the business of deal-making has fundamentally changed, Calder said. Before the downturn, New York hedge funds didn't always understand the basics of the industry, such as working interests or how basins play out.

"The downturn basically sent all these hedge funds to school," he said, adding that those funds hold sway over 10 to 15 E&Ps now since lien-holdings were converted to equity in restructurings.

"The problem is, they don't see industry the same way traditional management teams see it," Calder said. "They also don't believe any one basin should be 10 companies with separate G&A. They believe there should be consolidation."

Whether that's right or wrong, he didn't opine. "But that's their view of the world."

In Energen's case, Icahn and other activists wanted the company to sell, resulting in the deal that brought Diamondback in; the deal closed on Nov. 29.

Trauber sees merit in investors' demands to find scale or greatly increase shareholder value. Even "brand-name investors" are increasingly playing the role of activists, though they may do so behind the scenes.

Management teams also tend to become entrenched from time to time and genuinely like running their companies, even if going it alone may not be in the best interest of shareholders.

"I can't think of any more fragmented sector of the world that benefits from putting these companies together," he said. "You've got to look at these combinations and the [economies of scale and cost savings] that they bring."

With the drawbridge to public markets pulled up, Calder said some companies are finding alternatives.

"Public companies are looking for another avenue to make these transactions that may not simply rely on going to the public markets," he said.

Consolidation among E&Ps and among oilfield-services firms seems inevitable, the panelists said, regardless of being shunned by public markets.

Trauber said that, in October, perhaps 40 or 50 small, private, oilfield-service companies were up for sale, though "close to 90% of them are not being sold. They're not meaningful to anybody by themselves. They just don't have a home."

Many private E&Ps face the dilemma of having matured to a stage at which they would be better served as public vehicles but cannot muster support for an IPO.

"Just in our own backyard we have at least 10 IPOs that want to go public that aren't able to go public," Trauber said, including out-of-favor gas-weighted E&Ps and Gulf of Mexico operators.

Exit via SPAC

Yet multiple exits remain open to private companies. For one, private capital "wants to be out there," Calder said.

"There must be 200 to 300 funds out there, looking to get into oil and gas right now," he said. "When that's the case, there are only so many management teams you can hire."

"Even the largest companies right now are very nervous about doing [a] large transaction because they're scared their stock is going to get absolutely hammered," said Andrew Calder, a Houston-based partner in law firm Kirkland & Ellis LLP.

In November, QEP Resources Inc. struck a deal to sell its Williston Basin assets to Vantage Energy Acquisition Corp. for $1.65 billion in cash plus up to 5.8 million shares. Vantage and other special-purpose acquisition companies (SPACs) continue to be popular among investors.

And more are coming, Trauber said. "Why are there more SPACs coming? Because there's dysfunctionality among the equity markets. A SPAC invests the greatest capital—more capital than you're likely to get doing an IPO."

Despite the success of blank-check companies that formed Magnolia Oil & Gas Corp. and Centennial Resource Development Inc., not all SPACs are destined for success, Calder said. For private companies, there's always uncertainty that the SPAC's investors won't like a transaction when one materializes.

But a private E&P's transaction with a SPAC also offers the flexibility of taking cash, stock or both, Trauber said. More deals are on the way, he added, citing the fragmented energy space.

"There are so many companies looking for a home."

Acconcia said he sees opportunities for private companies to sell to private buyers. With the public market diverted from energy, Blackstone will try to grow through organic and inorganic consolidations.

"We look at it as an opportunity," he said.

Blackstone's public and private companies try to develop the endurance and capital flexibility required to live through rough cycles, independent of public currency. Otherwise, companies find may find themselves at the mercy of public markets and forced into M&A that is neither accretive nor dynamic.

"What most companies are trying is to be patient," Acconcia said. "That's part of what you do in a volatile market." □


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WTI-HOUSTON FUTURES

Exchange-listed trading of light, sweet delivered to the Houston Ship Channel has begun.

ARTICLE BY
CHRIS SHEEHAN, CFA

There are new financial tools at the disposal of U.S. light, sweet oil producers that are chasing the higher prices associated with export markets. CME Group has launched a WTI (West Texas Intermediate) Houston futures contract with delivery to Enterprise Products Partners LP's Houston system. Intercontinental Exchange Inc. has launched WTI trading with delivery to Magellan Midstream Partners LP's East Houston terminal.

Trading of CME's January 2019 contract began Nov. 5 and, in a thinly traded market typical of a newly launched contract, was $63.57/bbl in mid-November. This compared with WTI delivered to Cushing at $57.35, while Brent was trading at $66.90.

The CME-contract delivery options are to Enterprise's Crude Houston (ECHO) terminal, its Houston Ship Channel (EHSC) facility or to Genoa Junction. The contract offers "a new way to price and hedge WTI light, sweet crude in Houston," CME reported, and "will provide a superior hedging tool for the expanding U.S. export market."

Since the U.S. lifted its decades-old oil-export ban in 2015, international markets have played a growing role for U.S. producers. Tim Dove, Pioneer Natural Resources Co. CEO, said in the operator's third-quarter earnings call that, "with the Permian Basin growing as fast as it is … there really is no alternative for the entire industry other than to export.

"We're going to satiate U.S. refining capacity … for this type of oil—even though there are a couple of expansions underway—within a relatively short period of time based on that growth rate."

Pioneer ships some 200,000 bbl/d of oil to buyers in Europe and Asia. It's met with "good demand in the world markets," Dove said.

"In particular, this light, sweet [WTI] brand of crude oil works in a world where we're trying to reduce sulfur content in motor fuels and in maritime-related fuels. So it's right up the alley of some of the big refining centers."

In the CME announcement in September of the contract's upcoming launch, Peter Keavey, the exchange's global head of energy, said, "We believe the [Houston] network of domestic users and [this] location close to export facilities will ensure this contract provides transparent price discovery and risk transfer in the growing Houston region."

Price transparency

The launch of the new Houston futures contract was partly inspired by interest from overseas buyers, Owain Johnson, CME's London-based managing director of energy research and product development, told *Investor*.

"The fastest-growing part of our energy business is on the international side, and we had been getting a lot of inquiries from customers around procurement and hedging of Houston barrels due to the growing U.S. export market," he said.

"They wanted a little more price transparency in the Houston area for export volumes as well as greater ability to directly risk-manage some of those barrels. And the export community has been looking for a benchmark upon which to base their analytics as to where they should try to sell those barrels.

"Should you market those barrels into Europe or into Asia? And, then, you have to look at the various spreads—for example, the Houston-Brent spread or the Houston-Oman spread. There's interest in locking in those spreads."

U.S. producers want to move barrels to a coastal market to realize a price improvement over land-locked Cushing. Meanwhile, European and Asian buyers are looking for improved purchase-price realizations relative to Houston-Brent or Houston-Oman.

real change—very positive for the U.S."

> "Everyone is looking for those spreads, and Houston is the missing leg of the spread trade."
>
> —Owain Johnson, CME

Houston to Oman

"Everyone is looking for those spreads," he said. "And Houston is the missing leg of the spread trade."

For example, Johnson said, consider an E&P that has taken firm transportation on pipe for its WTI from Midland, Texas, to Houston. For it to nail down the profits of transporting its barrels to the Gulf Coast, it needs to be able to lock in forward prices for, say, six or 12 months.

In terms of selling U.S. crude into international markets, he added, "it's happened. The U.S. has gone global, and it is only going to get further widespread.

"The U.S. crudes are really getting popular, and it's growing exponentially. People dip their toe in the water, then they take a test cargo, and, then, they take a slightly bigger cargo. And …, suddenly, it just becomes part of the standard diet for the Asian refiners."

Export markets are mainly Asia, but also Europe. "You're seeing Midland crude move to Northwest Europe. Midland is popular in Asia too. I think China's back again. There was a little bit of a slowdown, but I've seen them coming back in.

"It was only last year that I saw the U.S. producers at the big Asian oil events; this year, there were scores of them."

A direct link is being forged with Asia and sidestepping Brent, which is a big change, he added.

"The U.S.-to-Asia direct link is getting built, and it's very positive for WTI and for Houston. In the past, people were looking at Asia via Brent, meaning they'd go from WTI-to-Brent spread and, then, Brent-to-Oman spread.

"Now they're looking to go straight from WTI to Oman or Houston to Oman. That's a real change—very positive for the U.S."

Houston-Cushing spread

Johnson sees recent infrastructure buildout as validating long-term prospects for the new futures contract.

"There's an enormous amount of money going into improving logistics, expanding export capacity, building VLCC (very large crude carrier) ports," he noted. "Everyone wants to get VLCCs loaded out of the U.S.

"The huge amount of investment that's going into this tells us this is a long-term story. We wouldn't be doing this if we didn't think Houston has a really good long-term opportunity ahead."

In its announcement, CME noted that Enterprise, the largest U.S. oil exporter, has 19 ship docks on the Gulf Coast. Its network of pipelines, storage facilities and marine terminals can handle more than 4 million bbl/d.

As for the risk of supplanting Cushing, Johnson said the two trading hubs are essentially complementary. "It's so helpful to be able to build onto an existing pool of liquidity [at Cushing].

"We believe that the new Houston contract with physical delivery locations is just an add-on to what we have at WTI Cushing and cash settlement in Houston."

Moreover, growth in Houston-contract trading will benefit from the complementary role it has to Cushing. The new physically delivered contract could also trade WTI Houston vs. WTI Cushing as a CME-listed spread.

Dan Brusstar, CME senior director, energy research, wrote in October in an overview of the new contract, "This mirrors how WTI Houston trades in the underlying cash market and will provide access to the deep liquidity of the WTI Cushing futures contract." □

ICE HOUSTON

Trading began Oct. 22 of Permian WTI delivered to Houston as the HOU contract on Intercontinental Exchange Inc. (ICE) to Magellan Midstream Partners LP's East Houston terminal via the Longhorn and BridgeTex pipeline systems.

"Houston has become the pricing center for U.S. crude oil production and exports, and the new Permian WTI futures contract is designed to serve hedging and trading opportunities in this growing market," ICE reported upon the launch.

The exchange estimated Permian production had grown by this past fall to 3.5 MMbbl/d.

"When we were designing the Permian WTI futures, customers consistently told us that it was critical to offer a high-quality, well-known, crude oil spec deliverable in Houston and available for the waterborne export market," Jeff Barbuto, ICE vice president, oil markets, said in a company report.

Mark Roles, Magellan vice president, commercial crude oil, said, "The new ICE contract provides customers with extensive delivery options, pricing transparency and liquidity in the Houston Gulf Coast crude oil market, while increasing demand for Magellan's pipeline and storage services."

Laura Blewitt, energy fundamentals analyst for RBN Energy, wrote in mid-November that "the race is on" as "Houston crude oil futures contracts compete for market share."

"Ever since crude flows to the Gulf Coast took off five years ago," she wrote, "the crude market has been clamoring for a trading vehicle that would accurately reflect pricing in the region that dominates U.S. demand from refineries, imports and exports.

"Now, there are two."

The ICE and CME contracts differ in delivery points, although all in Houston. "Will both survive? Probably not," she wrote. "Futures markets tend to concentrate liquidity—trading activity—into a single vehicle that best meets the needs of the market.

"So which of these will come out on top? That's what the crude oil market wants to know."

She added that the specifications differ for each of the contracts as to the quality of the crude. "That is not unusual for futures contracts with different delivery points. In fact, it is to be expected," she wrote.

But, she added, "it is important to note that crude oil quality is a particularly significant issue right now as the specs for crude oil delivered at Cushing … are about to undergo a significant change …. The change [became] effective with delivery [this] month."

The net result of the technical specifications "will make it more difficult to 'blend up' low-quality crudes with very light crudes into blends that will meet CME WTI specs."

Meanwhile, "lighter barrels can be delivered on both Houston contracts."


THE
CRITICAL
PIECE OF YOUR MIDSTREAM
PUZZLE

RAYMOND PLANK, 1922-2018

We remember this oil and gas dealmaker extraordinaire, financial innovator and philanthropic leader.

ARTICLE BY
LESLIE HAINES

Legendary oilman Raymond Plank, the founder and retired chairman of Apache Corp., left his mark on a wide range of industry and charitable groups before he passed away Nov. 8, 2018, at his beloved Ucross Ranch outside Sheridan, Wyo. He was 96.

Inscribed on a fountain at Apache Corp.'s Houston headquarters are the words of founder Raymond Plank: "The capacity of the individual is infinite. Limitations are largely of habit, convenience, acceptance of things as they are, fear or lack of self-confidence."

An avid reader to the end, "growth" and "learning" were words he used again and again when *Investor* last spoke with him in 2012 upon publication of his memoir, "A Small Difference," which draws on diaries he kept throughout his life. The title refers to advice his father gave him at age 10: always make at least a small—positive—difference in people's lives.

Plank did that in spades. His remarkable oil and gas career, spanning more than 50 years before he retired in 2009, enabled him to grow Apache to thousands of employees, touching lives over the years from Canada to South America and Australia and from the Rockies, West Texas, Oklahoma and the Gulf Coast to the North Sea and Egypt.

Simultaneously, he endowed and influenced support for many philanthropic endeavors that make a difference in the lives of communities, such as founding the Fund for Teachers, which provides summer travel and enrichment grants to kindergarten through 12th-grade teachers and founding schools for girls in Egypt.

He also presided over the launch of Apache's celebrated "1 Million Trees" program that awards grants of trees to nonprofits—such as Boy Scouts—throughout the U.S. for public planting. The 14-year-old program's initial goal was 1 million trees; it's now at more than 4 million and counting, all in public spaces and in 17 states.

Born in 1922 and raised in Minneapolis, he was at Yale when Pearl Harbor was attacked. He enlisted and joined B-24 bomber pilots in the U.S. Army Air Corps in the Pacific during World War II, flying 40 combat missions and earning a Bronze Star. Three of the planes he piloted never flew again, barely making it back and being so damaged they were scrapped for parts.

After the war, Plank returned to Yale, graduating in 1946 with a bachelor of arts, majoring in international relations, and returned to Minneapolis where he soon formed a small bookkeeping, tax and accounting firm.

He and two friends, Truman Anderson and Chuck Arnao, formed Apache in 1954 with $250,000 and flipped a coin to determine who would be president: Plank won, and the rest is history. Today Houston-based Apache's market cap is about $13 billion, and net cash provided by operating activities in third-quarter 2018 was $1 billion.

The E&P's 2019 production is projected to hit at least 400,000 barrels of oil equivalent per day, with more than half of that from the Permian Basin.

Coming from a financial background, Plank was always creative. In 1956, the nascent Apache offered its first oil and gas drilling fund and was an industry leader in that popular format until it dropped annual drilling-program sales in 1986. In 1981, the company created the first upstream MLP, but it was the first to leave that structure when oil and gas prices collapsed and tax laws changed in that decade.

In the early '80s, when acquiring another E&P, Plank devised what was a unique deal structure at the time—the buyer was protected if commodity prices fell, but the seller got upside if they rose. This structure became a case study at Harvard Business School. Years later, Plank endowed the Raymond Plank Professorship of Global Energy Policy at Harvard, following his lifelong interest in international affairs.

Apache went public in May 1969, and it grew steadily by making large, savvy deals throughout the '80s and '90s, including a few corporate mergers and many more asset acquisitions, including from Amoco Corp., Royal Dutch Shell Plc, Repsol SA, Texaco Inc. and Occidental Petroleum Corp.

"Raymond was a pioneer in the acquire-and-exploit strategy that ultimately transformed the U.S. E&P business," recalled George Solich, who for more than a decade was Apache's business-development chief and is now CEO of FourPoint Energy LLC. "We moved from an industry that, at the time, was dominated by major oil companies to one driven by independents.

"I remember him telling us 'One man's garbage is another man's treasure.' Looking at the shale revolution today, he couldn't have been more right!"

At one time, the company was the largest gas producer in the Anadarko Basin and had the largest operated position on the Gulf of Mexico Shelf. Apache also began venturing abroad in 1988, at one time holding concessions or production in Canada, Poland, China, Australia and Argentina's Vaca Muerta Shale. It later retrenched to a U.S. focus on the Permian, remaining in Egypt and, at press time, announcing another significant discovery in the North Sea.

Plank received much recognition and had served on numerous civic, charitable and industry boards. He was honored as CEO of the Year three times by the Wall Street Transcript, and was named among Hart Energy's "100 Most Influential People of the Petroleum Century," a special report published in 2000.

People said he was irascible, frank, passionate and a force of nature. He was always interesting, always outspoken and always advocating for U.S. producers at the state and federal levels. During the severe gas-price disruptions of the '80s, he called for a gas producers' co-op similar to what the Florida orange growers had. He also lobbied successfully against the federal fixed-gas-price system of the time.

Plank's many interests included studying history and politics, supporting the arts and the environment, and fishing, hunting and flying his plane. In 1981, he created the Ucross Foundation on his 20,000-acre working ranch in northeastern Wyoming: A group of old ranch buildings was restored to become a conference center, hosting an artist-in-residence program. Several Pulitzer Prize, Tony and National Book Award winners are among those who have stayed there.

But service to others was a cornerstone of his life, always leading to hands-on philanthropy. Among the many charitable causes he created, Apache built 203 one-room schools for young girls throughout Egypt, and, in 2001, he endowed the Fund for Teachers, which has supported more than 5,000 U.S. teachers with stipends and sabbaticals.

The diary he kept from age six formed the basis of his aforementioned memoir, which detailed his childhood, war service, education and how he grew Apache through diversification into real estate and other industries but always circled back to focus on oil and gas. In "A Small Difference," Plank described key deals and decisions that made the company, the politics of management transitions along the way, the pros and cons of acquire-and-exploit vs. drilling big discoveries, and his life philosophy.

"When I was really young, I sold eggs from our family farm," Plank recounted. "Later on, another kid and I dug a ditch from a guy's service station, when we were about 14, I think. He used a hose to move oil—and water that was used for washing cars—down into the ditch and it defiled the environment.

"Today, I think people recognize increasingly that they have a responsibility to the environment, and that that is part of the higher cost structure of doing business … and we have to be able to do it at a price of $50 or $70 a barrel."

That environmental stewardship continues at Apache even today, as the company annually donates thousands of trees across the U.S.

"It's not about what we get; it's about how we get it and how we use it," he wrote. "It isn't what we inherit or pursue; it's about whether and how we elect to grow. It's been a superior life and it's continuing," he told *Investor* in 2012.

"Lifelong learning is so important. If I weren't learning I wouldn't be around, because it's my mind which allows me to still get around. I've probably read 1,000 books so far this year." □

—Excerpted from "A Small Difference" and selected interviews with* Oil and Gas Investor *through the years.

IN PLANK'S WORDS

"My suggestion is colored by my experience, but at the outset you have to understand the importance of having a plan. I had done a lot of planning before I started Apache. You front-end-load your ambition with your considerations and what you hope to accomplish, otherwise you're like a milk-bottle top bumping along the banks of a creek.

"But the plan is not worth much if you can't make decisions, and you have to be able to adapt, like Eisenhower did in World War II. Adaptability to changing circumstances is very important. It's kind of like when you have your first kid—you've got to learn how to be a parent.

"Get your thoughts in order on the culture you have in mind and live by that. Now you are in the midst of a revolution, so how do you intend to approach that? I do believe the reserves are there, we've got 100-year reserves. I believe those reserves are technologically proven to exist and also in other places in the world. It shouldn't be held hostage by those seeking their own moment in the sun ….

"We can contribute a great deal more and the country would do better. Very high oil prices are the enemy of a robust economy, but they don't have to be. The devil's in the details …. The opportunity in energy is so great … but you can't have compromise.

"What do you want to do? Compromise technology, integrity, reality? You need to bring this issue into the category of education, and a spirit of collaboration."

THE E&P SURVEY SAYS

Cautious optimism prevails in the findings of the fall 2018 edition of the Grant Thornton/Hart Energy survey of the state of the oil and gas industry.

The E&P industry enters 2019 much as it entered 2018—planning to focus on a few core areas and to spend money wisely. At the same time, the economics of the sector continue to show improvement, with industry insiders saying they are able to keep production levels flat while maintaining current activity and re-establishing their strong cash flow positions.

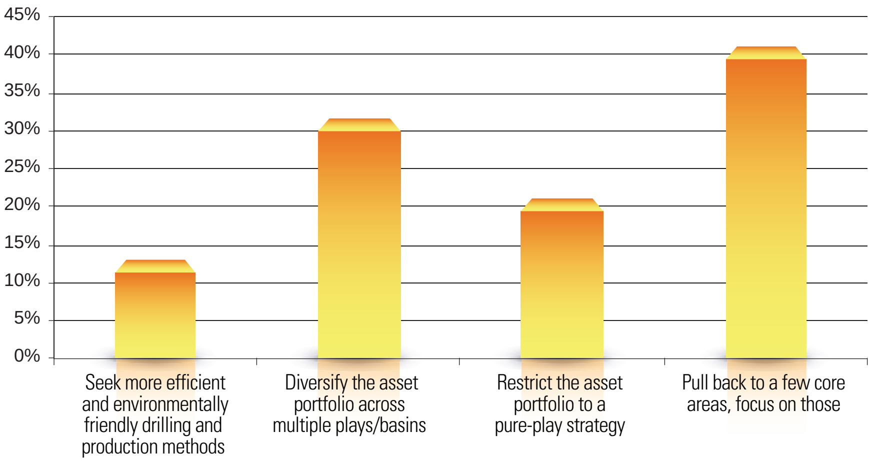
Interest in A&D has increased slightly since 2017, but still with vigilance. Differing buyer/seller expectations remain a main concern. While 2017 saw more actual transactions, 2018 saw larger transactions.

Overall, the value of technology to run the business and of data analytics to gain insights seems to be well established. Yet basin analytics and tech service and supply information remain key items that industry insiders have trouble obtaining.

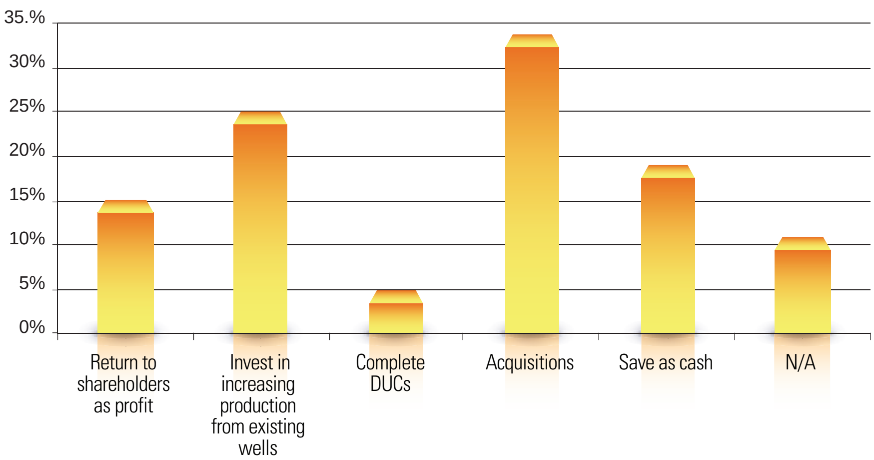
These were some key findings from the fall 2018 Grant Thornton/Hart Energy Survey, where responses reflected a desire for steady growth amid relative optimism around the economy, but also exhibited continued caution. One respondent seemingly summed it up by saying it would "continue internal growth, expanding by purchasing existing infrastructure where similarities would be beneficial to business growth and continuity."

Kevin Schroeder, national managing partner for the energy industry at Grant Thornton, said, "We are seeing a trend of consolidation, especially by larger companies looking to increase holdings and focus on core basins, such as the Permian Basin, while also seeing the industry rapidly respond to infrastructure challenges that have put production growth at risk."

Which strategy fits your company within the next 1-3 years?



Where would you put extra dollars?



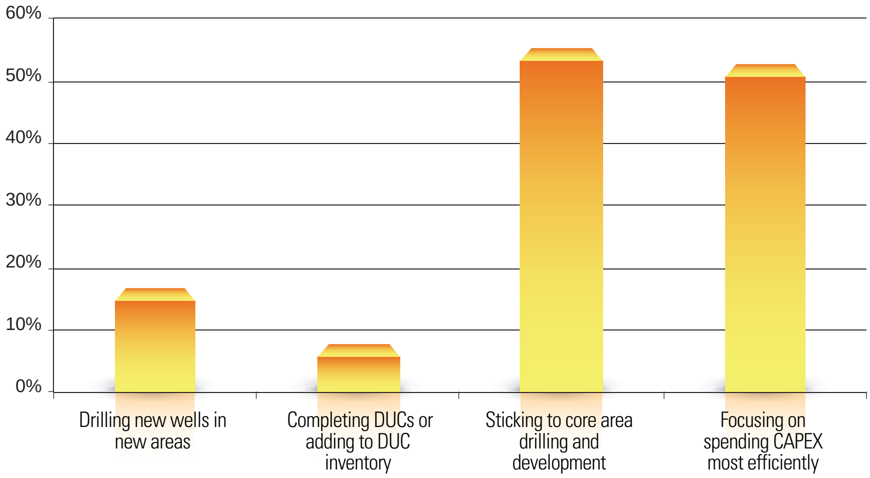
Strong and steady

Similar to the fall 2017 findings, producers are shoring up areas they know best. When asked "Which strategy fits your company within the next one to three years?" the top response was to pull back to a few core areas and sharpen focus on those.

