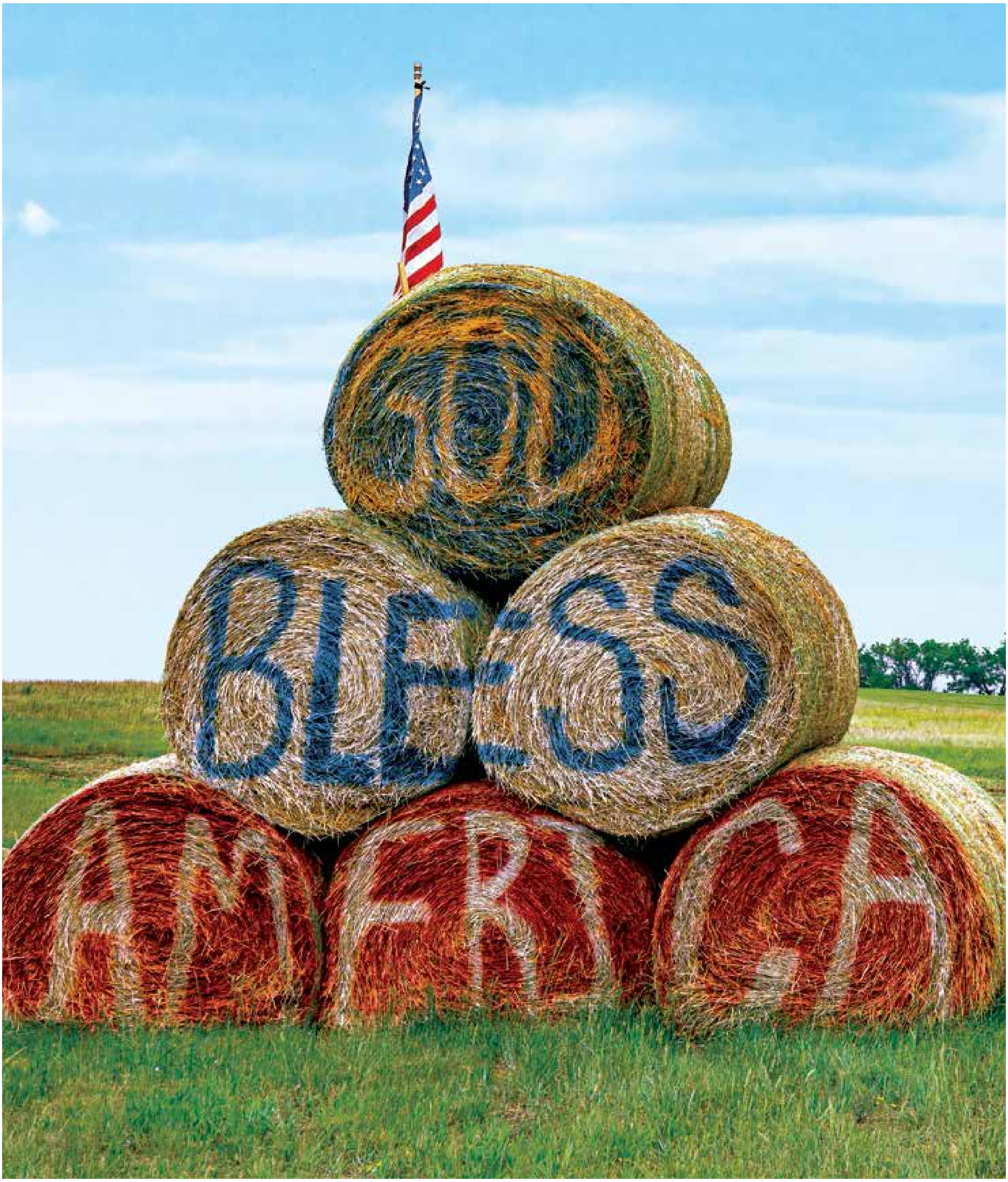
Oil and Gas Investor

AUGUST 2019



Bakken operators make hay in bold step-outs from core acreage.

HARTENERGY

Completions Count

In these challenging times, count on our veteran, cycle-tested team to help execute your most important strategic initiatives.

Completing transactions in today's energy markets requires effort, patience and good advice. At Petrie Partners, we are proud of our long track record of successful execution for both public and private companies, and welcome opportunities to support our clients under any industry conditions. Whether it's working with managements and boards to consider strategic alternatives, navigate corporate mergers or optimize asset monetizations, Petrie's seasoned team helps bring strategic objectives to completion.

Petrie Partners

Houston 713.659.0760

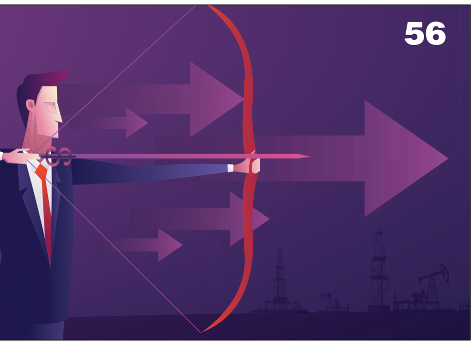
Denver 303.953.6768

petrie.com

HARTENERGY
EVENTS | MEDIA | RESEARCH | DATA

Oil and Gas Investor

AUGUST 2019/VOLUME 39/NUMBER 8



CELEBRATING

25

YEARS

Kayne Anderson

Energy Funds

ENGAGED IN ENERGY INVESTING

SINCE 1992

811 Main Street, 14th Floor · Houston, Texas 77002 · (713) 493-2000

1800 Avenue of the Stars, Third Floor · Los Angeles, California 90067 · (800) 638-1496

www.kaynecapital.com

Oil and Gas Investor

1616 S. Voss Rd., Suite 1000
Houston, TX 77057
1.713.260.6400 Fax: 1.713.840-8585
HartEnergy.com

Editor-in-Chief
Steve Toon
stoon@hartenergy.com

Executive Editor-at-Large
Leslie Haines
lhaines@hartenergy.com

Senior Financial Analyst Chris Sheehan, CFA
csheehan@hartenergy.com

Senior Editor Darren Barbee
dbarbee@hartenergy.com

Chief Technical Director, Upstream Richard Mason
rmason@hartenergy.com

Midstream Editor-at-Large Paul Hart
pdhart@hartenergy.com

Activity Editor Larry Prado
lprado@hartenergy.com

Associate Managing Editor Brandy Fidler
bfidler@hartenergy.com

Assistant Managing Editor Bill Walter
bwalter@hartenergy.com

Group Managing Editor, Digital News Group Len Vermillion
lvermillion@hartenergy.com

Contributing Editors
Velda Addison, Terrance Harris, Susan Klann,
Joseph Markman, Emily Patsy

Editor-at-Large Nissa Darbonne
ndarbonne@hartenergy.com

Corporate Creative Director
Alexa Sanders
asanders@hartenergy.com

Art Director Robert D. Avila
ravila@hartenergy.com

Sr. Graphic Designer Lisa Goodrich
lgoodrich@hartenergy.com

Senior Marketing Manager Tamara Murphy

Vice President, Marketing Greg Salerno

Publisher
Kevin C. Holmes
kholmes@hartenergy.com • 713.260.4639

Director, Content Sales (Subscriptions) Attrice Hunt
ahunt@hartenergy.com • 713.260.4659

Vice President, Sales Darrin West
dwest@hartenergy.com • 713.260.6449

Director, Business Development Chantal Hagen
chagen@hartenergy.com • 713-260-5204

Ad Materials Coordinator Carol Nunez
cnunez@hartenergy.com

HARTENERGY
EVENTS | MEDIA | RESEARCH | DATA

Vice President and Editorial Director
Peggy Williams

Chief Financial Officer
Chris Arndt

Chief Executive Officer
Richard A. Eichler

COLUMNS

DEPARTMENTS

ABOUT THE COVER: East of Watford City, N.D., the epicenter of current drilling activity in the Bakken Shale, a local created a patriotic display for the Fourth of July. Photo by Stephen Collector.

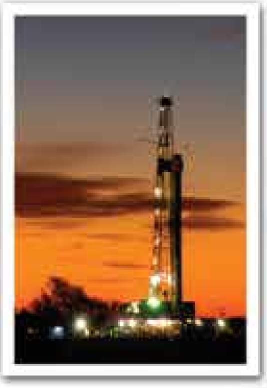
Information contained herein is believed to be accurate; however, its accuracy is not guaranteed. Investment opinions presented are not to be construed as advice or endorsement by *Oil and Gas Investor*.

Oil and Gas Investor (ISSN 0744-5881, PM40036185) is published monthly by Hart Energy Publishing, LP, 1616 S. Voss Rd., Suite 1000, Houston, Texas 77057. Periodicals postage paid at Houston, TX. Ride-along enclosed. Advertising rates furnished upon request. **POSTMASTER: Send address changes to Oil and Gas Investor, PO Box 5020, Brentwood, TN 37024.** Address all correspondence to *Oil and Gas Investor*, 1616 S. Voss Rd., Suite 1000, Houston, Texas 77057. Telephone: +1.713.260.6400. Fax: +1.713.840.8585. oilandgasinvestor@hartenergy.com

Subscription rates: United States and Canada: 1 year (12 issues) US$297; 2 years (24 issues) US$478; all other countries: 1 year (12 issues) US$387; 2 years (24 issues) US$649. Single copies: US$30 (prepayment required). Denver residents add 7.3%; suburbs, 3.8%; other Colorado, 3%.

Copyright ©Hart Energy Publishing, LP, 2019. Hart Energy Publishing, LP reserves all rights to editorial matter in this magazine. No article may be reproduced or transmitted in whole or in parts by any means without written permission of the publisher, excepting that permission to photocopy is granted to users registered with Copyright Clearance Center/ 013-522/96 $3/$2. Federal copyright law prohibits unauthorized reproduction by any means and imposes fines of up to $25,000 for violations.

REPUTATION. EXPERTISE. SERVICE.



Netherland, Sewell & Associates, Inc. is one of the most respected names in independent reserves reporting. For over 50 years, we have provided high quality engineering, geological, geophysical, and petrophysical consulting services to petroleum and financial concerns worldwide.

Our clients use our reports for regulatory agency filings, stock exchange offerings, project financing, equity determinations, and acquisitions and divestitures. Each evaluation is based on technical expertise, sound professional judgment, and accepted practices.

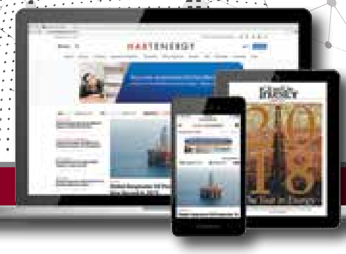
With NSAI, you get our team of experts and a reliable, respected report.

NETHERLAND, SEWELL & ASSOCIATES, INC.

Serving Our Clients For Over 50 Years

Dallas 214.969.5401, Houston 713.654.4950
www.netherlandsewell.com
email: info@nsai-petro.com

HARTENERGY.COM



ONLINE CONTENT | AUGUST 2019 | Subscribe at **HartEnergy.com/subscribe**

LATEST CONTENT

Tom Ward-Led Company Lands Western Anadarko Acquisitions
The acquisitions represent the first transaction within a new partnership between Ward's Mach Resources and Houston-based private-equity firm Bayou City Energy.

Rice Brothers Take Control Of EQT Board In Proxy Fight
Toby Rice was also named president and CEO of EQT Corp., succeeding the shale gas giant's former top exec, Robert McNally.

Vista Oil & Gas To Form First Vaca Muerta Shale Midstream Company
Vista Oil & Gas will create the Vaca Muerta's first midstream company supported by a multimillion-dollar investment from Riverstone Energy and Southern Cross Group.

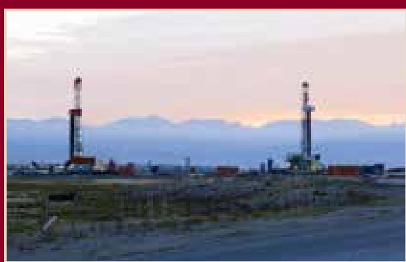
Texas Company Forms $165 Million JV To Develop Permian Wolfcamp
Ares-backed Development Capital Resources agreed to partner with an unnamed private operator to fund development of the Permian's Wolfcamp Shale.

Callon Petroleum To Acquire Carrizo For $3.2 Billion
Callon Petroleum will gain core oil-weighted positions in both the Permian and Eagle Ford Shale through its combination with Carrizo Oil & Gas.

Halcón Resources CFO Quentin Hicks To Step Down
Halcón Resources Corp. CFO Quentin Hicks steps down, marking the second CFO and fourth overall executive change for the Permian Basin oil and gas producer since the start of the year.

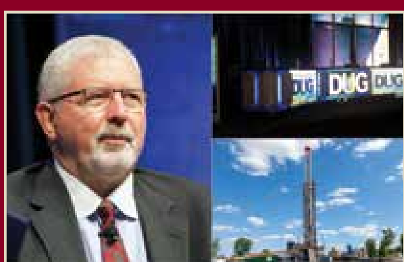
ONLINE EXCLUSIVES

Analysis Shows Well Interference's Role In Scoop/Stack Productivity Decline
The surge in child wells has brought well spacing and interference concerns across U.S. shale plays.

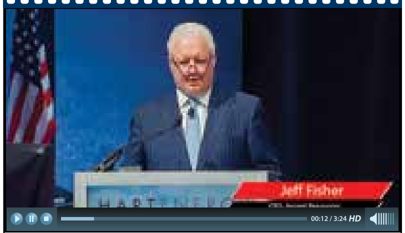


Interview: Southern Gas Association Always Ready For Challenges
New SGA President and COO Suzanne Ogle talked with HartEnergy.com about her new role with the association, women in energy and the energy transition that is at hand.

DUG East: Key Players Eye Increased Production In Utica
Drillers highlight the positive outlook for the Utica Shale play, which some say is often undervalued.



Videos



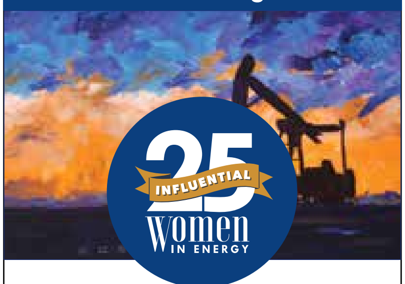
HART ENERGY CONNECT: Best Practices, Spending In The Appalachian Basin
A look at some of the recent presentations shared at Hart Energy's DUG East conference and exhibition in Pittsburgh.

www.HartEnergy.com/videos

What's Trending

1. Callon Petroleum To Acquire Carrizo For $3.2 Billion
2. The Top 100 Private E&Ps
3. DUG East: Attacking The Perils Of Longer Laterals, Parent-Child Well Intervention
4. U.S. Shale Firms Put Up $16.5 Million To Build West Texas Charter Schools
5. Bison, Marathon Oil Enter Into 15-Year Water Infrastructure Agreement

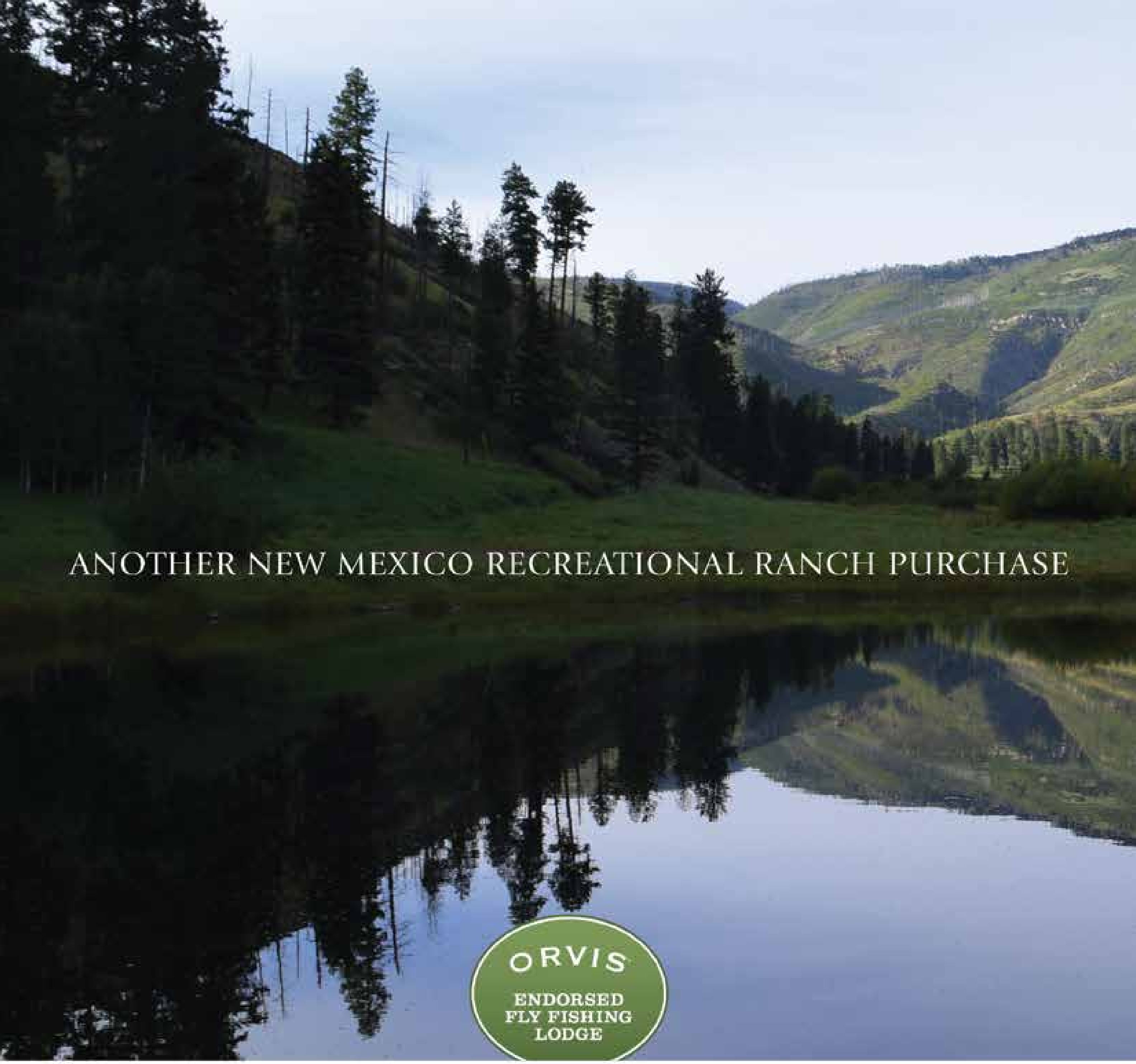
Awards Program



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

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

HartEnergy.com/women-in-energy



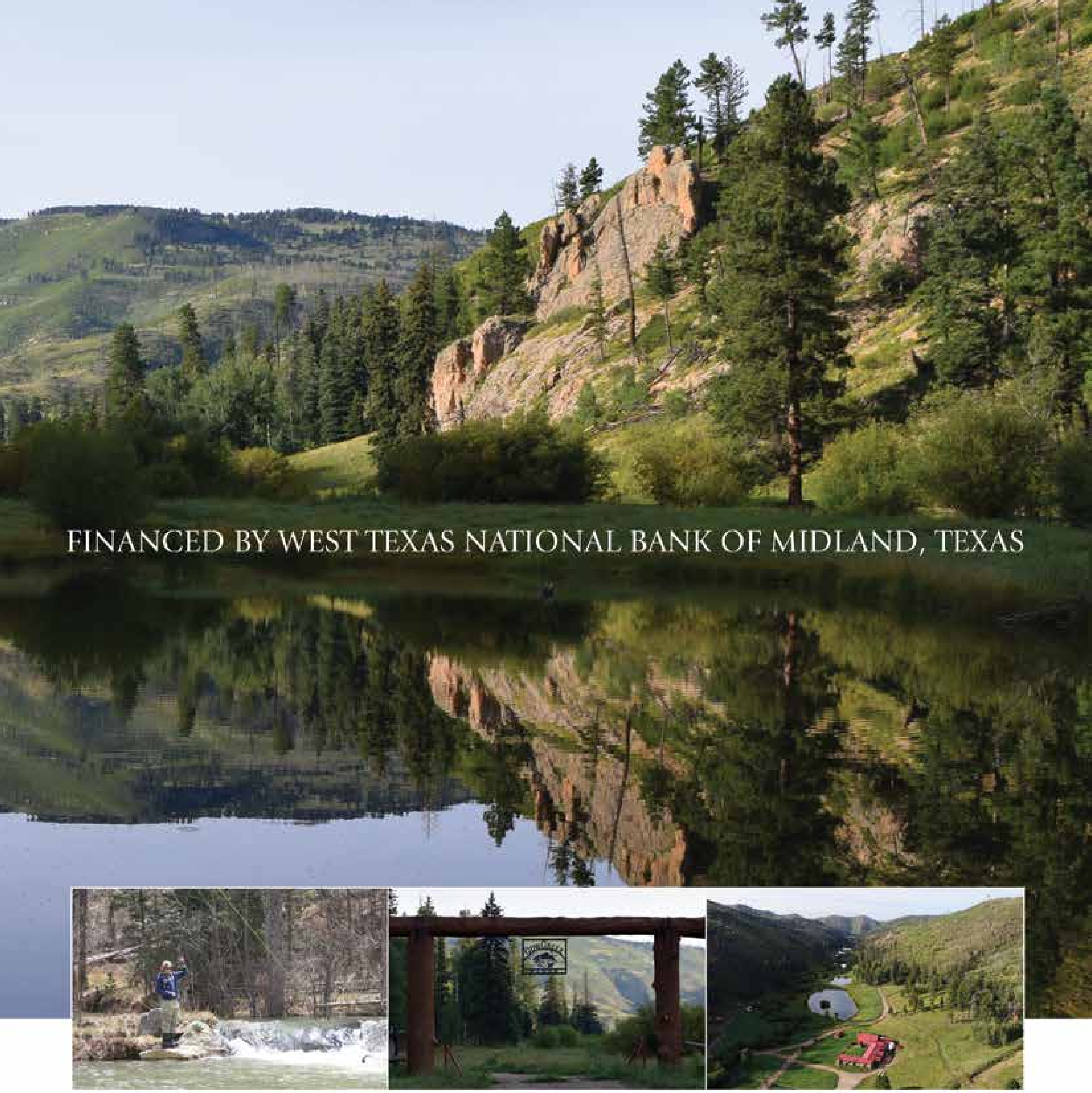
WTNB recently financed the Cow Creek Ranch acquisition, a members-only fishing lodge which will boast 34 Members.