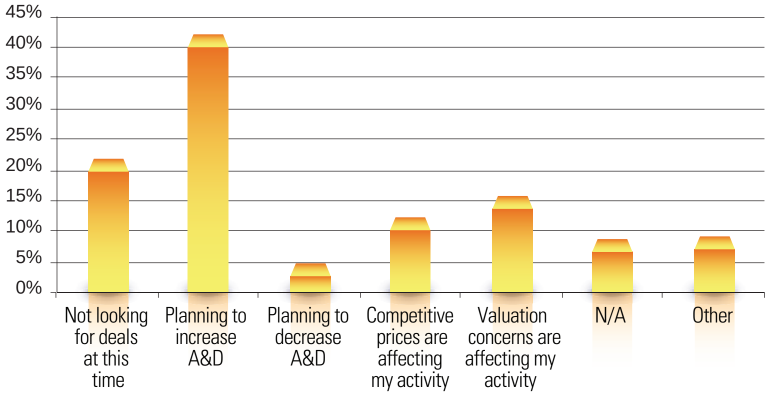
In terms of prioritizing capex, 53% said they would stick to core-area drilling and development, while 50% want to focus on capex more efficiently. This is the second year that 50% or more of respondents said they'd prioritize spending in this way, and it shows a continued determination to operate with discipline to maintain regular growth.

"Coming out of this latest downturn, companies largely continue to show diligence and focus in their core areas," Schroeder said. "It's not necessarily about reserve replacement and production increases as key performance indicators of the past. We see companies operating with focus on efficiency, return and profitability improvement."

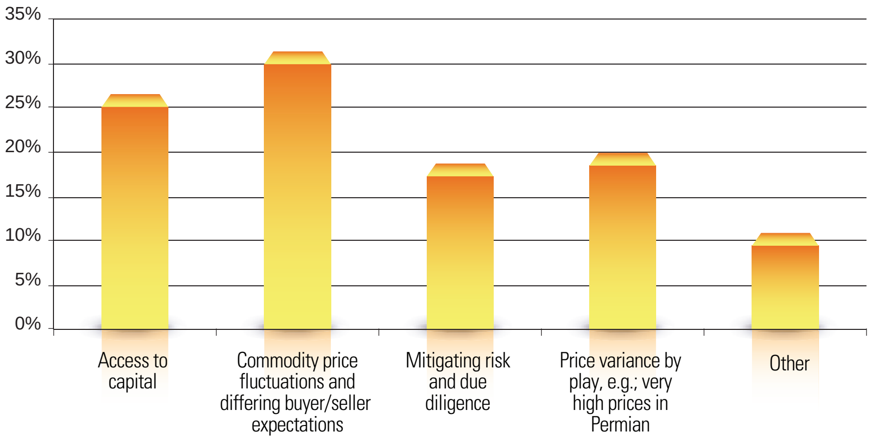
How are you prioritizing 2019 capex?



What are your A&D plans?



If active, what A&D&M challenges are you facing?



Similarly to 2017, 47% of respondents said they are using incremental improvements throughout the value chain to reduce costs or increase margins.

A&D

Interest in A&D showed a dip from 2017, with 40% of respondents indicating this past fall that they plan to look into transactions, down from 49% in 2017. Prudence prevails: One respondent noted it was looking for "high-quality opportunities that currently produce profitable cash flow with no further capex requirement." Another is looking for growth "most significantly based on a business 'fit' model."

A decision to sell or merge was named as the organizational strategy deemed most important today. At the same time, one respondent named "complex financing and ownership of potential deals" as an obstacle to deal making. Concerns about access to capital around A&D were down from 2017, possibly reflecting a more robust economy.

"Private-equity funds are selling acreage they bought earlier. Assets that went into bankruptcy previously are now producing, and the outlook is stable," said Kyle Reid, managing director of transaction advisory services at Grant Thornton. "Investors are quick to monetize past investments."

Those who plan A&D activity this year expressed main concerns around commodity-price fluctuations and differing buyer/seller expectations. The bid/ask spread came up in the 2017 survey as well, so this may mark a continued disconnect between buyer/seller.

"Meeting buyer and seller expectations" was cited by one respondent as a key obstacle, while another said it was "difficult to find properties at a fair price."

This news could reflect an improved market and more buoyant economy in which it's harder to find distressed assets to buy and producers feel less pressure to sell.

"The speed in which new production is coming online indicates demand and surplus can quickly be achieved. With the cost of production hovering just above $40 per barrel (bbl) in areas, the outlook of oil prices ranging from $55/bbl to $75/bbl should satisfy investors," Reid said.

Related to this, when survey participants were asked if they consider buyer/seller pricing to be stabilizing, 52% of respondents said "no," up slightly from 48% who said "no" in 2017. This may mark continued uncertainty even as the economy has moved forward.

International spending

Most companies, at 90%, indicated they do not plan to increase foreign spending—a jump from 2017 when 69% indicated they did not plan to expand spending outside the U.S. Of those in 2017 that did plan to expand, 21% said they would expand into Canada—which remains the biggest draw this year, but at a marked drop to only 4%.

The choice of Canada is not surprising, given its political stability and geographic location. In addition, Schroeder said, "Production costs offshore remain higher as compared with the shale and [other] onshore opportunities in the U.S. Companies and investors are certainly eyeing offshore exploration and development opportunities, but at this point the U.S. onshore continues to prevail."

Technology

As for technology, when asked what big data and data analytics they found most relevant, 48% cited technology data—specifically reservoir, fracking and completions. Others cited transactions data and production-forecasting data.

One respondent indicated data has been important since he got into the E&P business in 1974: "Only the tools to use for analysis have changed, with computing hardware and software technology capability." Applying artificial intelligence (AI) in a timely manner and competitor performance metrics were cited as very relevant to running a smart operation.

At the same time, respondents indicated they have difficulty obtaining technology service and supply advice, and also play and basin analytics.

The biggest technology-infrastructure challenges cited were the cost of implementing a new tech platform and integrating systems to ensure compatibility.

Cybersecurity dropped in importance as a major tech issue from the 2017 survey—and it wasn't a high priority in 2017 either—with only 7% citing cyber issues and vulnerabilities as a big risk.

"Many in the industry may be complacent about cyber threats," Schroeder said. "But I believe we'll see this view change in the near term during what I expect to be a period of rapid increase in the use of and reliance on technology and third-party applications and vendors.

"We shouldn't wait for an event to happen to get our attention."

The findings around data and technology indicate the industry is well aware that it's valuable, yet it may still have trouble translating information into action through the steady use of data around operations, unexpected situations that might arise and a deep view that allows more informed decisions.

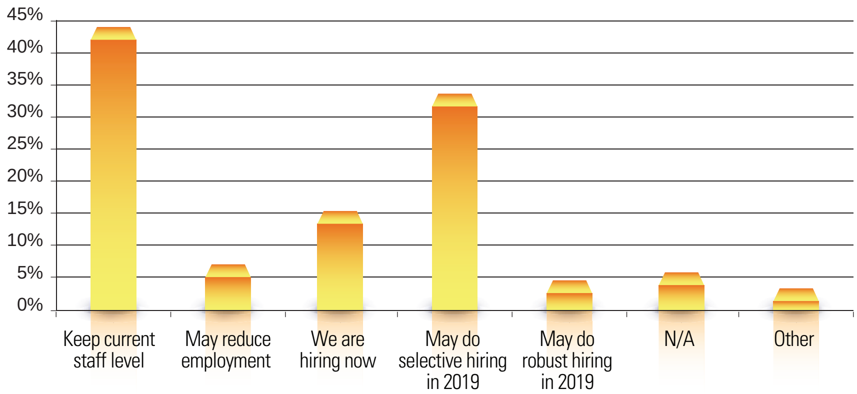
Risky business

Regulatory hurdles and delays were named key risks, followed by the ability to close on A&D. Safety and environmental issues were cited as a key risk by 24% of respondents.

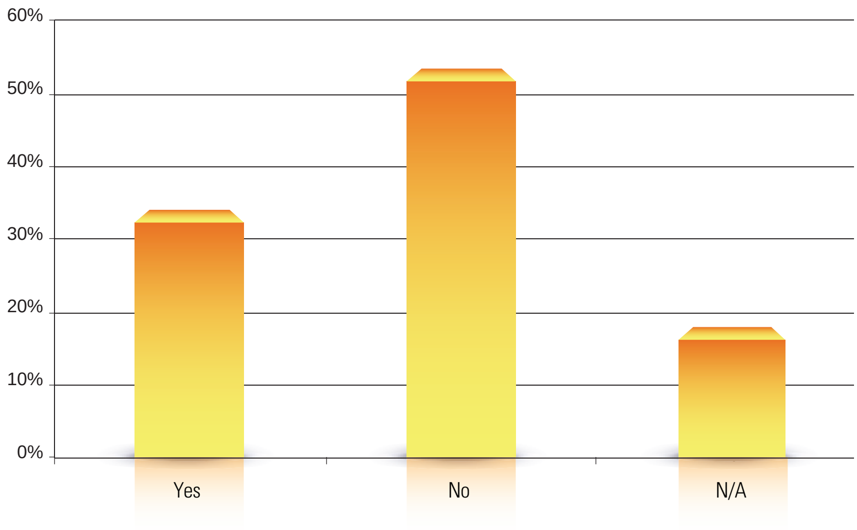
"This number could be higher," said Michael Osina, a partner in tax services at Grant Thornton. "More focus on environmental stewardship could broaden the public's view of the industry and attract younger people, particularly millennials."

The finding that regulatory hurdles are a major risk was interesting because in answer to the question of "How concerned are you that state, local and federal regulations will restrict your business?" a large majority, at 57%, responded "little."

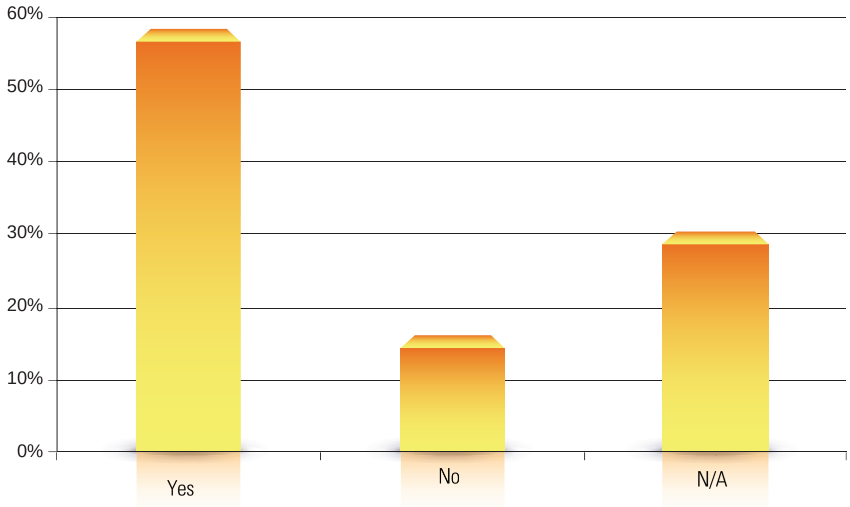
What are your staffing plans?



Have you found buyer/seller prices stabilizing?



As an operator, are you able to keep production flat?



Similarly, 58% indicated that they had little concern that trade policies would affect business. This may be due to the industry being so global, with little change year-over-year.

Staffing

Generally, hiring new talent doesn't seem to be a priority for 2019. In fact, 42% of respondents said they plan to keep staffing at the current level, while 32% said they may do selective hiring. Only 3% said they planned robust hiring for 2019.

This is not a big change from 2017, when 41% of the respondents indicated they were keeping their current staffing level. This can stem from companies that are still operating with caution and a focus on efficiencies and profit improvement. At the same time, Reid said, "Staffing is the No. 1 issue for oilfield-services companies that can't meet the demand for growth in the Permian."

Schroeder added, "We are seeing more use of partnerships, joint ventures and outsourcing in the industry, and companies are also looking at new forms of talent, specifically those with mathematics, science and analytic skills."

Meanwhile, "E&P companies can range quite significantly in financial health and stability, with many growing and in need of people, while others are continuing to manage resources and liquidity that may not afford them to hire as robustly."

Breaking it down

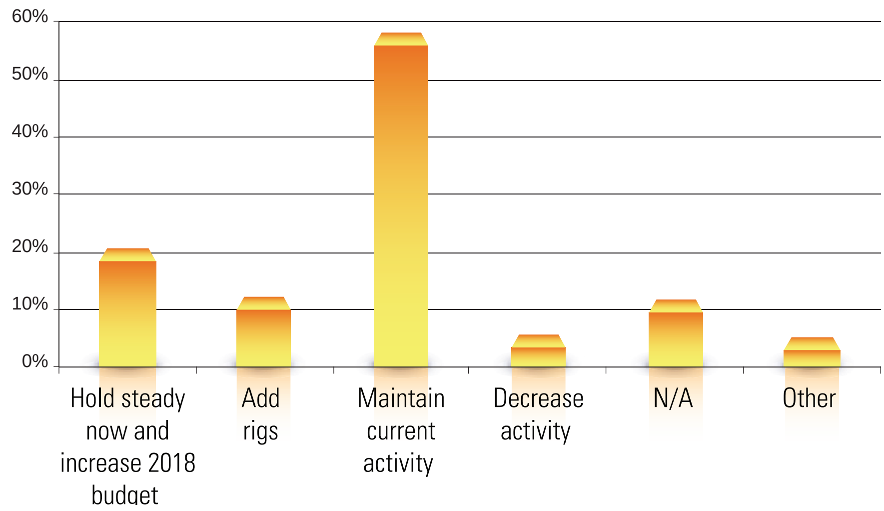
The survey reflects a mood of cautious optimism as the U.S. oil and gas industry and the economy have improved. Yet, volatility in the industry is always present, with supply and demand risk and the effect of unanticipated economic factors borne from political uncertainty.

Despite strides and a seeming comfort level with technology as a whole, the industry still could improve around the use of AI, robotics and analytics—an expansion that could attract more young people who are looking for innovative roles.

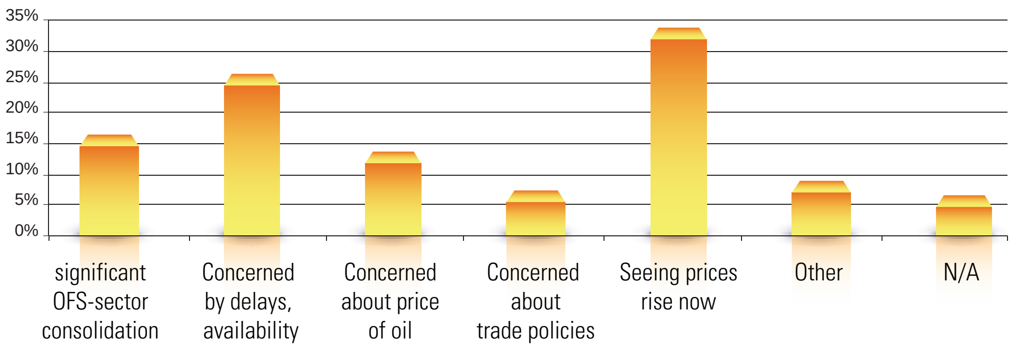
Schroeder said, "We are a highly technical and innovative industry that has made amazing advancements in the way we explore for, develop and produce oil and gas, but a sector that has lagged others in the use of technology to run the business.

"We have a chance to now advance in these areas and to attract a new generation of talent that is willing to be disruptive and to be a part of a culture that fosters new thinking." □

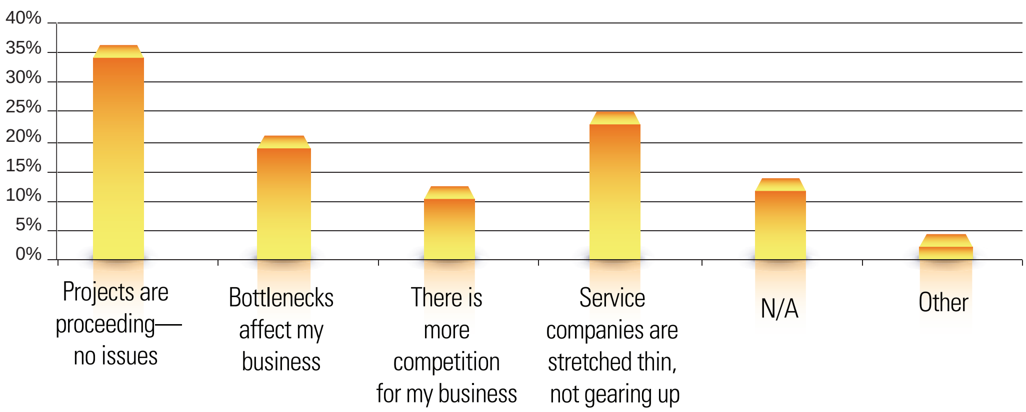
In your current cash-flow position, what are you prepared to do?



How do you see OFS prices/demand going forward?



How have OFS issues affected your business?



The latest Grant Thornton/Hart Energy Survey was based on answers from 472 respondents in October 2018 in leadership positions within U.S. independent producers, midstream operators, oilfield-service companies and financial firms. Participants included CEOs, COOs, CFOs, CIOs, senior vice presidents, board members, general counsels, and tax and finance professionals. References to the 2017 survey are based on some 500 respondents with similar backgrounds.

Founded in Chicago in 1924, Grant Thornton LLP is the U.S. member firm of Grant Thornton International Ltd., one of the world's leading organizations of independent audit, tax and advisory firms.

THE PURE-PLAY RISK

Specialization works—until it doesn't. Specialists would be wise to consider these hidden risks.

ARTICLE BY
RAOUL LEBLANC

ILLUSTRATION BY
STEFANO MORRI

A continuing trend toward greater specialization in the oil and gas industry is enabling companies, particularly in North American shale plays, to achieve greater efficiencies, please investors and improve financial results.

But an IHS Markit analysis shows this corporate strategy is putting many companies at significant risk to market volatility, fragility and vulnerability to unforeseen events.

Specialization is increasingly driving strategic focus for oil and gas operators because, for a time, it works, and the market prefers and rewards specialists. When focusing on one play type or asset, like an athlete who focuses on a single sport, one tends to get better at it and become faster and more efficient.

Investors and investment banks are the primary drivers pushing this strategy, and, while there is certainly great upside to this approach, there are also new risks that may not be readily apparent to the C-suite executives.

For much of the industry's history, bigger was unquestionably better. This made sense on many levels because the industry spans the globe and faces a nearly unparalleled array of political, financial and technical risks. Scale and diversity, it was argued, were the best buffers against these risks.

That "bigger is better" truism, however, has been supplanted by an inexorable push toward specialization. The trend started with the emergence of the shale industry and gathered momentum when those successes attracted increased spending and exposed the often poorer risk-reward ratio of many international investments.

Two new developments accelerated the trend toward onshore specialization. First, shale production has grown large enough to generate significant cash flows, allowing companies to sell the "distraction" of other asset types, which virtually every large E&P player has done in their North American portfolio.

Companies now specialize in shale, offshore assets, CO_2 plays or other themes. Examples include Encana Corp.'s split and Occidental Petroleum Corp.'s spinoff of its 95-year-old California business.

Secondly, the maturation of major shale plays beyond the delineation phase has reduced risk by revealing the overall quality of acreage-holdings. As the industry moved into the low-risk, high-capital phase of the plays at the same time cash flows collapsed post-2014, companies focused on their best assets.

Operators that once strived for breadth in technologies and geography now compete in narrower competitive bands in pursuit of a deeper, more limited, set of skills. Global producers increasingly focus on countries or regions, shifting away from international activities to onshore North America. Within North America, the hypercompetitive environment has pushed producers to become pure-play companies.

Skills, endurance

Within the U.S. upstream segment, the transition from conventional to unconventionals has been profound. At the dawn of the tight-rock era, virtually all companies in the U.S. held portfolios characterized by conventional oil and gas holdings in multiple regions, plus some near-field exploration opportunities.

As the potential of shale became apparent, they shifted capital deployment toward those assets, retaining conventional assets as cash generators to fund early-stage positions.

The biggest independents—Chesapeake Energy Corp., Devon Energy Corp., Anadarko Petroleum Corp. and EOG Resources Inc.—are examples. While their end results turned out differently, each moved to buy a significant foothold in multiple plays.

The companies understood that some plays fail and that, despite best efforts, their acreage might not be in the "sweet spot" of well quality. Diversification among the various plays hedged those risks.

Anadarko, Devon, Encana and Pioneer Natural Resources Co. were among independents that led the retrenchment to the U.S. onshore. Now, even global companies including Chevron Corp., Exxon Mobil Corp. and BP Plc are redirecting significant capital to the U.S. onshore—and, in particular, the Permian Basin.

Like decathletes, major companies possessed a breathtaking range of skills and endurance, but, as more specialists dig down on particular technologies and geographies, the decathletes are finding it hard to compete. This has been particularly evident in the majors'

Like decathletes, major companies possessed a breathtaking range of skills and endurance.

struggle to compete with shale specialists at their own game.

Specialization narrows a company's horizons. Building an operation around developing a single or narrow portfolio of assets—even one as prolific as the Permian—may determine a company's lifespan.

This has already been witnessed with producers focusing on older gas plays, such as the Barnett or Pinedale, and is even creeping into the more mature Bakken play, where investors have grown concerned about the dwindling inventory of core drilling opportunities.

The divide

There are few companies spanning the shale-gas and shale-oil divide. There are no major producers with significant positions in both the Marcellus/Utica, the top gas play in the U.S., and the Permian Basin, the top oil play.

Increasingly, producers are becoming pure-play companies focusing on just one basin—or even subsections of a single basin. Pioneer Resources is selling its Eagle Ford assets to go "all in" on the Permian Basin, where it holds a large, market-leading position.

The question becomes one of what happens to those single-play specialists when their play is no longer competitive with other shale basins.

The push toward specialization also risks sapping a company's ability to explore new frontiers. And in today's environment, new-ventures investments are a costly distraction from near- and medium-term objectives. The problem will become apparent over time if the company fails to successfully migrate from its core asset.

Perhaps the greatest risk of specialization comes from environmental volatility. The specialist company is fragile to unanticipated changes—the kind the corporate giants were built to withstand.

For instance, a sudden public turn against fracking in the form of a regulatory ban or judicial stay—like that which recently threatened Colorado's Wattenberg play or what occurred with regards to the ban on new deepwater drilling in the Gulf of Mexico following the Macondo disaster—could spell serious trouble for a company with no other options in its portfolio outside of its area of specialization.

Additionally, other options of cheaper supply could undermine the economics of a single type of asset. A breakthrough in renewables technology or more forceful government policy to cut carbon emissions could quickly sap value from a company's portfolio if it isn't able to adapt and compete.

Investors will be quick to abandon a company that loses out in these market shifts. This divergence of exposures creates a gaping wedge between management and shareholders in an era of specialists.

Short-term interests

In the past, investors wanted asset diversification to protect the company's long-term viability. Today, investors seek diversification through their own investment in many different companies, so they are more focused on a company's short-term financial performance rather than its long-term viability.

That works for the investors, but it may run counter to the company's long-term best interests. With that in mind, it is imperative for company leaders to assess and understand their specific risks and, then, create a strategy to mitigate those risks without sacrificing short-term growth.

Ironically, while the narrower skill sets of specialization do deliver financial results and the specialization trend will continue, during the recent oil price downturn, the integrated business model proved its worth.

As falling prices undercut the profitability of upstream operations, the integrated companies saw their downstream operations pick up the slack, while the more diversified portfolios gave them more options to find attractive investment opportunities.

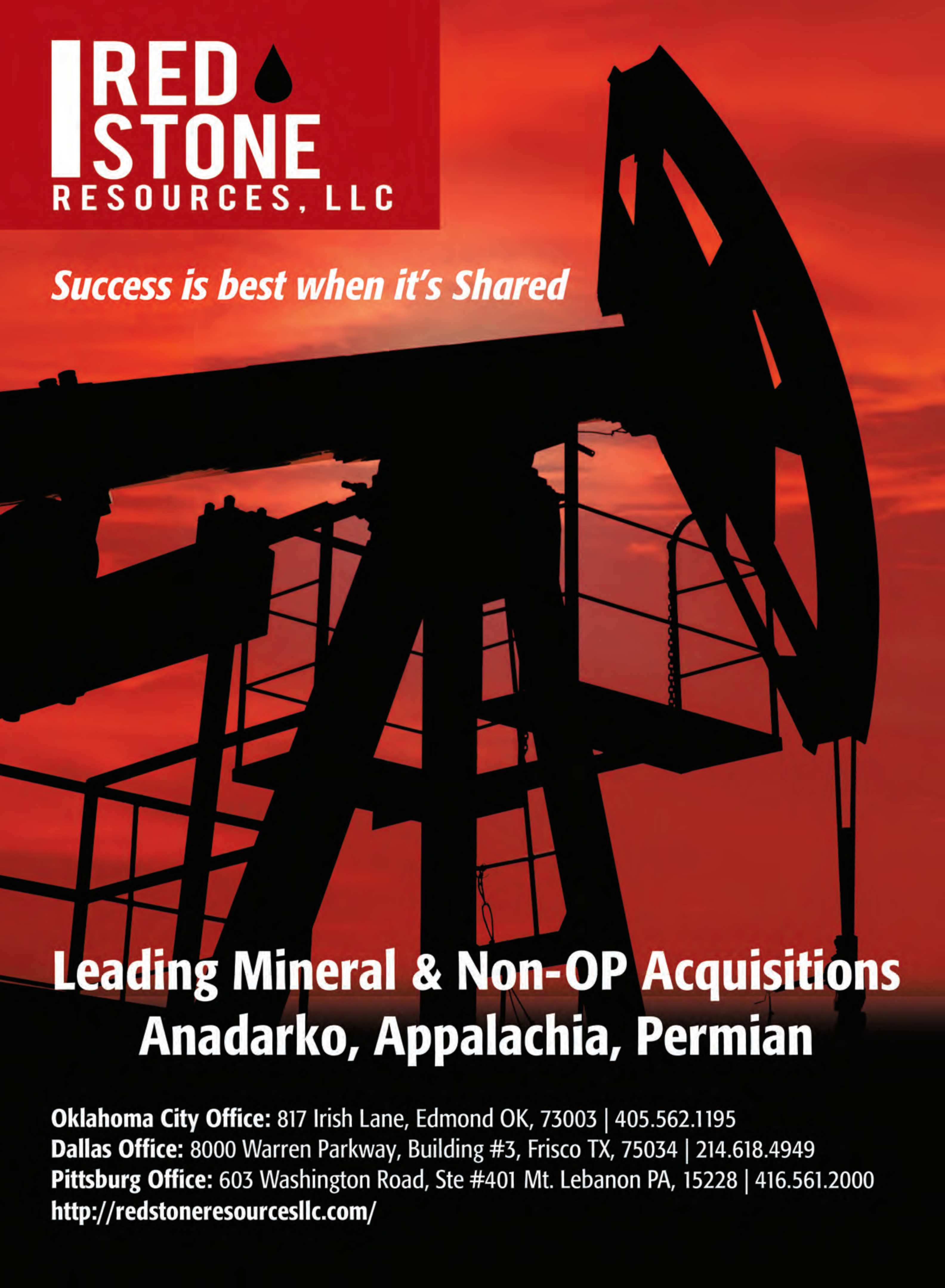
In the U.S. onshore, every play is in the process of down-spacing. The point is that every asset—and especially the disproportionately small core areas that some operators specialize in—is finite and will deplete. In the long term, companies will need to transition to a new asset.

In addition to exhaustion concerns, specialization in the development phase, which is where most companies are at this point in unconventionals, also makes it difficult for companies to add significant shareholder value. IHS Markit sees oil and gas companies typically creating the most shareholder wealth by taking chances on unproven rocks and delivering big new reserves in the proving and optimization stages of a play.

A company focused on the efficient manufacturing of shale wells at the mid-life stage must invest the bulk of the lifetime capital during this phase, but enjoys relatively little value-add from low-risk capital deployment. Opportunities for value creation are especially thin for later entrants that paid an entry premium for premier plays like the Permian.

The key here is that specialization works—until it doesn't. The industry's rush to focus is exposing companies to systemic and company-level risks that "diversification" previously reduced. Specialists would be wise to consider these hidden risks and develop options to mitigate them. □

Raoul LeBlanc is vice president of financial services at IHS Markit and an author of the IHS Markit corporate-strategy analysis "The Promise and Peril of Specialization."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Cimarex's $1.6-Billion Permian 'Bolt-On'

CIMAREX ENERGY CO. SAID Nov. 19 it will acquire Reeves County, Texas, pure-play **Resolute Energy Corp.** in a cash-and-stock transaction worth about $1.6 billion, including the assumption of $710 million of debt.

Resolute, which has faced recent investor pressure to pursue a sale or merger, is a "bolt-on asset ... tailor-made for Cimarex," Tom Jorden, Cimarex chairman, president and CEO, said in the announcement.

But the deal is already facing disapproval from private-equity firm **Kimmeridge Energy Management Co.**, which pushed for Resolute's sale in October because of its low share price but isn't satisfied with Cimarex's offer.

Based in Denver, Resolute controls 21,100 net acres, 83% HBP, in Reeves County in the southern Delaware Basin, averaging 79% working interest, 97% operated. Production averaged some 35,000 barrels of oil equivalent per day (boe/d), 45% oil, during the third quarter.

Cimarex's Reeves position would grow 34% to total 82,953 net acres. Its overall Delaware Basin-holding will grow to 280,100 net acres. Combined production, based on the two companies' third-quarter 2018 output, would be 253,400 boe/d. The figure includes Cimarex's output from its Midcontinent holdings. The combined enterprise value, based on share value at the time of the announcement, would be $10.7 billion.

"It is a perfect fit with our existing Reeves County position and will allow us to leverage our knowledge and deliver superior results over a broader asset base for the benefit of both Cimarex and Resolute shareholders," Jorden said.

Additionally, he expects the Resolute assets to generate free cash flow in 2019, "basically funding any additional development capital from the start."

Mike Kelly, senior analyst with Seaport Global Securities LLC, wrote that the Resolute acreage fits Cimarex's position "like a glove," plus the valuation is right. "Cimarex sat on the M&A/A&D sidelines over the last few years, refusing to pay $40,000 per acre for non-accretive Permian deals that were acreage-heavy but light on cash flow," Kelly wrote.

"We think the patience was worth it and that the Resolute acquisition is right in Cimarex's wheelhouse." He estimated Cimarex is paying about $22,000 per acre—more than 20% less than the Delaware average.

"We think this deal will truly add shareholder value—it's accretive, acreage quality is better than Cimarex's portfolio average and oilier, it won't stretch the balance sheet, the assets are already free-cash-flow positive, plus the potential upside on the synergies front is meaningful," Kelly wrote.

Ben Dell, managing partner of Kimmeridge, which held 2.8 million Resolute shares or more than 10% of outstanding as of Nov. 14 as per an SEC filing, believes the value from Resolute's transaction with Cimarex still comes up short for investors.

"We are pleased to see that Resolute's management team has finally acted and believe consolidation is required in this industry. However, we feel that the proposed purchase price undervalues Resolute," Dell said in a statement provided to *Investor*.

Resolute CEO Rick Betz said in the deal announcement that the combination of "our assets and people with the incredibly strong platform that Tom and his team at Cimarex have built will surely lead to superior results for the shareholders of both companies."

The offer is a roughly 14.8% premium to Resolute's pre-announcement closing price of $30.49. Under the terms, Resolute shareholders have the option to receive 0.3943 Cimarex common share or $35 in cash or a combination of $14 and 0.2366 Cimarex share per Resolute share.

Upon closing, Resolute shareholders will own roughly 5.6% of the combined company.

Cimarex plans to fund the cash portion with bank-line borrowing and with cash on hand, which includes proceeds from a recent asset sale in Ward County, Texas. It expects to complete the transaction before April 1. Upon closing, the Cimarex board and executive team will be unchanged.

Evercore Inc. is exclusive financial adviser to Cimarex for the transaction; **Akin Gump Strauss Hauer & Feld LLP** is legal adviser.

For Resolute, **Petrie Partners Securities LLC** and **Goldman Sachs & Co. LLC** are acting as financial advisers; **Arnold & Porter** and **Wachtell, Lipton, Rosen & Katz**, legal advisers.

—Emily Patsy

In Trail To Permian, QEP Quits Haynesville, Williston For Billions

QEP RESOURCES INC.'S November played out as a farewell tour of North Dakota, Montana and Louisiana as it agreed to nearly $2.5 billion in two deals in the Bakken and Haynesville shales.

QEP appears to be on the last legs of a journey to pure-play Permian Basin status following its Nov. 19 deal to sell the Haynesville/Cotton Valley business in northwestern Louisiana to **Aethon III BR LLC** for $735 million.

Aethon III, an affiliate of Dallas-based investment firm **Aethon Energy Management LLC**, was formed to acquire assets onshore North America in partnership with the **Ontario Teachers' Pension Plan** and **Redbird Capital Partners LLC**.

QEP's Haynesville/Cotton Valley business covers about 49,700 net acres, including 137 gross operated producing wells. Production during the third quarter averaged about 49,500 boe/d, 100% dry gas. It also owns midstream infrastructure on a majority of the property.

"The sale of our Haynesville/Cotton Valley business is an important next step in our process of becoming a Permian pure-play company," Chuck Stanley, QEP chairman, president and CEO, said in a news release.

In the Bakken, blank-check **Vantage Energy Acquisition Corp.** is buying the QEP assets for up to $1.725 billion in cash and stock.

Vantage Energy is a $560-million SPAC (special-purpose acquisition company) formed by **NGP Energy Capital Management LLC** and E&P veteran Roger Biemans. QEP's Williston Basin assets include the South Antelope and Fort Berthold areas as well as mineral interests.

They consist of more than 100,000 net acres in the core of the Bakken and were producing 46,000 boe/d. The transaction stands to create a large-scale, pure-play Williston operator to be called **Vantage Energy Inc.** with Biemans leading it as chairman, president and CEO.

The two sales bring QEP's total divestitures beginning in July 2017 to $3.4 billion.

Tudor, Pickering, Holt & Co. (TPH) analysts reported that the Haynesville deal price is roughly in line with their estimate of market value. With most of the proceeds of the company's Williston sale earmarked for debt reduction, the analysts believe the Haynesville proceeds will allow QEP to begin its $1.25-billion-share repurchase.

"We absolutely think buybacks are the right move, given the implication that the market is not paying for growth," the analysts wrote.

QEP's Stanley, who is retiring from the company this month, said in November that proceeds from the Haynesville sale will be used to fund ongoing development of QEP's core Permian assets, reduce debt and return cash to shareholders through share repurchases.

QEP put one Haynesville well—100% working interest— online during the third quarter. It had a peak 24-hour IP of 34 MMcfe/d from a 10,622-foot lateral. At quarter-end, it had no rigs in the play.

Aethon III expects to assume QEP's firm gas-transportation agreements at deal closing. In addition, QEP will novate gas-derivative contracts for 40 Bcf to Aethon for the last 11 months of 2019. Closing is expected by Feb. 1; the effective date, July 1, 2018.

Latham & Watkins LLP provided legal counsel to QEP in the Haynesville deal. For Aethon III, **BMO Capital Markets Corp.** was transaction advisor; **Weil, Gotshal & Manges LLP** and **Sidley Austin LLP**, legal counsel.

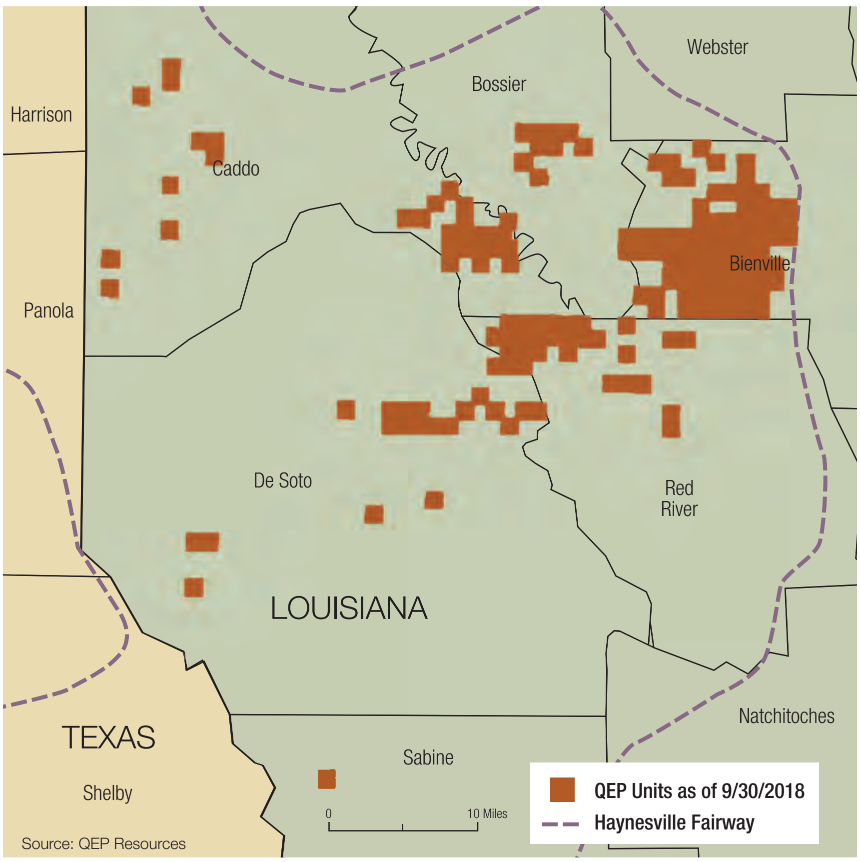
—Emily Patsy

QEP Resources: Permian Pure-Play Path

Asset Location	Buyer	Date Closed	Value ($MM)
Haynesville/ Cotton Valley	Aethon Energy	Pending	$735
Williston Basin	Vantage Energy	Pending	$1,725
Uinta Basin	Middle Fork Energy Partners	September 2018	$155
Pinedale Anticline Field	Oak Ridge Natural Resources	July 2017	$740
Southern Wyoming	Undisclosed	July 2017	$37.5
Total:			**$3,392.5**

Source: Hart Energy

QEP's Haynesville Assets



Chesapeake Trots Out $4-Billion WildHorse Deal

FOUR YEARS REMOVED from any acquisitions, **Chesapeake Energy Corp.** bounced back Oct. 30 with a proposed deal for **WildHorse Resource Development Corp**. worth nearly $4 billion.

Beginning in 2016, Chesapeake has closed $4.5 billion in divestments as it has attempted to overcome crushing debt complicated by collapsing commodity prices.

Oklahoma City-based Chesapeake's offer for WildHorse is stock, assumption of $930 million in debt and between $275- and $400 million of cash paid from its bank facility.

Houston-based WildHorse has barely been broken in as a public company; it IPOed in December 2016. But it has been a dominant force in Southeast Texas, building a roughly 420,000-net-acre position in the Eagle Ford Shale and Austin Chalk.

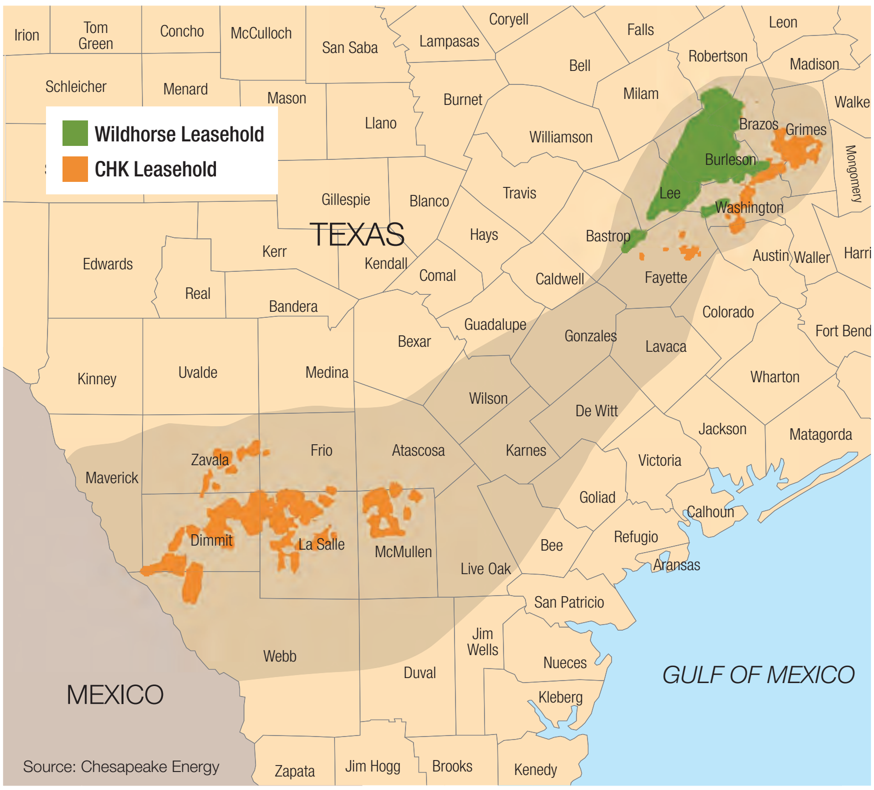
The company's acreage, of which about 80% to 85% is undeveloped, also has access to premium-price Gulf Coast markets. Net production is about 47,000 barrels of oil equivalent per day (Mboe/d); 88% is liquids and 73% is oil.

The deal offers WildHorse shareholders either 5.989 shares of Chesapeake common stock or a combination of 5.336 shares and $3 in cash per WildHorse share.

Doug Lawler, Chesapeake president and CEO, said in a news release, "The addition of WildHorse, together with our substantial growth profile in the Powder River Basin, advances our transformation into a highly competitive company with a diverse portfolio of high-quality assets, a stronger balance sheet and meaningful oil-growth potential."

More than 80% of future drilling and completion activity will be directed toward high-margin oil opportunities, it added.

Chesapeake Energy's Acreage Position In Wildhorse Leasehold



WildHorse Resource Asset Overview

Net acres	420,000
Percent undeveloped	80% – 85%
Average working interest	84%
Average net revenue interest	66%
Net production (Mboe/d)	47
Liquids / Oil	88% / 73%

Source: Chesapeake Energy

Pro forma, its Eagle Ford position will grow to roughly 655,000 net acres with some 150 Mboe/d of production, about 60% oil.

Companywide, Chesapeake expects to grow oil production to up to 130 Mbbl/d in 2019 and up to 170 Mbbl/d in 2020, bringing its oil-weighting to 30% from a late-2018 level of about 19%. It also expects the combination will reduce its annual costs by between $200- and $280 million.

Jay Graham, WildHorse chairman and CEO, said in the announcement, "We are extremely proud of the company we built and brought public less than two years ago. This combination creates an impressive oil-growth platform, which provides both immediate value and potential for significant long-term upside to our shareholders.

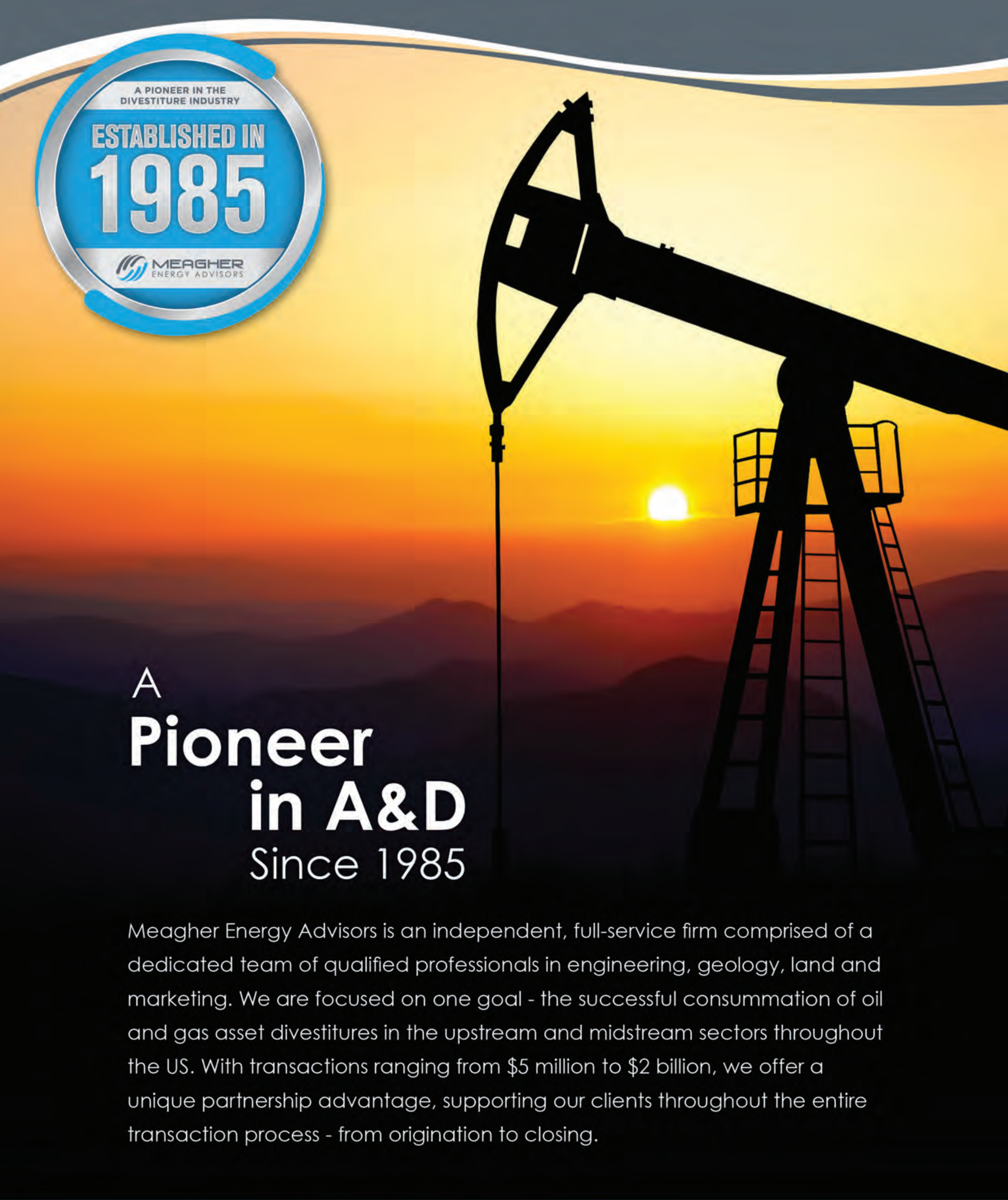
"As a highly regarded operator, Chesapeake brings the technical expertise and operational efficiencies needed to maximize the value of this premier asset."

At closing, Chesapeake shareholders will own up to 55% of the combined company. The final ratio will depend on the payment option elected by WildHorse shareholders.

Investment funds managed by **NGP Energy Capital Management LLC**, collectively WildHorse's largest shareholder, have entered an agreement to vote their shares for the transaction, which is expected to close before July 1.

Goldman Sachs & Co. LLC was financial adviser to Chesapeake; **Wachtell, Lipton, Rosen & Katz** and **Baker Botts LLP** were legal counsel. **Tudor, Pickering, Holt & Co.**, **Morgan Stanley & Co. LLC** and **Guggenheim Securities LLC** were financial advisers to WildHorse; **Vinson & Elkins LLP** and **Akin Gump Strauss Hauer & Feld LLP** were legal counsel.

—Emily Patsy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Diamondback Reveals $313-Million Midland Bolt-On Acquisition

DIAMONDBACK ENERGY INC. recently revealed another acquisition that was too good for the Midland, Texas-based company to pass up, despite an already blockbuster quarter of M&A activity.

Building on its track record of growth within cash flow, Diamondback said in its Nov. 6 earnings release that it closed additional tack-on acquisitions in the northern Midland Basin during the third quarter for $312.5 million.

The additional transactions brought its deal-making for the quarter to well over $10 billion.

It kicked off its buying spree in early August with a roughly $1.25-billion cash-and-stock purchase of **Ajax Resources LLC**, an E&P backed by **Kelso & Co**. and having leasehold in the northern Midland. Less than a week later, the company followed with an agreement to buy fellow Permian producer **Energen Corp**. in an all-stock transaction worth roughly $9.2 billion, including debt assumption.

The Ajax acquisition closed Oct. 31, followed by the Energen deal on Nov. 29.

The newest acquisition comprises 3,646 net leasehold acres and related assets from **ExL Petroleum Management LP**, **ExL Petroleum Operating Inc**. and **EnergyQuest II LLC**. Located in Martin and Andrews counties, the assets have roughly 3,500 boe/d of estimated current net production.

Diamondback appears to have paid roughly $44,000 per adjusted acre for its latest expansion—a premium to the $36,000/acre paid for Ajax, **Capital One Securities Inc.** analysts estimated.

The ExL et al. property is adjacent to Diamondback and Ajax property in an area Diamondback calls Spanish Trail North.