An angler's paradise, this **Orvis-endorsed** fly fishing lodge is one of the most desirable places to fly fish in New Mexico and is one of New Mexico's best kept secrets. With over 4 ½ miles of private streams and seven high mountain lakes teeming with trophy rainbows, browns and brookies, every day is a great day.

CowCreek RANCH

WTNB™

MEMBER FDIC EQUAL HOUSING LENDER

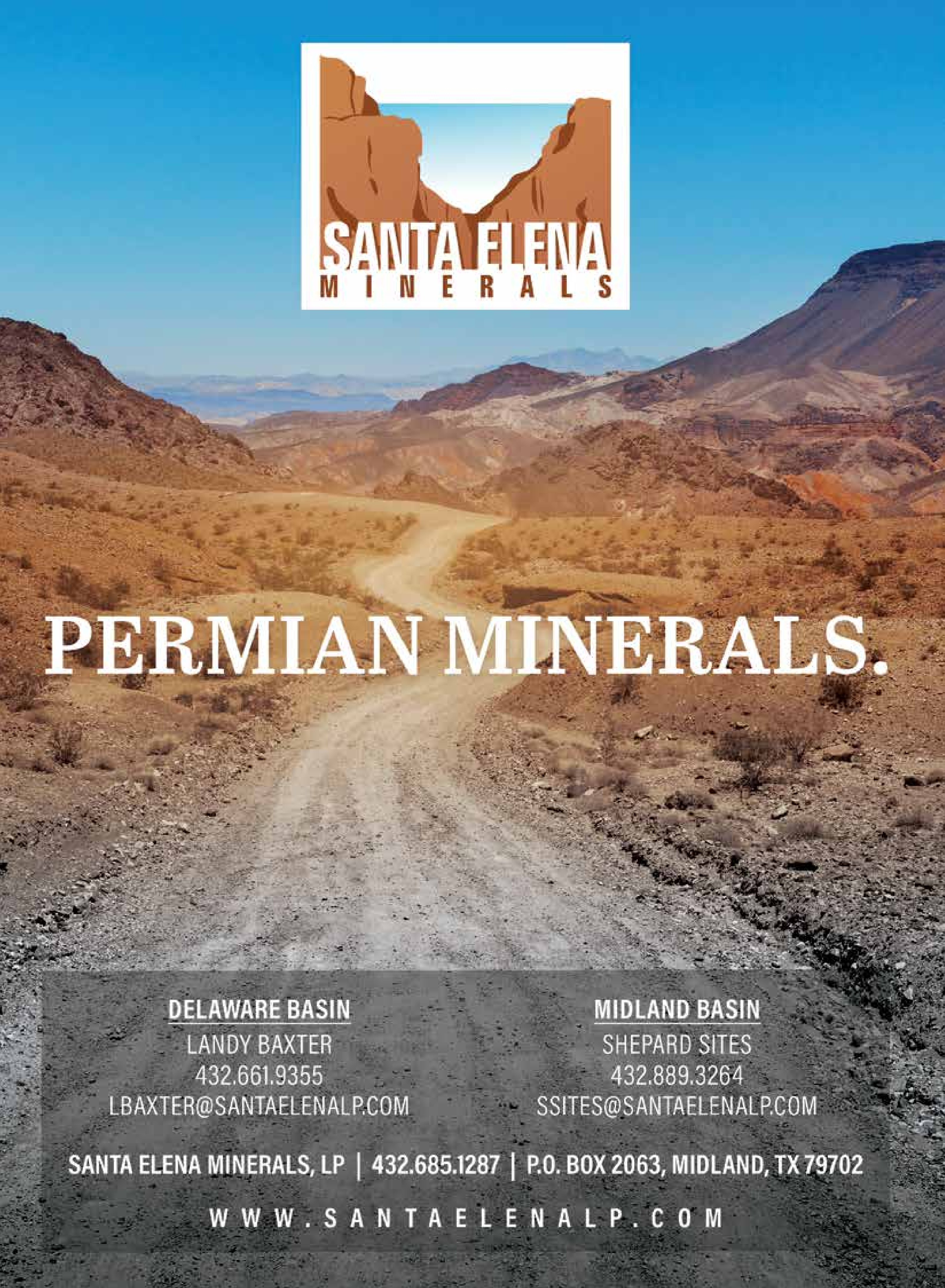


Contact WTNB today for your land and ranch financing needs.

Brady Ross | SVP- West Texas Division Manager
6005 Eastridge Road, Suite 120 | Odessa, Texas 79762
1.877.493.7862 ext: 9804 | Direct: 432.687.9804
Bross@WTNB.com

Crockett Calk | SVP- Market President
810 East Broadway | Denver City, Texas 79323
1.877.493.7862 ext: 9659 | Direct: 806.592.8521
Ccalk@WTNB.com

AG LENDING SINCE 1904 | LAND | RANCHES | FARM & EQUIPMENT | NMLS 410435 | 877.493.7862 | WTNB.com


SANTA ELENA
MINERALS
PERMIAN MINERALS.
DELAWARE BASIN
LANDY BAXTER
432.661.9355
LBAXTER@SANTAELENALP.COM
MIDLAND BASIN
SHEPARD SITES
432.889.3264
SSITES@SANTAELENALP.COM
SANTA ELENA MINERALS, LP | 432.685.1287 | P.O. BOX 2063, MIDLAND, TX 79702
WWW.SANTAELENALP.COM

RICE REDUX

STEVE TOON,
EDITOR-IN-CHIEF

Has the oil and gas industry ever before witnessed what took place last month at EQT—in which a disgruntled investor effectively staged a coup to seize control of the board and management of a major E&P company, and then took over operations? Then again, has the management team of an acquired and long-closed company ever said, "We want our assets back because we think we can do better than you"—and get them?

Never.

Sure, we've seen individual E&P shareholders become "activist investors" and buy up a sizeable interest to shake up management. Think Carl Icahn and his impact on Chesapeake Energy Corp. and in SandRidge Energy Corp. Fir Tree Capital Management wrested control of Halcón Resources Corp. and continues to look for an exit. Lion Point Management took formidable stakes in Resolute Energy Corp. and Carrizo Oil & Gas Inc. and pushed for sales of each earlier this year—and each did.

But neither Icahn, nor Fir Tree's Evan Lederman, nor Lion Point's Didric Cederholm took the captain's chair to run the company according to their visions.

Toby Rice did.

But the Rice team was not your typical activist shareholder. Brothers Toby, Derek and Daniel—the operational braintrust behind Rice Energy Corp.—became sizeable investors when EQT bought the brothers' Appalachian start-up for $6.7 billion (before debt) in December 2017, much of that in equity consideration. Then the value of that equity quickly went south.

It can be debated as to why. EQT's CEO at acquisition, Steve Schlotterbeck, left the company on short notice and temporarily adrift. The newly appointed CEO, Robert McNally, was heralded as having 20 years of oil and gas experience, but his resume was absent of E&P leadership. And the company was focused on—or distracted by—the separation of its midstream assets from the upstream.

When operational snafus arose last fall, sending capex up and production targets down, investors were spooked. EQT's stock plunged 75% since the merger, and the Rice brothers lost hundreds of millions. The anticipated merger synergies that were to create upside had evaporated. And the Rices went into action to either turn around the ship or take it over.

Now, following an 80% investor vote of confidence to reconstruct the board to the Rice team's makeup, Toby Rice is CEO of the nation's largest gas producer by volume. His mandate: make EQT as successful as Rice Energy once was. The measure will be shareholder returns.

But the world has changed since the Rice brothers last ran an E&P company. Generalist investors have wholesale abandoned the sector, leaving only hard-core, grizzled oil-and-gas-addicted investors to play. And natural gas prices trending below $2.50 don't help with investability or cash flow.

Can the Rice brothers save EQT?

Existing investors think so, evidenced by the overwhelming board vote. The Rice team's 100-day plan calls for implementing techniques to deliver well-cost savings of 33% predicated on simultaneous development of large pads, and integrating digital and analytical technologies that were successful at Rice.

"The Rice team is in an enviable position," said Welles Fitzpatrick, a SunTrust Robinson Humphrey analyst, following the vote, "as it has the opportunity to tell a resurrection story and grab attention from investors in a market where others are struggling."

Can this type of coup ever happen again? According to Parkman Whaling's Michael Hanson, unlikely.

"I'm sure there will be many postmortems held and case studies written about the 'Rice Revolution,' as board rooms around the industry wonder if what happened at EQT could happen to them. While general underperformance and a broken business model will continue to drive shareholder activism, I doubt coups like Rice's vs. EQT will become the norm," he wrote in an email newsletter.

And why not?

"How many shareholders in energy today really care enough to spend the time and capital to mount a proxy war? It's so much easier to sell and focus on other companies or industries that might provide a better opportunity to make money," he said, but, "if I had lost a significant portion of my net worth and had a good idea to right the ship, I'd put up a fight too."

They did. They won. Now they must execute, because everybody is watching to see how this story ends.

APOLLO

NATURAL RESOURCES

Creative Capital Solutions, Proven Investment Expertise

APOLLO NATURAL RESOURCES combines technical and financial capabilities to deliver consistency, certainty, and speed to a wide range of investment opportunities in the energy industry from $25 million mezzanine financings to $1 billion private equity investments. For more information, email energyinfo@apollolp.com or contact us at:

GLOBAL HEADQUARTERS
9 West 57th Street
New York, New York

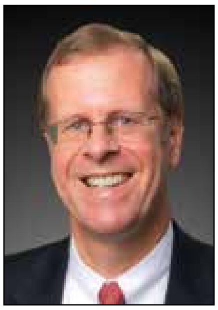
Greg Beard
Private Equity
(212) 822-0750

HOUSTON OFFICE
700 Louisiana Street
Houston, Texas

Dan Vogel
Credit
(212) 822-0740

Apollo Global Management, LLC • New York • Los Angeles • Houston • London
Frankfurt • Luxembourg • Singapore • Mumbai • Hong Kong www.agm.com

RISK-ON, OR RISK-OFF?



CHRIS SHEEHAN, CFA
SENIOR FINANCIAL ADVISOR

Zigzagging a path through recent trade friction and geopolitics has often been bewildering. Is market sentiment for the day "risk-on" or "risk-off"? A Wall Street Journal article likened the "risk-on, risk-off" phenomenon to market forces being split into two buckets. One has "haven assets" that rally when investors "grow skittish." The other has "growth assets" that rally as "risk appetite returns."

To state the obvious, commodities like oil are not risk-off or haven assets. And "skittish" is likely an understatement of energy investors' mood. A recent Simmons Energy note detected some "increased investor scrutiny in assessing risk/reward" in energy. However, it noted "the complexity factor has never been higher as multiple externalities continue to drive a wide range of outcomes."

According to the Simmons note, generalist investors have set a high bar to consider returning to energy. E&Ps' ability to generate a free-cash-flow (FCF) yield is a "threshold requirement," and a FCF yield in line with that of the S&P is targeted. "Given the weak competitive structure of the upstream industry and the prolonged legacy of underperformance," the Simmons note said, "generalists increasingly require minimum FCF yields of about 5% and a persuasive line of sight to low double digits."

A surprisingly narrow divergence in the oil price can, according to Simmons, make a significant impact on FCF. At a $50-per-barrel (bbl) West Texas Intermediate (WTI) price, about 20% of Simmons research coverage can deliver 5% or more oil growth and generate a 5% FCF yield. But with only a small shift higher to $55/bbl, as much as 65% of its coverage can grow at 5% or more and generate a 5% FCF yield.

The smaller group meeting the 5% FCF metric at $50/bbl, said Simmons, is tilted toward "large-cap diversifieds and high-quality Permian pure-plays often with scale."

A report by Bernstein also sees $50/bbl as a pivotal level. If using cost of capital as a target rate of return, it said, even in the Permian a majority of producers fail to hit their cost of capital at $50/bbl. However, at $60/bbl, "roughly half" of producers manage to hit the target, skewed to those with larger footprints and blocky acreage. Bernstein said $60/bbl is "near marginal cost" for crude in North America as a whole.

With $5 to $10/bbl fluctuations in price able to move U.S. oil economics meaningfully on the margin, making forecasts is difficult, especially if oil demand suddenly drops markedly. In this year's first quarter, according to EIA data, global demand for crude was growing at a meager pace of around 300,000 barrels per day (bbl/d), the "weakest since 2011," noted Simmons.

The problem: "U.S. supply growth outpacing global demand growth isn't a comforting outcome," observed Simmons.

A Macquarie note, however, cited certain factors indicating that "demand is bad, but looks worse than it is.

"We estimate global product demand was reduced by 800,000 bbl/d to 1 MMbbl/d from February to April 2019," said Macquarie. Distillate demand, in particular, was hit by "abnormally mild winter weather" in Europe, Asia and the Middle East. Also, it noted, Midcontinent flooding "reduced crude runs, gasoline demand and diesel demand by disrupting U.S. planting seasons."

With refinery turnarounds taking longer than normal, "we are six weeks behind a normal ramp-up in refining runs," said the Macquarie note in mid-June. With normalized weather and the end of the turnaround season, third-quarter global refinery runs are projected to be up 2.5 million bbl/d over prior quarter levels. In turn, it said, this should "at the least create a strong floor for price."

With an ongoing emphasis on capital discipline—and a drive to generate FCF—will the U.S. E&P sector moderate its production growth? As of June 23, the 48-month WTI strip stood at roughly $53.50, according to Simmons, partway to the $55/bbl level that would allow almost two-thirds of its research universe to achieve 5% growth coupled with a 5% FCF.

A risk is that production growth continues to be too much of a good thing. One issue is that, even if the public and private E&P sectors dial down growth, only time will tell if the majors "revisit their unbridled growth agenda," said Simmons. Notably, ExxonMobil Corp. and Chevron Corp. unveiled ambitious growth programs in the Permian earlier this year.

Of course, geopolitics remains a huge variable. Could Mideast skirmishes escalate into real conflicts and provide a much more bullish backdrop for oil? Or does rising U.S. supply provide a kind of "firewall" against geopolitical events?

Risk-on, or risk-off?

CONFIDENCE EARNED.

M&A Advisory

Petrobras	Divestiture of 50% Ownership Interest in POGBV	Vitol, Africa Oil, Delonex	$1,530,000,000	Exclusive Advisor	Pending
Murphy Oil Corporation	Advised on the Acquisition of Gulf of Mexico Assets from	LLOG Exploration	US$1,375,000,000	Financial Advisor	June 2019
PetroRio	Acquisition of 51.74% WI in the Frade Field from	Chevron	Undisclosed	Exclusive Advisor	March 2019
Newfield	Advised on the Combination with	encana	$7,700,000,000	Advisor	February 2019
Halcón Resources	Divestiture of Delaware Basin Water Infrastructure Assets	WaterBridge	Up to $325,000,000	Financial Advisor	December 2018
Enbridge	Corporate Simplification	Enbridge, Enbridge, Enbridge, Spectra Energy Partners	C$22,730,000,000	Financial Advisor	December 2018
Sierra Oil & Gas	Farm-out of Block 2 in Offshore Mexico	Talos; Pan American Energy	Undisclosed	Exclusive Financial Advisor	October 2018
Baytex Energy Corp	Advised on the Combination with	RRX	C$1,900,000,000	Financial Advisor	August 2018
Cimarex	Advised on the Divestiture of Delaware Basin Assets to	Callon Petroleum	$544,500,000	Exclusive Financial Advisor	August 2018
SK	Acquisition of gathering and processing assets in the Delaware Basin as part of a $1.75 billion transaction	Brazos Midstream	$250,000,000	Exclusive Financial Advisor	May 2018
ExxonMobil	Advised on the Divestiture of 50% interest in Scarborough gas field to	woodside	$744,000,000	Exclusive Financial Advisor	March 2018
Cabot Oil & Gas Corporation	Advised on the Divestiture of Eagle Ford Assets to	Venado Oil & Gas	$765,000,000	Exclusive Financial Advisor	March 2018

Capital Markets

Enterprise Products Partners L.P.	Senior Notes	$1,250,000,000 $1,250,000,000	Joint Bookrunner	June 2019
Antero Midstream	Senior Notes	$650,000,000	Joint Bookrunner	June 2019
NuStar Energy LP	Senior Notes	$500,000,000	Joint Bookrunner	May 2019
Ensign	Senior Notes	$700,000,000	Joint Bookrunner	April 2019
EnLink Midstream	Senior Notes	$500,000,000	Joint Bookrunner	April 2019
ONEOK	Senior Notes	$1,250,000,000	Joint Bookrunner	March 2019
Archrock Partners	Senior Notes	$500,000,000	Joint Bookrunner	March 2019
Cimarex	Senior Notes	$500,000,000	Joint Bookrunner	March 2019
Valero	Senior Notes	$1,000,000,000	Joint Bookrunner	March 2019
Energy Transfer	Senior Notes	$4,000,000,000	Joint Bookrunner	January 2019
Matador Resources Company	Senior Notes (Add-On)	$300,000,000	Joint Bookrunner	October 2018
Shell	Has sold its shareholding in Canadian Natural Resources Limited	$3,300,000,000	Joint Bookrunner	May 2018

gbm.scotiabank.com/energy

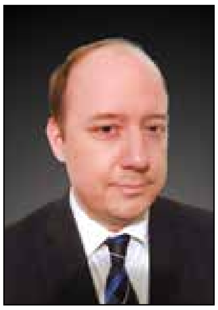
Scotiabank™

GLOBAL BANKING AND MARKETS

ADVISORY SERVICES • RISK MANAGEMENT • TRADING • FINANCING • RESEARCH

™ Trademark of The Bank of Nova Scotia. Used under license, where applicable. Scotiabank is a marketing name for the global corporate and investment banking and capital markets businesses of The Bank of Nova Scotia and certain of its affiliates in the countries where they operate, including Scotia Capital Inc. (Member-Canadian Investor Protection Fund and Investment Industry Regulatory Organization of Canada). The Bank of Nova Scotia is a Canadian chartered bank. Scotia Capital (USA) Inc. is a broker-dealer registered with the SEC and a member of FINRA, NYSE, NFA and SIPC. The Bank of Nova Scotia is authorised and regulated by the Office of the Superintendent of Financial Institutions Canada. The Bank of Nova Scotia is authorised by the UK Prudential Regulation Authority and is subject to regulation by the UK Financial Conduct Authority and limited regulation by the UK Prudential Regulation Authority. Details about the extent of The Bank of Nova Scotia's regulation by the UK Prudential Regulation Authority are available from us on request. Scotiabank Europe plc is authorised by the UK Prudential Regulation Authority and regulated by the UK Financial Conduct Authority and the UK Prudential Regulation Authority. Not all products and services are offered in all jurisdictions. Services described are available only in jurisdictions where permitted by law.

INDIE A&D



DARREN BARBEE
SENIOR EDITOR

The A&D market's mana, drained by nearly nine months of flabby oil prices, is replenishing, mostly with smallish deals. But a larger liability is looming.

So far in 2019, oil and gas deals have taken an indie turn in the market, with mid-sized deals transacting in Alaska and the southern Midland Basin. Management teams are still exploring mergers and large-scale acquisitions, according to a recent snapshot of analyst reports.

Companies such as EOG Resources Inc., Chesapeake Energy Corp., Pioneer Natural Resources Co. and others are being picked by analysts (Out of thin air? Who knows?) as potential buyers and sellers.

Capital One Securities analyst reports identified several potential deal makers—with caveats aplenty:

- Ring Energy closed its Wishbone acquisition in April and will continue to look at smaller deals—but its balance sheet "likely keeps the company on the sidelines from pursuing larger acquisitions";
- Pioneer continues to look at monetizing the far end of its drilling inventory—however, a Drillco is much more likely, with a decision expected in the second half of 2019;
- Noble Energy Inc. remains open to acquisitions and consolidation over time—yet CEO Dave Stover told Capital One he believes M&A will play out over time with the volatility in oil, gas and equity prices slowing the pace of deals; and
- In a July 7 report, Goldman Sachs analysts additionally ranked EOG and Pioneer as top-ranked M&A candidates, which the firm considers a 30% to 50% probability that they could become acquisition targets.

On the sly in the second quarter, crafty business development folk have been breaking trail to execute deals in a cold market. In a July 10 regulatory filing, for instance, Magnolia Oil & Gas LLC reported that it would buy Eagle Ford and Austin Chalk assets.

Magnolia bought from companies it collectively called "Titanium" sellers: VP EF LP and VP EF Royalty LP. The assets, which were not otherwise detailed, will be purchased with an undisclosed sum of cash and about 3 million shares of newly issued Magnolia stock. On May 6, the day of the agreement, the stock portion of the deal was worth about $39.7 million.

As with the first quarter's Occidental Petroleum Corp. merger agreement with Anadarko Petroleum Corp., smaller deals have been drowned out. The much-ballyhooed $2.2 billion Comstock Resources Inc. combination with Covey Park Energy LLC dominated analysis with the novel concept of private companies selling to public E&Ps.

The deal also set off speculation among Morgan Stanley analysts that Chesapeake might look a lot more appetizing for investors if it could pull off a sale of its own Haynesville acreage.

Morgan Stanley estimates that Chesapeake's year-end 2019 leverage will be 4.3 times, the firm said in a June 27 report. A divestment on the scale and valuation of Covey Park would drop the company's leverage to 0.8 times, Morgan Stanley said.

However, in the A&D Fantasy Leagues, the bid-ask spread remains a real hurdle. Could the debt-factor—overall, E&Ps are staggeringly overleveraged—be the catalyst that finally gets deals done?

A July 11 Fitch Ratings report delved into just how in the red E&Ps are. Think scarlet. In the past 12 months, the default rate for energy companies' debt stands at 4.1% compared to 1.9% for the overall market. So far this year, energy accounts for 30%, or $5.4 billion, of defaults. Energy includes various commodity types, such as coal, along with oil and gas.

But some upstream companies are closer to their own end zone than they would like. Sanchez Energy Corp., for instance, has a July 15 interest payment on its largest unsecured tranche, Fitch said.

On the bright side, several companies were removed from the bond naughty list due to "M&A activity or improved liquidity," Fitch said.

E&Ps such as Sanchez, EP Energy LLC, Denbury Resources Inc. and Ultra Resources Inc. top the crimson zone with a combined $9.4 billion in debt due in July and August.

In A&D land, the reality of this may prove harsh. Sellers are, rightfully, holding out for the best price possible for their assets. How long they hold out may be a matter of their noncore portfolio and the flexibility of their lenders.

As the joke goes, "bankers help you with the problems you would not have had without them."

EVENTS CALENDAR

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

EVENT	DATE	CITY	VENUE	CONTACT
2019				
Tipro Summer Conference	Aug. 7-8	San Antonio	Hyatt Hill Country Resort	tipro.org
EnerCom The Oil & Gas Conference	Aug. 11-14	Denver	Westin Denver Downtown	theoilandgasconference.com
IPAA Supply and Demand Meeting	Aug. 19	Dallas	Petroleum Club	ipaa.org
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
PIOGA Fall Conference	Sept. 24-25	Seven Springs, Pa.	Seven Springs Mountain Resort	pioga.org
DUG Eagle Ford	**Sept. 24-26**	**San Antonio**	**Henry B. Gonzalez Conv. Center**	**dugeagleford.com**
A&D Strategies and Opportunities	**Oct. 22-23**	**Dallas**	**The Omni Dallas**	**adstrategies.com**
Executive Oil Conference	**Nov. 4-6**	**Midland, Texas**	**Midland County Horseshoe Pavilion**	**executiveoilconference.com**
IPAA Annual Meeting	Nov. 6-8	Washington, D.C.	Fairmount, Georgetown	ipaa.org
DUG Midcontinent	**Nov. 19-21**	**Oklahoma City**	**Cox Convention Center**	**dugmidcontinent.com**
Marcellus-Utica Midstream	**Dec. 3-5**	**Pittsburgh**	**David L. Lawrence Conv. Center**	**marcellusmidstream.com**
Privcap Game Change	Dec. 3-4	Houston	The Houstonian	energygamechange.com
2020				
Private Capital Conference	Jan. 23	Houston	JW Marriott Houston	ipaa.org
NAPE Summit	Feb. 3-7	Houston	George R. Brown Conv. Center	napeexpo.com
Energy Capital Conference	**Mar. 2**	**Dallas**	**Fairmont Hotel**	**energycapitalconference.com**
Women in Energy Luncheon	**Mar. 4**	**Houston**	**Hilton Americas-Houston**	**womeninenergylunch.com**
CERAWeek by IHS Markit	Mar. 9-13	Houston	Hilton Americas-Houston	ceraweek.com
DUG Permian	**April 6-8**	**Fort Worth, Texas**	**Fort Worth Convention Center**	**dugpermian.com**
OGIS New York	April 20-22	New York	TBA	ipaa.org
DUG Haynesville	**May 19-20**	**Shreveport, La.**	**Shreveport Convention Center**	**dughaynesville.com**
Midstream Texas	**June 2-3**	**Midland, Texas**	**Midland County Horseshoe Pavilion**	**midstreamtexas.com**
AAPG Annual Conv. & Exhibition	June 7-10	Houston	George R. Brown Conv. Center	ace.aapg.org/2020
Monthly				
ADAM-Dallas/Fort Worth	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Greater East Texas	First Wednesday, even mos	Tyler, Texas	Willow Brook Country Club	getadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.com
ADAM-Permian	Bi-monthly	Midland, Texas	Midland Petroleum Club	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.com
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Houston Petroleum Club	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	sblackhefg@gmail.com
Houston Producers' Forum	Third Tuesday	Houston	Houston Petroleum Club	houstonproducersforum.org
IPAA-Tipro Speaker Series	Second Wednesday	Houston	Houston Petroleum Club	tipro.org

Email details of your event to Brandy Fidler, bfidler@hartenergy.com.
For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com.

This announcement appears as a matter of record only

$775,000,000

We are pleased to announce the closing of

Carnelian Energy Capital III, L.P.

June 2019

Carnelian
Energy Capital

An energy investment firm focused on lower-to-middle market equity investments in the North American upstream, midstream and oilfield services sectors

www.carnelianenergy.com


WHITING
WLL POWER
Whiting Petroleum Corporation is an independent exploration and production company. We are a leading crude oil producer in North Dakota and operate substantial assets in northern Colorado.
At Whiting we are committed to economically attractive and environmentally responsible operations. Our hydraulic fracturing advancements, state of the art geoscience lab and expertise in exploration have made it possible for us to increase production and reserves while reducing emissions, minimizing surface impacts, and preserving precious water resources.
1700 Broadway | Suite 2300 | Denver, Colorado 80290-2300 | P: 303.837.1661 | F: 303.851.4923
WWW.WHITING.COM

NewsWell

E&P executive comp falls into line with other industries

The relative underperformance of E&P stocks against the S&P 500 has brought renewed focus to executive compensation. A July 9 report from Cowen and Co. noted that "E&P management compensation is under the magnifying glass more than ever." The Cowen analysts, led by David Deckelbaum, surveyed the compensation structures of E&Ps that they cover with an emphasis on how bonus metrics could motivate strategies.

In general, the analysts found that E&P general and administrative (G&A) and executive compensation are not out of line when compared with other industries, contrary to what investors might think. "Within our coverage alone, G&A per barrel of oil equivalent (boe) is projected to be just under $3/boe (inclusive of capitalized items), down 20% since 2017 and likely to continue to decline as companies look to bring the investing public closer to wellhead returns that are widely advertised as being 50% to 100%-plus in company presentations."

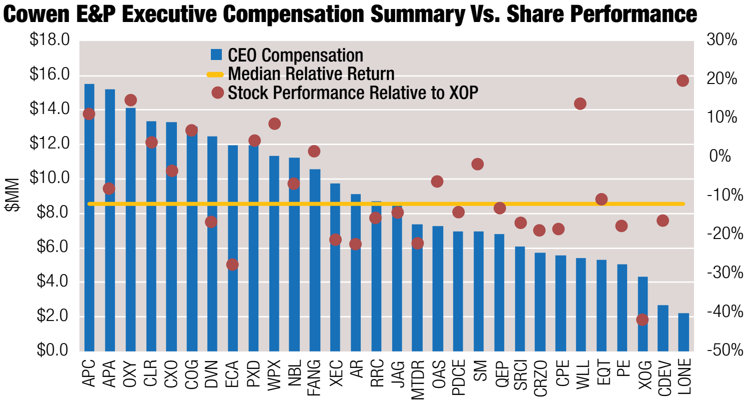
As for compensation, they found that as a percent of market cap, "energy executive pay is less than 0.08% on average, relatively in line with industrials, consumer discretionary stocks and utilities, and just above the average of 0.07% for several observed sectors." And, when compared as a percent of cash flows, executives at energy companies are lower than the average of 0.9%, at less than 0.6% of cash flows. E&Ps tend to reward their managements with equity and restricted shares rather than cash.

"One of the more salient arguments we find is that energy executives do not own enough shares of their company, which is a fair criticism that seems to be getting addressed by compensation award weightings toward equity and other non-cash vehicles." The Cowen research shows that energy CEOs on average own only about 0.20% of their company's stock. At consumer discretionary companies, average stock ownership by CEOs is about 1.20%.

Cowen's look at total executive compensation, including base salary, bonus, stock and option awards and other compensation, found that on average the CEOs of E&Ps it covers were compensated $8.6 million for a median stock return of -40%, or -12% vs. the XOP. While noting that the fall in oil prices took a toll and that these totals weren't compared to other sectors' stock performance, the analysts said that, for instance, ECA [Encana Corp.] screens poorly "given a 28% relative return to the XOP in '18 vs. CEO compensation that screens more than 40% higher vs. the median E&P in our coverage."

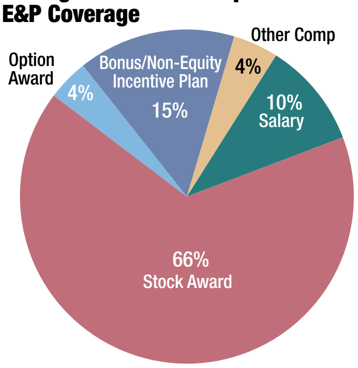
Among the operators scoring best on this data were Lonestar Resources and Whiting Petroleum Corp., where CEO compensation was less than the median for E&Ps.

Cowen E&P Executive Compensation Summary Vs. Share Performance



Source: Cowen and Co., company reports, Bloomberg

Average Executive Comp Mix For E&P Coverage



Source: Cowen and Co., company reports

Occidental Petroleum Corp. and Anadarko Petroleum Corp. outperformed the XOP with CEO compensation that was more than 64% and 80% vs. the median E&P, the analysts found.

Total G&A reviews of the E&Ps indicate that many operators plan to increase spending per rig this year. "Against a capital disciplined/FCF orientated backdrop that's driven a reduction in activity, G&A per rig looks set to increase in '19 vs. '18 for 22 of 30 operators under coverage, which could signal additional headcount rationalization ahead," the Cowen analysts said. They also highlighted Diamondback Energy Inc. as "among the top three efficient operators, or the most efficient operator, on every [operating] metric."

—Susan Klann

Will U.S. shale live up to production expectations?

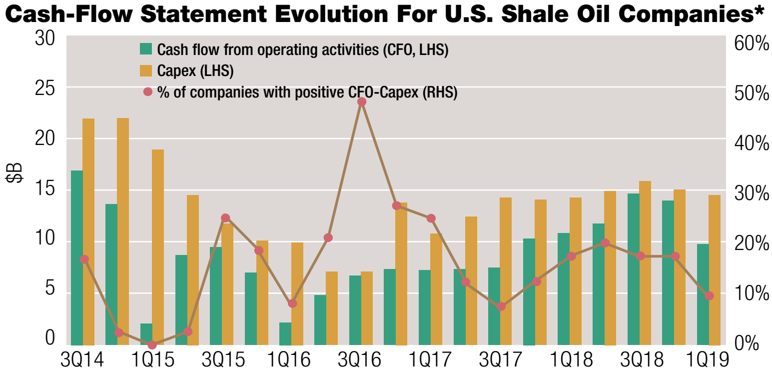
U.S. shale oil and gas production could grow to about 27 million barrels (MMbbl), accounting for 25% of the global market share through the 2030s, according to the CEO of Rystad Energy.

If financial barriers were removed, producers could push the number higher, Jarand Rystad, founder of the energy consultancy firm, told attendees of a recent forum. This is despite cash flow returns being negative—massively negative.

"It's a long, long growth story, and, of course, that growth story requires a lot of cash," Rystad said, later pointing out how shale developments essentially killed talk of Arctic exploration in the U.S. and impacted expectations for growth offshore.

With improved technology and

Cash-Flow Statement Evolution For U.S. Shale Oil Companies*



*Based on a peer group of 40 dedicated U.S. shale oil companies
Source: Rystad Energy

techniques, shale players have pumped higher concentrations of proppant and fluid, tinkered with cluster spacing and drilled longer laterals to get more oil from reservoirs while bringing down costs.

"From 2016 it has halved the average breakeven price and the volumes have almost doubled," Rystad said of the shale industry. He added that access to in-basin sand has been a driving factor during the last year.

But with skittish investors, a push toward cleaner sources of energy and the threat of having social licenses to operate revoked, will the projected shale growth come to fruition?

Panelists participating in the forum co-hosted by the firm and Pareto Securities shared their thoughts.

"The growth is possible if you take a look at the prospects," said Nicole Baird, asset manager for Equinor. "One of the reasons why we're seeing the growth is that it's not about well count. It's lateral length," which has grown by nearly 140% during the last four to five years for Equinor. It's not uncommon to hear about shale wells with lateral lengths of 15,000 to 17,000 feet, she added. "What it really allows you to do is to reduce that well count."

Couple that with drilling efficiencies and "all of a sudden these wells are becoming incredibly prolific and highly profitable," Baird said.

She earlier pointed to the rise of unconventional gas in the Appalachian Basin, where she said industry production has grown from about 2 billion cubic feet per day (Bcf/d) 10 years ago to about 28 Bcf/d today. "That is actually more than what's produced off the Norwegian Continental Shelf," Baird said, adding Appalachia production is projected to reach 42 Bcf/d by 2027.

Offshore players on the panel also weighed in on the topic.

Looking at how some U.S. shale players' capex has consistently outstripped cash flow from operations quarter after quarter, Transocean CEO Jeremy Thigpen questioned how long that would last.

"That doesn't strike me as a sustainable business model. … Is

Northern
Oil & Gas, Inc.

Adam Dirlam,
EVP–Land

Nicholas O' Grady,
Chief Financial Officer

952.476.9800

ir@northernoil.com

it technically possible for unconventionals to continue to grow? I guess," said an admittedly biased Thigpen, head of an offshore drilling company with a fleet that includes more than 50 floaters. "But until something happens with the business model, I don't know how you keep investing money into a business where you're investing more than you're pulling out."

But Rystad pointed out how companies are reinvesting in the shale business, which is actually yielding a 25% internal rate of return. "Then you can choose yourself as an investor whether you want to return that cash back to the industry or keep it for yourself," Rystad said. However, he added, management of companies are free to reinvest in the company, which is perhaps worrying investors.

Earlier in the panel discussion, Independence Contract Drilling CEO Anthony Gallegos mentioned the need for more information on declines and depletion rates, and he highlighted how the industry has been laying down land rigs.

The U.S. land rig count dropped to 939 the week of June 21, compared to 1,052 a year earlier, according to Baker Hughes, a GE company. Many E&Ps are cutting spending to focus more on shareholder returns and paying down debt. Rigs have also become more efficient.

"I can say from the industry perspective to continue the kind of growth momentum that we've enjoyed over the last half decade will be a challenge—no doubt about it," Gallegos said. "Service costs are not sustainable. The same pressure that our customers have been under for the last couple of years to focus on returns, free cash flow, that attention now is directed at oilfield services. Certainly, we as public companies have to be very mindful of that."

If the maintenance capex required to run a fleet of drilling is truly considered, "service costs must go up and will have to go up, or we're not going to have a service industry to drill the wells."

Plus, well density and communication between wells, or parent-child relationships, is a "much bigger issue than is understood today, and I think it will continue to be a bigger issue," Gallegos added. "That's going to have an implication on the number of wells that ultimately can [be] drilled."

—Velda Addison

Range-bound prices threaten oil producers in 2019 and beyond

E&Ps shaved development and production costs substantially after the commodity price downturn in 2014, but those gains may now be hobbled.

Recent reports from Moody's examined how credit conditions are changing for the North American E&P sector in a time of more modest and range-bound commodity prices. The analysts determined capital efficiency, leverage and the effects of shareholder-friendly activity all pose risks after a brighter environment in 2018.

Moody's review of 40 independent oil and gas companies indicated that "range-bound commodity prices today, cost inflation and geological issues will all limit further gains in capital efficiency during 2019-20." Companies included in the reports consisted of several large E&Ps such as ConocoPhillips Co., Occidental Petroleum Corp. and EOG Resources Inc.

The research firm's study of capital efficiency showed that drilling costs are moving higher based on the three-year all-source leveraged full-cycle ratio (LFCR).

The Moody's analysts calculate LFCR by dividing a company's leveraged cash margin by its three-year average all-sources finding and development cost. Moody's said that investment–grade E&Ps typically have LFCRs of at least two times, with a one-time LFCR indicating a company's ability to replace reserves at breakeven costs.

Largely underpinning LFCR results for E&Ps are commodity prices. According to Moody's assessment, West Texas Intermediate (WTI) oil prices averaged $66 per barrel (bbl) in 2018, compared to $51/bbl in 2017 and $43/bbl in 2016.

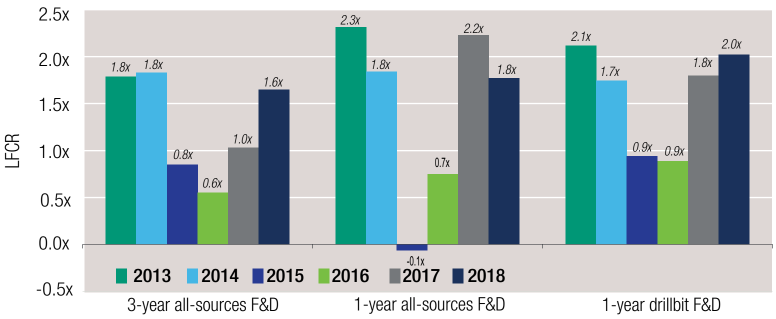
"While operating and capital cost optimization is one component of improvement in the LFCR, the other significant component of the LFCR is the commodity price itself," Moody's analysts said.

In fact, for E&Ps to maintain a consistent LFCR of 1.5 times or more, WTI oil prices need to average $60/bbl or higher—"especially with drilling costs increasing and natural gas prices still weak, at less than $3 [$MM British thermal unit]," the analysts said.

Moody's outlook is for oil prices to remain between $50 and $70 through 2020, and natural gas at between $2.50 and $3.50. The analysts noted that E&Ps need $60 oil or above to improve LFCR.

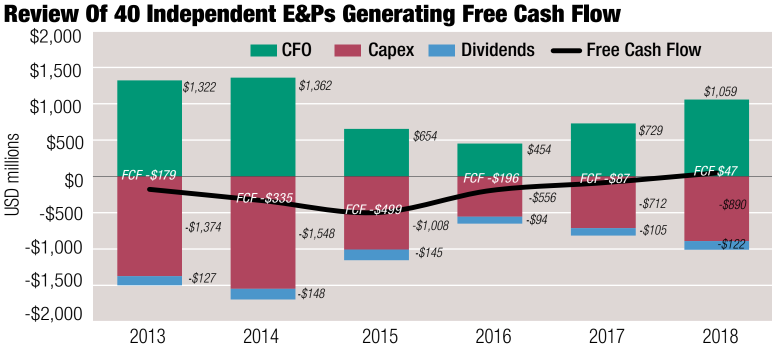
Higher commodity prices are

E&P Three-Year F&D Costs And One-Year F&D costs



Source: Moody's Financial Metrics

Review Of 40 Independent E&Ps Generating Free Cash Flow



Source: Moody's Financial Metrics, company financial statements

CUSTOMIZED SOLUTIONS TO ENERGIZE YOUR BUSINESS.

The power of 150 years of lending experience with the capital your business needs today. That's what you'll find with First Tennessee relationship managers who focus on the upstream, midstream and service sectors. Whether it's reserve-based lending, midstream acquisition or construction financing or working capital solutions, we're ready to get to the core of your business needs and exceed your expectations.

A LEADER IN ENERGY FINANCE

TPIC
Texas Petroleum Investment Company
Texas Petroleum Investment Corporation
$1.5B
Senior Secured Credit Facility
Lender

FLETCHER PETROLEUM Co., LLC
Fletcher Petroleum Co., LLC
$100.0M
Senior Secured Credit Facility
Sole Lead Arranger

CASTEX
Castex Energy 2014, LLC
$50.0M
Senior Secured Credit Facility
Sole Lead Arranger

TO SET UP A MEETING CONTACT: JOHN LANE, EVP & ENERGY MANAGER, 832-839-5556 OR JBLANE@FTB.COM
DAVID MCCARVER, SVP & RELATIONSHIP MANAGER, 832-214-9752 OR WMCCARVER@FTB.COM
DAMIEN MEIBURGER, SVP & RELATIONSHIP MANAGER, 832-839-5567 OR DGMEIBURGER@FTB.COM

©2019 First Tennessee Bank National Association operating as First Tennessee Bank and Capital Bank. Member FDIC.

FIRST TENNESSEE.

A New Beginning...

BlueRock
ENERGY PARTNERS

For 25 years, the BlueRock team has fueled oil and gas independents' growth with flexible capital solutions, regardless of commodity price cycle. With new industry-veteran investors, BlueRock is now poised to take aspiring producers to the next level. BlueRock targets investments for upstream acquisitions, development plans, and recapitalizations in the $5MM-$25MM range, with potential to $50MM. Our passion is partnering with great people who have a clear vision where they want to go. How can we help you?

BlueRock Energy Partners
945 Bunker Hill, Suite 325
Houston, TX 77024

(281) 376-0111
www.bluerockep.com

also similarly the fulcrum in companies' attempts to reduce debt.

"Despite boosting financial flexibility, very few E&P companies will be able to reduce debt in 2019 after sufficiently covering reinvestment needs and shareholder distribution," Moody's analysts said. "Higher prices are needed for the sector to further de-lever since companies can do little to further reduce costs or repay debt in today's price environment."

With companies pressured to live within cash flow and return money to shareholders, the ability to reduce leverage is bleak. Though, Moody's analysts said E&Ps have indeed made gains in their efforts to satisfy investors on this front. Last year, 15 of the 40 E&Ps produced free cash flow vs. just four in 2014.

"In 2018, 50% of the 14 investment-grade E&Ps and 31% of the 26 speculative-grade companies delivered free cash flow," the analysts said. "Even more importantly, they achieved this level of operating cash flow in 2018 with far less capital investments and lower commodity prices, spending 42% less capital than in 2014, and with commodity prices roughly 30% lower."

Additionally, Moody's analysts noted that aggregate operating cash flow for the group was much stronger in 2018 than during 2015-17 and was only 22% lower than in 2014.

"Moreover, these 40 companies as a group generated free cash flow for the first time in 2018, indicating an enhanced ability to tolerate lower commodity prices," the analysts said.

Moody's found that average drilling and completion costs declined significantly during 2015-18, but the analysts believe drillbit finding and development (F&D) costs are unlikely to decline any further, with rising service costs offsetting any drilling efficiencies. In particular, they said a scarcity of new equipment will prompt a rise in drilling costs this year and next.

As for those who might look to buy rather than drill, the analysts noted that "unit costs for acquisitions in 2018 were 70% higher than in 2017." Moody's believes acquisition costs will only become more punitive this year and going forward. The analysts see acquisition F&D increasing "as valuations get richer and acquisitions get pricier."

"Gaining scale in prolific basins is going to become increasingly important as companies compete for good drilling inventory and to secure infrastructure resources such as pipeline capacity and water handling," the analysts said.

Another sign of coming challenges: "Negative reserve revisions returned in 2018 as companies tempered their five-year growth outlooks."

Lastly, Moody's weighed in on the dangers of "aggressive share buybacks" that could offset rising cash flow going forward, making it harder for E&Ps to grow and weakening their credit quality as they fail to reduce debt.