Diamondback CEO Travis Stice said in the third-quarter earnings call that the opportunity to acquire the additional acreage was too good to pass up. Further, Diamondback maintains a "fortress balance sheet for just these types of opportunities."

"We felt like we had differential knowledge in the area because of our legacy activity," Stice said. "We felt like we had willing sellers [and] that they weren't marketing the process broadly. And we felt like we could bring our expertise to wells that could immediately compete for capital ..."

The challenge for Diamondback now is execution, he said, specifically on the estimated $3-billion worth of synergies expected from the merger with Energen. As a result, Diamondback will, for the most part, be on the sidelines on the acquisition front.

"We understand that the battle lines are drawn for us to execute on those synergies. ... We're more or less on the sidelines until we get this merger integrated and start delivering materially on the synergies that we talked about," he said.

Diamondback operated 13 rigs and had five dedicated frack spreads during the third quarter. It assumed an additional rig after closing the Ajax acquisition.

During the third quarter, Diamondback drilled 40 gross horizontal wells and turned 43 operated horizontals to production. The average completed lateral length was 9,638 feet.

With both Ajax and the ExL et al. acquisitions complete, it expected to develop the Spanish Trail North position with between eight and 12 well pads targeting Wolfcamp A, Lower Spraberry and Middle Spraberry. It estimates this will generate an internal rate of return of more than 100% in long-lateral development.

For full-year 2018, it expected to turn between 170 and 175 gross operated horizontals to production.

Into the fourth quarter, Diamondback generated $12 million in free cash flow while growing production 45%. Third-quarter production was 123 Mboe/d (72% oil). Its track record of growth within cash flow reached 15 consecutive quarters, Seaport Global Securities analysts wrote in a Nov. 8 report.

Stice said, "In a world where capital discipline is now the primary theme across North American energy and companies are discussing what they plan to do, look no further than what Diamondback has done over the past three years.

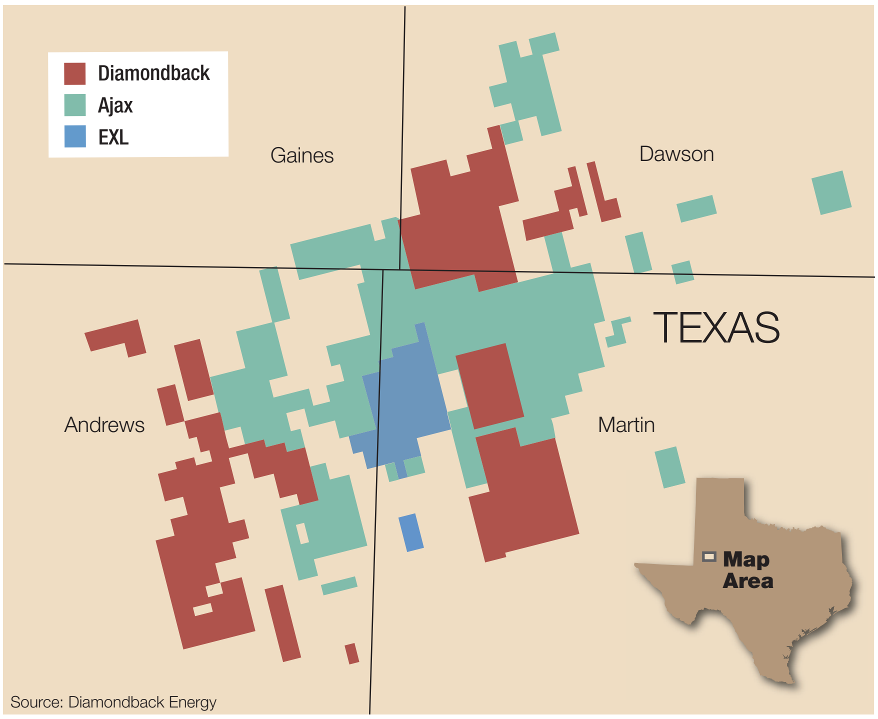
"Our operating philosophy has not changed: maximize production growth within cash flow, maintain best-in-class operating metrics, low leverage, and execute on acquisitions accretive to our current acreage position and per-share metrics—all of which, we [continued] to do in the third quarter."

Diamondback's third-quarter 2018 net income was $157 million. Adjusted EBITDA was $372 million, up 60% from $232 million a year earlier.

At Sept. 30, Diamondback had $492 million in standalone cash and no bankline borrowings.

—Emily Patsy

Spanish Trail North Acreage Map



SandRidge Exits Permian's Central Basin Platform

SANDRIDGE ENERGY INC. said Nov. 5 it exited the Central Basin Platform (CBP) in the Permian Basin in a sale as the Oklahoma City-based E&P tackles operational efficiencies through A&D deal-making.

The divestiture follows the conclusion of SandRidge's strategic review process, which attracted multiple potential buyers earlier in 2018.

The CBP sale was to **Avalon Energy LLC** for $14.5 million. It included roughly 13.1 million common units of SandRidge Permian Trust.

Meanwhile, SandRidge acquired properties in the Mississippian Lime and Northwest Stack areas of Oklahoma and Kansas for $25.1 million. The seller wasn't disclosed.

"These are small but important next steps that help demonstrate our ability to improve profitability and create shareholder value," Bill Griffin, SandRidge president and CEO, said in a news release.

SandRidge's CBP position largely consisted of shallow, low-net-revenue-interest wells burdened by a substantial overriding royalty interest conveyed to the trust. Lease restrictions and trust limitations on these properties significantly constrain development beyond work on existing wellbores.

The company expects the sale will simplify its operations with the removal of a large population of low-rate and shut-in wells, collectively averaging 1 boe/d each and with direct lifting costs of $30.50/bbl.

The CBP divestiture, which includes almost 1,500 wells, will also eliminate roughly 32% of SandRidge's total asset-retirement obligations, it reported.

Griffin said that the CBP properties accounted for more than 12% of SandRidge's total operating expenses, while contributing only 4% of first-half 2018 production.

"The sale price of these properties represents an attractive valuation, particularly considering their minimal growth potential and royalty-interest burden, which requires SandRidge to cover 100% of operating costs but only receive 34% of revenues," he said.

He added that the exit simplifies SandRidge's portfolio and operations, allowing it to increase focus on executing its long-term development and growth strategy in the Northwest Stack in Oklahoma as well as in the Rockies in North Park Basin.

Its Midcontinent acquisition "consolidates working interest in acreage and properties currently held by the company, requiring no additional staffing to operate," Griffin said.

SandRidge operates roughly 80% of the wells involved and holds a working interest in most of the remaining wells operated by others in its acquisition. As of September, the properties had monthly net production of 3,775 boe/d and monthly net operating income of $1.5 million, the company reported.

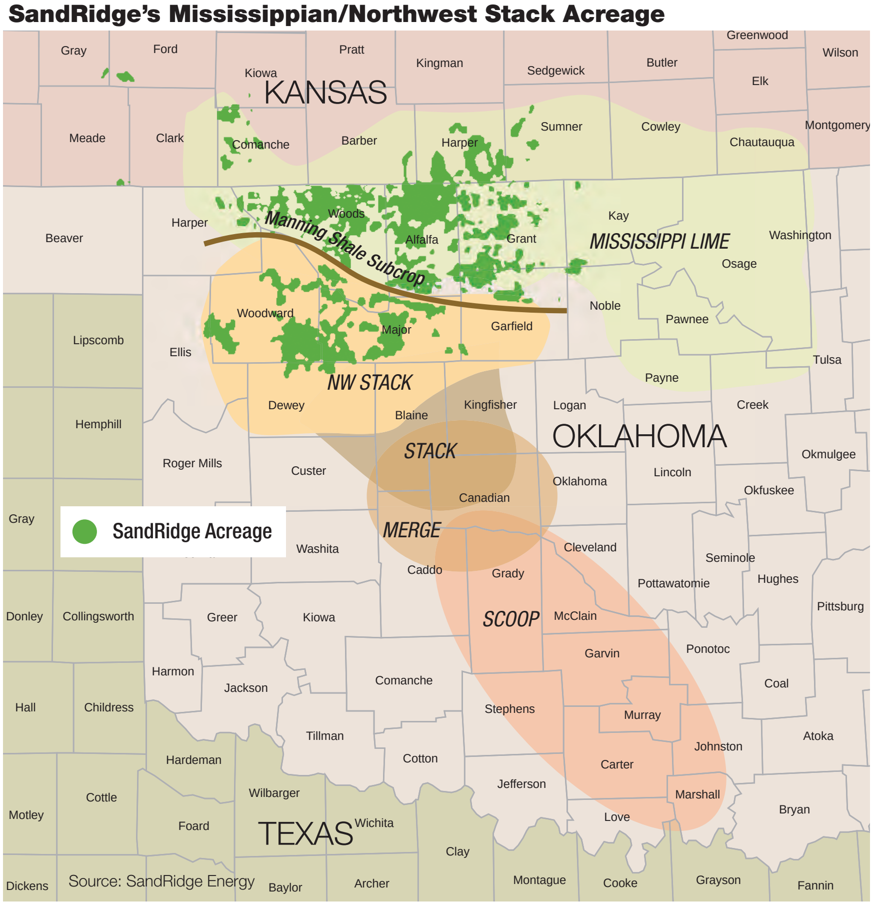
SandRidge also acquired an additional 13.2% interest in its produced-water-gathering and -disposal system.

The transaction is accretive to cash flow and net asset value per share, it reported. It estimates an associated payback period of fewer than three years.

Griffin said, pro forma for the two transactions, SandRidge expects a 2,615-boe/d net increase in production, $0.67/boe in reduced direct lease-operating expenses and incremental proved PV-10 value of roughly $38 million.

—*Emily Patsy*

SandRidge's Mississippian/Northwest Stack Acreage



Denbury Adding Eagle Ford In $1.7-Billion Penn Virginia Merger

DENBURY RESOURCES INC. said Oct. 28 it will acquire Eagle Ford operator **Penn Virginia Corp.** in a cash-and-stock transaction valued at about $1.7 billion, including debt assumption.

The acquisition of Houston-based Penn is expected to give Denbury a new core area in the oil window of the Eagle Ford. The Plano, Texas-based E&P, which focuses on CO_2 EOR, currently operates in two key areas: the Gulf Coast and Rockies.

Chris Kendall, Denbury president and CEO, said the transaction marks a "defining moment."

"Through this combination, we plan to focus Denbury's significant EOR expertise on the prolific Eagle Ford Shale, positioning us at the forefront of this exciting new arena for EOR," Kendall said in a news release.

"Denbury's passion for improved oil recovery and our deep technical knowledge give us a strong advantage on this new frontier."

Further, he believes Penn's Eagle Ford assets will add many years of high-value, low-breakeven development, and he expects the combined company will immediately generate positive free cash flow.

Denbury is offering 12.4 shares and $400 million cash. It intends to finance the deal with cash on hand and with debt comprised of a new $1.2-billion credit facility and a $400-million senior secured second lien.

Analysts with **Capital One Securities Inc.** estimate Denbury will acquire Penn for roughly $2,700 per acre, after ascribing about $1.45 billion of value for existing PDP (proved developed producing) based on discounted cash flow analysis at $65/$2.75 flat, implying $66,000 per flowing boe/d.

"Overall, [it's a] positive transaction that provides Denbury with additional high-margin properties at an attractive acquisition price," the Capital One analysts wrote after the announcement. The median per-acre price of major Eagle Ford transactions during the past two years implies about $1,300 per acre, they added.

Penn completed its transformation into a pure-play Eagle Ford Shale operator with the sale of its Oklahoma properties in July.

The company holds roughly 84,000 net acres in the Eagle Ford across Gonzales, Lavaca and Dewitt counties in South Texas, about 92% HBP and 99% operated. Second-quarter net production was about 22,200 boe/d (74% oil).

Capital One analysts forecast about $35/boe cash margin in 2019 for Penn, which the firm noted was among the top 10% in its coverage.

John Brooks, Penn president and CEO, said in the announcement that he believes the merger maximizes value for the company's shareholders and represents an ideal outcome for Penn and all of its stakeholders.

"Applying Denbury's demonstrated expertise in EOR to the oil-rich resources of our large, contiguous, Eagle Ford acreage provides our shareholders the opportunity to maximize value acceleration of [Penn's] … assets," Brooks said.

The deal's $1.7-billion price equates to $79.80 per Penn share, an 18% premium to the pre-announcement closing price. Post-closing, Denbury is expected to have a $6-billion enterprise value based on the pre-announcement share value.

Second-quarter 2018 production of the combined companies totaled 84 Mboe/d; proved reserves at year-end 2017 were about 343 MMboe.

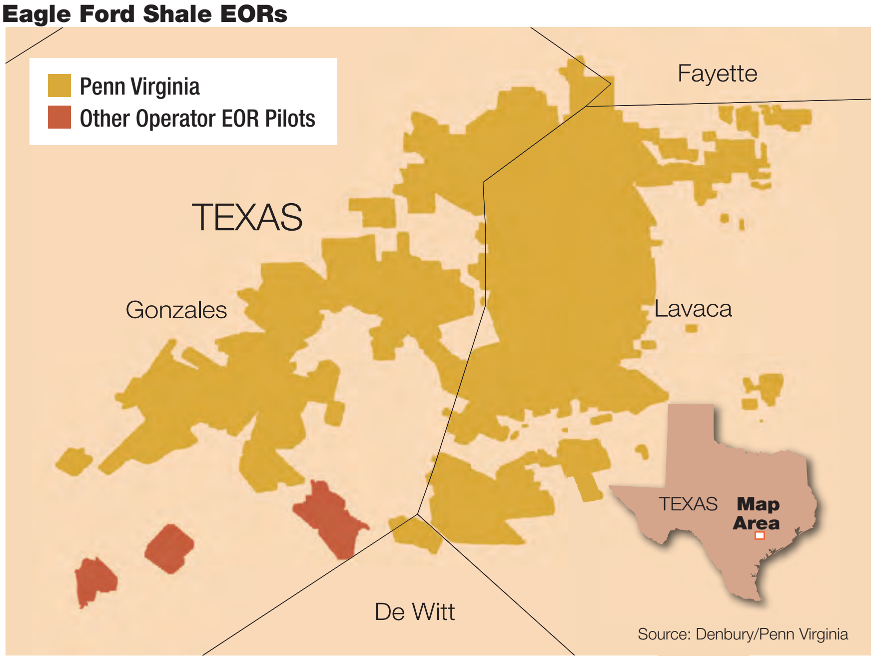
Two Penn board members are to join the Denbury board, expanding this to total 10. Denbury stockholders will own about 71% of the combined company. The deal is expected to close by April 1.

Guggenheim Securities LLC was lead financial adviser to Denbury; additional financial advice was provided by **J.P. Morgan Securities LLC. Vinson & Elkins LLP** provided legal counsel.

Jefferies LLC was financial advisor to Penn; legal services were provided by **Skadden, Arps, Slate, Meagher & Flom LLP** and **Gibson, Dunn & Crutcher LLP**.

—*Emily Patsy*

Eagle Ford Shale EORs



NANCY PATTON
Broker Associate
630 E. Hyman Avenue
Aspen, Colorado 81611
O: 970.925.8810
M: 970.309.4759
nancy.patton@elliman.com

Pioneer Draws $400 Million For Pressure-Pumping Unit

PIONEER NATURAL RESOURCES Co. continued to trim its portfolio as it transitions into a Permian Basin pure-play operator with an agreement on Nov. 13 to sell its pressure-pumping assets for $400 million in cash and stock.

Oilfield-service operator **ProPetro Holding Corp.** will pick up Pioneer Pumping Services in exchange for $110 million cash and a stock issuance representing 17% ownership in Midland, Texas-based ProPetro.

ProPetro will also provide Irving, Texas-based Pioneer with pressure-pumping and related services for up to 10 years.

Pioneer expects the deal to improve capital efficiency and long-term cost competitiveness in its core Permian operations. It launched a strategy in 2018 to become a pure-play Permian operator, where it planned to channel its entire $3.4-billion capex for the year.

Consequently, it had been in selling mode for most of the year, divesting assets that, in some cases, had been part of its portfolio for decades. Sales in South Texas, West Panhandle and Rockies had resulted in proceeds of more than $500 million.

Next on the chopping block are its remaining South Texas assets in the Eagle Ford Shale. The company expected to announce a deal by year-end 2018 and to begin 2019 as a Permian pure-play.

Tim Dove, Pioneer president and CEO, said in a news release that the long-term nature of Pioneer's agreement with ProPetro will benefit both companies.

"We are very pleased to announce our agreement with ProPetro that provides Pioneer with dedicated capacity from the leading pressure-pumping service provider in the Permian Basin," Dove said.

"Their robust operational track record aligns with our commitment to being the most efficient low-cost Permian operator."

ProPetro, which IPOed in March 2017, provides pressure-pumping and complementary services in North American resource plays. Its agreement with Pioneer is expected to increase its scale in the Permian Basin.

ProPetro had 20 hydraulic fracturing fleets in the Permian with an aggregate deployed capacity of 905,000 hydraulic horsepower, as per its SEC filings Nov. 8.

The deal was expected to close by year-end 2018.

—Emily Patsy

Pioneer Natural Resources 2018 Divestitures

Location/ Asset	Buyer	Month Closed	Value ($MM)
Eagle Ford JV	Sundance Energy	April	$102
CO Raton Basin	Evergreen Natural Resources	July	$79
TX W Panhandle	Undisclosed	August	$201
TX Sinor Nest	Undisclosed	Pending	$132
Pressure Pumping	ProPetro	Pending	$400
Total:			**$914**

Source: Hart Energy

Lonestar Resources Builds Thrifty Eagle Ford Expansion

PURE-PLAY EAGLE FORD operator **Lonestar Resources US Inc.** said Nov. 19 it acquired bolt-on properties in DeWitt County in South Texas as it rides high on increase borrowing capacity.

Lonestar acquired 3,084 gross (2,706 net) acres from **Sabine Oil & Gas Corp.** and **Alerion Gas AXA LLC** for $38.7 million. The properties, 95% operated, are in the Sugarkane Field in an area that Lonestar CEO Frank Bracken said, in the news release, features some of the thickest Lower Eagle Ford Shale.

"In combination with our expanded and enhanced credit facility, we have financed the acquisition in a manner that leaves Lonestar with the highest level of liquidity in the company's history, while expanding our Eagle Ford Shale position in an attractive part of the play," Bracken said.

The acquired properties produce 800 barrels of oil equivalent per day (boe/d) from 20 wells. Estimated annualized EBITDAX is $6 million. Lonestar paid about $3,200 per acre, assuming $40,000 per flowing boe, according to John Aschenbeck, senior analyst with **Seaport Global Securities LLC**.

"We are fans of this acquisition as it once again demonstrates Lonestar's ability to consistently tack on blocks of high-quality Eagle Ford acreage at attractively priced valuations," Aschenbeck wrote after the news.

Additionally, Lonestar identified about 26 Lower Eagle Ford drilling locations on the properties, which Aschenbeck valued at about $335,000 per location. The company also sees additional potential in the Upper-Lower Eagle Ford, Upper Eagle Ford and Austin Chalk.

Lonestar plans to apply its Eagle Ford know-how already gained in the play toward further results. "We believe the application of our geo-engineered drilling and completion process can yield highly productive wells that yield attractive rates of return on invested capital," Bracken said.

"As is typically the case with our acquisitions, we see potential to increase lateral lengths and further enhance returns."

Pro forma, Aschenbeck estimates Lonestar has about 63,600 net acres in the Eagle Ford with roughly 13,300 boe/d of production.

In addition, Lonestar reported that its borrowing base increased to $275 million from $190 million, the interest rate fell 0.5%, and the term was extended to November 2023. Its draw on the revolver post-acquisition was $163.9 million.

Aschenbeck wrote that Lonestar's $111.1 million that remains available to draw is "more than ample, given our expectations for Lonestar to fund its fiscal-year 2019 capital program within cash flow."

Lonestar estimates proved reserves added from the deal total 13 million boe/d of which 3.2 million are PDP (proved developed producing) and 100% Lower Eagle Ford. Based on the strip at closing, the proved reserves had PV-10 value of $77 million.

The effective date was Aug. 1. **UBS Investment Bank** was exclusive transaction adviser to Sabine.

—Emily Patsy

TRANSACTION HIGHLIGHTS

FAYETTEVILLE

■ **Southwestern Energy Co.** closed its $2.3-billion sale of its Fayetteville Shale business to **Flywheel Energy LLC**, a private company backed by **Kayne Anderson Private Energy Income Funds,** the companies said Dec. 4.

Flywheel acquires the E&P and midstream assets for $1.865 billion in cash and assumption of $438 million of future contractual liabilities.

Southwestern exits Arkansas to operate as an Appalachian pure-play E&P. The proceeds will accelerate activity in southwestern Appalachia in West Virginia.

Southwestern will also retire $900 million of senior notes and the outstanding balance under its revolver, repurchase stock up to the remainder of the company's $200-million stock-buyback program and invest in Appalachian assets during the next two years.

"This strategic transaction represents a further significant step in the transformation of the company," Bill Way, Southwestern president and CEO, said in a news release.

"We're now better positioned to leverage our leading technical and operating capabilities to drive greater value from our highly attractive and significant asset base in Appalachia, pay down debt and create even greater financial flexibility."

CALIFORNIA

■ **Royale Energy Inc.** said Oct. 22 it formed a joint venture (JV) with **California Resources Corp**. to drill 30 wells throughout the Rio Vista Field, the largest dry-gas field in California.

Rio Vista, located in the Sacramento-San Joaquin River Delta in northern California, was discovered in 1936 and has produced about 4 trillion cubic feet from more than 15 stacked gas reservoirs, according to a Royale press release.

Royale said the JV with Los Angeles-based California Resources expands a previous JV development area to the entire Rio Vista Field. The expansion will provide Royale up to three years to drill to any of the multiple, stacked productive formations in the prolific and historic property.

"The joint venture will lead to multiple years of drilling activity at Rio Vista at a time of upward-trending natural gas prices due to declining natural gas inventories nationwide," Royale said.

Royale is an independent E&P company based in San Diego. The company has its primary operations in California's Los Angeles and Sacramento basins.

WILLISTON BASIN

■ **Oasis Petroleum Inc.** said Nov. 8 it agreed to sell midstream interests in a $250-million dropdown that the Houston-based company said will improve its leverage position.

Oasis will sell the interests to its midstream affiliate **Oasis Midstream Partners LP** in a transaction financed equally by debt and equity.

The divested assets include a 15% interest in **Bobcat DevCo LLC**, which is focused in the Williston's Wild Basin operating area, and 30% interest in **Beartooth DevCo LLC**, which owns significant water-infrastructure assets across most of Oasis' core operating areas in the Williston.

MIDLAND BASIN

■ **Roxo Energy LLC** sold its Permian Basin assets to **Murchison Oil and Gas LLC** in early November, less than two years after Roxo's entry into the play.

Roxo will sell its 5,300 contiguous acres in Howard and Borden counties, Texas, targeting the prolific Wolfcamp and Spraberry in the northern Midland Basin. The leasehold is surrounded by significant development activity by quality offset operators, according Roxo.

Financial terms of the transaction were not released.

Murchison, which closed the deal in late October, financed the purchase with an investment group led by **Angelo Gordon & Co.** that included **MSD Partners LP** and **Ares Capital Corp**.

GULF OF MEXICO

■ Buyout firm **Blackstone Group LP** and privately held **LLOG Exploration Co.** are working with an investment bank to sell their Gulf of Mexico (GoM) exploration joint venture (JV) for more than $2 billion, Reuters reported Nov. 6 based on sources familiar with the matter.

The divestment attempt is the latest to emerge from the U.S. GoM as higher oil prices allow those with capital-intensive investments in the region to sell them at much more attractive valuations than in recent years.

The **LLOG Bluewater** JV between Blackstone and LLOG was announced in November 2012, with a pledge to invest more than $1.2 billion to bolster LLOG's operations in the GoM.

The duo is working with **Barclays Plc** to sell the venture, according to four sources aware of the matter. Initial information had been sent to potential buyers, one of the sources added.

POWDER RIVER BASIN

■ Bozeman, Mont.-based Massif Oil & Gas' management team will return to the Powder River Basin after securing backing from private-equity firm **NGP** for **Massif Oil & Gas II LLC**.

Massif previously built a position in the Powder's Campbell County, Wyo., that it sold in third-quarter 2018 to **Vermilion Energy Inc**. for $186 million.

Massif II has hopes of leveraging its proprietary relationships and operational expertise for another go-around in the basin.

"Following our success in the Powder River Basin, we are excited to partner with NGP to build a company focused on creating significant value for its partners," Massif CEO Barrett Frizzell said in a news release.

Frizzell, along with the rest of the management team at Massif, will continue their same roles for Massif II. Led by Frizzell, the Massif II team includes Adam Gollofon, COO; Scott Sheehan, CFO; Brian Burdette, executive vice president, subsurface; and Dave Thornquist, executive vice president, land.