"Higher cash flow and efficiencies should ultimately enhance shareholder returns, but only when investors feel assured that any fall in commodity prices will be temporary and that rising prices will persist for longer," the analysts said.

—Susan Klann

EDF

A home for North American hydrocarbons

EDF Trading North America specializes in commodity price risk management solutions with a focus on leveraging its downstream demand to serve the upstream oil and gas sector. We are part of the EDF Group of companies, one of the world's largest generators of electricity and a global consumer of energy including Natural Gas, NGLs, Crude Oil, and LNG.

www.edftrading.com

Ben Rich
ben.rich@edftrading.com
281-653-1736

Chris Beyer
chris.beyer@edftrading.com
281-653-1068

Rafael Cruz
rafael.cruz@edftrading.com
281-653-1656

Permian Basin still needs additional pipeline investment

While concern about overbuild of pipeline capacity in the oil-rich Permian Basin exists in the near future, the growing supply of crude from the hottest U.S. shale basin will make it necessary for extra takeaway capacity by the end of the next decade, according to research from Wood Mackenzie.

Wood Mackenzie's research is forecasting more pipeline investment will be needed before the 2030s hit because up to 500,000 additional bbl/d of oil will need to be transported to market to ease the bottlenecking that has become synonymous with the Permian Basin. As a result, midstream companies should get ready to build at least one more major pipeline out of the Permian to Gulf Coast markets, said John Coleman, Wood Mackenzie's principal analyst of North America crude markets.

"The narrative right now is focused very much on the short term, there will be excess capacity," Coleman told HartEnergy.com. "What we want to do is highlight that we agree with that in the short term. But longer term, looking beyond the next five years, we do expect growth to continue moving forward with that driving the need for either one new build from the Permian to the Gulf Coast market or expansion probably across multiple systems."

Despite the forecasted demand, Coleman added he expects the Permian Basin will still see a moderate overbuild coming in the early 2020s as the current wave of pipeline investments get completed.

The current infrastructure investment boom—one of the largest in U.S. history—includes seven proposals for new Permian pipelines, four of which have ultimately reached final investment decision. These are expected to move an additional 4 million barrels per day (MMbbl/d) of oil capacity bound for the U.S. Gulf Coast by the end of 2022. More than 2 MMbbl/d of that new capacity will make its way to the Corpus Christi market for export, according to Wood Mackenzie.

The global natural resources consultancy firm predicts two to three years of overbuild from the rapid increase in capacity as pipelines come online before the normal long-haul capacity supply and demand conditions re-emerge. U.S. Gulf Coast-bound capacity will tighten as production growth expands well in the 2030s.

However, Coleman said if pipeline isn't expanded in the Permian by the mid-2030s, takeaway capacity will become a major concern again. He expects without more investment, the Permian-to-Gulf Coast pipelines will surpass 92%. That will make it necessary for pipeline expansions or greenfield capacity, he added.

The Permian Basin, which covers 75,000 square miles in West Texas and southeastern New Mexico, has benefited from improvements in technology that made it possible to increase oil extraction from shale formations. Currently, the U.S. is the largest oil producer in the world as it's pumping 12.1 MMbbl/d, led by production out of the Permian.

Wood Mackenzie has production in the Permian peaking at around 7.1 MMbbl/d by the late 2020s or early 2030s. Though, the firm's forecast differs with predictions from another analyst with the Bank of America Merrill Lynch of production tripling to 9 MMbbl/d in the next three years during a time of concern of overbuild.

Coleman didn't discount other analysts but stuck by Wood Mackenzie's forecast.

"You will see a number of different forecasts out there," he said. "Some are very much more bullish than ours; some might even be less than ours. We try to [weigh] a number of factors, and that is how we come out with our roughly 7 MMbbl/d number."

—Terrance Harris

Scoop/Stack uncertainty sends mixed signals as expectations reset

The still blossoming Scoop/Stack plays of Oklahoma's Anadarko Basin have attracted oil and gas players, lured by low acreage cost, proximity to Cushing and production potential.

But if market conditions worsen, aspirations for higher returns could steer producers to more developed plays such as the Permian Basin, according to a report by Dallas-based market intelligence firm Alerian.

Plus, production is projected to fall, reversing a recent uptick, according to the U.S. Energy Information Administration. A drop in Stack rig counts vs. a rise in Scoop rig counts in recent months has infused angst among those down the pipeline.

The mixed signals could spark concern for some industry players. One midstream company has already lowered its 2019 guidance for natural gas gathering and processing volumes. Some E&Ps are redirecting capital to other basins; however, others are focusing on certain areas and getting favorable results as they gain knowledge about what works and what doesn't.

Alerian said some headlines about the Scoop/Stack "likely read more negatively than the reality."

"For example, increased drilling efficiencies and a shift to the Scoop from the Stack soften the implications of the notable decline in the rig count over the last year," Alerian said in the report. E&Ps have also honed in on quality areas, bringing down well costs and cycle times and getting more from each rig.

Data from Baker Hughes Inc., a GE company, show rig counts for the Cana Woodford Basin—which includes the Scoop/Stack—dropped about 40% to 45 rigs at the end of May, compared to 76 about a year earlier. The overall U.S. land rig count declined by 10% during that time.

While oil price volatility, geopolitics and takeaway capacity in some regions may be behind the slowdown, Alerian pointed out rig efficiency and better techniques gained through the years have enabled companies to improve well performance with fewer rigs.

Continental Resources Inc. is among them.

The company reported in April that its production in the Scoop, where its Project SpringBoard is underway, rose 9% to average nearly 67,700 barrels of oil equivalent per day (boe/d). The company also said it is achieving its objectives with 25% fewer rigs.

Project SpringBoard production could hit 18,000 barrels per day (bbl/d) in the third quarter, up from the previously estimated 16,500 bbl/d, due to improved cycle times and well productivity. The project targets the Springer, Sycamore and Woodford reservoirs.

Continental's Stack production for the first three months of the year averaged just more than 56,500 boe/d, down sequentially but up from a year earlier.

Alerian also mentioned Encana's plans to drop to four rigs from 10 in the Stack during the second quarter but noted strong well performance was still driving production growth. Oil and condensation production are up 30% so far in second-quarter 2019 compared to first.

"We have pumped our high-intensity completion design on more than two dozen wells with development spacing of six to eight wells per section. Results from these wells have been very strong," Encana CEO Doug Suttles said in a June 10 statement. "When our industry-leading well costs are combined with our favorable royalty structure (<20%) and agreements to access preferred oil and gas markets, we can deliver strong and competitive returns in the Stack."

Encana, which completed its acquisition of Newfield Exploration in February, said its Anadarko Basin production was averaging a record of more than 160,000 boe/d—a double-digit increase during first-quarter 2019.

But news from the Anadarko Basin has not been overly optimistic.

"[Devon Energy's] management said on the first-quarter 2019 call that they would drop a frack crew in the Stack in second-half 2019 and that reducing investment in the Stack would be the first lever to pull if needed to stay within their capital budget," Alerian said in the report. "In other words, [Devon] would prioritize other plays over the Stack if necessary."

The company cut capital spending allocated for the Stack to 20% this year from 31% last year, according to Reuters calculations based on company presentations. The reallocation aims to improve cash flow from the Stack while focusing investment where returns are better, spokesman Tim Hartley said.

Spending cuts were also made by Cimarex Energy Co., which slashed its planned spend to 15% from 30% last year.

"Because we were living within cash flow, we just had a higher degree of confidence and decided to swing more of our capital into the Delaware Basin this year," Thomas Jorden, CEO of Cimarex, said in a first-quarter earnings call.

In addition, Alerian said recent struggles of Stack pure-play Alta Mesa Resources Inc. could also be concerning.

"In recent quarters, [Alta Mesa] has reduced its estimates for average well production, daily production, and pipeline volumes. This year, the company has written down assets by $3.1 billion, laid off nearly a third of its employees, and is being investigated by the SEC for potential fraud due to reporting errors," Alerian said.

But geology is not to blame, according to Alerian, which pointed to "numerous missteps by management and high spending" as reasons behind missed targets and lowered guidance.

However, the geology in the Scoop/Stack is complex.

"The Scoop/Stack is not a traditional shale play, so when you think about developing it, there are a number of different rock types," Denise Yee, vice president at consultancy RS Energy Group, told Reuters. "As it's so complex, the hydrocarbon mix changes across the play, and the oil window is limited."

Like other basins, there have also been parent-child well challenges.

These problems are reflected in a higher median breakeven price needed to cover costs in the Scoop and Stack, according to data from consultancy Rystad Energy. Since the start of 2018, that price has been $54.53 and $53.15 per barrel of oil, respectively, higher than the Permian, Bakken, Denver-Julesburg and much of the Eagle Ford shale basins.

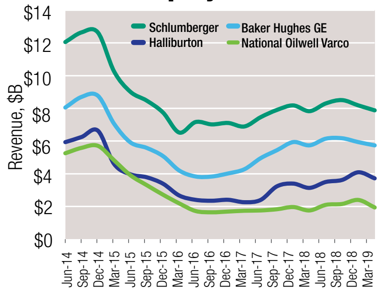
"The 'Permian Jr.' nickname set some lofty expectations," said Shak Ahmed, research analyst at RS Energy. "The play is resetting expectations around what it is capable of, and while this won't be painless, it will be better in the long term."

—Velda Addison

Analysts: Oilfield service growth "muted" into 2020

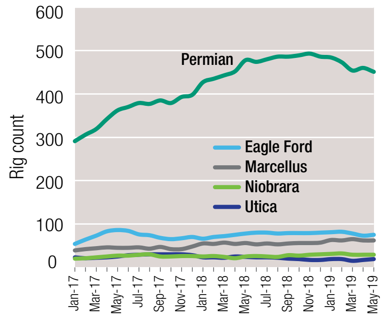
Relief for recovering oilfield service providers won't be coming anytime soon, according to a recent Moody's report. Thanks to E&P budgets remaining tight as a result of investor demands, Moody's forecasted "muted" growth for the service industry this year and into 2020.

Select OFS Company Revenue



Source: Moody's Financial Metrics, company reports

Select Basin Rig Counts



Source: U.S. Energy Information Administration, Moody's Investors Service

Moody's outlook for the oilfield service sector, though, remains stable based on fundamental business conditions in the oil and gas industry during the next 12 to 18 months, the credit rating agency said in a report issued in mid-June.

After hitting a rig count peak last November, the number of land rigs in North America has actually dropped off somewhat. Additionally, dayrates for North American rigs have also seen no relief, and more pricing pressure is expected.

Sreedhar Kona, vice president and senior analyst for Moody's Investor Service, expects the North American rig count to remain flat at about 1,000 depending on whether oil prices rise.

"Overall rig activity still remains only about 50% of the most recent peak following a steep fall," Kona wrote in the report.

By contrast, there is some expectation that the rig count for international land rigs will tick upward through this year.

Kona said the international and national oil companies are "not as constrained as the North American public E&P companies in their ability to spend on drilling activity." However, the same hobbled capital spending trends on the part of E&Ps internationally, as well as range-bound oil prices, will limit upside.

In North America, excess equipment will continue to overhang the oilfield service market and pricing. For this to change, commodity

Cathay Bank

Fuel your success with resources from our energy finance specialists

Whether your needs include reserve-based lending or cross-border experience, our Oil and Gas Group has the expertise to power your growth.

We can help.

Ask us about our wide range of energy finance products that can be customized for you.

Dale Wilson	SVP, Manager	832-517-6151	Dale.Wilson@cathaybank.com
Stephen Bacala	VP, Portfolio Manager	225-964-1116	Stephen.Bacala@cathaybank.com

Forbes 2019 BEST BANKS IN AMERICA TOP 10

cathaybank.com | 800-922-8429

MEMBER FDIC

prices will need to improve or drilling increases. Kona said declines from shale forcing producers to take on second-tier acreage might help demand. Though these potential positives are probably several years out.

In the near term, the large number of drilled but uncompleted wells (DUCs) could improve business.

"The number of U.S. [DUCs] soared to more than 8,500 in the first quarter of 2019, according to the U.S. Energy Information Administration—an all-time high—promising a steady need for well completions through 2020," Kona wrote.

The hottest drilling targets in the U.S.—particularly the Permian Basin and to a lesser extent the Eagle Ford and the Marcellus shales—promise a healthier environment for oilfield service providers.

Moody's noted that the Permian "produced over 4.1 MMbbl/d while using 451 rigs in May 2019—a massive increase from 1.6 MMbbl/d and roughly 550 rigs in mid-2014." But the downside is that this demand is drawing competitors.

As producers continue to drill more efficiently and streamline their operations, and as service providers' high-tech rigs speed up drilling, Kona said the rig count may have hit a ceiling of about 1,000 total rigs.

Drillers with high-spec rigs, including Helmerich & Payne Inc., Patterson-UTI Energy Inc., Nabors Industries Ltd. and Precision Drilling Corp., have seen their margins increase significantly since the beginning of 2017, almost doubling in some cases, according to Moody's financial metrics and company reports. Utilization has not kept pace, however.

For the largest service companies, revenue has slowed into 2019 after a rise last year, and EBITDA margins are slim. The Moody's report found that Schlumberger Ltd. had about a 20% EBITDA margin in March of this year. Comparatively, Baker Hughes Inc., a GE company, had about a 22% margin, while Halliburton Co. had about a 16% margin and National Oilwell Varco Inc. about 8%.

In the offshore drilling arena, offshore drillers still face excess capacity despite modest improvement thanks to new long-term contracts and a slight rise in utilization, according to the Moody's report.

Kona wrote the "oversupplied offshore segment is probably years away from rationalizing" although the new deepwater contracts announced by Diamond Offshore Drilling Inc. and Transocean Ltd. are a plus.

Dayrates for offshore service providers have risen but are still well off the peak. The Moody's analyst looks for a pickup in deepwater activity in the North Sea, the Persian Gulf, Southeast Asia and other international offshore areas to push utilization to high levels in the short term.

Lastly, Moody's noted that consolidation will be a trend, particularly for smaller oilfield service companies.

"Without significant organic growth opportunities, and amid low equity valuations and weak commodity prices, many smaller companies will likely consolidate through stock-financed M&A transactions, since the companies will be strapped for cash and unable to access debt markets," Kona wrote.

A more upbeat scenario for offshore service industry could turn on OPEC production cuts, continuing stress in Venezuela or strong oil demand in India and China.

"Multiple years of underinvestment in resource development and declines in mature production bases would accelerate E&Ps investment in 2020 and beyond if crude demand holds up," concluded Kona.

—Susan Klann

Permian Basin will need more water investment

Energy data and analytics firm Drillinginfo Inc. forecasts about $17.3 billion in water investment will be needed in the Permian Basin, the biggest oil field in the U.S., by 2025 to sustain activity.

Driving the spending is the need for produced water disposal, which has increased along with production growth.

"Water processing and operations can have a significant impact on any operators' LOE [lease operating expense]," said Akash Sharma, a senior petroleum engineering analyst and consultant for Drillinginfo. Understanding that from various standpoints—including disposal, trucking and treatment—is crucial, he added.

The amount was formulated based on forecasts that projected water production tied to certain drilling scenarios, which factored in water-related costs such as sourcing, recycling, transportation and injection.

The average slickwater frack job—which dominates in the Permian—used about 16 million gallons of water in 2018. Five years earlier, the average was about four million gallons, according to Sharma, who spoke on the topic during a recent Drillinginfo webinar. Although frack sizes and aggressiveness have increased, he pointed out how the trend has stabilized as operators have figured out formulas that work.

Still, "having access to treated high-quality water to support a lot of these frack operations moving forward is going to be critical for sustained operations [and] growth in the region," he said. "I think the availability of freshwater and the amount of investment going into water treatment is going to become increasingly important."

In the dry desert conditions of the Permian Basin, water remains a critical natural resource for oil producers. Anticipated production growth means companies are paying closer attention to water usage, disposal and recycling. Surface water constraints have already led operators to reuse flowback and produced water, which is leading to cost savings.

Sharma said produced water from the Permian grew from 37% to 48% of the national produced water from 2014 to 2018 as fracks got bigger, activity increased and operators explored new areas in the basin. This, in turn, pushed up disposal activity—Sharma described as the "cheapest way of handling produced water"—especially in Reeves, Loving and Eddy counties.

To devise the water economic analysis, Drillinginfo developed forecasts, including a base case and a range of forecast scenarios. On the aggressive side, the firm forecast a 10% improvement in IP and a 10% drop in drilling and completion (D&C) costs. The most conservative forecast scenario, including a 10% drop in well performance, is possibly the result of increased parent-child well interference and a 10% rise in D&C costs.

The oil and gas forecasts were then combined with water-oil ratios, Sharma explained. Meanwhile, frack water forecasts were devised based on stabilizing water

ENCAP INVESTMENTS L.P.

The leading provider of growth capital to the independent sector of the U.S. oil and gas business.

Houston Office: 1100 Louisiana Street, Suite 4900, Houston, Texas 77002 | 713.659.6100
Dallas Office: 3811 Turtle Creek Blvd., Suite 2100, Dallas, Texas 75219 | 214.599.0800
www.encapinvestments.com

usage and frack trends, which he said have stabilized.

"Oil and gas production volume is going to be the driver not only for produced water but also for what needs to be disposed of and the amount of frack water that will be needed for activity," he said, noting none appear to be flatlining.

But there are some risks.

These include disposal wells nearing capacity and increased seismicity, the focus of research underway is to determine epicenters and impact. "This could potentially have a huge impact on the ability to build disposal infrastructure in the long run," according to Sharma.

Many producers are already focusing on water issues.

ExxonMobil Corp., for example, is building an integrated water management system that aims to "efficiently move water across our acreage and enable recycling and reuse of produced water," the company said on its website. "In our New Mexico operations, we recycle a portion of the water produced from wells and utilize it to support drilling and completion activities."

ExxonMobil, which has a 1.8 million net-acre position across the Delaware and Midland basins, aims to produce 1 million barrels of oil and gas per day by 2024 from the Permian.

Recycling produced water is also leading to savings for shale players. Among those highlighted by Drillinginfo was Cimarex Energy Co., which recycled more than half of its produced water last year. The company had a savings of $1.20/bbl of water.

Companies in Permian have taken on more responsibility in water handling, Sharma said, noting those with contiguous positions tend to have better water spend criteria in the basin.

Comparing the Delaware and Midland sub-basins, he said the latter has more water production due to higher activity.

"But more of the new leasing activity is concentrated around that southern Delaware Reeves county southern New Mexico border," Sharma said. "We expect that to pick up significantly as well. … One advantage for operators on the Midland side of the basin is more infrastructure to handle and process produced water."

However, investment in more water and water-related infrastructure will be needed across the basin.

"Investment in water treatment, investment in disposal and investment in transportation associated with that aspect of water handling is expected to increase and is expected to play a vital role in any field development project that we expect from key Permian developers going forward," Sharma said.

—Velda Addison

Analyst: 'We need oil exports to keep going'

In less than four years, hydrocarbon exports have vaulted from a twinkle in Harold Hamm's eye to a critical component of U.S. oil and gas economics.

"Our livelihood, the livelihood of the industry, is going to rely on exports for the next four to five years or longer," said Scott Potter, managing director of business development for RBN Energy, at Hart Energy's recent Midstream Texas conference. "We need exports of crude oil to keep going; we need exports of natural gas to keep going."

The 40-year ban on U.S. oil exports ended in December 2015 as a result of a passage in an omnibus spending bill passed by Congress and signed by President Barack Obama. Harold Hamm, chairman and CEO of Continental Resources Inc., spearheaded lifting of the ban, in part to support an industry struggling with a plunge in oil prices.

Prices have since stabilized, and efficiencies have allowed producers to thrive even at lower breakevens. That has led to an oil production growth forecast that is strong across U.S. unconventional plays, but spectacular in the Permian Basin.

"Next year sometime or definitely in 2021, the Permian Basin will be at the point where we are producing as much crude oil in the Permian Basin as we produced in the whole U.S., including the Gulf of Mexico, back in 2004," Potter said.

Which begs the question: Where is it all going to go?

Shale plays provide an abundance of light oil (40 degree to 50 degree API), but the U.S. refining sector has maxed out on how much it can take. Refineries in this country require 8 MMbbl/d of imported heavy crude to keep running at full tilt. Potter said that means 20% of current U.S. crude output and all incremental barrels for at least the near future must be put on ships destined for overseas markets.

"We have to have the pipelines built, we have to have the docks and we have to have the ships because we can't use it here," he said.

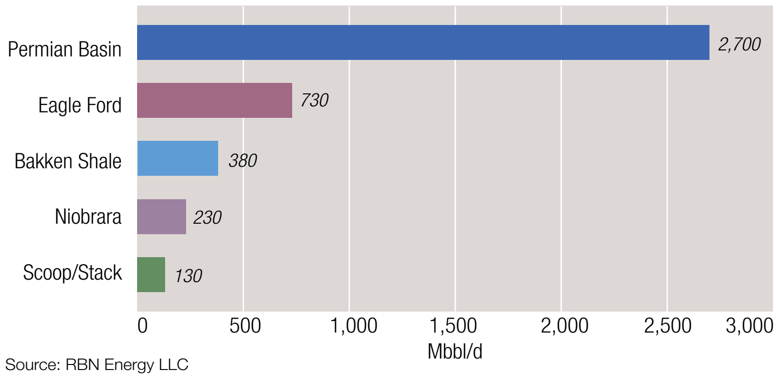
The case with natural gas isn't much different. The Permian Basin produces about 12 billion cf/d, and about half of that is exported to Mexico through pipelines and LNG tankers.

But the production growth prediction sometimes brings a skeptical response from industry operators. What if the price of WTI drops to $50/bbl? (On June 20, WTI spiked 5.5% to $57/bbl after Iran shot down a U.S. drone).

Potter isn't concerned, noting that the price collapsed to around $26/bbl in 2015 and Permian production continued to grow, albeit not as dramatically as when the price recovered in 2017.

"Maybe [the price collapse] flattened out the growth, but it's still growing, so I don't that think that $53 a barrel is going to slow the Permian Basin," he said. The Permian price relative to the price

Oil Production Growth By Basin, 2019-2024



Source: RBN Energy LLC

18TH ANNUAL

A&D STRATEGIES AND OPPORTUNITIES CONFERENCE

TOPICS DISCUSSED:

- ✔ Deal-making hotspots
- ✔ Public equity, private equity & barriers to deal-making
- ✔ Bid/Ask Gap
- ✔ Data & ROI
- ✔ Latest opportunities and strategies for mineral buying
- ✔ Oil & Gas Price Outlook



REGISTER TODAY: ADStrategiesConference.com at the Cushing, Okla., hub typically is pretty close, but there have been times that it's been $20 a barrel less, he added. Every time it drops like that, he said, it means pipeline capacity is lacking.

That issue is on the way to being resolved, with 4.3 MMbbl/d of crude pipeline capacity proposed to move product out of the Permian between now and 2021. The six projects include Wink-to-Webster, Cactus II, EPIC, Gray Oak, Midland-to-Echo III and Permian Express IV. When built, Potter said, the industry should be in a pretty good position to get crude from the Permian Basin to Gulf Coast destinations of Houston, Corpus Christi and Nederland, Texas.

Then what? To paraphrase the Sheriff Brody character in "Jaws," the export sector is going to need bigger boats.

"One of the questions people give me is, 'Is anybody still trying to put money into this industry?'" Potter said. "And I say, absolutely, they're looking for the big projects and one of them is the VLCC [very large crude carrier]."

VLCCs can carry as much as 2 million barrels of oil. By comparison, Germany consumes 2.4 MMbbl/d of oil. The proposed crude export terminals would boast a capacity of 12 MMbbl/d, though Potter doubts all will be built.

If there is a headwind in the export scenario, it might be complacency. The solution to the U.S. supply/demand imbalance has been exports.

"For the past five, six years we just put it on ships and they sailed off into the horizon and we said, 'great, problem solved,'" Potter said. "But no one really has their arms around the question of: Is that demand for propane and natural gas, crude oil going to be there? We just assume it is, and nobody really knows for sure if it is going to be there in five, 10 years."

—Joe Markman

How does GoM stack up against shale?

U.S. shale is still all the rage, with long laterals around 10,000 feet in the Permian Basin and 18,000 feet in Appalachia getting enough oil and gas from reservoirs to set production records.

But offshore, including the U.S. Gulf of Mexico (GoM), is competing with shale activity as breakevens continue to improve, according to industry experts.

Oil companies have lowered breakevens by some 40% to 60% since 2013, according to Tim Bjerkelund, senior management consultant for Rystad Energy. Speaking during the Rystad Energy and Pareto Securities Shale and Finance Forum, Bjerkelund pointed out how the breakeven for Royal Dutch Shell Plc-operated Vito development in the GoM has dropped from $67/bbl to $35, putting it on par with $37 breakevens seen in the Permian's Delaware sub-basin in New Mexico.

Similar stories are unfolding offshore in other parts of the world like the North Sea, where operator Equinor has brought down the breakeven for Johan Sverdrup Phase 1 from $40/bbl to $15.

Companies have revamped designs and worked closely with suppliers and partners, among other efforts, to bring down costs offshore, traditionally known for having expensive projects. The focus comes as offshore projects work to stay alive alongside more nimble shale projects as companies keep eyes on spending.

"We know that the shale companies have done the same," Bjerkelund said.

He compared a Vito-type development to a Permian-type development to illustrate how the economics of the two could compare. Investing, for example, $2.5 billion in each of the projects yields essentially similar production profiles—the big difference being whether production is wanted sooner rather than later.

"In total, a Vito type of field would get 280 million barrels in total oil equivalents. A shale portfolio gets 200," he said. "So, then the question is, do you want 200 tomorrow or do you want 280 over the next 20 years?"

But what's the payout?

Assuming $60 Brent and $55 WTI, he used one of Rystad's models to calculate how cash flows would look given investment and costs, and offshore had higher IRR and NPV, though shale also fared well. Still, there are other elements to consider.

"You have to commit quite a bit more money upfront compared to shale where you start to get some revenue from that first well you're going to drill," Bjerkelund said. However, optionality adds another element to the mix.

The key is investment in facilities that enable production over the long term, according to Bjerkelund.

Subsea wells tied back to existing production facilities have been reducing not only costs but also start-up times in the GoM.

"Similarly, in shale you can expand your portfolio by another well or by another 10 wells. So, both of these projects have apparently a lot of optionality," he said, noting incremental drilling opportunities.

With offshore, an operator may find pockets of oil that it either didn't know about earlier or didn't sanction in the initial phase. Accessing these resources isn't as expensive because of all of the previously invested money on the facility, he added.

Bjerkelund also pointed out how some of the biggest undeveloped discoveries in the GoM are second phases of projects. Phase two of the BP-operated Kaskida is on the list.

"So, in total we actually have a project that is better than it initially was," he said.

Companies like Anadarko Petroleum Corp., BP, Shell and Talos Energy are relying on existing infrastructure to uplift economics for exploration and production.

Infrastructure is also playing a key role in the Permian, where some companies have been challenged by insufficient takeaway capacity.

Oil giants ExxonMobil Corp. and Chevron Corp., global players with major Permian-focused growth plans, are taking strategic steps.

"They're building in a very structured way in order to be able to fully utilize the value of their infrastructure as they go along," Bjerkelund said. "They're used to this type of thinking; you build your infrastructure, you capture the big money and then you start adding option value to that development over the long term."

But there are some offshore projects that are essentially "dead in the water" due to high costs and very long lead times, he said. The key is to have an offshore portfolio stocked with "real good projects because they are competing with shale every single day and that means that you need to do exploration properly, but that's a whole different ballgame."

—Velda Addison

Industry Intelligence. Focused Legal Perspective.
HIGH-YIELDING RESULTS.

Whether it's managing an environmental or regulatory matter, inspecting for pipeline safety, acquiring title and rights to land, or partnering to develop midstream assets, we help solve complex legal problems in ways that favorably impact your business and bring value to your bottom line.

Meet our attorneys at **babstcalland.com.**

Babst | Calland
Attorneys at Law
Where Trust and Value Meet.

PITTSBURGH, PA | CANTON, OH | CHARLESTON, WV | HOUSTON, TX | SEWELL, NJ
STATE COLLEGE, PA | WASHINGTON, DC

CONFERENCE

Eagle Ford 2.0

A New Generation Takes the Reins

Register Today!
DUGEagleFord.com

Plays Covered:

- Upper Eagle Ford
- Lower Eagle Ford
- Austin Chalk
- Woodbine

DUG EAGLE FORD

2018 Stats:

- 1,551 Attendees
- 28 Speakers
- 62 Sponsors
- 120 Exhibitors



EXHIBITION

Presented by:
HARTENERGY

Hosted by:
E&P Oil and Gas Investor MIDSTREAM

Prices INCREASE August 30. Register today at ***DUGEagleFord.com.***

CELEBRATING 10 YEARS 2010-2019

CONFERENCE & EXHIBITION

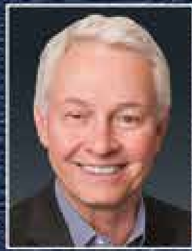
DUG EAGLE FORD

Sept. 24-26, 2019

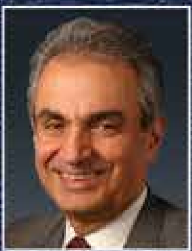
Henry B. Gonzalez Convention Center
San Antonio, Texas

Featured Speakers:

Wendy King
Vice President, Great Plains BU, Lower 48, **ConocoPhillips**



Steve Adam
Executive Vice President & COO, **SilverBow Resources, Inc.**



Dr. Ali Daneshy
President, **Daneshy Consultants Int'l**; *adjunct professor of Petroleum Engineering,* **Cullen College of Engineering, University of Houston**

Branden Kennedy
CFO, **Venado Oil & Gas**

Additional Speakers*:

- **Charles Cusack**, *President & CEO,* **Recoil Resources**
- **William E. Deupree**, *Founding Partner, President & CEO,* **Escondido Resources**
- **Peter Duncan**, *President & CEO,* **MicroSeismic**
- **Bryce Erickson**, *Senior Vice President,* **Mercer Captial**
- **Bernadette Johnson**, *Vice President, Market Intelligence,* **Drillinginfo Inc.**
- **Phil Martin**, *CEO,* **New Century Exploration LLC**
- **Eric McCrady**, *CEO,* **Sundance Energy Corp.**
- **Mark A. Norville**, *President,* **Blackbrush Oil & Gas**
- **Kirk Spilman**, *President & CEO,* **Pursuit Oil & Gas**

**New speakers are being added daily.*

NEW

Well Interference Forum:
The Business & Engineering Challenges

Sept. 24, 2019 ★ 1:00-4:45 PM

This half-day forum** addresses well interference in developing tight oil & gas resources. Topics include current understanding of the phenomenon, specific issues in tight formations and emerging methods industry experts are using to address these issues.

***Separate registration required.*

Prices INCREASE August 30. Register today at ***DUGEagleFord.com.***

BUILDING A BIGGER BAKKEN

The Bakken's operators are seemingly locked into a dwindling geography in North Dakota, but companies are increasingly returning to their wildcatter roots to see how far they can stretch the Williston Basin's core.

ARTICLE BY
DARREN BARBEE

PHOTOGRAPHY BY
STEPHEN COLLECTOR

The first horizontal wells drilled in North Dakota were fierce and untamed. The rock seemed to buck and fight, pushing the drillbit away. In 1995, Continental Resources Inc. began drilling the Red River B Formation in an interval of 8 to 10 feet. Geosteering hadn't advanced past the pencil and paper phase. The goal was to stay in the oil-saturated top half of the zone, said Harold Hamm, chairman and CEO of Continental.

"But, in the beginning, you were out of zone more than you were in," he said.

Horizontal drilling was in its infancy. Fracture stimulation of oil wells was years away. And the wells that Continental drilled in Cedar Hills Field were tough.

"Drilling the Red River was kind of like drilling blind with a cane, and you're tapping the top of the zone and the bottom of the zone and then trying to stay in," Continental president Jack H. Stark said.

But by March 2004, Continental's Robert Heuer 1-17R well in Divide County, N.D., had become the Bakken's first commercial producer from a hydraulically stimulated horizontal well. And the world changed.

"I will never forget looking at the core and seeing oil staining down in the Three Forks Formation," said Continental Resources Inc. chairman and CEO Harold Hamm.

Previous page, Hess Corp.'s Tioga gas plant is seen from a farm in the outskirts of Tioga, N.D. Facing page, a tanker is on its way to a Hess workover rig in Williams County, N.D.

Fifteen years have passed since Continental Resources drilled the first commercially producing, horizontally stimulated well in the Bakken. The Williston Basin might be considered middle aged as shale oil plays go, but it continues to surprise the industry with its vitality.

For years, Continental has created sophisticated, five-year plans that offered a precise outlook for the company. While Continental already produces about 14% of the Bakken's oil, this year's plan caught Hamm and Continental's management team off guard.

"It really shocked us," Hamm said. "We knew we had really had good inventory, but when you look out there and Continental's inventory still totals 4,000 wells in the Bakken," Hamm said. That figure does not include the company's nonoperated well interests.

Continental has drilled roughly 1,800 Bakken and Three Forks wells, according to Stark. "So we're through maybe 25% to 30% of our inventory at this point," he said.

Despite the basin's maturity, North Dakota trails only Texas in production, which has soared this year. In January 2019, operators set a record by producing an average 1.4 million barrels per day, 96% of which were from the Bakken and Three Forks formations.

But questions of longevity continue to pester the Williston Basin. In a June report, analysts at Seaport Global Securities said of WPX Energy Inc., for instance, that "the best stuff in the Bakken seems drilled up."

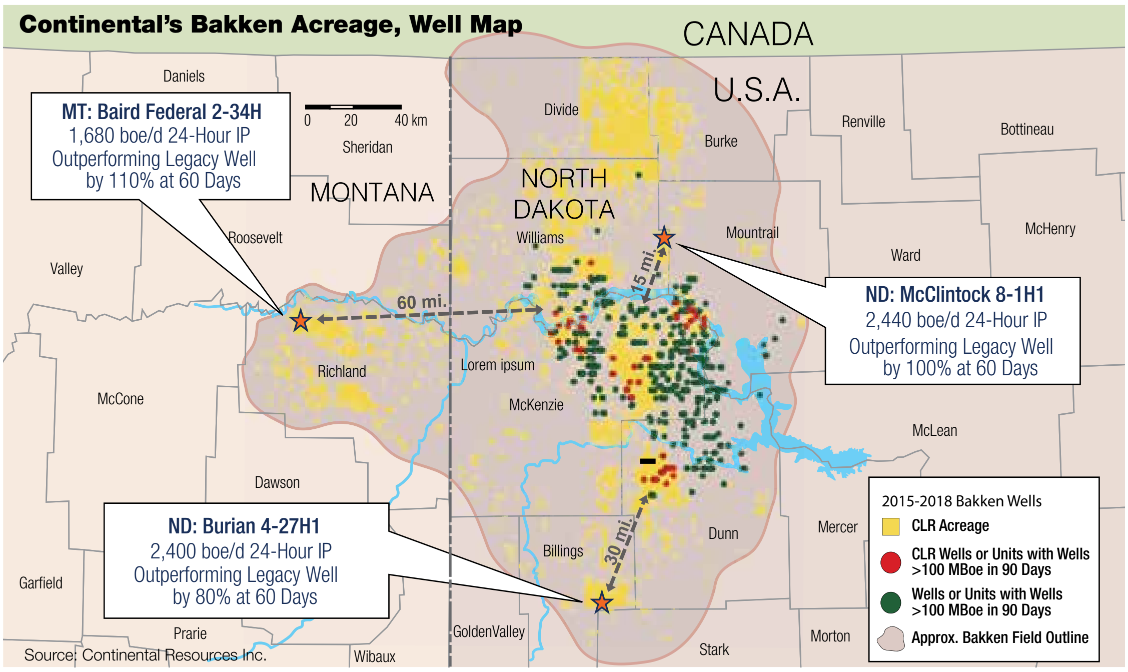
Despite construction of new oil pipelines, natural gas capacity remains limited. In some cases, companies have backed off production in order to meet the state's natural gas flaring and venting caps.

And while Bakken E&Ps face the same questions as companies in other shale plays, operators in the maturing basin are saddled with more pointed questions. As the basin's natural resources are depleted, how much is left? Is the Bakken truly boxed in?

Hess Corp., among other companies, has efforts to drill areas once thought to be second-tier.

"We're nowhere [near] done drilling in the Bakken," said Barry Biggs, vice president of onshore operations at Hess. The company's Bakken program will encompass 160 wells in 2019, mostly in the core of its position. About 25 of the wells will explore the hinterlands.

The Bakken's shelf life is a moving target. Its estimated remaining inventory is between



Continental is performing strategic step-out tests to optimize completions to uplift well performance in North Dakota and Montana.

34,000 and 98,000 well locations, according to a 2018 study by the North Dakota Pipeline Authority. At an assumed rate of 100 new wells drilled and completed monthly, North Dakota's initial run of wells could last up to 81 years—or as few as 28.

The Bakken's stamina hinges on the pace of drilling and oil prices, said Brian Velie, an analyst as Capital One Securities Inc.

Because of the oil price downturn and its continuing aftershocks, as well as takeaway constraints in the Bakken, companies have slowed down more than they have accelerated in the past few years, Velie said.

Continental used the time to learn "a great deal more about how to create additional stimulated rock volumes," Hamm said.

The delay in development has increased the lifespan of the Bakken's inventory. But beyond that, and outweighing pacing assumptions, is a shift toward new exploration in the fringes of the play.

"There's a movement now, and it's been ongoing, toward the development or the expanding of the core," Velie said.

Upstream companies are targeting their Tier 2 acreage not with the expectation of surpassing the core's economics, but with the goal of bringing wells online that make a similar return.

"If they're running out of core, they can't necessarily go back with a better recipe and get even better economics on that core because those locations are largely drilled," he said. "But they continue to get similar returns on lesser rock because of the completion improvements."

From a dollar and cents standpoint, Tier 2 wells perform similarly to the last well drilled in the core. Production rates are unlikely to match core acreage, but wells produce to the degree "that they're making good returns," Velie said.

Nicholas L. O'Grady, CFO at Bakken non-op company Northern Oil and Gas Inc., said that over the past few years, most rigs have hugged the core. Now, they're starting to push out toward western and northern Williams County, southern Billings County and even into Montana.

"We've seen a handful of results in those areas, and a handful of operators who have really gone after it successfully, like a few private-equity-backed companies," he said. "We are encouraged by what we're seeing outside of the core."

Bakken runway

Beyond the Bakken, clues to the next Williston formation were hiding in a library—a core sample library.

Three Forks core samples, stored at the University of North Dakota, had Hamm doing a double take.

"I will never forget looking at the core and seeing oil staining down in the Three Forks Formation," Hamm said.

The Tioga gas plant, in Tioga, N.D., was built in 1954 and has been in operation ever since. Hess is increasing its capacity from 250 MMcf/d of gas to 400 MMcf/d with a $150 million planned expansion.

He was convinced the formation was separate and distinct from the middle Bakken. Skeptics dismissed the idea.

In July 2008, Continental set out to prove them wrong by drilling its Three Forks well. In June 2009, to prove the Bakken was a separate formation, the company drilled over the Three Forks' ceiling, with the wells crisscrossing in McKenzie County, N.D. Continental's Mathistad 2-35H Bakken well came online and for its first seven days averaged 995 barrels of oil equivalent per day (boe/d). To that point, it was the company's strongest performing Bakken well.

"Sure enough, a year later, half of the people up there were staking a well in the Three Forks," Hamm said.

The Bakken's consistency has quieted any naysayers over its potential. In 2011, the U.S. Geological Survey put the Bakken's reserves at 3.8 billion barrels (Bbbl) of recoverable oil. By 2017, the Bakken had already produced 2.4 Bbbl, according to the U.S. Energy Information Administration.

Operators have thrived by beating the odds: improving cycle times, innovating with technology and completions and spending less to produce more.

Hess' presence in the Bakken is already massive. At $60 oil prices, Hess can drill its current inventory of 50% or better IRR wells for the next 15 years.

"We've got a lot of running room," Biggs said.

What constitutes the core Bakken areas is already starting to blur, O'Grady said. Northern's interests extend to 6,500 penetrations, and the company will be a participant in 40% of every Bakken and Three Forks well drilled in the basin.

Early results by operators have more than doubled Northern's productivity estimates.

One producer, which purchased extension acreage from a large independent, is bringing wells online that Northern foresaw having 300,000-bbl EURs.

"They're consistently making six, seven, 800,000-barrel wells," O'Grady said. Operators have been "very careful about how they complete them and the technology that they use."

More recently, E&Ps such as Continental are also making an effort to retrace their steps. In April, the company announced that three stepout wells in Montana and North Dakota, dozens of miles from the Bakken core, yielded IPs ranging between 1,680 and 2,400 boe/d.

Stark calls the wells "bold step-outs" to prove modern technology works in other parts of the basin.

"We've stepped out here to the southern reaches of our leasehold, to the western reaches of our leasehold" and toward the north, he said.

Continental drilled its step-out Montana well in Richland County, in Elm Coulee Field, where the company was solidly producing in 2011.

Continental was looking in the other direction at the time. The company's step-outs were headed toward the north, and the company was envisioning development of the North Dakota Bakken "on 320-acre spacing like Elm Coulee Field in Montana," according to Continental's August 2011 Securities and Exchange Commission filings.

Hess Corp. 2019 Drilling Program By Field

Field	Keene	Stony Creek	East Nesson	Beaver Lodge/Capa	Other[1]
EUR (Mboe)	1,350	1,300	1,100	1,100	950
IRR	>100%	80%	60%	70%	45%
2019 wells online	45	30	40	20	25

Source: Hess Corp. 1) Other fields include Goliath, Red Sky and Buffalo Wallow.

Continental took new technology into what would be considered "older areas that hadn't been as active for us," Stark said.

"And that's not too far from where we started in North Dakota, really. It's just up the road," he said.

The Montana well outperformed a legacy well by 110% within 60 days.

Continental's 4,000-well inventory includes the outlying areas, but its stimulation work is proving the uplift in performance, reserves and rate of returns that the company expected.

"We've just uplifted the quality of that inventory through the technology," he said.

Hess is on a similar path, though one ultimately separated by time and geography: Bakken now, offshore Guyana later. In between, the company sees plenty of opportunity for detours outside of the Bakken core.

The company holds about 550,000 acres with 2,700 well locations economic at $60 West Texas Intermediate (WTI). And the Bakken will be the growth engine for the company in coming years. By 2020, Hess anticipates annual free cash flow of $750 million, depending on oil prices, Biggs said.

Producing that cash flow requires Hess to primarily drill its core, Tier 1 acreage.

What comes after 2021 is what Hess is at work on now.

"What we're trying to do here is prepare ourselves, to give us time to further crack the code, for lack of a better term, to where our drilling locations will be coming out further out in our campaign," he said.

This year, Hess will test areas in the east, north and northwest, in fields called Red Sky, Goliath and East Nesson. Last year, the company ramped up to six rigs and will keep up the pace through 2020 before ratcheting down to four rigs in 2021. Some of the rigs will conduct drilling tests in an effort to create a bit of Tier 2 to Tier 1 alchemy.

"We don't talk about it much either, but Little Knife, which sits down south of Keene, is another area that has inventory remaining out further in our drilling program," Biggs said. "We're trying to prove out where we have large inventory left after this 2021 time frame. That's the gist."

Testing boundaries

In its early days in the Elm Coulee portion of the Bakken, Continental's stimulation technique was essentially "pump and pray," Hamm said.

Barry Biggs, vice president of onshore operations at Hess, said the company is moving out of its core areas to "prepare ourselves, to give us time to further crack the code" in outlying areas.

Hess rigs are conducting tests in the Red Sky, Goliath and East Nesson fields to expand its inventory of economic locations.

Hess' Inventory Alchemy

While the technique proved effective and profitable in Montana, moving into North Dakota, the zones were deeper, higher-pressured reservoirs with far less porosity in the rock, he said.

As Stark put it, the middle Bakken is tight rock. "If you pull out the core and look at it, the middle Bakken looks like the concrete in your driveway," he said.

As the company shifted to North Dakota, Continental found that Montana completion methods "didn't work at all," Hamm said.

Last year, Continental's well completions averaged about 11 days. Today, the company can complete a well in as little as seven or eight days, said Chris Nichols, northern regional completion manager at Continental.