U.S. LNG

■ Japan's **Toshiba Corp.** will exit its U.S. LNG business by paying China's **ENN Ecological Holdings Co. Ltd**. more than $800 million to take over the unit as part Toshiba's plan to shed money-losing assets, Reuters reported.

The sale concludes a venture that puzzled analysts when it was announced in 2013. Asian LNG prices have plunged 42% in the past five years and the potential for future losses spurred Toshiba's exit.

Under the deal, Toshiba will sell its **Toshiba America LNG Corp.** unit to ENN Ecological, a unit of **ENN Group**, for $15 million, according to the Reuters report.

"The project posed a huge risk, because no one knows how the situation will be over the next 20 years," Toshiba CEO Nobuaki Kurumatani told reporters at a press conference.

The company booked a charge of 93 billion yen (US$818 million) in exiting the LNG business in its earnings it announced on Nov. 8.

TRANSACTION HIGHLIGHTS

PERMIAN BASIN

■ **Flat Creek Resources LLC** has secured an initial capital commitment of $400 million from **EnCap Investments LP** and management to pursue a Permian Basin strategy, the company said Nov. 14.

Flat Creek, based in Fort Worth, Texas, is an independent energy company focused on core acreage consolidation and exploitation, initially in the Permian Basin in West Texas and New Mexico.

The company was formed by CEO Mike McCracken, former COO of Permian E&P **Black Mountain Oil & Gas**, which sold to **Marathon Oil Corp.** in 2017 for $700 million.

The management team additionally includes **XTO Energy Inc.**'s former Midland Basin geologist and a principal for private-equity firm **Avista Capital Partners**' oil and gas investments.

NORTH SEA

■ British petrochemicals company **Ineos** is in exclusive talks with **ConocoPhillips Co.** to buy North Sea oil and gas fields worth $3 billion from the U.S. energy company, the *Sunday Times* newspaper reported without citing sources.

Reuters reported in May that ConocoPhillips was preparing to sell North Sea assets to focus on shale production in the U.S. More recently, Bloomberg reported that the oil major aimed to sell $3 billion of assets.

■ **Serica Energy Plc** said Nov. 5 it will grow its presence in the U.K. North Sea with an agreement to acquire further interests in the Bruce and Keith fields from **BHP Billiton Ltd.**

As part of the agreement, **Serica Energy (UK) Ltd**. will acquire a 16% interest in Bruce Field and a 31.83% interest in Keith Field as well as associated infrastructure from **BHP Billiton Petroleum Great Britain Ltd.** for an undisclosed amount.

In all, Serica is expected to have 94.25% ownership in Bruce Field and 91.67% in Keith Field following completion of the company's recent acquisitions, which also include pending purchases in the region from **BP Plc** and **Total SA**.

"This acquisition, in addition to the previously announced transactions with BP and Total, place us in an even better position to unlock increased value from the assets and benefit from economies of scale," Serica CEO Mitch Flegg said in a statement.

MONTNEY

■ **Blackbird Energy Inc.** and **Pipestone Oil Corp.** agreed to merge in October, forming a pure-play, condensate-rich E&P in the Montney Shale play in Alberta.

The companies said they plan an all-stock merger, forming **Pipestone Energy Corp.** The companies also announced C$310 million in equity and debt financings, which are expected to fully fund a planned 2019 exit production rate of 14,000 to 16,000 boe/d.

Pipestone Energy is set to have the single-largest condensate-rich acreage position in the "sweet spot" of the over-pressured window of the Montney fairway, according to the companies' joint press release.

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'POWER' PLAY IN THE WESTERN ANADARKO

RICHARD MASON, CHIEF TECHNICAL DIRECTOR

The old is new once again in the western Anadarko Basin that straddles the state line between the Texas Panhandle and western Oklahoma. Privately held independents are applying super-extended laterals and multi-stage, high-intensity completions to revive a quasi-unconventional resource play.

The current revival is the latest in a province that has witnessed almost 45,000 wells during the past 100 years and generated 15 trillion cubic feet of gas—much of it liquids-rich at 1,250 to 1,350 British thermal units—and 300 million barrels (bbl) of oil.

The western Anadarko is home to two hydrocarbon plays. The gas-rich Granite Wash is characterized by debris fans along the forefront of a geologically ancient mountain front. The second occupies a shallow shelf pro-grading south and west into the ancient basin and is characterized by a liquids-rich gas and black-oil play.

Combined, these make the western Anadarko a stacked-pay play with up to 26 formations that demonstrate hydrocarbon potential in Pennsylvanian-aged formations.

Tulsa-based Tecolote Energy LLC spent $260 million beginning in 2016 to acquire 210,000 HBP acres, mostly along a diagonal front approximately 60 miles long in Hemphill and Wheeler counties in the Texas Panhandle and in Roger Mills, Custer and Beckham counties in Oklahoma, essentially paying PDP (proved developed producing) values for cast-off acreage from Devon Energy Corp., Samson Resources Inc. and Chevron Corp.

Currently, Tecolote's 245,000 acres feature working interest above 82%. Internally, the company incorporated 10,000 wells, assimilated hundreds of miles of 3-D seismic and thousands of drilling logs into a coherent database allowing engineers to suss out the best landing zones and completion techniques.

Tecolote is going long, emphasizing 10,000-foot laterals and adopting completion-intensity techniques from other resource basins. The company employs 1,500 pounds of sand and 2,100 gallons of fluid per lateral foot, while decreasing stage-spacing from 300 feet to 180 feet.

Tecolote generated four of the 10 best horizontal wells among its first six efforts in Hemphill County, Texas, including a record-setting-lateral-length Mathers State 172-156 CL EX 1H at 12,592 of horizontal displacement with a 30-day cumulative production of 35,015 bbl of oil.

The offset Mathers 1518-165 EX 1H was completed at 2,320 barrels of oil equivalent (boe/d) out of a 7,257-foot lateral in the Marmaton D zone.

Employing a branding technique common to Oklahoma E&Ps—originators of the Cana Woodford, Scoop and Stack plays—Tecolote christened the effort as the Panhandle Oil Window, Extended Reach play—the "Power Play."

Company CEO Maurice Storm told attendees at Hart Energy's DUG Midcontinent Conference in November that the Granite Wash is among the best zones in boe per thousand feet of lateral in the Anadarko Basin on 12-month cumulative production. This metric represents 44,000 boe per thousand feet of lateral and has only been exceeded recently with newer Anadarko Basin wells farther east, in the Scoop-Woodford play.

Tecolote is pursuing a two-rig program to drill three well pads separated by stepouts 15 to 20 miles apart. Production was expected to exceed 30,000 boe daily by year-end 2018.

Tecolote is just one player in a broader story. FourPoint Energy LLC has amassed more than 750,000 acres and has employed big-data analytics and extended-reach laterals to achieve economically positive results in the western Anadarko. Meanwhile, start-up Presidio Petroleum LLC has acquired 60,000 acres in the Oklahoma Panhandle to exploit the Cleveland, Tonkawa and Marmaton on the shelf section of the western Anadarko.

The western Anadarko suggests there is still a future for smaller independents within a broader industry trend that emphasizes consolidation as the main avenue to exploit resource plays.

The latter may be the case in theory. However, the reality in the field is that technically astute management teams who employ the latest well-construction learnings are picking up cast-off acreage at PDP valuations, obtaining PUDs (proved undeveloped reserves) for little to no cost, and squeezing hydrocarbons out of formations that were originally developed under older methodologies.

These independents find the western Anadarko attractive with pre-existing infrastructure for access to hydrocarbon-processing and to the larger, national marketplace.

The king—in the form of larger, publicly held operators—may be dead in the western Anadarko. But, long live the privately held, smaller-firm "king" that is ascending the throne.

EASTERN U.S.

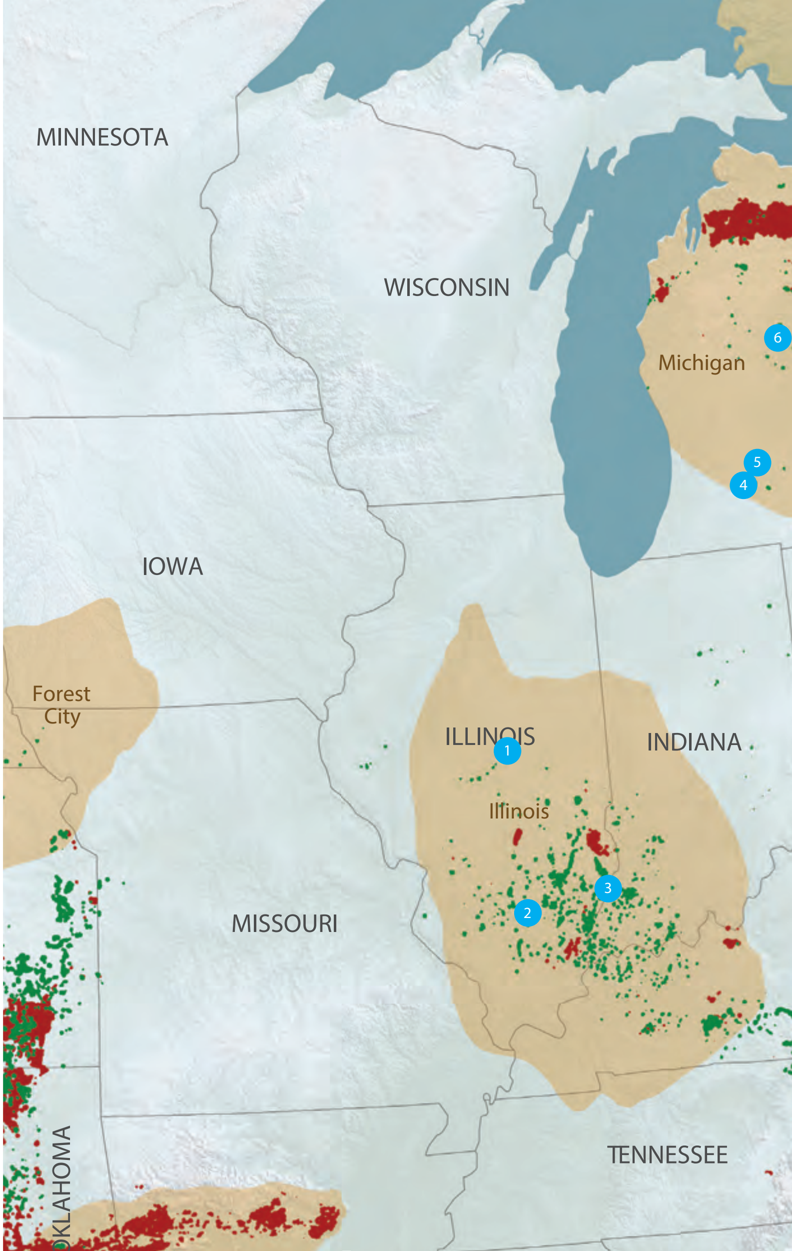
1 ***Podolsky Oil Co.***, according to IHS Markit, is drilling a deeper pool test in Mt. Auburn Consolidated Field. In Christian County, Ill., #2 T.R. McMillen has been permitted to 7,400 ft. The Precambrian venture is in Section 4-15n-1w. Podolsky has been active in the field and the most recent completion was at the 1,954-ft #1 Hill Family Trust about 1 mile northeast in Section 3. It was tested in 2017, pumping 4 bbl of crude and 13 bbl of water per day from Silurian at an unreported depth. Production in the field extends 12 miles southwest of Fairfield, Ill.,-based Podolsky's drillsite. The deepest wells in the field, which was opened in 1943, yield crude from Silurian. Additional Silurian production in Blackland Field is southeast of the company's current venture and it also operates several wells in the Christian County reservoir.

2 In Jefferson County, Ill., ***Gesell's Pump Sales & Service*** has spud a 6,200-ft wildcat, #1 Karber Trust. The Ewing Field venture is targeting oil pays in Platteville and is in Section 31-4s-3e. Within one-half mile north, the Whittington, Ill.-based company was active in the area in 2014 at #1 Jack Thompson. The venture was drilled to 3,763 ft, with some oil shows encountered in Warsaw at 3,744-63 ft. Gesell also completed #2 Hayse in Section 32, pumping 16 bbl of crude and 30 bbl of water per day from McClosky Lime at 2,926-32 ft. The company's nearby #3 Hayse was completed in 2013 in a Lower Salem lime zone at 3,734-51 ft. Through September 2018, recovery from both wells totals 17.549 Mbbl of crude. After completing #1 Karber Trust, the rig will be moved to the southwest to drill a 6,200-ft Platteville test at #2 Pickens-Chenault in Section 25-5s-2e.

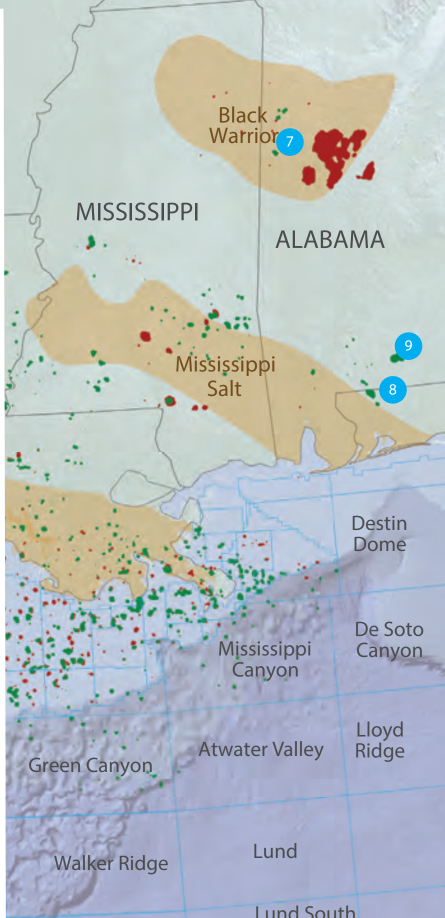
3 ***Trey Exploration Inc.*** has received a permit to drill a wildcat McClosky test in Indiana's Knox County. The #22-12 Newton State Unit will be in Section 22-1s-12w and has an estimated total depth of 2,400 ft in Mt. Carmel Consolidated Field. Nearby drilling is northeast in St. Francisville Consolidated Field, where several operators have drilled or are planning to drill McClosky Lime tests. Trey is based in Newburgh, Ind.

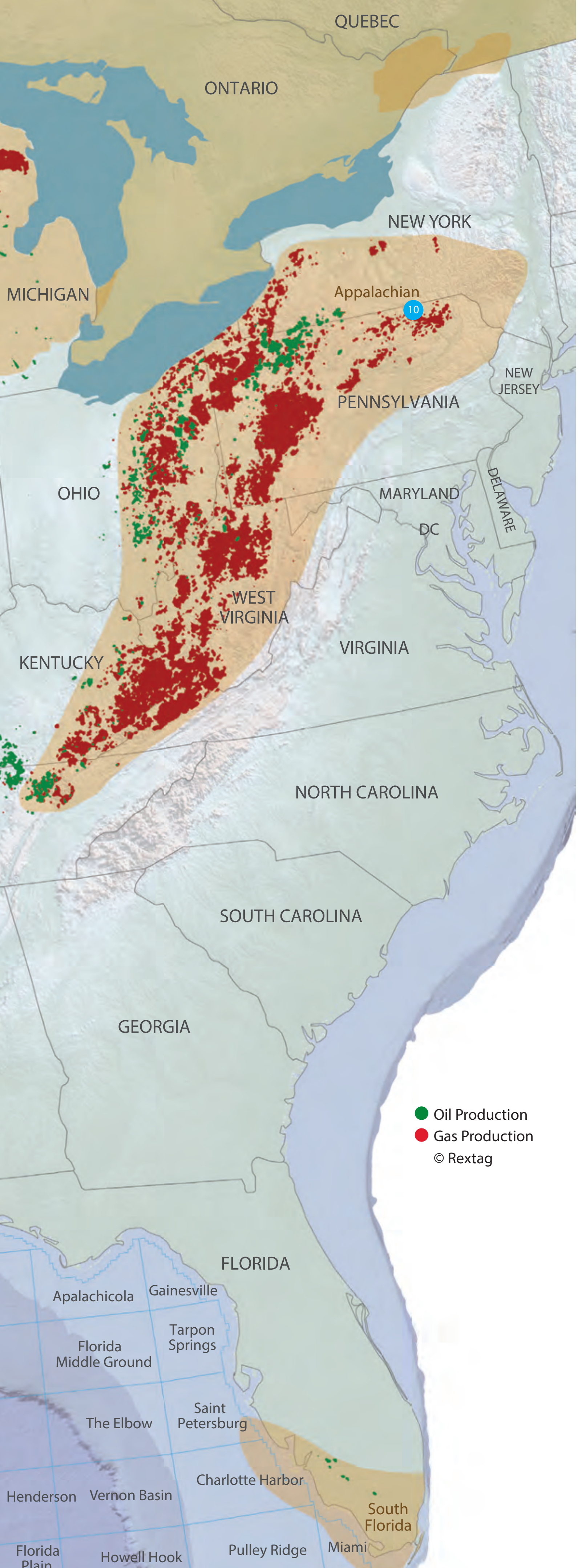
4 A third exploratory test was added to ***Savoy Energy LP***'s Trenton/Black River program in Calhoun County, Mich. The #1-3 Lily is permitted to 4,100 ft, and it will be vertically drilled in Section 3-4s-8w. Nearby drilling by the company is within 1 mile north at #2-34 Weeks in Section 34-3s-8w. It has a planned depth of 4,100 ft. The company's offsetting #1-34 Seymour was drilled in late 2018 to 4,050 ft and it has 5 1/2-in. casing set on bottom. The new tests are about 7 miles west of Trenton/Black River oil production in Tekonsha Field, a Calhoun County reservoir opened in 1959. The most recent field well was completed in 2014.

5 IHS Markit reported that ***Savoy Energy LP*** is drilling a second Trenton/Black River exploratory test in Calhoun County, Mich. Located in Section 34-3s-8w, #2-34 Weeks has a planned depth of 4,100 ft. The company's offsetting #1-34 Seymour was drilled in September to 4,050 ft with 5 1/2-in. casing set on bottom. No oil wells have been drilled in the section. The most recent drilling in the area was in 2002 at ***West Bay Exploration***'s #1-4 Wright in Section 4 and was abandoned at 3,530 ft in Black River. About 8 miles west is Kalamazoo County's Climax Field, a Trenton/Black River reservoir opened in 2014 by ***Axia Energy***. Savoy's headquarters are in Traverse City, Mich.



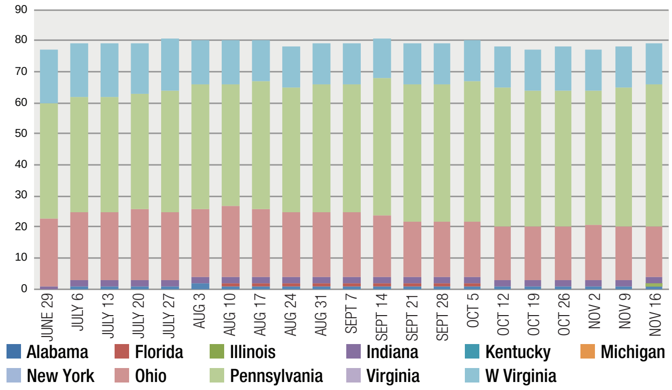
6 A 3,600-ft wildcat is underway by Enid, Okla.-based ***Maverick Brothers Resources LLC*** in Montcalm County, Mich. The #1-15 Wickes Trust is in Section 15-11n-7w and is targeting oil pays in Dundee Lime. Nearby drilling is within 1 mile south in Section 22 at a Dundee Lime wildcat drilled in 1965—#1 Brown was abandoned at 3,421 ft. Dundee Lime oil production in Entrican Field is about 1.5 miles southwest of Maverick's drillsite. The field was opened in 1966 and the last drilling in the Michigan reservoir occurred in 2008. To the south are several Dundee Lime wells in Stanton Field and most of the field's wells yield crude from Traverse Lime at 2,900 ft and Alpena Lime at 2,950 ft.





Eastern U.S. Rig Count

June 29, 2018-Nov. 16, 2018



Data compiled from Baker Hughes

7 ***Land & Natural Resources Development*** has received a permit to re-enter a well in Pickens County, Ala. The #1 Peco Foods 2-1 has a planned depth of 4,500 ft and is in Section 2-19s-14w in Coal Fire Creek South Field. The venture is targeting oil in Pottsville A. The original Black Warrior Basin well was completed in 1985, flowing 25 Mcf of gas and 140 bbl of oil per day from a Fayette zone at 4,062-74 ft. Land & Natural Resources is based in Tuscaloosa, Ala.

8 ***Sklar Exploration Co.*** is underway at the first of two Norphlet oil tests in Santa Rosa County in the Florida panhandle. The #1 Polk Estate 13-5 is a 15,500-ft directional well and is in Section 13-5n-29w. The second planned test is within 1 mile northwest at #1 Bates 2-2 in irregular Section 2. The proposed total depth is 15,500 ft; successful completions would reopen Mount Carmel Field. Nearby production is at a 1972 completion at #39-3 Finlay Heirs in Section 39. It was tested flowing 960 bbl of 46-degree-gravity crude and 6.4 MMcf of gas per day from Norphlet perforations at 15,260-80 ft. It was drilled to 15,399 ft. Well recovery through 1979 totaled 325.963 Mbbl of crude and 327 MMcf of gas. Two other wells in the field, #632 T.M. Hendricks 27-3 and #36-1B Wolfe-Hendricks 36-1, have produced a combined 4.2 MMbbl of crude and 4.2 Bcf of gas from Norphlet. About 2 miles west is Smackover production in Jay Field. Sklar's headquarters are in Shreveport, La.

9 A Smackover completion by ***Fletcher Petroleum Co.*** was tested flowing 393 bbl of 46-degree-gravity crude and 143 Mcf of gas per day. The directional Brooklyn Field completion, #1 Anderson Johnson 11-9, is in Section 11-3n-13e of Conecuh County, Ala., and was drilled to 11,988 ft. Production is from perforations at 11,797-11,808 ft. Gauged on a 16/64-in. choke, the flowing tubing pressure was 400 psi. The field has been extended during the past year with Smackover completions by Fletcher and ***Ventex Operating***. Ventex's nearby #1 Pate 11-3 was tested flowing 433 bbl of crude and 271 Mcf of gas from Smackover. In the same section, Fletcher's #1 Pate 11-2 was tested producing 377 bbl of crude and 196 Mcf of gas through perforations at 11,757-11,772 ft. Fletcher's headquarters are in Fairhope, Ala.

10 According to ***Southwestern Energy Co.***, the company drilled the longest lateral in the company's history on company-owned acreage in Susquehanna County, Pa. The horizontal Marcellus Shale well, #2H Mitchell South, was drilled to 22,610 ft, with a lateral bottoming 3 miles southeast at a true vertical depth of 6,175 ft. It is in Section 7, Franklin Forks 7.5 Quad, Franklin Township. Southwestern is based in Spring, Texas.

GULF COAST

1 Additional details have been released on Denver-based ***Rocky Creek Resources LLC***'s two Eagleville Field-Eagle Ford Shale producers in Lavaca County (RRC Dist. 2), Texas. The #1H Five Star Unit flowed 5.598 MMcf of gas, 546 bbl of 51.3-degree-gravity condensate and 886 bbl of water per day. During testing on an 18/84-in. choke, the flowing casing pressure was 6,520 psi and the shut-in casing pressure was 6,875 psi. Acidized and fractured perforations are at 13,616-20,592 ft. It was drilled to 20,690 ft (13,202 ft true vertical) in the Elizabeth Tribble Survey, A-446. It bottomed about 1.5 miles southeast in Benjamin Whitson Survey, A-490. In Stephen Adams Survey, A-70, #1H Kloesel flowed 4.117 MMcf of gas, 617 bbl of 47.5-degree-gravity oil and 1.554 Mbbl of water per day from fracture-stimulated perforations at 13,221-20,828 ft. Tested on a 20/64-in. choke, the flowing tubing pressure was 5,280 psi. It was drilled to 20,955 ft (13,201 ft true vertical) and bottomed about 1.5 miles northwest.

2 A Word Field-Lower Wilcox oil well was completed by ***Capital Star Oil & Gas Inc.*** in Lavaca County (RRC Dist. 2), Texas. The #1 W. Ainsworth Oil Unit flowed 312 bbl of 46.3-degree-gravity crude and 1.892 MMcf of gas per day from perforations at 10,448-72 ft. Gauged on an 11/64-in. choke, the flowing tubing pressure was 4,533 psi and flowing casing pressure was 1,000 psi. It was drilled to 11,041 ft and is on a 120-acre lease in John M. Ashby Survey, A-1. Capital Star's headquarters are in Houston.