"That allows us to reduce our cost per well," he said. "It's really helped drop costs out of the system. And we're just making bigger wells in the process."

As a pioneer in the Bakken, Continental progressed through trial and error. Rather than coast on their success, the company and its peers have stepped up experimentation.

"Each of these are iterative points," Stark said. "As you go through time, each new turn of events stimulates a new thought and a new direction, or a new approach. And it just expands your perspective and understanding."

After years of technological breakthroughs, the push to expand bounds of the Bakken core will rely on proven successes combined with advances in data and technology.

In the fall of 2007, Continental was just beginning the transition to multiple-staged completions. A dozen years later, wells that once used 3 million pounds of proppant now use 10 million pounds. Stage counts have risen from five or six to as many as 60. And the company has tinkered with how to gain more exposure to the reservoir and the optimum spacing for perforation clusters.

"We've dialed in on a lot of those variables," Nichols said. "We've figured out through design of the perforations, the job size and the pressures, the rates" to increase the number of perforation clusters stimulated per well stage. The results have cut days off of completion times, allowing for reductions in costs per well.

Pictured above, the refrigeration process equipment at Hess' 250-MMcf/d Tioga gas plant in Tioga, N.D.

Pipe Up

The Bakken's chief vulnerability for most of this decade has been a choking lack of pipelines to ship out its rich, low-sulfur oil.

With the construction of the Dakota Access Pipeline, among others, shipments of oil by rail have dropped from a highpoint of 700,000 barrels per day (bbl/d) in December 2014 to about 300,000 bbl/d in April 2019, according to estimates by the North Dakota Pipeline Authority.

While oil infrastructure is available in 2019, oil price differentials have shot up from time to time in the recent past due to takeaway constraints, said Brian Velie, an analyst at Capital One Securities Inc.

Piping out natural gas remains a weak spot.

Hess Midstream Partners COO John A. Gatling said the company has executed a disciplined strategy to support not only Hess Corp. but other third parties in the basin. The company will also take advantage of Hess' push toward average production of 200,000 barrels of oil equivalent per day.

"That obviously creates a substantial platform for us to build our midstream on top of and in support of Hess' upstream operations," he said. "We were very fortunate to have built our strategic infrastructure in the best acreage of the basin, right on top of Hess' position."

Hess Midstream has continued to carefully expand its infrastructure in the basin in 2018 and 2019.

In February, Hess Midstream announced it would purchase Summit Midstream Partners' Tioga Gathering System that overlays some of Hess' key acreage position in the West.

"We've been able to integrate that and transfer that value both to Hess Midstream but also to the upstream, offering some better economies as it relates to gathering and ultimately transporting, processing, terminaling and exporting the upstream's business," Gatling said.

> "We'll have the largest single plant in the basin at Tioga, and then we'll have the second-largest processing capacity available in the basin as well."
>
> —John A. Gatling, Hess Midstream Partners

In April, Hess Midstream also announced it would expand the capacity of its Tioga gas plant to 400 million cubic feet per day (MMcf/d) from its current capacity of 250 MMcf/d. The expansion is expected to cost $150 million.

"As we see [Hess Corp.'s] production growth continue to move up, we also see third parties growing as well, and that created an opportunity for us to triple the size of our original expansion plan, which was previously discussed at about 50 MMcf/d," Gatling said. "So now we're kicking that to the total expansion of 150 MMcf up to 400 MMcf/d. So that's going to be great."

In 2018, the company began a $325 million capital expansion program. Hess Midstream also partnered with Targa Resources to build a gas plant south of the Missouri River that will increase its gas processing capacity to 500 MMcf/d.

"We'll have the largest single plant in the basin at Tioga, and then we'll have the second-largest processing capacity available in the basin as well," he said.

Together, Hess and Hess Midstream have been able to establish long-term takeaway capacities for crude residue and NGL.

"When you look at the full value stream from the wellhead, all the way to the markets, we feel like we're in a very strong position to deliver all the hydrocarbon to where it needs to be, and when it needs to be there," Gatling said.

Despite the Bakken's high oil cut, operators in the basin continue to struggle with throttling back natural gas flaring. In 2017, Bakken operators vented or flared 88.5 billion cubic feet (Bcf) of gas, nearly 18.5 Bcf more than in 2016, according to the U.S. Energy Information Administration.

North Dakota Industrial Commission Flaring/Venting Order

Deadline	Percentage of natural gas captured
Oct. 1, 2014	74%
Jan. 1, 2015	77%
Oct. 1, 2020	90%

Source: North Dakota Pipeline Authority

The Environmental Defense Fund estimates North Dakota flared and vented gas is worth $220 million.

Barry Biggs, Hess vice president of onshore operations, said the company has kept in compliance with state rules and regulations and, taking into account appropriate credits, run slightly below North Dakota's 12% cap on flaring basinwide. Hess earned credits by investing in equipment in certain areas or well pads, including incinerators, or through the extraction of the NGL, he said.

"But those are short term [solutions] as infrastructure gets built out," he said.

Hess, like other operators, must ultimately meet state requirements that, by Oct. 1, 2020, set out to capture 90% of natural gas and 95% afterward.

As Hess Midstream's infrastructure keeps pace, Biggs said that upstream operations will be able to more easily hit the state's requirements.

"As our wells come online, there's a period initially of flaring, and then as the infrastructure in all areas is completely built out to meet it with this ramping up to Hess' gross of 500 MMcf across the basin," he said. "We will be in compliance, and we don't see any issues of being able to do that."

Continental Resources Inc. chairman and CEO Harold Hamm said the company's ambition is to lead the industry in the amount of gas it saves.

From time to time, that's meant delaying well pads from coming online until a pipeline is built, constructed, and then a plant can process associated gas from oil wells.

"Sometimes it delays production a little bit to get facilities that you need, particularly plants, and then one of the big holdups … is this is a very rich gas," he said.

Gatling said that it's unfortunate that operators are behind from an infrastructure perspective.

"We would like to be capturing more gas, but it's also a bit of a high-class problem in that the wells and the basin in general are meeting expectations and, over the last several years, it's continued to beat expectations," he said. "Because the wells had been performing so well, and in particular, as Hess has transitioned to plug-and-perf and seen even better improvement on overall production rates, we're playing catch-up a little bit."

Hess Midstream's infrastructure plans are intended to meet Hess' needs as well as those of third-party producers.

"Third parties are having the exact same issue Hess is having," he said. "So just generally across the basin wells are performing better than expected."

Midstream companies have had to play catch-up as new technological advances, drilling and completions and cycle times improve, putting significant pressure on the infrastructure.

"We're definitely flat out executing work, and that's another reason why, as an example, we announced a threefold increase in our process and expansion," Gatling said. "We see that opportunity of continued growth, in particular, as Hess makes its way to 200,000 barrels of oil equivalent per day."

Damon Knupp and Torrey Ollermann (left) check the oil level of the sight glass in a compressor building at the Tioga gas plant.

"Instead of treating five of those clusters, we can treat eight," he said. "And [we] can treat eight clusters with one staging event, so that reduces our wireline time, our time on location for our crews."

In addition to its step-outs in other areas, Continental is among those companies that operate large units in the basin, according to Hamm

Large-scale development units have the potential to create "tremendous efficiencies going forward," he said.

"We're doing another one of those now and certainly, carrying out those types of developments is going to be quite the economic deal," Hamm said, adding that Continental is working on an "exceptionally large unit." He declined to give more detail.

Hess is also turning toward refinement in its operations while also exploring ways to innovate through completion techniques, technology trials, fiber optics and fiber coil.

The company's most recent, significant move has been transitioning to plug-and-perf completions after being one of the last holdouts of sliding sleeves, Biggs said.

"We did a big study last year that looked at the incremental profitability coming from moving to a plug-and-perf," he said. "That's resulted in us now saying we should hit 200,000 barrels [of oil equivalent] a day by 2021, which translates into $750 million in free cash flow."

The company sees automation, analytics and well design as areas in which it can make breakthrough reductions in drilling costs.

Hess is also working with Nabors Industries Ltd. and evaluating fracking optimization and automation.

Facing page, a row of propane bullet storage tanks at the Tioga gas plant.

"We're working with Nabors to try to automate and optimize the drilling sequence using our real-time drilling center, rig automation—all underpinned by predictive data analytics," he said.

"From a geosteering standpoint, the wells can geosteer themselves. From a data analytics standpoint, we can have the right weight on bit, rotation—all the drilling parameters," he added.

Hess is also studying new well designs that use monobore or a one-casing string design only. The company also tirelessly experiments with completion techniques to fit different areas. Tests are run on the number of entry points, well spacing, sand loading and diversion techniques.

With further technology trials, Biggs said Hess' goal is to whip up the best completion recipe for each area and "get the most out of the rock."

Buying Bakken

In 1985, Hamm began his exploration of the Williston. Oil prices had fallen, and the Williston wasn't just out of favor, but "pretty much dead to the world," he said.

In 2003, its impressive success in Montana, Continental stepped into North Dakota and leased 300,000 acres.

After the Heuer well, the company leased another 400,000 acres and continued to build a position that would top out at 1.2 million acres in the Bakken alone.

"Go find the next one," Hamm recalls telling his exploration team after confirming Elm Coulee Field. "This is good, but it's under our belt. Go find the next one.

"And they did."

Williston operators in need of inventory always have acquisitions open to them. But buying Bakken is no longer an easy or desirable task for public companies.

So far this year, the most notable A&D move seen in the Bakken was QEP Resources Inc.'s termination of a deal to sell its North Dakota and Montana assets for $1.73 billion. The first quarter was bleak for upstream A&D generally as oil prices nosedived to end the year.

Large-scale acquisitions are dangerous to companies, particularly in a market environment that punishes any deals, no matter how enticing to a board of directors.

"In North Dakota, you're not going to put your company at risk to go make big acquisitions," Hamm said. "We continue to do strategic things that make sense for the company. I'm talking about a few sections here . . . that make sense within our plays."

All public companies face a tightrope walk on Wall Street. Investors want to see an adequate number of drillable locations without the need to acquire more, Velie said.

"No matter what price you get for the next 100 locations you buy, if they're at the end of that location queue and you don't get to them in 15 years, from a net present value those aren't worth much at all in today's dollars," he said. "It's hard to justify that capital outlay today for wealth that won't produce for a decade or more."

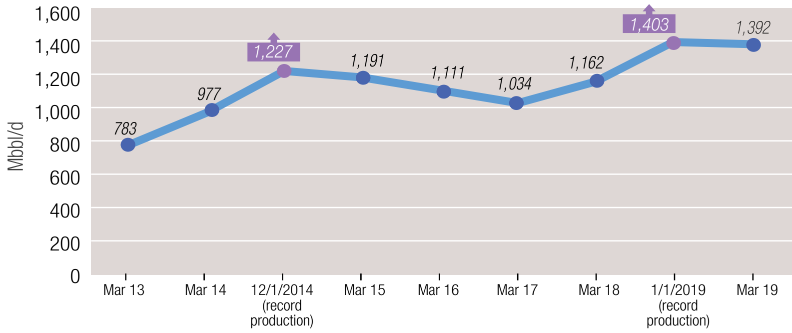
In the past 18 months, Northern Oil and Gas has been the basin's most consistent acquirer, albeit of nonop interests. Since the start of 2018, the company has made four large publicly announced transactions totaling more than $820 million.

Because it seeks out nonoperated interests, Northern is able to target slices of acreage in units operated or being developed by the largest producers. To find the best deals, the company has built a vast and complex database to track oil and gas development and deals in the basin.

In deals this year, Northern acquired assets from Flywheel Energy LLC and W Energy Partners for about $300 million each. Both come with a roughly 50:50 split of PDP and inventory.

"These assets have a good, healthy producing base," O'Grady said. "They're midlife cycle, but they've got significant growth left on them."

Bakken Oil Production



In January 2019, operators set a record by producing an average 1.4 million barrels per day, 96% of which were from the Bakken and Three Forks formations.

Of its four major acquisitions since June 2018, the company gained significant inventory while just one transaction was "truly a PDP deal, but the price was right," he said.

"In general, our ability to build core inventory is still strong. But I do think that the Bakken is mature. That's a good thing for making money: its midlife cycle, with strong well control," he said. "To be totally candid, in the deals we've done, most of the focus has been on adding additional inventory in the core."

While Northern has plenty of largess, like other companies it has noncore acreage, much of which has zero ascribed value to it—though it appears promising.

But Northern's data also show that what is considered core and noncore is a matter of perspective.

"Is it what we deem as core? Not always. But new areas are often what a core well was three or four years ago," O'Grady said. "We always tell people that our view is that there's the rock and there's the operator. The rocks definitely vary in quality, but we believe that the performance is driven by the quality of the operators as much as the rock."

Below, a historic cabin, built in 1895, sits near Iverson Road in Williams County, N.D. Facing page, West of Ray, N.D., in Williams County, a vintage truck carrying a cheeseburger and fries display is parked in a field as an advertisement for Mattie B's restaurant.

While the results in other areas are encouraging, it doesn't mean extension areas won't be sensitive to oil prices. Extension wells also tend to decline more sharply or have higher water cuts.

On a broader scale, O'Grady said that even if core wells were to show no major improvement, successful extension wells that the company participates in are getting materially better.

"And we think many operators within the core continue to refine their techniques. If they're catching up to the best practices, that in turn means there's still room for the average well to continue to get better," he said.

In May, KKR and Western Natural Resources LLC entered into a partnership to acquire producing and undeveloped oil and gas assets in the Williston Basin.

Velie said that privately funded ventures may have more of a presence in the Bakken because, with oil prices suffering, "these assets are probably getting picked up for what, in historical terms, would be very favorable terms."

While new entrants may be scouting the Bakken, it's likely that more private-equity-backed teams are looking for an exit, O'Grady said.

"I think it really depends on how they're capitalized and if there is a clock on that capital," he said.

Private companies also don't face the pressures of fitting an acquisition in with a narrative or lining up the company balance sheet.

"They can act on strictly an economic basis that doesn't have to fit with a narrative of the broader company that has to report publicly," he said.

With the public markets in disarray and credit markets souring, A&D has stagnated to some degree in the Bakken as well as other plays.

"That's not Bakken specific. That's really oil and gas specific. And I think there's less new capital in general, public or private," O'Grady said.

In the Williston, Northern Oil and Gas estimates $5 billion worth of nonop packages are up for sale, including a large percentage that is tied to private-equity money or is distressed.

"We see all these packages when they're being shopped," he said. "And what I tell you is that a lot of them are not trading because often the prices have gotten low enough that a lot of people have not been willing to accept where the market prices are today. We deal with it every day. We continue to raise our return thresholds, because the clearing price has been falling."

Nevertheless, money always flows into the basin, where its maturing properties appeal to certain types of investors.

"These assets are generally producing cash the day you buy them, but without the data and experience it would be very easy to make poor returns on capital," he said.

But private equity's problems are mounting. "I think that there is a coming storm in which some of these funds have to ultimately monetize their assets due to fund life issues," he said, noting that Northern sees some of the same assets come to market in two or three failed processes and the price keeps going down.

That's worked to Northern's advantage. "Not even four years ago, to get acreage in the Bakken you would have paid PV7 or PV8 for the PDPs, and then had to pay a per acre or per location value to everything that was undeveloped, despite minimal well control," O'Grady said.

In today's market, it's not uncommon to buy a well and get several locations thrown in so an operator, mineral owner or family office can be free of its capital obligations.

The Bakken is genuinely a money-making business now, he said.

"If you have the engineering and technical expertise, you can go and buy things with a true private return … earning a solid return on capital," he said. "Any development you get is generally just gravy to that. That is not the way this space has been for the last 10 years since shale took off. I've covered this space for 18 years, and I haven't seen this since probably 2002 or 2003."

Hamm said that private-equity teams also weren't a factor early in the Bakken, and most leases are held by eight to 10 large companies.

"I wouldn't say that nobody's for sale," he said. "I mean people do that. But you don't have as many of the private equities up there in that field just because it wasn't the flavor of the day."

And the real players, including Continental, are in the basin to stay.

"We made it work and were willing to stick with it," he said. "The evolution that you see today, you know, we're that evolution. I'm not sure it's complete, but we're beginning to level off here at the top." □

Hawkwood energy

$1,000,000,000
Senior Secured Revolving Credit Facility
Participant

VENADO OIL & GAS

$1,000,000,000
Senior Secured Revolving Credit Facility
Participant

Sabinal Energy

$750,000,000
Senior Secured Revolving Credit Facility
Participant

GOODNIGHT MIDSTREAM

$420,000,000
Senior Secured Revolving Credit Facility
Co-Agent

COGENT MIDSTREAM

$300,000,000
Senior Secured Revolving Credit Facility
Participant

SABALO ENERGY

$250,000,000
Senior Secured Revolving Credit Facility
Participant

BAYSWATER

$200,000,000
Senior Secured Revolving Credit Facility
Syndication Agent

HORIZON resources

$200,000,000
Senior Secured Revolving Credit Facility
Sole Bank

CALIBER MIDSTREAM

$120,000,000
Senior Secured Revolving Credit Facility
Co-Documentation Agent

Let us be your bridge to continued success.

At East West Bank, we are all about building long-term relationships and seeing our upstream and midstream customers excel. With our financial resources, industry knowledge and the seamless execution our clients have grown to expect, we are committed to providing "best-in-class" banking solutions.

- Ranked among the top 8 "Best Banks in America" by *Forbes* in 2019
- Top 25 largest banks in the U.S. by market cap and asset size
- Full range of energy finance solutions

Give us a call and experience our shared entrepreneurial drive.

Energy Finance Team
469.801.7360
energy@eastwestbank.com
eastwestbank.com/energy

EAST WEST BANK

NASDAQ: EWBC Member FDIC

CHASING OPTIONALITY

From wellhead to water, with a trading floor in between, ARM Energy Holdings continues to grow. CEO Zach Lee has inked four big joint ventures so far this year.

INTERVIEW BY
LESLIE HAINES

Zach Lee co-founded ARM Energy Holdings LLC, originally known as Asset Risk Management, in Houston in 2004. Still in his mid-20s, he built it on a foundation informed by his experience in commodities trading and related jobs at Duke Energy Trading & Marketing LLC and Entergy-Koch Trading LP. He worked in structured products and natural gas derivatives after earning a degree in business administration, specializing in finance, at Texas A&M University.

Fifteen years on, ARM has expanded well beyond hedging advisory. Today it also provides physical oil and gas marketing (it employs about 80 marketers and traders), and it builds and operates midstream systems in several basins. More recently, it added a fourth business line by putting its balance sheet to work through an internal team called the optimization group, which takes capacity on a pipeline or leases storage space, then aggregates production from several of its smaller E&P customers that otherwise might not have the ability to secure such capacity on their own.

"We step into the market for them and take risk on their behalf," Lee said.

The midstream unit contributes roughly 60% of total gross revenue; 30% is the physical marketing and trading and optimization group, and 10% is hedging. Between these four strategies, ARM serves more than 250 customers through offices in Calgary, Denver, Midland, Oklahoma City and Pittsburgh, with field offices in the Delaware Basin.

ARM began developing midstream assets in 2014. Most notably, it formed the Kingfisher Midstream LLC system serving the Stack play in 2015, which it sold in 2018 to Silver Run Acquisition Co. II for $1.35 billion. At the time, Kingfisher had processing capacity of 350 million cubic feet a day (MMcf/d) and 400 miles of gas and oil pipelines in the play.

Lee turned his sights to other basins. In 2017, ARM formed Salt Creek Midstream LLC in the Delaware Basin, with funds managed by Ares Management LP. Salt Creek offers natural gas and crude gathering, compression, cryogenic processing and water gathering services across nearly 1 million acres in Texas and New Mexico. Additionally, Salt Creek completed an NGL header system to serve Apache Corp.'s Alpine High development and Salt Creek's gas customers.

"We want to own midstream assets and then we want to be able to put our own capital at risk. If we can go find the market, and see a bottleneck, then we marry those two."

Currently, construction of a crude oil gathering, terminaling and transportation system joint venture with Noble Midstream Partners is underway, to give Permian producers access to Texas Gulf Coast markets.

In one deal example unveiled this summer, Delaware Basin pure-play Lilis Energy signed a firm takeaway and sales agreement with Salt Creek for 6,000 barrels a *day (bbl/d) of capacity through June 2020 and 5,000 bbl/d from July 2020 through June 30, 2024. Lilis contributed its acreage in Winkler, Loving and Lea counties; Salt Creek will provide capital to develop water gathering and disposal.*

We caught up with Lee recently to see what drives ARM's expansion, and what's next.

Investor Why did ARM migrate from hedging advisory to operating midstream assets? There's such a difference between trading on a computer screen and building infrastructure out in the field.

Lee We started the company in April 2004 to work with small to midsize companies to help them design and manage their hedge portfolios, but when unconventional shale hit, we saw this market get turned upside down. We saw areas such as the Northeast that had always been short gas become long gas. We saw this explosion of infrastructure. These shale basins changed from an F&D [finding and development] standpoint too, and so our customers came back to us and said, "We need help with this." We had a strong understanding of supply and demand on a basin-by-basin level.

We got into the physical marketing business first (in 2013), just trying to navigate this new normal. Then we had to figure out how to move that oil and gas around, and that led to what we're really good at as a firm, which is figuring out where the bottlenecks are and bringing a midstream solution that solved the bottleneck. So we went from being a third-party vendor to being accretive to the producer—and that led us to the midstream in 2014. A lot of midstream companies have been supply-push oriented, but we have been more demand-pull oriented. We said, "Let's start with the market and work our way back."

Investor How do you define or handle risk?

Lee Working in the upstream, you're taking a bet on one company or one well at a time and on the commodity, whereas with Salt Creek Midstream we have 22 customers in nine different counties. It's a bet on the Delaware Basin, but the main risk I have is that an operator on our system might decide to put more of his capital into the Midland Basin than into the Delaware. Midstream allows you to play with more elements.

One reason Kingfisher was so valuable is that we were exposed to multiple producers and approximately 300,000 gross acres were committed to the system, and Alta Mesa was only about a third of that. When we sold it, we had a quarter or two quarters of transition period and then we were out.

If you believe the U.S. is going to continue to grow production, then the midstream com-

Salt Creek Midstream LLC, a Delaware Basin partnership between ARM and Noble Midstream Partners LP, links oil from Pecos to Reeves and Winkler counties.