3 ***GeoSouthern Energy Corp.*** completed an Austin Chalk gas well in the Washington County (RRC Dist. 3), Texas, portion of Giddings Field. The discovery is on 657-acre Upper Texas Coast lease in Duncan McIntyre Survey, A-158. The #1H Gary-Wickel initially flowed 4.982 MMcf of gas, 7 bbl of 60-degree-gravity condensate and 82 bbl of water per day. Production is from fracture-treated perforations at 13,460-19,180 ft. The flowing tubing pressure was 2,396 psi during testing on a 26/64-in. choke. The horizontal well was drilled to 19,337 ft, 12,959 ft true vertical, and bottomed about 1.5 miles northwest. GeoSouthern is based in The Woodlands, Texas.

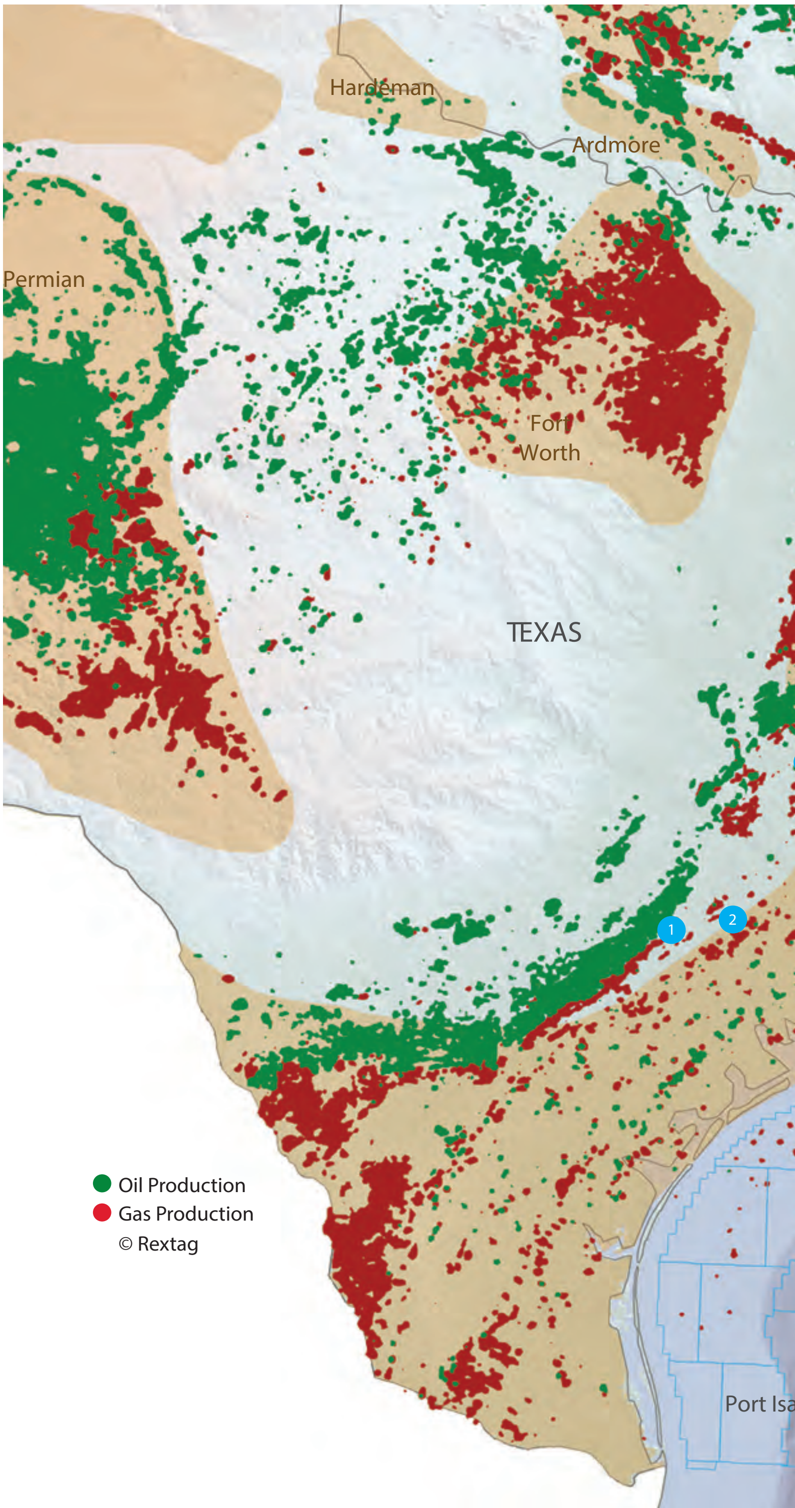
4 ***Anadarko Petroleum Corp.*** announced a discovery on the company's Hadrian North expansion project. The #8SS OCS G21447 is on Keathley Canyon Block 919. The Woodlands, Texas-based company hit 200 net ft of oil pay in two reservoirs. No total depth was disclosed and completion work on the well is expected to be finished in early 2019. Area water depth is 7,400 ft.

5 An exploratory test has been scheduled by ***Castex Energy Inc.*** on previously undrilled Ship Shoal Block 127. The #1 OCS G36219 will be in the northeastern portion of Ship Shoal Block 127 and area water depth is 42 ft. Castex, according to IHS Markit, acquired the drilling rights to the Block 127 lease in 2018. In 2015, the company submitted a drilling plan for Ship Shoal Block 104 (OCS G35231) just north of the planned Block 127 test. Castex has not filed a permit for the proposed Block 104 exploratory test.

6 Houston-based ***Talos Energy LLC*** has received a permit for a development test in the company's Boris Field in the deepwater Gulf of Mexico. The #3SS OCS G16727 will be drilled in the central portion of Green Canyon Block 282 and area water depth is 2,350 ft. Offsetting the company's scheduled test is a Pliocene oil well drilled in 2002 and now operated by Talos: #1 OCS G16727 has recovered 10.4 MMbbl of crude and 17 Bcf of gas as part of Block 282 field. Talos also operates #2 OCS G16727 on Block 282 as well as #1SS OCS G26302, which bottomed northeast on Block 238.

7 ***Walter Oil & Gas Corp.*** plans to bring online early this year a second Miocene well in offshore Louisiana's South Timbalier Block 311 Field. According to partner ***W&T Offshore***, #2-A OCS G24990 was drilled from the A platform on South Timbalier Block 311. It bottomed south in Block 320. In W&T Offshore's latest earnings release, the company announced the Gulf of Mexico well logged 163 ft of net pay. No total depth was disclosed, but completion work is ongoing, with the well to be placed online via existing infrastructure. The #3-A OCS G24990 is underway and is also scheduled to bottom in Block 320. This venture is also considered a low-risk Miocene opportunity. W&T holds a 10.8% stake in the South Timbalier Block 311/320 project. Walter's headquarters are in Houston.

8 A Miocene gas well in St. Charles Parish, La., was completed by ***Costa Energy LLC***. The #1 Simoneaux was tested flowing 2.23 MMcf of gas and 77 bbl of 47-degree-gravity crude per day through perforations at 11,440-64 ft. The directional well is in irregular Section 13-15s-20e and bottomed one-half mile north in Section 12. It was drilled to 12,475 ft with a true vertical depth of 11,760 ft. Tested on a 15/64-in. choke,



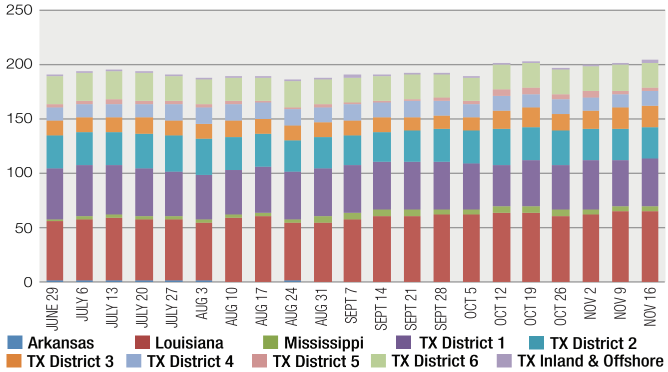
the flowing tubing pressure was 3,730 psi and was placed in Bayou des Allemands Field, which straddles the St. Charles/Lafourche parish line. Costa Energy's headquarters are in Irving, Texas.

9 In Lafourche Parish, La., ***Hilcorp Energy Co.*** has completed a Lake Raccourci Field well. The #1 State Lease 21782 flowed 19.758 MMcf of gas and 275 bbl of 41-degree-gravity crude per day from Bigenerina 2 (Miocene) at 13,848-13,934 ft. It was directionally drilled to 14,681 ft, 14,594 ft true vertical, and is in Section 24-21s-20e. Offsetting the bottomhole of the discovery is a vertical test drilled in 1951 at #1 State Lease 01449, which was abandoned at 14,065 ft. Hilcorp's headquarters are in Houston.

10 Covington, La.-based ***LLOG Exploration*** plans to drill several deepwater tests on previously undrilled Green Canyon Block 612. According to an exploration plan filed by the company, three tests could be drilled from offsetting surface locations in the northeastern portion of the tract. Water depth in the area is 4,200 ft. Southwest is ***BHP Billiton***'s Shenzi (Green Canyon Block 654) Field, which came online in 2007. Wells in the deepwater reservoir produce from Miocene at 22,542-28,865 ft. South of LLOG's prospect is ***BP***'s Atlantis Field in Green Canyon Block—online since 2006, it produces from Williana, Pliocene and Miocene at 16,460-22,486 ft.

Gulf Coast Rig Count

June 29, 2018-Nov. 16, 2018

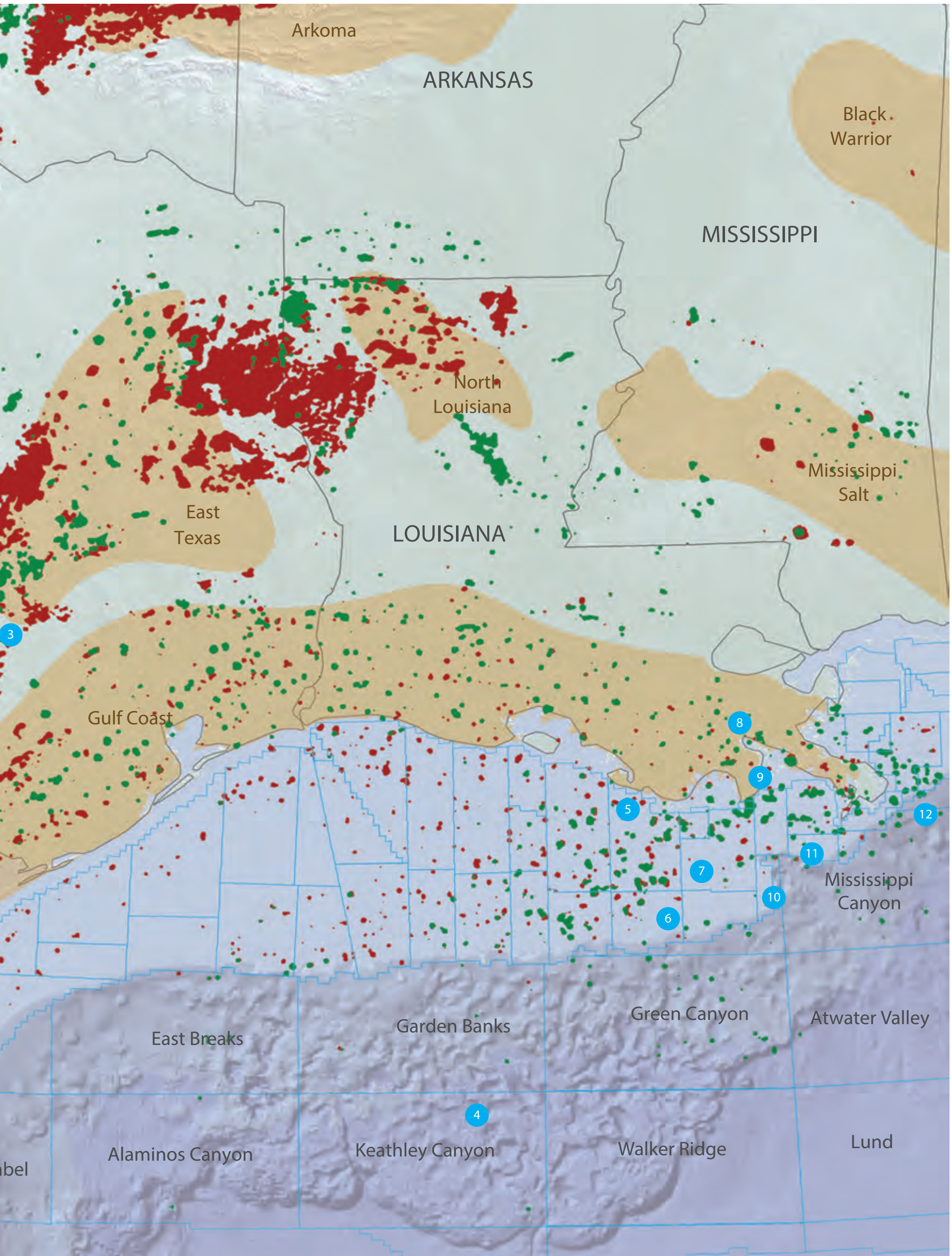


Data compiled from Baker Hughes

11 ***Shell Oil Co.*** has spud a deepwater test as part of the company's Mars/Ursa field expansion project. The #1 OCS G33170 is in the western part of Mississippi Canyon Block 764. The venture is in 3,300 ft of water and will be drilled to the north and will bottom in Block 720. There has been no previous drilling on Block 720. Nearby production is in Mississippi Canyon Block 807, the Mars B development. Houston-based Shell has drilled and permitted numerous tests as part of its plan to grow production in the area.

12 ***Anadarko Petroleum Corp.*** has received approval for an exploration plan to expand the company's producing Horn Mountain field to the west. As many as 16 tests could be drilled from various surface locations on Mississippi Canyon Block 81 (OCS G35312), Block 82 (OCS G35313) and Block 126 (OCS G18194). There has been no previous production on blocks 81 and 82. Area water depth is 4,300 ft. Southeast is the company's Yellowfin prospect— additional drilling is planned to expand production in the area. The prospect will consist of Block 128 (OCS G35964) and Block 129 (OCS G10977) and as many as 20 tests could be drilled on the two tracts.

All data in the Exploration Highlights section are based on sources believed to be reliable, but accuracy cannot be guaranteed. In no way should publication of these items be construed as an express or implied endorsement of a company or its activities.



MIDCONTINENT & PERMIAN BASIN

1 Dallas-based ***Matador Production Co.*** released details on several recently completed wells in the Delaware Basin in Lea County, N.M. The #214H Strong 14-24S-33E AR is producing from Lower Wolfcamp A flowing 3.67 Mboe/d (77% oil) during a 24-hour initial potential test. It was drilled to 17,180 ft and bottomed in Section 14-24s-33e. The #211H Leo Thorsness 13-24S-33E AR flowed 2.087 Mbbl of 46.3-degree-gravity oil and 4.914 MMcf of gas per day (2.906 Mboe/d) from acid- and fracture-stimulated perforations at 12,616-16,887 ft. The #131H Irvin Wall State Com produces from Third Bone Spring in the Antelope Ridge area. It initially flowed 2.343 Mboe/d (81% oil) from treated perforations at 11,741-16,329 ft. According to IHS Markit, Matador also completed its first 2-mile lateral in the Delaware Basin. The #203H David Edelstein State Com was drilled in the Rustler Breaks area of Eddy County. The Purple Sage Field well was tested in Wolfcamp A-XY perforations at 9,653-19,171 ft and flowed 1.86 Mbbl of oil and 3.107 MMcf of gas (2.378 Mboe/d).

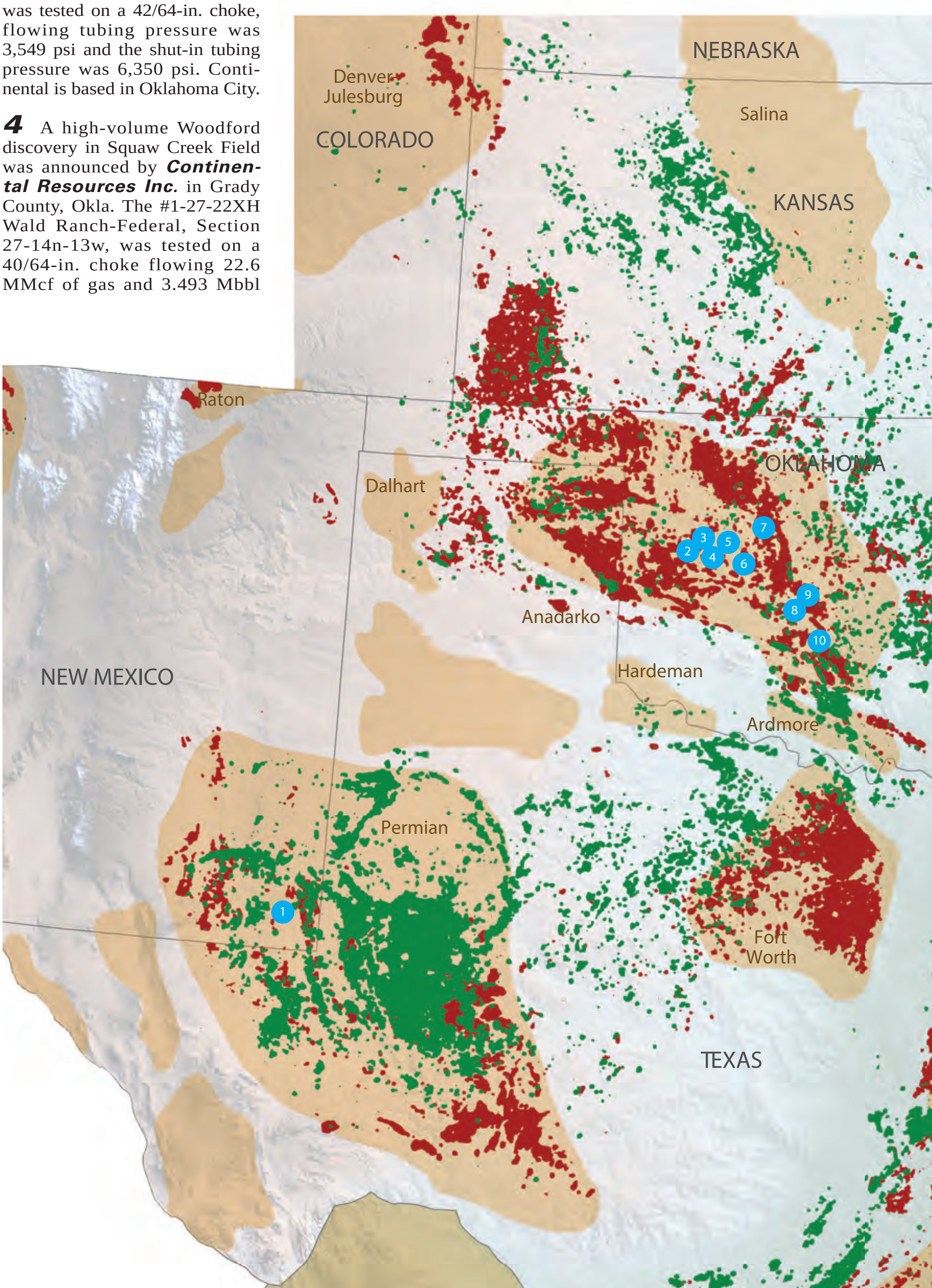
2 Tulsa-based ***Unit Petroleum Co.*** completed a two-section horizontal test targeting bypassed Red Fork reserves in Thomas South Field in Custer County, Okla. The #1HX Schrock 2215 is in Section 22-14n-14w. It produced 1.361 Mbbl of 42-degree-gravity oil, 1.52 MMcf of gas and 1.08 Mbbl of water during a 24-hour test on a 32/64-in. choke. The flowing tubing pressure was 2,650 psi. Production from Red Fork is at 11,191 ft-18,243 ft. Plans called for the well to be drilled north to 20,705 ft with a bottom-hole location in Section 15-14n-14w; however, no additional information is available.

3 A Custer County, Okla., Woodford producer flowed 18.1 MMcf of gas and 3 bbl of 51-degree condensate per day. The Anadarko Basin well by ***Continental Resources Inc.***, #1-14-11XHW Nolt, is in Section 23-14n-14w and is producing from acidized and fractured perforations between 14,952 and 22,094 ft in a north lateral. It was drilled to 22,328 ft (14,407 ft true vertical) and bottomed in Section 11-14n-14w. The Thomas South Field venture was tested on a 42/64-in. choke, flowing tubing pressure was 3,549 psi and the shut-in tubing pressure was 6,350 psi. Continental is based in Oklahoma City.

4 A high-volume Woodford discovery in Squaw Creek Field was announced by ***Continental Resources Inc.*** in Grady County, Okla. The #1-27-22XH Wald Ranch-Federal, Section 27-14n-13w, was tested on a 40/64-in. choke flowing 22.6 MMcf of gas and 3.493 Mbbl of water per day. It was tested after acidizing and fracturing between 14,330 and 23,463 ft. The Stack-play well was drilled north to 23,650 ft (13,747 ft true vertical) and bottomed in Section 22-14n-13w.

5 ***Continental Resources Inc.*** reported preliminary production data from a high-volume, six-well Meramec multiunit in the Anadarko Basin Stack play in Blaine County, Okla. According to IHS Markit, #2- through #7-6-7XHM Simba wells were drilled from pads in Section 6-14n-12w and Section 31-15n-12w, with parallel laterals extending 2 miles south to bottom-holes in Section 7-14n-12w. The ventures went online flowing at an average rate of 24 MMcf of gas and 621 bbl of condensate per well (27.729 Mboe combined) per day. Projected total depths ranged from 22,502 to 22,764 ft.

6 IHS Markit announced that Oklahoma City-based ***Devon Energy Corp.*** completed an Anadarko Basin-Meramec well that flowed 23.4 MMcf of gas, 180 bbl of 52-degree-gravity condensate and 2.566 Mbbl of water. The Oklahoma City-based company's #1HX Mad Dog 31_30-14N-11W is in Section

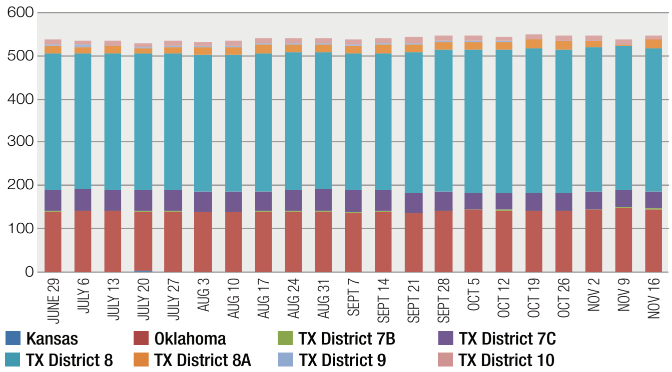


31-14n-11w, of Blaine County, Okla. It was drilled north to 23,082 ft and bottomed in Section 30-14n-11w and production is from a fracture-stimulated zone between 13,205 and 22,857 ft. Gauged on a 36/64-in. choke, the flowing tubing pressure was 4,850 psi. Additional completion details are not available from the Stack play discovery that is near the juncture of Elm Grove Field and the Watonga-Chickasha Trend.

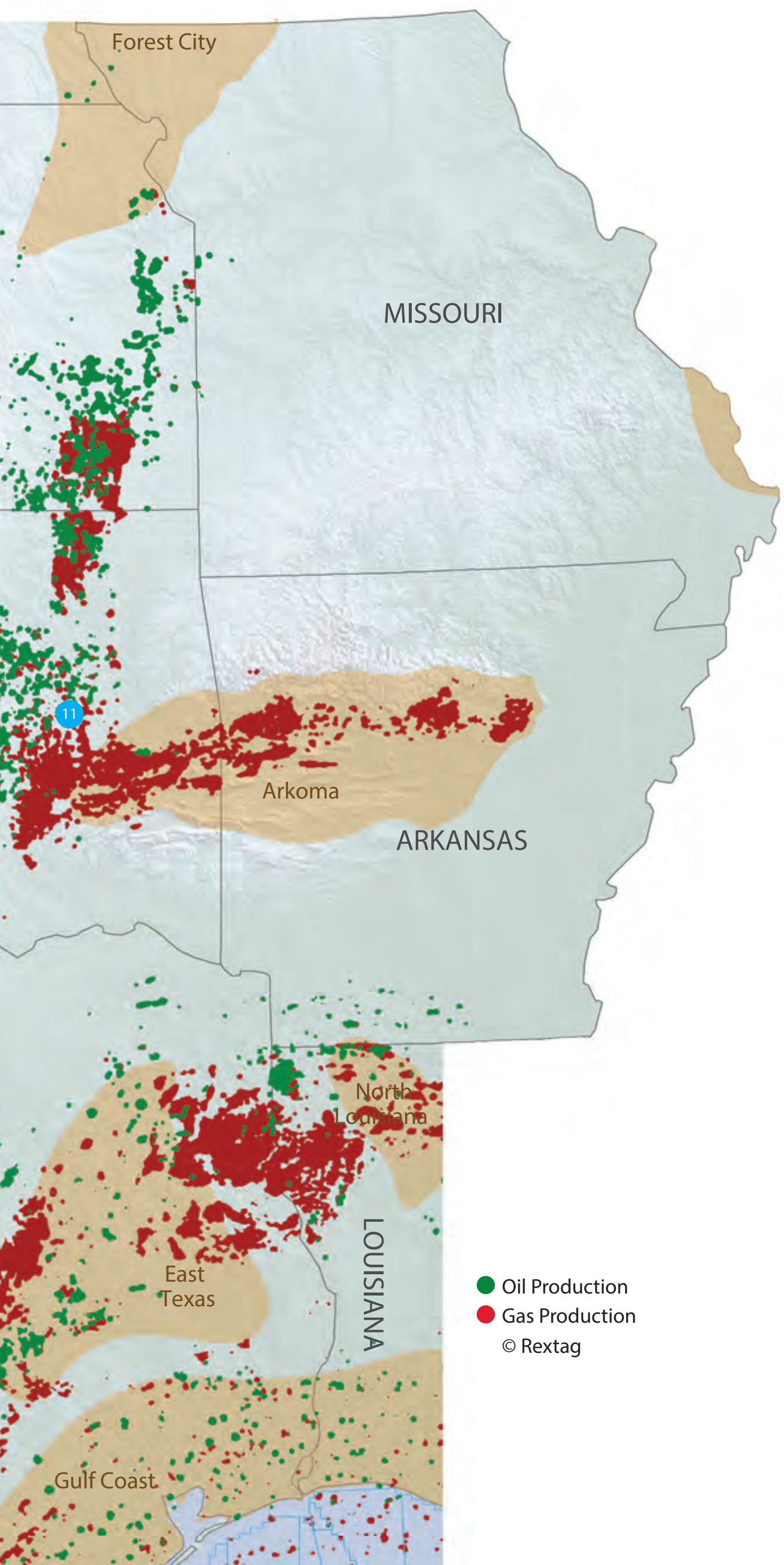
7 ***Devon Energy Corp.*** completed two wells from a drillpad in Section 10-16n-9w at its increased-density project in Kingfisher County, Okla. The #2HX Showboat 10_3-16N-9W was tested on a 64/64-in. choke producing 697 bbl of 41-degree-gravity oil, 1.47 MMcf of gas and 2.618 Mbbl of water per day. It was drilled north to 19,336 ft (8,932 ft true vertical) and bottomed in Section 3-16n-9w. It was fractured in 69 stages at 9,332-19,120 ft. About 30 ft east on the pad, #3HX Showboat 10_3-16N-9W is producing 489 bbl of 43-degree-gravity oil, 1.07 MMcf of gas and 4.123 Mbbl of water per day. It was tested through perforations in a parallel lateral between 9,375 and 19,063 ft following a 64-stage fracturing. It was drilled to 19,251 ft (8,998 ft true vertical) and bottomed in Section 3-16n-9w.

Midcontinent & Permian Basin Rig Count

June 29, 2018-Nov. 16, 2018



Data compiled from Baker Hughes



8 A two-section Mississippian producer by ***Continental Resources Inc.*** was completed in Grady County, Okla. Located in Section 19-7n-5w, #2-30-31HS Triple H initially flowed 1.654 Mbbl of oil, 1.55 Mcf of gas and 1.343 Mbbl of water per day from Goddard. Production is from acidized and fractured perforations at 11,922-22,137 ft in a south lateral extending across Section 30. It was drilled to 22,308 ft (12,093 ft true vertical) and bottomed in Section 31-7n-5w.

9 A Goddard Shale completion by ***Continental Resources Inc.*** flowed 1.21 Mbbl of 44-degree-gravity oil and 938 Mcf of gas and 1.29 Mbbl of water per day. The Anadarko Basin well, #4-30-31HS Triple H, is in Section 30-7n-5w of Grady County, Okla. The Tabler East Field well was drilled south to 22,107 ft (11,935 ft true vertical) and bottomed in Section 31-7n-5w. Production is from perforations at 11,758-21,934 ft and it was tested after acidizing and fracturing.

10 Four Lower Springer Shale producers were announced by ***Continental Resources Corp.*** in the Anadarko Basin. The Scoop play wells are in Garvin County, Okla. The #3-30-19XHS Lyle, Section 31-3n-4w, flowed 1.3 Mbbl of 45-degree-gravity oil, 2.14 MMcf of gas and 1.654 Mbbl of water per day during testing on a 28/64-in. choke. It was drilled north 2 miles to 23,992 ft (13,136 ft true vertical) and bottomed in Section 19-3n-4w. It was acidized and fractured between 13,608 and 23,760 ft. About 1.5 miles to the northeast in Section 20-3n-4w, #4-20-17XHS Omer flowed 883 bbl of oil with 1.24 MMcf of gas and 1.141 Mbbl of water per day. Production is from treated perforations at 13,494-22,568 ft. It was drilled north to 22,743 ft (12,895 ft true vertical) and bottomed in Section 17-3n-4w. About 30 ft west, #5-20-29XHS Omer initially flowed 718 bbl of oil, 920 Mcf of gas and 1.211 Mbbl of water per day. Production is from a fractured and acidized lateral at 13,117-19,189 ft. Drilled to 19,364 ft, the true vertical depth is 13,220 ft and it bottomed to the south in Section 29-3n-4w. About one-half mile north, #7-20-29XHS Omer flowed 1.184 Mbbl of 44-degree-gravity oil, 1.51 MMcf of gas and 1.91 Mbbl of water per day. It was drilled south to 20,210 ft (13,976 ft true vertical) and acidized and fractured between 13,063 and 20,041 ft and bottomed in Section 29-3n-4w.

11 Tulsa-based ***Trinity Operating LLC*** has reported preliminary completion information from a multizone, Arkoma Basin producer in Section 26-9n-18e in Haskell County, Okla. The #1-26/35/2H Audrey was tested flowing 7.31 MMcf of gas and 2.55 Mbbl of water daily from acidized and fractured zone in Woodford at 5,892-6,727 ft; Hunton at 6,727-45; Woodford at 6,745-8,870; Mississippian 8,870-9,000; and Woodford at 9,000-12,005 ft. The 12,174-ft well has a true vertical depth of 5,840 ft and was drilled south across Section 35-9n-18e and bottomed in Section 2-8n-18e.

WESTERN U.S.

1 Dallas-based ***Principle Petroleum LLC*** has completed a new producer on the western flank of the Big Horn Basin. The #11-16 Hunt-Fee initially pumped 90 bbl of 14-degree-gravity oil and 1.18 Mbbl of water per day. It was drilled in Section 11-50n-102w of Park County, Wyo. Production is from Phosphoria perforations at 3,988-4,024 ft and Tensleep perforations at 4,137-96 ft. It was drilled to 4,355 ft and cased to 4,348 ft. The Phosphoria interval was acidized, while the Tensleep interval was fracture-stimulated. The well is on the southern end of the north-south-trending Hunt Field.

2 A stepout horizontal Niobrara gas discovery was reported by ***Black Hills Exploration & Production Inc.*** in the Piceance Basin. The Denver-based company's #7-23AH Homer Deep Unit was tested flowing 7.9 MMcf of gas with 3.795 Mbbl of water per day. It is in Section 7-8s-98w of Garfield County, Colo. The well was drilled southeast to 18,005 ft. It bottomed in Section 20-8s-98w in neighboring Mesa County and the true vertical depth is 6,867 ft. It was tested on a 28/64-in. choke after a 48-stage fracturing between 8,335 and 17,842 ft with a flowing casing pressure of 2,800 psi.

3 A horizontal Lewis Sand discovery by ***Southland Royalty Co.*** was tested flowing 504 bbl of oil with 4.74 MMcf of gas and 763 bbl of water per day. The #15-33-2H Chain Lakes is in Section 33-23n-93w in Sweetwater County, Wyo. Production is from a horizontal lateral extending from 11,123 ft south-southwestward to 16,709 ft, 11,460 ft true vertical. It was tested on an 18/64-in. choke after fracture stimulation in 21 stages (plug-and-perf) between 12,048 and 16,565 ft. The flowing casing pressure was 4,050 psi. Southland is based in Fort Worth.

4 ***Enduring Resources LLC*** announced results from two San Juan County, N.M., Gallup completions drilled from a pad in Section 18-23n-8w in the San Juan Basin. The #501H Rodeo Unit initially flowed 549 bbl of oil, 1.14 MMcf of gas and 38 bbl of water per day. Production is from a horizontal lateral drilled southeastward to 12,465 ft. It bottomed in Section 29-23n-8w with a true vertical depth of 4,963 ft. It was tested on a 30/64-in. choke following 33-stage fracturing between 5,792 and 12,387 ft. About 20 ft southeast, #500H Rodeo Unit was completed initially flowing 212 bbl of oil, 102 Mcf of gas and 195 bbl of water per day. Production is from a horizontal lateral drilled to the southeast to 11,590 ft, 4,985 ft true vertical, and bottomed in Section 20-23n-8w. It was tested after 30-stage fracturing between 5,658 and 11,518 ft. Enduring's headquarters are in Denver.

5 London-based ***BP Plc*** announced results from two horizontal Mancos producers in the San Juan Basin portion of San Juan County, N.M. The #604-2H NEBU Com, Section 13-31n-7w, produced an average of 8.83 MMcf of gas per day. It was drilled eastward to 17,193 ft and bottomed in Section 18-31n-6w with a true vertical depth of 7,089 ft. It was tested on an 18/64-in. choke following 48-stage fracturing between 7,397 and 16,991 ft and the flowing casing pressure was 1,900 psi. About one-half mile south is #602-1H NEBU Com in Section 12-31n-7w. The discovery had an average 30-day initial production rate of 12.9 MMcf of gas per day. It was tested on an 18/64-in. choke following 64-stage acidizing and fracturing between 7,760 and 17,306 ft and the flowing casing pressure was 1,550 psi. It was horizontally drilled east to 17,517 ft and bottomed in Section 7-31n-7w. The true vertical depth is 7,065 ft.

6 Oklahoma City-based ***Renos Land & Minerals Co.*** has completed an extended-reach horizontal Niobrara wildcat in the Powder River Basin. IHS Markit reported that #35-72 15-1H Bowman Draw Unit is in Section 15-35n-72w of Converse County, Wyo. It produced an average of 241.9 bbl of oil, 21.71 Mcf of gas and 116 bbl of water per day. It was horizontally drilled southeast to 18,332 ft and bottomed in Section 22-35n-72w. The true vertical depth is 11,987 ft. The company's completion plans called for a 28-stage fracturing.

7 A Turner Sand discovery by ***Chesapeake Operating Inc.*** was tested flowing at a peak average rate of 3.133 Mboe/d (47% oil). The Powder River Basin well, #36-34-69 B TR 1H Wyoming, is in Section 36-34n-69w of Converse County, Wyo. It was drilled north to a proposed depth of 21,251 ft with a bottom-hole location in Section 24-34n-69w. Production is from a 10,246-ft lateral. Further details are not yet available from the Oklahoma City-based company.

8 Two Laramie County, Wyo., horizontal Codell producers were completed at a drillpad

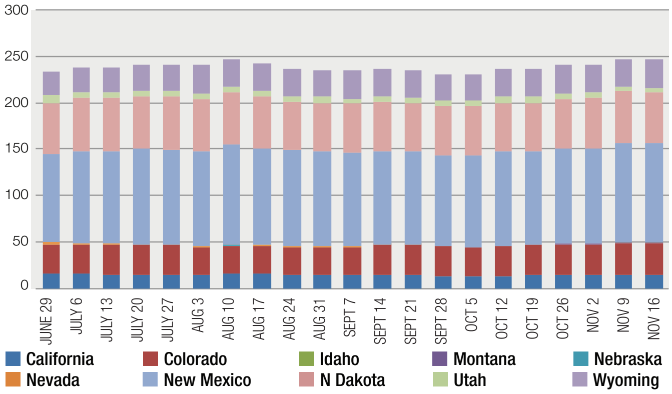
in a northern Denver-Julesburg by Houston-based ***EOG Resources Inc.*** The pad is in Section 35-13n-65w in the company's Jubilee fee leases. The #239-3502H Jubilee is producing 1.2 Mbbl of 38.8-degree-gravity oil, 836 Mcf of gas and 1.244 Mbbl of water per day from gas lift. Production is from a horizontal lateral extending southwest to 19,570 ft, 8.715 ft true vertical, at a bottom-hole location in Section 2-12n-65w. It was tested on a 54/128-in. choke following 48-stage fracture stimulation between 8,907 and 19,497 ft with a flowing casing pressure of 1,179 psi. The #542-3502H Jubilee is producing via gas lift 787 bbl of 38.8-degree-gravity oil, 566 Mcf of gas and 1.174 Mbbl of water per day. Production is from a horizontal lateral extending southward to 18,589 ft, bottoming in Section 2-12n-65w with a true vertical depth of 8,674 ft. Tested on a 58/128-in. choke following 43-stage fracturing between 9,126 and 18,528 ft, the flowing casing pressure was 1,035 psi.

9 ***Burlington Resources Oil & Gas Co LP***, a subsidiary of ***ConocoPhillips***, completed four extended-reach horizontal Niobrara producers on a common drillpad about 5 miles south of Denver International Airport. The discoveries were drilled from a pad in Section 35-3s-65w in Adams County, Colo. The #3-65 36-31-1DH Big Sandy produced an average of 644 bbl of oil, 692.333 Mcf of gas and 869 bbl of water per day. The #3-65 36-31-2AH Big Sandy produced an average of 653 bbl of oil, 814.166 Mcf of gas and 871 bbl of water per day. The #3-65 36-31-2CH Big Sandy produced an average of 653 bbl of oil, 488.315 Mcf of gas and 1.444 Mbbl of water per day. The #3-65 36-31-2 BH Big Sandy produced an average of 617 bbl of oil, 369.466 Mcf of gas and 1.794 Mbbl of water per day.

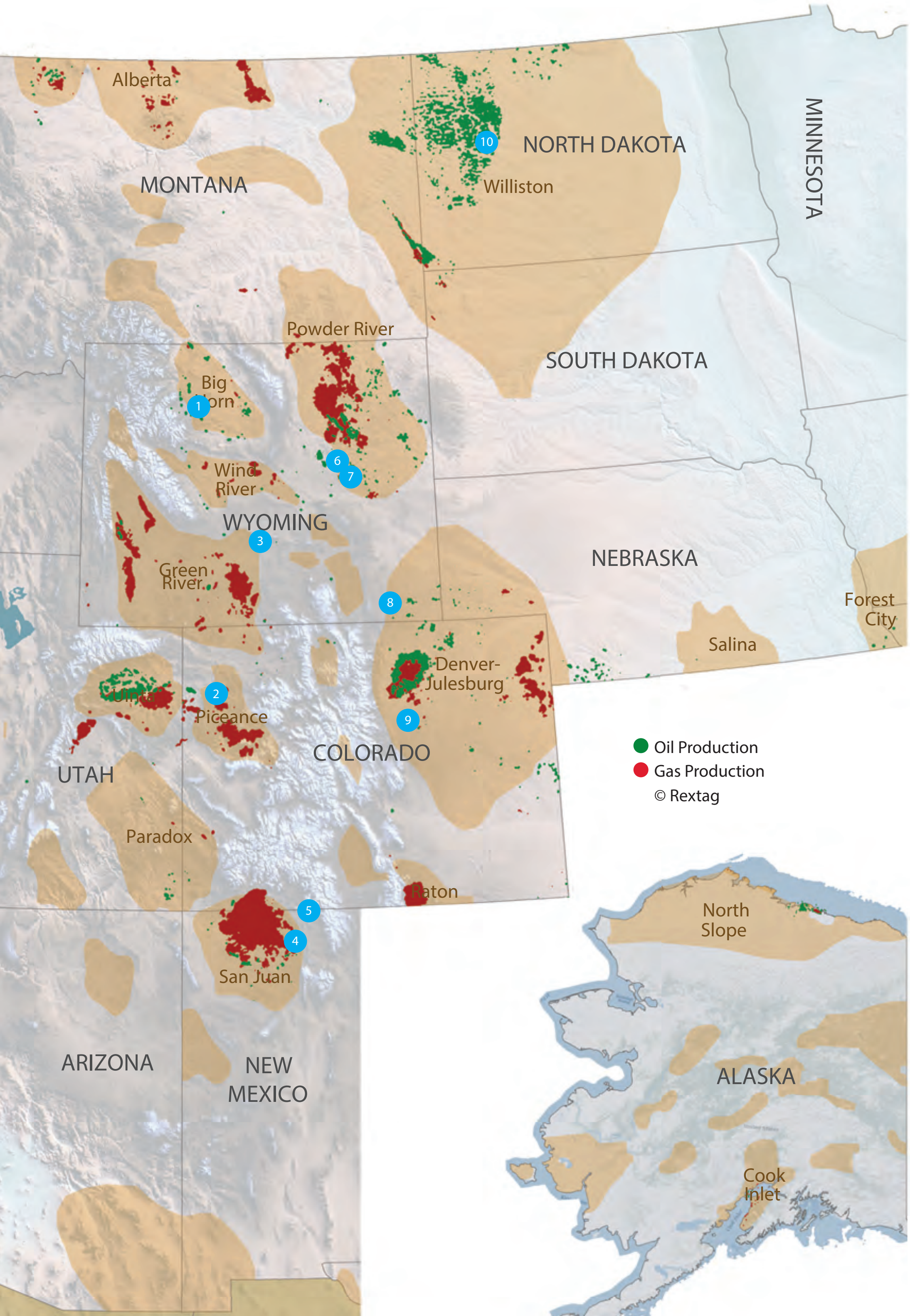
10 At ***Marathon Oil Corp.***'s Myrmidon prospect in North Dakota, the company reported another high-volume Bakken producer on the Fort Berthold Indian Reservation. The #14-23H Whitebody-USA is in Section 22-151n-94w in McKenzie County. It was tested flowing 8.702 Mbbl of oil, 10.023 MMcf of gas and 5.818 Mbbl of water per day from Middle Bakken. The Reunion Bay Field well is producing from a horizontal lateral extending from 11,017 ft eastward to 23,630 ft (10,706 ft true vertical) at a bottom-hole location in Section 19-151n-93w, extending under the Missouri River. It was tested on a 64/64-in. choke following 57-stage fracturing between 11,114 and 23,499 ft with a flowing casing pressure of 2,150 psi. The Houston-based company is also nearing completion in three additional extended-reach wells at the pad, #13-23H Yellowface-USA, #13-23H Lamar-USA and #12-23TFH Jerome-USA.

Western U.S. Rig Count

June 29, 2018-Nov. 16, 2018



Data compiled from Baker Hughes



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INTERNATIONAL HIGHLIGHTS

A November report by the International Energy Agency (IEA) indicates that the global demand for natural gas will surge during the next 20 years.

Demand for natural gas is expected to increase 45% by 2040, with gas providing 25% of global energy demand. According to the IEA, gas will become the second-largest source of global energy, after oil. The IEA also expects LNG exports will overtake pipeline gas as the main form of long-distance trading, accounting for more than 60% of inter-regional trade by 2040.

The United States expected to become the world's leading LNG exporter by the mid-2020s with a host of new suppliers emerging after 2025.

A shift in trade is towards the Asia-Pacific region, with China soon to become the world's largest gas-importing country, with net imports approaching the level of the European Union by 2040. China is also on track to surpass Japan as the largest LNG importer.

The report also estimates $8.4 trillion of investment is needed in global gas supply to 2040 to ensure secure and reliable resource. Construction for liquefaction capacity is being built to handle 100 billion cubic meters of LNG. Much of this capacity is being built in Australia and the United States.

—Larry Prado

1 Chile

Geopark Ltd. has announced results from exploration well #1-Jauke in the Fell block in Chile. It was drilled to 9,592 ft and tested flowing 5.8 MMcf of gas from Springhill with a wellhead pressure of 2,738 psi. According to the Calgary-based company, additional production history is necessary to determine stabilized flow rates. The Jauke gas field is part of the large Dicky geological structure in the block and has the potential for multiple development drilling opportunities in the Magallanes Basin. According to the company, petrophysical analysis indicates hydrocarbon potential in the shallower El Salto formation, which will be tested in the future. El Salto was structurally tested at #1-Uaken and additional drilling there is planned. The Fell block produced approximately 2.9 Mboe per day (66% gas).

2 Brazil

Petrobras has begun exploratory drilling on its operated Peroba Block in the pre-salt region of the Santos Basin offshore Brazil. Petrobras added to its portfolio, in 2017-18, 21 new blocks in the offshore Santos, Campos, Parana and Potiguar basins. The Peroba Block is south of the Lula Field and east of Sapinhoa Field. According to the Rio de Janeiro-based company, surveying indicates the high potential of the area. The water depth is between 2,100 and 2,600 m. Petrobras is the operator of the Peroba Block and well with 40% interest in partnership with ***BP*** (40%) and ***China National Petroleum Corp.*** (20%).

3 North Sea

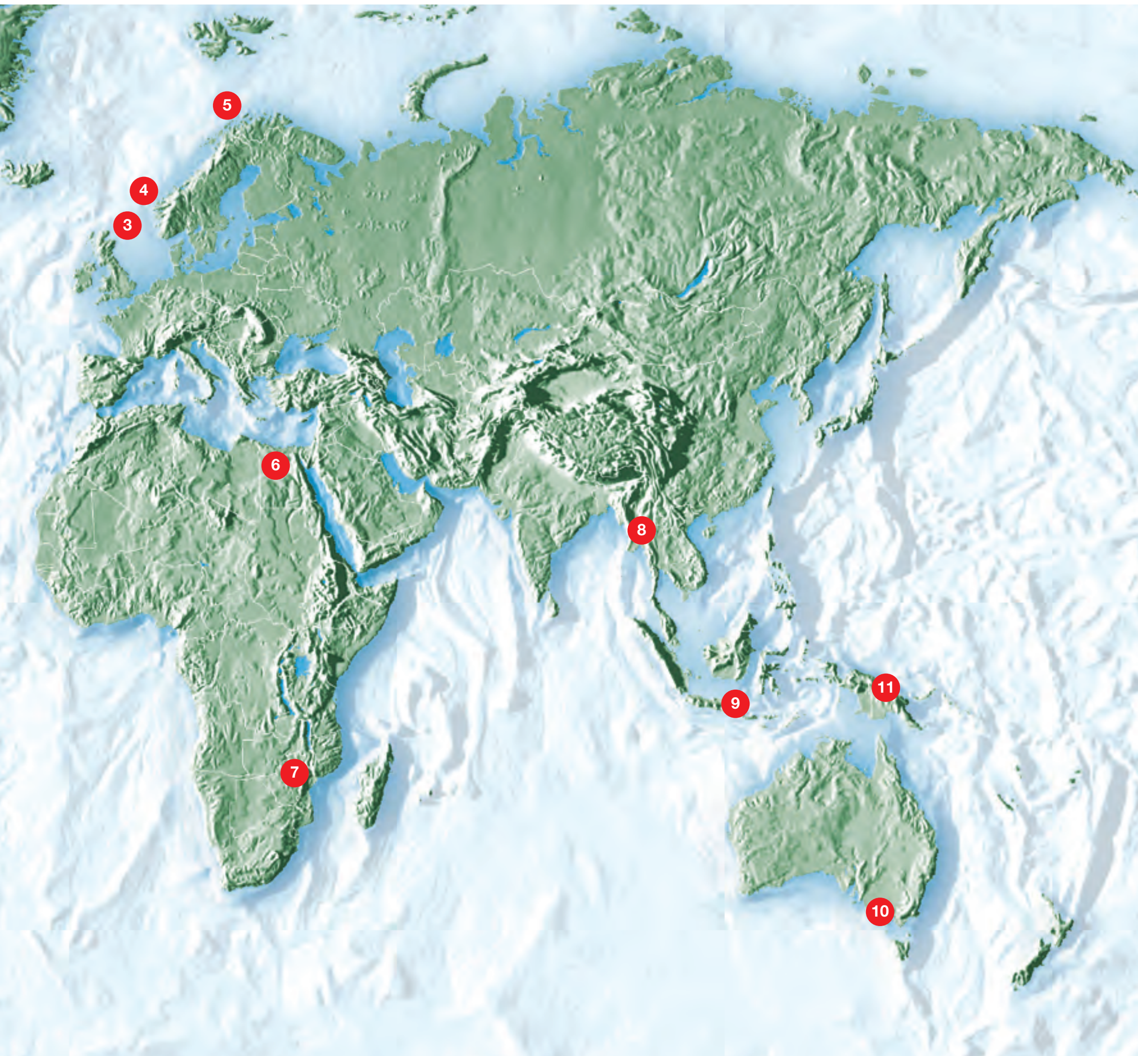
An oil discovery was announced by ***Azinor Catalyst*** at its Agar-Plantain exploration well in the UK sector of the North Sea, Block 9/14a in license P1763. The #9/14a-17B well and sidetrack hit a 20-m interval of excellent quality oil- and water-bearing sands with no water/oil contact. This venture delineated the eastern extent of the hydrocarbon discovery and additional appraisal drilling is planned. Reservoir oil sample analysis is planned to establish oil quality. The current estimate of recoverable resources is 15-50 MMboe. The #9/14a-17B will be plugged and abandoned. London-based Azinor Catalyst is the operator of the well, Block 9/14a, and license P1763 with 25% interest in partnership with ***Cairn Energy***, holding 50%, and ***Faroe Petroleum*** with 25%.