PHOTO COURTESY ARM

panies will allow that to happen and they will benefit, but they are not directly tied to the upstream economics. On the flip side, midstream returns have historically been lower than upstream returns, but they are a safer vehicle. The oil and gas business is beginning to look more and more like a mining business, and we felt like we sort of were just the middlemen, and that was not accretive.

Investor What is this thing you call the optimization group?

Lee Starting in 2017, we formed a team, the optimization group, but we kept it kind of quiet. What we'll do is take out spare pipeline capacity, or we'll lease storage; we put it on our balance sheet, and then we try to marry that up with the producers we have.

We want to own midstream assets and then we want to be able to put our own capital at risk. If we can go find the market, and see a bottleneck, then we marry those two. We will not look to do a midstream asset unless we also see a downstream angle—it's too competitive. Obviously we have to find a basin with a supply push, but we have to see there's a bottleneck and bring demand pull to that.

Investor Can you give us an example?

Lee We own all these assets, and so it's the optimization group's job to extract value out of those. For example, we move gas out of Waha, Texas, to California; the optimization group does that. We're buying gas from producers on our system and sending it out there, and sometimes they're paying us because we can move it to California—it's very odd.

We've got all these producers committed to Salt Creek, so what happens if gas goes negative? They're going to stop drilling and that's bad for us, so let's try to figure out how to move gas.

Investor How do you do that?

Lee We move gas for them and for our own account. If we can increase their netback, that exposes us to have to take out more capacity, but our guys were staying in front of it before the market turned upside down. It is weird times.

Investor But ARM's hedging business helps every other part of your business.

Lee Absolutely. There are times when our guys will even step in and make a market if it's too illiquid, especially on the basis side. We understand the market because we are in it every day; we're not just reading about it.

The business has evolved, where we are beginning to own midstream assets and control the hydrocarbons. We have moved from being a service vendor to being more accretive to the producers, to be able to provide capital and take on risk.

For example, we'll take out capacity of 100,000 bbl/d at a certain rate, but we're not the anchor on a long-haul pipe say, coming from the Bakken. Now 100,000 bbl/d might be a one dollar rate, but a 5,000-bbl/d producer can't do that—his rate might be $2 a barrel. So we'll aggregate all the producers that are our customers and say, Let's ride on this lower rate together.

It's a merchant type transaction, but we'd do it only where we see there's a need.

Investor What really led you to expand like this?

Lee I think it's the natural progression. As producers get to a certain size and keep growing, they're asking us for more, and they're asking us to put our balance sheet to work. We are trying to be accretive and step into risk on their behalf. I feel we have to bring something to them and not just be a third-party vendor. If we own capacity to Corpus Christi, then that's something we can provide that maybe not everybody else can provide.

Investor Exports have changed everything. How are you playing that aspect?

Lee Exports dovetail with our assets. We've worked really hard to understand unconventional shale, and two years ago we saw that U.S. exports would happen. We [ARM] now export gas to Mexico; we export oil to the global market. We lease dock capacity in Corpus and Houston; we have pipe capacity. And we have a JV with a global trading company into the export markets.

We [the JV with the trading company] are the largest anchor shipper on one of the long-haul pipelines out of the Permian, at 150,000 bbl/d. We took out the capacity initially but then we didn't want to stop at the dock. After talking to some international buyers though, we found that the folks that do things on the water in a global market are really good at it, and they've been doing it for a long time, so we thought it'd be better to partner with one of them. I think we have a view of the market, but we know what we are beginners at, so I think we found a fantastic export partner. But I can't tell you who.

Investor How do these partnerships or JVs come about?

Lee As a company we have always been very opportunistic and entrepreneurial, and we want all our employees to think like owners, which works well because they all have different relationships. What happens typically is, we're looking at doing something ourselves. I think if you are not greedy, and you are honest with yourself on what you do really well, then you look at what someone else can bring to the table. That's how a lot of these JVs start. You form a partnership with someone who does the other things well.

Take a look at our JV with Noble Energy [Inc.] in the Delaware. They had a large amount of acreage in their upstream, and we had a large amount of acreage near them. Both of us wanted to build a pipeline north to Wink, Texas, and the Noble team reached out to us, actually.

For us, it's about knowing what they bring to the table versus what we bring, and what are we able to give up with the economics. Noble's got a great name. We've worked with their midstream team, and we generally like them—we found them to be smart and aggressive, and it would be silly for both of us to build the same line.

Now with Apache, we were going to build an NGL line close to Waha, as were they. So

"We have moved from being a service vendor to being more accretive to the producers, to be able to provide capital and take on risk."

I approached the head of marketing and midstream at Apache. They had Alpine High; we had a bunch of dedicated acreage behind us. Let's combine.

Investor What is the secret to making sure these JVs work well?

Lee You've got to get very comfortable with your partner. With Apache, there's no amount of capital savings I could have provided them to where they could offlay the risk that this pipeline at Alpine High has to work; there are certain things we were willing to give up for them to have control over. Again, they're another great partner with a great name.

Anytime you do a joint venture, you have someone in your business, and they have a say. Do all the pros outweigh the cons? Noble and Apache are great partners, so it was an easy decision for us.

As for the global trading company—our traders have known their traders for a while; there's just a lot of relationships. They look just like us, they think like us. They were aggressive, they were creative, they were very easy to work with. We started operating as partners before the agreement ever got done, and I think that says a ton about that firm.

Our fourth JV is with EPIC Midstream NGL; we are a minority owner in that asset (in all the other JVs we are a 50% owner). With EPIC NGL, we are the largest midstream system in the Delaware. We wanted to have a seat at the table regarding the export market on the Waha NGL line and be able to grab value. So all in, Salt Creek is a Delaware Basin midstream company backed by Ares, and it has JVs with Apache, Noble and EPIC.

Investor It's certainly good to be in the Delaware if you are anywhere.

Lee Right. The vision of Salt Creek is to be a vertically integrated company from wellhead to water. When we surveyed the landscape, the companies we were competing with in the Delaware were intra-basin players but by having downstream, we can pull on different economics or different buckets.

Salt Creek has gas gathering and processing, oil and water gathering and disposal, and NGL transportation. We have leased an oil dock at Corpus. We have a large engineering office out in Pecos and a field office in Jal, N.M. At one point during construction we had 1,200 people working on Salt Creek, including contractors. We have pipe in the ground in nine counties. We've got nearly $2 billion in capital into it today—that's equity and debt.

Investor Are there further expansion plans?

Lee I think we'll always be expanding. We went very broad; I think we have subsets within each business, and we'll continue to harvest what we have today. Our system is so large, I don't think you'll see us do any acquisitions. We laid very large pipe. We do have a couple more JVs up our sleeve, but I can't say more or our BD guys would kill me.

Investor You'd rather build greenfield assets than buy them?

Lee Not necessarily. Historically we've done greenfield over brownfield, and it has better economics typically. You know, it's hard to look at other transactions compared to Salt Creek—the Delaware is the lowest-cost basin in the country, and to have this amount of acreage dedicated and be 600 miles from where demand growth is—this is a once-in-a-generation opportunity. We didn't get into the crude gathering business until mid-2018, and we didn't get into the water gathering business until Q4 of '18. You still have a lot of greenfield opportunities in the Delaware because of this massive supply push that dovetails directly into a demand pull—that doesn't happen that often.

Investor What about ideas in other basins?

Lee I think midstream opportunities going forward will be more brownfield … just because I don't think there are any more greenfield opportunities—there is no big new supply basin out there, but then E&Ps always figure something out.

There's certainly opportunity to build out infrastructure in the Powder River Basin, which is catching some attention now; however, there's lot of infrastructure there already … I think what you'll see is someone can go buy a system and then build on top of it. That's brownfield in nature.

Anything that's been developed in the last five years has plenty of infrastructure. Just to be able to go out there and buy raw land like in the Delaware—there's no more opportunities like that.

Investor So what opportunity set is next?

Lee In this environment, from an upstream standpoint, we are hyper-focused on being in areas of low cost with great rock. That's one. Two is the downstream; if you can combine those it covers up a lot of potential risk or pitfalls. So for us in the Delaware we wanted to be exposed to New Mexico, we wanted to be exposed to the south, to be exposed to the western gas condy, and be exposed to the eastern spots that are oily. That was done on purpose.

It was a big undertaking, so we had to find the right sponsor. Ares has a large balance sheet and they think long term.

Investor What is the long-term vision for Salt Creek?

Lee Before the market turned upside down, we both had the same vision, which is to build a self-sustainable business with scale and size, to build cash flow and try to harvest as much inventory [acreage] as possible within the Delaware. It was not going to be a quick flip. I didn't like thinking that the only way we could monetize this asset would be based on what someone else thinks it's worth. That was a risk we didn't like taking.

What you can't control is when that oil or gas is going to be produced. I can't tell a producer when to produce. What I can control is how I diversify across operators and across the basin and focus on pure-play oil and gas companies. We were hyper-focused initially on guys that were going to be running rigs today. We built large-scale pipe so we can scale up and start going after the larger E&P companies, but we focused on private-equity-backed companies first.

We set up an independent board for Salt Creek and for maybe being public someday, but I don't think we want to be public. You're talking about a potentially large enterprise here, and we like the fact that our traders can come in and harvest all this optionality around it.

Investor You talk about harvesting optionality a lot. So without it, you wouldn't do something?

Lee A core belief at ARM is that every asset has embedded optionality where we can figure out how to extract that value. I'll give you an example: every time you build an asset—tanks, for example—you build larger tanks than you'd need. Sometimes you just need that for overflow. But if it's just sitting there, I can use storage to play the contango market or use it for blending.

If I have additional pipe and our producers are flowing through it, what about the additional pipe that's not being used? Can I buy or truck barrels in? Do we have more dock capacity because we think that dock capacity is constrained? We over-buy optionality and overbuild our options. Everything has to be built on economics though, and go through the board. But there's a lot of hidden value there.

Investor What about growing the water business?

Lee That's not something you'll see us grow drastically because there's no downstream value; there's less optionality to it. We like the water business, and we'll continue to grow it as our customers demand it, but we don't see a bottleneck downstream. We only do the produced water gathering and disposal today.

Yes, you can add scale and get more producers and add more water, and I think that's where you'll see the water business go. For example, three producers pay a dollar each to handle water, whereas I can handle it for all three for $1.50. I get the scale and size instead of each of them trying to do it. We're trying to figure out the best way to grow it and provide good service. We don't want to sell it, that's for sure. The DNA for us is working on producers' behalf.

Investor How do you see the relationship between producers and the midstream unfolding?

Lee At the end of the day, producers and end users will come together and the middleman, the midstream, will be cut out. Producers will say, "why do I need you?" They will say "I need you, if you'll take on some of the risk and provide some capital," and that's what we've tried to do.

Investor Where can you grow then?

Lee I think we'd look into Oklahoma someday, because we know that area very well … but right now we have plenty to say grace over in the Delaware. You're going to see a lot of product hitting the coast, and it's not going to be efficient, so there may be opportunities there. We're hiring across the board. Our midstream grew a lot last year, and trading is growing this year from a personnel standpoint. We have a different group president for each business, and Salt Creek has its own CEO. But we're all going in the same direction. If one wins, the other ones win. They feed on each other, so it's been exciting. □

PHOTO COURTESY ARM

Salt Creek is supported by an average E&P customer acreage dedication of roughly 15 years.

DUG EAGLE FORD CONFERENCE DOCUMENTS "2.0" OPPORTUNITIES

The Eagle Ford became one of the first Big Plays back in the heady days of America's shale revolution. In its earliest development cycle, The Eagle Ford's complex geology and deeper horizons kept breakeven costs higher than some other areas (like the Bakken or the Permian Basin), but with dry gas, NGLs and a black oil window, there was something for everyone from the perspective of resource-in-place.

Fast forward to 2019 and, after several years of marked slowdown, the Eagle Ford is enjoying resurgent interest from a line-up of established and new players alike.

At the CERAweek conference this spring, Marathon Oil CEO Lee Tillman said, "I would compare the returns in the Eagle Ford to anything," he said, given its $4-5 million/well completion costs, oiliness and Louisiana light sweet pricing. "There's really nothing today on a zone-by-zone basis that can touch the Eagle Ford."

Hear and learn from the most active producers and top analysts in the region during 14 conference sessions.

2018 Event Metrics

1,551 Attendees

28 Speakers

62 Sponsors

120 Exhibitors

Current Eagle Ford updates ahead

Those who attend Hart Energy's 10th annual **DUG *Eagle Ford* Conference & Exhibition** (September 24-26 at the Henry B. Gonzalez Convention Center in San Antonio) will get an in-depth look at upstream development activity in the Eagle Ford as well as Texas' portion of the Austin Chalk. Speakers from several of the most active producers and operators as well as analysts, service company leaders and others will deliver a 360-degree view of what's happening on the ground.

The 2014-to-2016 commodity price collapse took its toll in this region. Some players folded their cards and others simply moved on to concentrate in areas like the Bakken and the Permian Basin – sound familiar? Now "Eagle Ford 2.0" boasts proximity to attractive Gulf Coast pricing for its crude oil and pipeline connections to export markets in Mexico (and to a burgeoning LNG and petrochemical complex in Corpus Christi) for its dry gas and NGLs.

Best practices drive efficiencies

At the 2018 DUG Eagle Ford conference last fall, Conoco Phillips' Chief Technology Officer Greg Leveille said break-evens in certain areas were as low as $20-to-$30 per barrel. Elsewhere, EOG has noted they can make money at $30 per barrel on some of their leases. This year, Wendy King, Conoco's vice president for its Great Plains business unit will take the **DUG *Eagle Ford*** stage to present insights on operating within cash-flow in today's business environment.

Less choice areas of the Eagle Ford have higher break-evens, but in general the play, especially its oil window, offers some of the lowest costs in the country. In that respect, today it's better than the Permian Basin.

Having accumulated "lessons learned" from roughly a decade of drilling experience, today's Eagle Ford drillers are enjoying better pricing, better markets and renewed opportunities. For an up-to-date look at producers and others on speaker slate, visit **DUGEagleFord.com**.

Permit activity is brisk in DeWitt, Karnes and Dimmit counties for companies like longtime South Texas player ConocoPhillips, which filed for 80 drilling permits in the region through June this year. Its subsidiary, Burlington Resources, and Chesapeake Energy, one of the original explorers in the modern shale era, each have about a dozen permits pending there, too.

Denver-based SM Energy intends to explore the liquids-rich Austin Chalk formation that lies above its Eagle Ford acreage. Its CEO Jay Ottoson recently told an investor conference, "The great thing about the Chalk here is that it's clearly got significantly higher liquids portion in it than the upper Eagle and potential. Productivity looks really good."

Well Interference Forum added

Hart Energy's first Well Interference Forum has been added as an optional program immediately prior to the opening reception for the main conference. Focused on the business ramifications of this less-than-understood phenomenon, the Forum speakers will include Wall Street analysts who'll examine practical aspects of the financial, policy and business implications of well interference. Attendees will get a clear depiction of how this critical issue is viewed by those outside the industry.

The Well Interference Forum also promises to deliver insights on what producers and pressure-pumpers are doing to avoid interference between parent and child wells in the first place. Be there as engineers and consultants dive into the industry's understanding of interference and potential solutions, including pre-loading and pressurization.

Exhibits & Networking, too

The exhibition floor at **DUG *Eagle Ford*** is known for outstanding networking opportunities. From the ice-breaker reception on Tuesday the 24th through the half-day program on Thursday the 26th, attendees and exhibitors will mingle morning, noon and night. From the cocktail reception to breakfast on the show floor, **DUG *Eagle Ford*** always provides plenty of face-to-face time with colleagues and peers. For more information about the conference, exhibition and the optional Well Interference Forum, visit the event web site at **DUGEagleFord.com**.

Get face-time with peers and other industry professionals in the exhibit hall at DUG Eagle Ford.

Unique to DUG Conferences, full-conference attendees are invited to join speakers for a candid Q&A session after their presentations.

CONFERENCE & EXHIBITION
DUG
EAGLE FORD

DUGEagleFord.com

Hart Energy **IndustryVoice®** allows sponsors to reach our audiences by enabling them to create and place relevant content in our media channels — in print, online, via social media and at live events. Each **IndustryVoice®** piece is produced by the sponsor and any opinions expressed by **IndustryVoice®** contributors are their own. For questions about **IndustryVoice®** programs, email IndustryVoice@hartenergy.com.

AIMING AT NARROW TARGETS

With sharply lower activity in equity and debt issuance, bankers look to niche markets and M&A.

ARTICLE BY
CHRIS SHEEHAN, CFA

The E&P mantra of living within cash flow leaves investment bankers with few tools on the table to be creative. Equity issuance is largely taboo, with E&Ps generally discouraged from even testing the public market. Refinancing existing debt is likely feasible for higher-quality issuers, but may be a precarious procedure for smaller E&Ps, since debt has come to be viewed as a four-letter word.

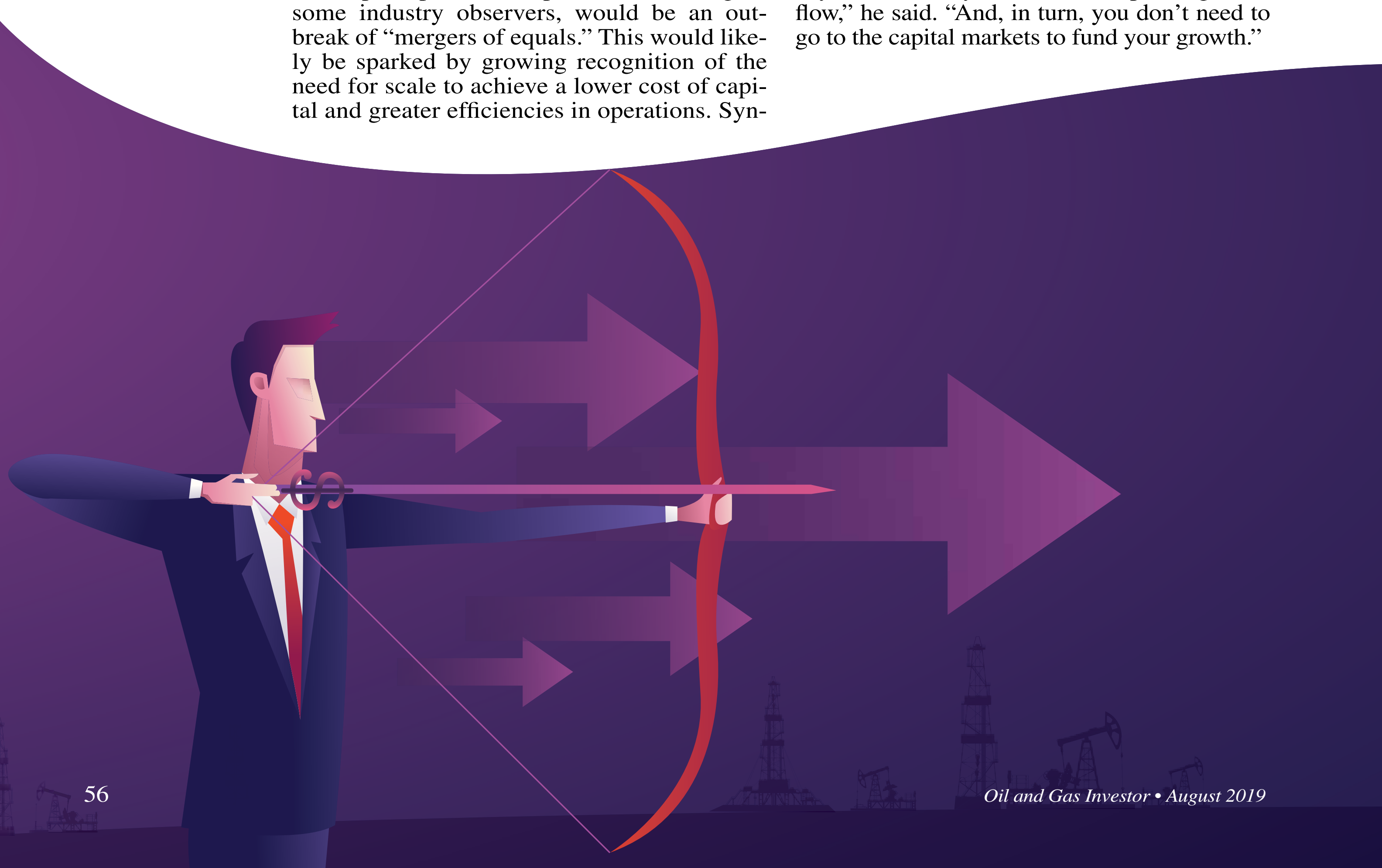
Of course, there are exceptions to the rule. The first half of this year has seen a follow-on offering and an IPO in the minerals sector, and more such offerings are said to be in the works over the balance of the year. Likewise, there have been equity issues in the midstream sector, including Diamondback Energy Inc. spinning off an IPO in the form of Rattler Midstream LP.

But perhaps most impactful, according to some industry observers, would be an outbreak of "mergers of equals." This would likely be sparked by growing recognition of the need for scale to achieve a lower cost of capital and greater efficiencies in operations. Synergies in general and administrative (G&A) expenses would also be a key driver of such mergers of equals.

Across the board, revenues in energy investment banking are down markedly, as year-to-date equity and debt issuance have trailed prior-year levels by a wide margin. Looking back another year, revenues are running at barely half the 2017 run-rate, said one investment banker.

'Dearth' of offerings

"There's a significant reduction, or dearth, in capital market offerings now," commented Tim Perry, global co-head of oil and gas investment banking with Credit Suisse. With shareholder pressure on E&Ps to adopt a returns-oriented strategy, focusing on free cash flow over growth, "by definition, you're not outspending cash flow," he said. "And, in turn, you don't need to go to the capital markets to fund your growth."



In addition, the sector has "largely de-levered itself," according to Perry. "I think the sector generally feels comfortable that their leverage statistics are fine, so they don't need to repair their balance sheets. And, again, they don't typically need to go to the equity capital markets to fund their capex needs because those needs are being met now from internally generated funds."

Various factors have made the industry less attractive to investment banking. The energy weighting in the S&P 500 Index has continued to slide to around 5%. In addition, the sector has suffered from bouts of commodity volatility, notably late last year and in late May/early June of this year. West Texas Intermediate slumped to about $45 per barrel (bbl) in late December and, after recovering, retreated from $60-plus to the low $50s in early June.