4 Norway

In the Norwegian section of the North Sea, ***Wellesley Petroleum*** announced results from appraisal wells #35/11-21S and #35/11-21A on the Grosbeak prospect in production license PL248I. The #35/11-21S hit a gross oil column of 90 m in the targeted Middle Jurassic Brent Group, with a 45-m net reservoir with good-to-excellent reservoir properties. Sidetrack well #35/11-21A encountered 20 m of high quality, gas-bearing reservoir and an 8-m oil column in the shallower Upper Jurassic Sognefjord and Fensfjord. The underlying Brent Group reservoir comprised a 50-m oil column in Ness with 9 m of sandstones lying within the oil zone. The updated range of recoverable resources in the Grosbeak discovery is 53-115 MMbbl of oil plus 269-432 Bcf of gas. Both wells were plugged and abandoned and development studies are planned. Wellesley, based in Stavanger, is the operator of PL248I, Block 35/11, and the Groesbeak wells with 90% interest in partnership with ***Concedo***, holding the remaining 10%.

5 Norway

Equinor completed #7220/5-3 Skruis exploration well in the Johan Castberg license in the Norwegian sector of the Barents Sea, confirming the discovery of 12-25 MMbbl of recoverable oil. Four wells are left in the program in this part of the Barents Sea and production could be tied into the Johan Castberg Field, which is set for startup in 2022. Recoverable reserves in Johan Castberg are estimated at 450-650 MMbbl of oil and the volumes from Skruis 2017 are not included in this estimate. Stavanger-based Equinor is the operator



of PL532, Block 7220/5, and the Skruis discovery well with 50% interest in partnership with Eni, with 30%, and Petoro with the remaining 20%.

6 Egypt

TransGlobe Energy Corp. reported it completed exploration well #6X SGZ in the South Ghazalat in the Abu Gharadig Basin in Egypt. It was tested flowing 2.437 Mbbl of oil, 1.4 MMcf of gas and, 21 bbl of water per day from a 42-ft interval in Lower Bahariya and 1.403 Mbbl of oil, 1 MMcf of gas and 210 bbl of water per day from a 23-ft zone in Upper Bahariya. The well was drilled to 5,195 ft and cased. The Middle Bahariya produced a small amount of formation water using nitrogen to lift the fluid to the surface from an 8-ft perforated interval. Based on the positive test rates from the well, the Calgary-based company will begin preparing a development plan for the discovery. TransGlobe is the operator and holds 100% interest.

7 Zimbabwe

According to ***Invictus Energy Ltd.***, the company has confirmed oil and gas in Block SG4571 in Zimbabwe. The apparently viable oil and gas reserves are in a 200-sq-km area in the Cabora Bassa Basin in the Muzarabani district in an under-explored interior rift basin. The original data was gathered in the 1990s and the oil and gas deposits are in a 200-sq-km area. Drilling and exploration is planned for 2020. Additional geophysical work is ongoing to identify further exploration targets. West Perth, Australia-based Invictus is the operator of Block SG4571 and the discovery area of the Muzarabani area with 100% interest.

8 Thailand

Pan Orient Energy Corp. has reported that its onshore Thailand exploration well #53L-DD1 encountered an interpreted, combined 26 m of net oil pay within three separate sandstone reservoirs between 960 and 1,125 m (true vertical). The interpretation was based on conventional openhole wireline logs and hydrocarbon indications observed during drilling and confirmed with post-drill pressure data and oil samples brought to surface. The oil is estimated to be approximately 28-degree-gravity. An appraisal well (#53-DD1) will be drilled from the same pad and will target two of the three reservoirs substantially up-dip of the discovery well. The discovery is in the northern part of Concession L53. Calgary-based Pan Orient is the operator of the L53 Block and wells with 100% interest.

9 Indonesia

Cue Energy Resources Ltd. reported elevated gas readings at exploration well #1-Paus Biru in offshore Indonesia's Sampang PSC. The well was drilled to 710 m and gas readings were encountered in the targeted Mundu. Additional testing, including pressure and fluid sampling, are planned to establish the fluid content, hydrocarbon columns and saturation of possible reservoir intervals encountered. Cue's headquarters are in Melbourne.

10 Australia

Brisbane-based ***Cooper Energy Ltd.*** has completed its prospective resource assessment (unrisked best estimate, P50) of the Annie and Elanora prospects in VIC/P44 and VIC/L24 in the offshore portion of South Australia's Otway Basin. The Annie prospect (VIC/P44) is estimated at 71 Bcf of gas and the Elanora prospect (VIC/L24) is estimated at 100 Bcf of gas. The primary reservoir targets are Waarre C and Waarre A, which are the productive reservoirs in the Casino and Minerva gas fields. Area water depth at the two prospects is 70-80 m. Elanora straddles VIC/L24, VIC/L30 and VIC/P44. Additional exploration, appraisal and evaluation is required to determine potentially moveable hydrocarbons. Participating interests in VIC/P44 and VIC/L24 are Cooper Energy (50% and operator); ***Mitsui*** (25%); and ***Peedamullah Petroleum*** (25%).

11 Papua New Guinea

Oil Search Ltd. has spud appraisal well #2-Muruk in the Highlands province in Papua New Guinea. The company is drilling the appraisal well on behalf of operator ***ExxonMobil Corp.*** in Juha Block PDL 9. It is approximately 11 km northwest of the discovery at #1-Muruk where the venture hit high-quality sandstone reservoirs similar to those found in Hides Field. The exploratory has a planned depth of 3,500 m and will test a Cretaceous Toro Sandstone reservoir. Houston-based ExxonMobil holds a 42% interest and Oil Search holds a 37.5% interest. Other participants in PDL 9 are ***Esso PNG***; ***Ampolex*** (PNG); ***Kumul Petroleum***; ***Nippon PNG*** and ***Gas Resources Juha***.

A YEAR-END POTPOURRI

Following a tumultuous October-November, it came as little surprise that year-end capital-market activity comprised a potpourri of deals making it to the finish line. Capital raises included midstream and E&P follow-on offerings, and a convertible as well as senior-note offerings from issuers in the midstream, E&P, oilfield-service and LNG sectors.

Oasis Midstream Partners LP (NYSE: OMP) announced on Nov. 8 an underwritten public offering of 2 million common units, which it priced at $20 per unit, a discount of more than 9% to the closing price.

With exercise of the full 15% overallotment, gross proceeds came to $46 million, which were earmarked to fund a portion of the $250-million purchase price of midstream assets from Oasis Petroleum Inc.

The purchase by Oasis Midstream involved an additional 15% interest in Bobcat DevCo LLC and an additional 30% interest in Beartooth DevCo LLC, taking its ownership to 25% and 70%, respectively.

Supplementing the above $46 million of proceeds, Oasis Midstream issued 3.95 million units directly to parent Oasis Petroleum, raising $79 million, with the remaining $125 million financed under its revolver.

Contango Oil & Gas Co. (NYSE: MCF) priced a follow-on offering of 7.5 million common shares at $4 per share for gross proceeds of $30 million. Proceeds are to reduce borrowings and for general corporate purposes, including funding potential acquisitions.

Engineering and construction firm KBR Inc. (NYSE: KBR) announced the pricing of a $350-million issue of 2.50% convertible senior notes due 2023. The notes have a conversion premium of 27.5%. Each $1,000 note is convertible into 39.1961 common shares, equating to a conversion price into KBR stock at $25.51. KBR serves the offshore energy and LNG sectors.

Freeport LNG Development LP issued $225 million of 5.55% senior notes due 2039, priced at a discount to yield 5.895%. Vantage Drilling International priced $350 million of senior notes yielding 9.25%.

In private equity, Flat Creek Resources LLC, led by executives formerly with Black Mountain Oil & Gas LLC and XTO Energy Inc., received an initial capital commitment from EnCap Investments LP of $400 million.

—Chris Sheehan, CFA

EQUITY

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Flat Creek Resources LLC	N/A	Fort Worth, Texas	US$400 million	The Permian Basin-focused company, led by former Black Mountain and XTO executives, secured an initial capital commitment of $400 million from EnCap Investments LP and management.
Oasis Midstream Partners LP	NYSE: OMP	Houston	US$46 million	Sold 2.3 million common units, including the 15% overallotment, at $20 per, a discount of more than 9% to the closing price. Proceeds will fund a portion of the $250-million purchase of midstream assets from parent Oasis Petroleum Inc. Supplementing, Oasis Midstream issued 3.95 million units directly to its parent, raising $79 million.
Contango Oil & Gas Co.	NYSE: MCF	Houston	US$30 million	Priced a follow-on offering of 7.5 million common shares at $4per share for gross proceeds of $30 million. Proceeds will reduce borrowings and support general corporate purposes including funding potential acquisitions.

DEBT

Company	Exchange/ Symbol	Headquarters	Amount	Comments
Murphy Oil Corp.	NYSE: MUR	El Dorado, AR	US$795 million	Closed the strategic deepwater Gulf of Mexico joint venture with Petrobras America Inc., a subsidiary of Petrobras, for net cash consideration of approximately $795 million. Murphy's net cash consideration of approximately $795 million is funded by $470 million of cash-on-hand with the remaining $325 million being drawn on the company's new senior credit facility.
Vantage Drilling International	OTC: VTGDF	Houston	US$350 million	Priced $350 million of 9.250% senior secured first-lien notes due 2023 in a private placement at par. The proceeds of will repay obligations under, and terminate, the first-lien credit agreement. They will also redeem outstanding 10% senior secured second-lien notes due 2020 and fund the purchase of a new jackup rig.

These deals and details on thousands more are available in real time in a searchable, sortable database at OilandGasInvestor.com.

ENERGY MOVERS

■ Denver-based QEP Resources Inc. chairman, president and CEO Charles (Chuck) Stanley will retire Jan. 14. Stanley presided over QEP's spinoff in 2010 from Salt Lake City-based Questar Corp.

Timothy (Tim) Cutt will become president and CEO on Jan. 15. Lead independent director David A. Trice, the retired chairman, CEO and co-founder of Newfield Exploration Co., will become chairman, as the QEP roles of chairman and CEO are separated going forward.

Cutt has 35 years of oil and gas experience, formerly with Exxon Mobil Corp., where he was president of ExxonMobil de Venezuela SA and president of Hibernia Management and Development Co. More recently, he was BHP Billiton Ltd. president of petroleum from July 2013 through February 2016. Most recently, he was CEO for Cobalt International Energy Inc.

■ Anadarko Petroleum Corp., The Woodlands, Texas, has named Robert (Bob) Gwin president. Prior, Gwin was executive vice president, finance, and CFO. Also, he was chairman of Western Gas Holdings LLC (WGH), chairman of Western Gas Equity Holdings LLC (WGEH), and president and CEO of WGH. Prior to his work for Western, he was Anadarko vice president, finance, and treasurer, and, while chairman of WGH and WGEH, he was chairman of LyondellBasell Industries NV.

R.A. (Al) Walker, Anadarko chairman, president and CEO, will continue as chairman and CEO.

Robert K. (Bobby) Reeves, executive vice president and CAO, has retired. Benjamin (Ben) Fink, was named executive vice president, finance, and CFO. Fink was an Anadarko senior vice president and was president and CEO of WGH and WGEH.

Alexandra (Alie) Pruner and Michael (Mike) Grimm have joined the Anadarko board. Pruner is CFO and a partner of Perella Weinberg Partners since it combined with Tudor, Pickering, Holt & Co. LLC, where she was CFO since inception.

Grimm is president of Rising Star Petroleum LLC and was chairman of RSP Permian Inc. through its sale in 2018 and of which he was a co-founder and was its CEO until 2014. Grimm is also a director of Energy Transfer LP.

■ Harvest Oil & Gas Corp., Houston, fka EV Energy Partners LP, has named Ryan Stash vice president and CFO. He was most recently a managing director at Regions Securities focused on the energy sector. Prior, he worked in the energy investment-banking group for Wells Fargo Securities for 11 years based in Houston.

■ Brent Smolik, past chairman, president and CEO of EP Energy Corp., has joined Noble Energy Inc., Houston, as president and CEO. He will be responsible for leadership of Noble's worldwide operations.

With 35 years of industry experience, Smolik was president of El Paso Corp.'s E&P unit that became EP Energy; president of ConocoPhillips, Canada; president of Burlington Resources Inc., Canada; and a vice president and chief engineer for Burlington.

Gary Willingham, Noble executive vice president, operations, resigned to pursue other opportunities.

■ Al Hirshberg, ConocoPhillips, Houston, executive vice president, production, drilling and projects, has retired after more than 35 years of working in the industry, including eight with ConocoPhillips.

Matt Fox, who led ConocoPhillips' E&P operations from 2012-2016, has been named executive vice president and COO with responsibility for worldwide E&P operations, corporate planning and technology.

Don Wallette Jr. was named executive vice president and CFO, with responsibility for finance, commercial, A&D and information-technology functions. Wallette's former roles for ConocoPhillips, include leading its business-development functions from 2012-2016.

■ Laredo Petroleum Inc., Tulsa, has named T. Karen Chandler senior vice president and COO. Chandler joined Laredo in 2012 and was vice president, operations, since 2016. Prior, she was with Exxon Mobil Corp. for 15 years, performing a variety of managerial and technical functions in drilling, completions and technology development.

■ EOG Resources Inc., Houston, has named Kenneth (Ken) Boedeker executive vice president, E&P. Boedeker was vice president and general manager of EOG's Denver office, which included responsibility for operations in the Powder River, Williston and D-J basins.

David W. Trice, executive vice president, E&P, assumes responsibility for EOG's Denver office as executive vice president and general manager.

Boedeker has more than 33 years of industry experience—24 of these with EOG. Trice's 25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years of experience include nearly 20 with EOG, including as a senior geologist in the Midland office.

Separately, EOG named Julie J. Robertson to its board. Robertson is chairman, president and CEO of Noble Corp., one of the world's largest offshore drilling companies. Previous roles at Noble included executive vice president from 2006 to January 2018.

Frank G. Wisner, a retired U.S. ambassador first elected to the EOG board in 1997, plans to retire from the EOG board at the end of his term.

■ Bonanza Creek Energy Inc., Denver, has named Brant DeMuth CFO. DeMuth was vice president of finance and the treasurer of SRC Energy Inc. and interim CFO of DJ Resources LLC.

■ Gulfport Energy Corp., Oklahoma City, named Donnie Moore interim CEO. He succeeds Michael Moore who stepped down as CEO, president and director.

Donnie Moore joined Gulfport as COO in January 2018 from Noble Energy Inc., where he was vice president of Noble's Texas operations for the Eagle Ford and Delaware Basin after holding leadership positions in other Noble business units.

■ Mike Dye has joined privately held MD America Energy LLC, Fort Worth, as CFO. MD America focuses on the East Texas Basin, where it holds some 71,000 net acres.

■ Former RSP Permian Inc. CEO Steve Gray has joined the board of Range Resources Corp., Fort Worth. RSP Permian was acquired by Concho Resources Inc. in 2018.

A founder of RSP, Gray was CEO from its inception in 2010 through its sale. Prior, he founded several successful oil and gas ventures spanning nearly 20 years in partnerships with private-equity financier Natural Gas Partners, and held petroleum-engineering roles for 11 years in various capacities.

In 2016, Gray received the national Ernst & Young Entrepreneur of the Year award in its Energy and Clean-Tech category.

■ David Dell'Osso was named executive vice president and COO of Parsley Energy Inc. He succeeds Matt Gallagher, who was previously appointed CEO, effective Jan. 1, and remains president. Prior to joining Parsley, Dell'Osso was senior vice president and general manager of the Northeast Appalachia Division for Southwestern Energy Co.

■ Midstream MLP Southcross Energy Partners LP, Dallas, named James "Jay" W. Swent III as chairman, president and CEO. Swent previously was president and CEO of Paragon Offshore. As a financial executive, he has managed several large company acquisitions, divestitures, joint ventures and financial restructurings.

COMPANIES IN THIS ISSUE

This index refers to the pages of the story or news item in which the company is first mentioned. Advertisers are in boldface.

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THE SHALE LIFE CYCLE

LESLIE HAINES,
EXECUTIVE EDITOR-AT-LARGE

If we track the life cycle of the shale plays as they unfold, what do they portend for U.S. production and the companies, investors and export markets that have come to rely on the shale story? Land rush, production rise, mature to sale, recycle and renew.

For an example, look to the trajectory of the Fayetteville in Arkansas, a dry-gas play that's been in the news lately: Its discoverer and long-dominant player, Southwestern Energy Co., is exiting its entire upstream and midstream position there. For $1.865 billion cash and another $438 million of assumed debt, the buyer is Flywheel Energy LLC. The latter began as Valorem Energy LLC in early 2017 with backing from the Kayne Anderson Private Energy Income Fund. In August 2018, Kayne committed a second time to the management team with $700 million of equity in the form of Flywheel, based in Oklahoma City.

Fayetteville production peaked in 2014 at 950 billion cubic feet (Bcf) a year—roughly 2.6 Bcf a day. Four years later, Flywheel is taking over Southwestern's 4,033 producing wells on more than 915,000 net acres and production that in 2017 totaled about 716 million cubic feet a day net.

This slowdown is a natural progression showing the shale's decline curve absent better completion designs and enough capex—not to mention the effects of low gas prices amid a surfeit of U.S. supply.

At press time, the U.S. was approaching 84 Bcf/d of gas production. But still, although this Fayetteville sale makes all the sense in the world for Southwestern, it seems like the end of an era somehow.

I recall when former CEO Harold Korell visited the Houston offices of *Oil and Gas Investor* to introduce himself and his new direction. One of his major goals at that time was to sell the company's local distribution company in favor of becoming a pure E&P. In 2003, it first leased acreage in the Fayetteville for $11 million, and, in 2004, he unveiled the shale.

Over time, the play grew like a weed; quarter after quarter, Southwestern delivered more production and became a Wall Street darling. No one seemed to question the economics at that time. Those were heady times. I ran into Korell at an investment event once and, as he rushed by, he said, "New York is on fire."

By 2011, some 3,689 Fayetteville wells had been drilled, mostly by Southwestern, which perfected the integrated model of operating rigs, frack crews, supplies and logistics.

When the University of Texas' Bureau of Economic Geology studied the play in 2014, it concluded there was 80 trillion cubic feet (Tcf) of original gas in place, with 38 Tcf technically recoverable, and full-field development of 18.2 Tcf as a mean recoverable amount by 2050.

Its base case, using an assumption of $4 gas, indicated 6,400 new wells could be drilled through 2030. It postulated that production would plateau between 2012 and 2015 (it did so in 2014), then begin a long slow decline as the annual well count fell and development moved from top-tier locations to the lesser-quality ones.

At one time, 15 operators worked the play, but nearly 100% of the production was owned by Southwestern, BHP Billiton Ltd. and XTO Energy Inc. The rig count rose to 30 in 2011, but, once gas started to decline below $3, the gold rush was fading.

Southwestern had to pivot. Like most other E&Ps, it went searching for a higher-margin, wet-gas play—or an entrée to crude oil. It migrated to the Marcellus and Utica in 2014, buying Chesapeake Energy Corp.'s assets there for $5.4 billion.

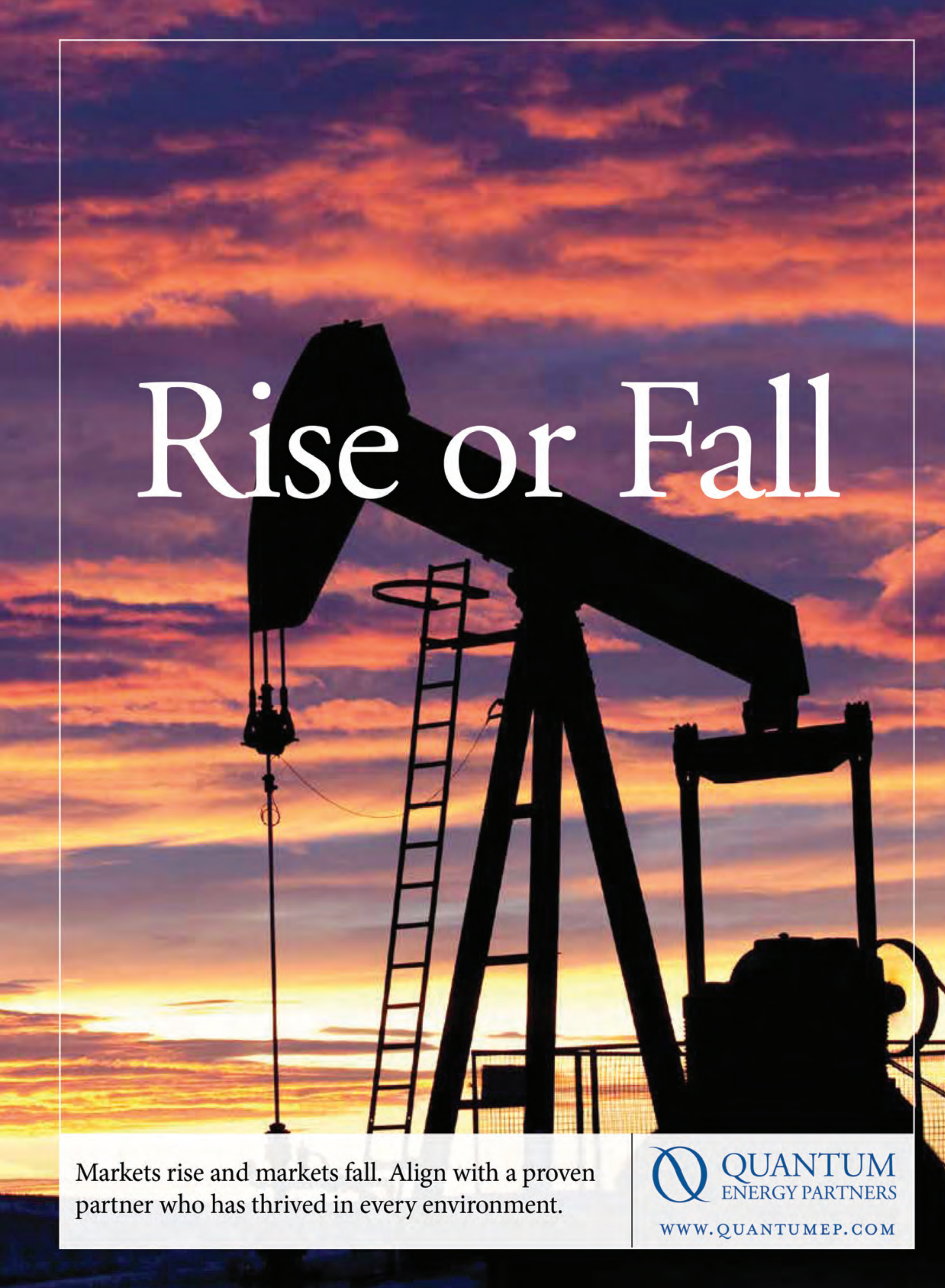
At one time the vast majority of Southwestern's production was from the Fayetteville, but, by second-quarter 2015, it was less than half as the company's Marcellus production rose. Meanwhile the Fayetteville rig count had plummeted to only four rigs by October 2015.

I visited the Fayetteville in its heyday and I came away impressed with the way Southwestern ran the whole operation with such precision. Huge whiteboards hanging in one of its field offices tracked rigs, trucks, equipment and mud as the play unfolded, presaging the full-field development efficiencies we see so often today.

Most recently, Southwestern's investor presentation outlined finding and development costs of $1.40/Mcf in the play—for a $2.7-million well, significantly below the costs posted five years earlier.

Now, it is up to Flywheel to carry on.

Mark your calendars for some upcoming Hart Energy events. Join us Feb. 12 in Houston for our annual Women in Energy awards luncheon, when we recognize 25 influential women in the energy industry. And, come to Shreveport Feb. 19 and 20 for DUG Haynesville, where we'll hear an update from operators on what's ahead for this new-again shale play.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