"The industry is facing a lot of challenges in getting investor interest in the sector right now," said Perry.

Capital markets activity got off to a particularly weak start this year. According to Christopher George, director of Drillinginfo Inc.'s Capitalize database, the first quarter saw "the fewest equity deals this decade."

Nonetheless, Credit Suisse has managed to win its share of business from the fairly modest number of equity issues raised of late in the energy sector. But it's been no easy task, said Perry.

"It's tough out there," he emphasized. Given the backdrop, "we're doing okay," he added. "And okay is pretty good for right now."

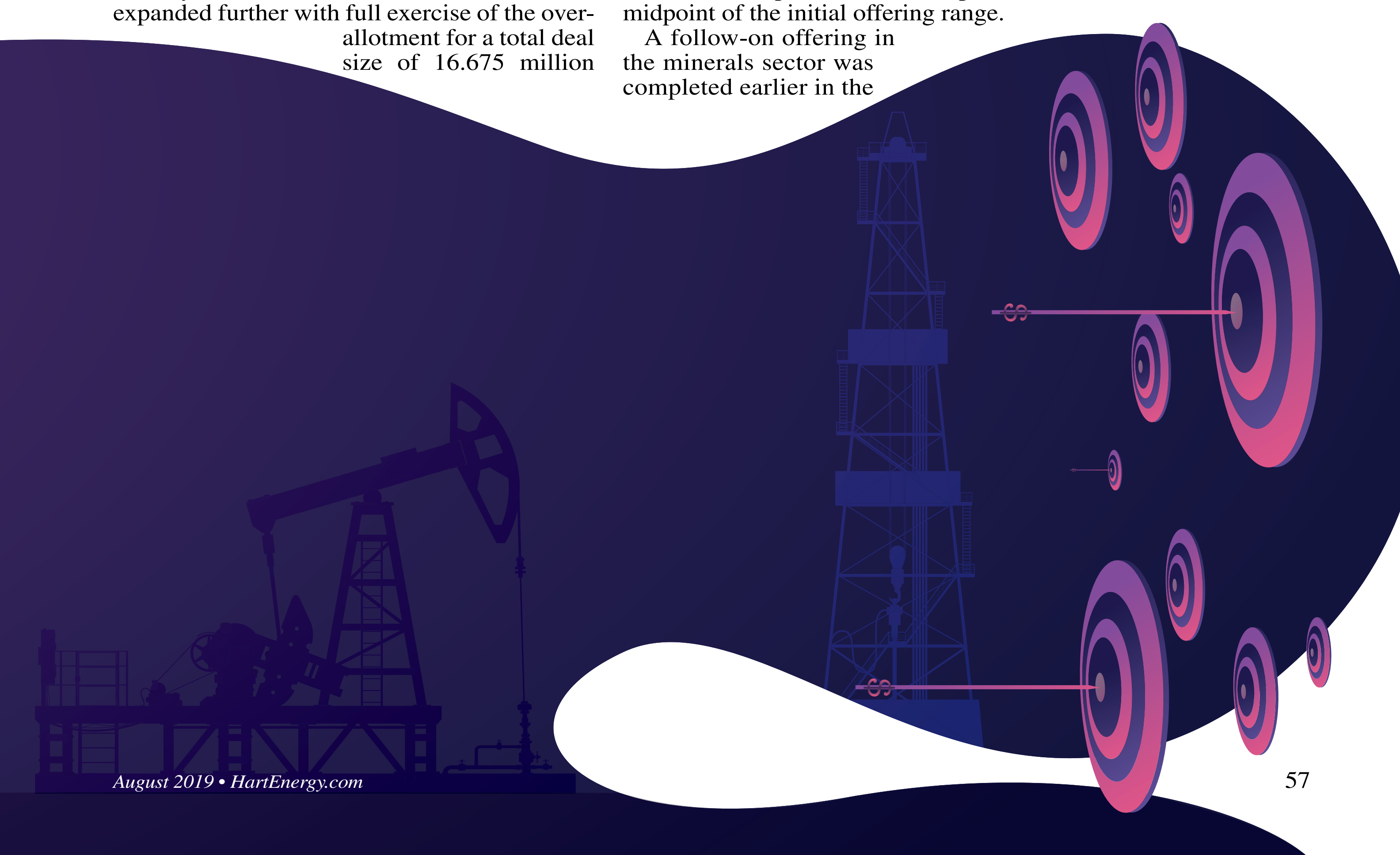
"There is a significant reduction, or dearth, in capital market offerings now," commented Tim Perry, global co-head of oil and gas investment banking with Credit Suisse.

Minerals and midstream

Notably, in minerals, Credit Suisse was the lead left bookrunner for the IPO of Brigham Minerals Inc., an issue that was upsized from initially 13.5- to 14.5 million shares and then expanded further with full exercise of the overallotment for a total deal size of 16.675 million shares. The Brigham offering was priced at the high end of the initial offering range of $15 to $18 per share.

Credit Suisse similarly served as lead left bookrunner for the IPO of Rattler Midstream LP, a spin-off of the midstream assets of Diamondback Energy Inc. The offering was expanded from initially 33.3- to 38 million shares, with the 15% overallotment option exercised in full for a total deal size of 43.7 million shares. The IPO was priced at $17.50 per share, the midpoint of the initial offering range.

A follow-on offering in the minerals sector was completed earlier in the



"The biggest thing going on now in the sector is M&A consolidation in the upstream sector," said Steve Trauber, head of global energy investment banking at Citi.

year by Viper Energy Partners LP. Viper, also a subsidiary of Diamondback, was similarly spun off in an IPO last year. Credit Suisse was sole lead bookrunner for this year's offering, which was raised from 8- to 9.5 million shares. From filing to offering, the deal was priced at a 5.4% discount.

"One area of capital markets where we continue to find investor interest is in minerals. There's a lot of positive energy in that group right now," observed Perry. "The Brigham Minerals offering was more than six times oversubscribed. Investors want free cash flow. And, of course, without the burden of capex, the mineral companies do produce a lot of free cash flow."

Perry also raised the prospect of transactions by private-equity-backed companies that own minerals. "I think that there is going to be more consolidation in that group," he said. "Several companies are thinking about merging with other companies in the sector to gain scale. And some mineral companies are considering whether to go public."

On the midstream side, Perry described Rattler as a "unique deal in the market," primarily due to its position in providing midstream services to Diamondback. "Diamondback has an incredible track record of value creation for its stockholders," he said. The offering was heavily oversubscribed, "and obviously it's traded very well in the aftermarket."

How does the pipeline for equity issuance look over the balance of the year?

"I think you'll expect to see across energy a limited supply of transactions. I think you'll find maybe one or two potential transactions in midstream, and you'll have one or two transactions in minerals," said Perry. "I think the transactions you'll see will have free cash flow through the cycle."

Mergers of equals

For Steve Trauber, head of global energy investment banking at Citi, M&A activity looms large for the energy sector as a means to attract interest from the investment community. In particular, to remain relevant, mergers of equals are likely to accelerate with a focus on companies whose enterprise value (market cap plus net debt) is $5 billion or less, he said.

"The biggest thing going on now in the sector is M&A consolidation in the upstream space," said Trauber. "All the companies are seeking to gain scale. Companies with an enterprise value of $5 billion or less know that they're undersized, that they don't have enough scale, don't have enough efficiencies, and the balance sheets are probably not as big as they need them to be.

"A growing number of small-cap companies are finding it increasingly hard to attract energy equity investors," Trauber continued. "It's going to be a game of scale and driving down costs. It's a commodity business, at the end of the day. You've got to have a low cost of capital, you need to have great efficiencies and you need to have some clout over your suppliers, and so on."

Speaking with *Investor* in early June, the Citi banker predicted multiple mergers occurring in the balance of the year.

"I think you're going to see at least five to 10 M&A deals in the next six months," he said. "There's a lot of dialogue going on under the surface. A lot of them are going to end up effectively being mergers of equals. That doesn't mean you won't have one company sort of survive; in certain cases, it may be more of an acquisition."

No more premium takeouts

Potential transactions "are going to have the feel of a merger as opposed to a big premium takeout, because nobody can afford big premiums to their stock price," said Trauber. "These E&Ps tend to trade at around the same multiple, so the benefits of this are really gaining scale and efficiencies, cutting G&A expenses and taking out some field costs to make a company investible again."

In terms of potential synergies, G&A expenses are clearly a key factor, and post-merger you obviously "don't need two CEOs, two CFOs, etc.," noted Trauber. "If you're in the same basin, you've got field costs. You still need people, but there's some overlap there, for example." Based on prior transactions, "you end up finding more synergies than you think are out there," he added.

The Permian, not surprisingly, is the basin considered most fertile for mergers, according to Trauber.

"The big guys want to buy oil, and the biggest, cheapest resource that exists is in the Permian," he said. "So you can imagine that everyone wants to be buying in the Permian.

There are only a few large, low-cost resource bases in the world. You've got Saudi Arabia, Russia, Brazil and maybe the Gulf of Mexico, and then you've got the Permian, which seems to be easiest and most accessible.

"I think you're going to continue to see companies merge there to get bigger and become attractive to some of the majors," said Trauber, noting Chevron Corp. remains a likely buyer after its unsuccessful bid for Anadarko Petroleum Corp.

"I do believe that major oil companies are going to make acquisitions of size in the Permian. They need more resources. The question is: When and whom?"

Chevron: Stay 'disciplined'

"Chevron has expressed an interest to be bigger in the Permian. There's no surprise around that," Trauber continued. "They've also expressed a strong opinion about being disciplined about how they do it and not overpaying to meet their objective. I think there are numerous opportunities in the Permian for them to continue to grow their business through acquisitions."

In terms of timing for a potential acquisition, "I would be very surprised if you don't see them do that over the course of the next 12 to 24 months," he said. "Do I expect them to do it in the next six months? Probably not, but I think they've got a very strong balance sheet, they've got good cash flow and they have a strong desire to be bigger in the Permian. So I do think they will be a buyer."

As regards smaller players in the Permian waiting for better conditions, Trauber struck a note of caution.

"No CEO wants to sell his stock when you're off 30% in the last 12 months or so," he observed. "You hope to sell at a strong valuation, and these are relatively weak valuations. My view is that you go ahead in spite of that now, or risk facing a continuing deterioration of valuation. As the valuation gets weaker on a relative basis, it's going to be harder to use the company's currency to help de-lever."

However, assuming key criteria are met—such as rock quality, strength of balance sheet and appropriate synergies—E&Ps may ultimately be able to "get comfortable with stock-for-stock deals," he said. "That's where you're really merging, you're not selling and you take the stock of a stronger, more liquid company with an enhanced balance sheet. That's the way people have to look at it."

Elsewhere, Trauber described the market for energy IPOs as "extraordinarily cold." One exception, he said, is the mineral sector, where various private-equity sponsors may combine mineral interests held by portfolio companies in preparation for going public. Alternatively, these interests may be merged into an existing, more liquid public mineral company in exchange for a mix of stock and cash.

Another exception may be the oilfield equipment sector. An example is Houston-based wellhead manufacturer Cactus Inc., which is characterized by "highly differentiated, high-margin, strong free-cash-flowing oilfield equipment," according to Trauber. The company has "market leadership, low capex and generates high rates of return on capital employed."

"Clients have got the message that everyone's meant to be self-funding," said Nathan Craig, managing director with J.P. Morgan Chase & Co. "Even if the capital markets were open at a price, you're not meant to be using them."

The SPAC struggle

As for raising money via a special purpose acquisition company, or SPAC, said Trauber, "they're just another form of going public. You can probably raise money in a SPAC, but then you have to find an acquisition target and bring energy investors into it, much like with an IPO. What will happen is that the SPAC investors will trade out, and you've got to establish a new following with energy investors. If you can't do an IPO, you'll really struggle to do a SPAC."

Recent conditions in investment banking "are some of the toughest I've seen in my 20 years on the capital markets front," said Nathan Craig, managing director with J.P. Morgan Chase & Co. Among the factors he cited for the slump: a lack of issuance in capital markets, clients being "inwardly focused" and "shareholder frustration."

"Broadly speaking, clients have got the message that everyone's meant to be self-funding," said Craig.

"Even if the capital markets were open at a price, you're not meant to be using them. There's the risk of a stigma if you were to run out and issue equity. The A&D market has been dismal, as well, and the reason for that is that the funding market has been challenged."

Debt now a 'four-letter word'

As regards the high-yield market, "for a lot of people, debt has now become a four-letter word," he continued. "If it's not a refinancing

Energy Equity And Debt Issuance

	Downstream	Integrated	Midstream	OFS	Upstream	Total
2018 Energy Bonds By Sector ($MM)	$4,950	$10,800	$39,550	$11,479	$22,311	$89,089
2018 Equity Raised By Sector ($MM)	$505	$0	$5,656	$7,238	$3,122	$16,521
2019 Energy Bonds By Sector ($MM)	$1,600	$5,140	$14,452	$1,137	$6,542	$29,571
2019 Equity Raised By Sector ($MM)	$0	$96	$1,920	$312	$790	$4,518

Source: Drillinginfo Inc. As of June 18, 2019

Bond and equity issuance across all energy sectors is a sliver of the prior pace.

of existing paper, clients have been reluctant to add incremental debt to the balance sheet. So issuance in credit has gone down, with the year-to-date level through May running at about one-quarter of prior-year levels."

The exception to the above is again minerals, which offers "a bright spot of activity," according to Craig.

"We expect two or three mineral IPOs in the next 12 months. There is some concern by investors that if you have too many mineral IPOs, then you get too much fragmentation, like we have in the E&P space currently. But minerals are hitting all the check marks investors want: free cash flow, modest growth, sustained dividend, low leverage and a real return on equity.

"There is absolutely a home for minerals. If you consider the market capitalization of public mineral companies compared to the opportunity represented by the entire mineral sector, public mineral companies represent only around 2% of the total value that is out there," he estimated. "There just aren't a lot of mineral opportunities in the public-equity domain today."

J.P. Morgan served as active bookrunner of the Rattler offering, which Craig described as being "substantially oversubscribed with incredibly high-quality names." Investors making money in Rattler may help open the energy IPO market, he said, but other offerings may not be quite as competitive.

"It's a little bit more of a challenge to bring a true new issue to the market with an unknown asset base, unknown management team, unknown track record. That's not to be underestimated," he cautioned. "The first thing institutional investors will ask is: 'Why do I need to own this? Tell me why I can't get similar exposure to this through someone else in the marketplace?'

"A governor of the IPO market from institutional investors—mainly upstream, but also midstream—is, 'Why do I need to own a forthcoming IPO when I can buy another great name company for an extremely low multiple over here?' It's also, 'How does it compete with all the other things I can buy that are trading very cheaply?' That makes IPOs hard right now."

Shareholder and management frustration

In terms of market sentiment, "there is frustration among shareholders and managements," observed Craig, while banking clients "are inwardly focused right now." For example, with some onshore E&Ps trading at or around PV10 values, questions arise: 'Why aren't you rewarded for what you're doing in your core operations?' No matter what you do operationally, it's not translating into your valuation multiples."

On the issue of G&A expenses, Craig said "it's hard to underestimate the amount of attention that investors are focusing on G&A. And that is a function of the frustration that they feel and the lack of investment returns. You have shareholders frustrated, and you have boards and management teams frustrated."

As regards M&A, "more than ever before there seems to be a belief—and this is coming from E&P clients—that there's a minimum market cap that you need to have in order to garner investor attention. Even if you're at that level, gaining investor attention can still be extremely challenging. And if you are not at that level, it makes the hurdle even higher for relevance," Craig said.

Commodity volatility

An added hurdle to overcome has been recent commodity volatility, which hasn't helped as the energy sector "transitions toward trying to meet what are relatively new metrics, such as living within cash flow, lowering leverage, etc.," noted Craig. "This kind of pivot is not something that happens overnight. And if you get significant volatility, it's just unhelpful for investors."

As the E&P sector moves forward to meet these goals, the task ahead for the upstream players is to "drive efficiencies so that they can deliver to the shareholder a return commensurate with the risk profile and the underlying commodity volatility in this industry," he advised. "And until you can demonstrate that, the shareholders are largely on strike."

In a market where capital options are few and far between, are there any avenues in energy to explore?

From high yield's collapse last December—ending the month without a single deal for the first time since 2008—the sector has improved somewhat, although volatility of late is "undermining" the recovery, according to Craig. Year-to-date energy issuance came to about $2.5 billion from five issues through May, down 75% from $10.2 billion from 24 deals in the year-earlier period, he said.

Drillcos are worth exploring, especially "in an era in which net asset value isn't being rewarded," said Craig. If E&Ps have to hold acreage and have a good line of sight on the economics of wells drilled on "good acreage with very solid rock, then I can see why E&Ps execute plans with Drillcos. In this capital-constrained market, I absolutely understand why there are increased conversations occurring around Drillcos." □

FIFTH THIRD BANK

FIFTH THIRD
CORPORATE BANK
ENERGY

WHERE
EXPERIENCE
AND
INNOVATION
INTERSECT.

Richard C. Butler
SVP, Corporate Banking Group Head
Energy

Richard and the Energy experts at Fifth Third Corporate Bank do more than offer competitive capital solutions. They build personal relationships with clients to provide meaningful guidance through all economic cycles—resulting in a partnership that's truly strategic, knowledgeable, flexible and efficient.

This is banking a Fifth Third better.

53.com/CorporateBank

Member FDIC


ASCENT
RESOURCES®
ENERGY RISING
Achieved >2.0 BCFE Per Day
Gross Operated Production
From its First 250 Utica Wells
Ascent is the
#1 producer in the
Prolific Utica Shale
&
8th Largest gas
producer in the
United States
Multi-Phase Production
with over 70,000 BBLS
Per Day of Gross Liquids
380 Committed
Employees
Making it Happen
ASCENT
RESOURCES
INTEGRITY FIRST
SAFETY ALWAYS
ASCENT IS
ON THE RISE!
www.AscentResources.com | 3501 NW 63rd Street | Oklahoma City, OK 73116 | 405-608-5544

THE FAR EASTERN CHALK

Overshadowed by behemoth unfracked Austin Chalk development in western Louisiana in the past, the formation's far eastern horizon is being tested for fracked, horizontal development.

ARTICLE BY
NISSA DARBONNE

Western Louisiana's Austin Chalk has produced some legendary fields, particularly Masters Creek, West Masters Creek and Sugartown. Combined, they've made 34 million barrels (MMbbl) of oil and 148 billion cubic feet (Bcf) of gas.

The eastern side of the Louisiana Chalk, though, has received little affection over the decades, particularly as operators sought underlying gas pay from the Tuscaloosa sands and ignored the fickle, fractured Chalk.

Spurring excitement now for the far eastern Chalk fairway that stretches from South Texas to Mississippi is that oil and gas heavyweights EOG Resources Inc. and ConocoPhillips Co. may be writing a new chapter in this region of the overall Chalk story.

Smaller-budget leaseholders in the eastern Louisiana Chalk have been hoping to go to school on what these bigger-balance-sheet explorers find—and what completion recipe they use in surfacing the bounty.

But it's been a long two years since news of EOG's Eagles Ranch 14H well ignited fascination with the eastern potential.

The well—in far southern Avoyelles Parish west of the Mississippi River—has 20,646 feet of total hole and a true vertical depth (TVD) of 16,026 feet. It was drilled in 62 days in North Bayou Jack Field.

Completed in September of 2017, it came on with 1,120 bbl of oil, 1.12 million cubic feet (MMcf) of gas and 2,947 bbl of water per day. The GOR was 1,033; oil gravity, 43. Per-

PHOTO COURTESY PETROQUEST ENERGY INC.

PetroQuest Energy Corp.'s leasehold is downdip of the Lower Cretaceous Shelf Edge, "which is one of the defining points in this play—not only by us but by many others," said Charlie Goodson, president and CEO.

Previous page, a Nabors rig drills for PetroQuest in Point Coupee Parish in early July to pull Chalk core. In the background is the Morganza Spillway, part of the Mississippi River flood-control system. Historically, oil and gas production facilities in the spillway's path are elevated some 6 feet to remain dry in the event the spillway is opened.

forations were made at between 16,000 and 20,550 feet.

March oil production was about 54 bbl/d. Cumulative production was just under 140,000 bbl.

More recently, the state released results of two ConocoPhillips wells—both east of the Mississippi. Hebert #1, with 19,461 feet of total hole and a TVD of 13,778 feet, was drilled in 54 days in eastern West Feliciana Parish in Jackson-Northwest Field.

It was completed in May for 206 bbl of oil, 0.134 MMcf of gas and 4,279 bbl of water per day. The GOR was 650; oil gravity, 37. Perforations were made at between 14,000 and 19,320 feet.

McKowen #1, with 19,161 feet of total hole and a TVD of 14,986 feet, was drilled in 70 days in western East Feliciana Parish in Freeland Field. It was completed in March with 60 bbl of oil, 0.034 MMcf and 3,498 bbl of water a day. The GOR was 567; oil gravity, 36.4. Perforations were made at between 15,000 and 18,745 feet.

A third ConocoPhillips well, Erwin #1, remained in confidential status as of late June. With 18,865 feet of total hole and a TVD of 15,500 feet, it was drilled in 46 days in West Feliciana Parish in Mount Common Church-Southwest Field. From it, 283 feet of core was taken, covering the entire Chalk section.

Also east of the Mississippi, EOG recently drilled Ironwood 37H-1 in 18 days, with 18,320 feet of total hole in northern East Feliciana. And it has a permit for plans to return to the west side of the Mississippi, this time in central Point Coupee Parish, with Brunswick #1. There, it is expected to drill a pilot first, pulling core of the Chalk.

ConocoPhillips has a fourth well, Soterra #1, that was being drilled at press time far east in St. Helena Parish. And it has a fifth permit, Jones #1, which is planned for southeastern East Feliciana.

That's it to date east of Masters Creek. Smaller operators remain on the sideline. One that was planning verticals near EOG in North Bayou Jack Field took permits in early 2018; the permits expired earlier this year.

Plugs and staging

Among those operators that have been waiting, Lafayette, La.-based PetroQuest Energy Inc. is ready for a go at it. The company had a rig en route to Point Coupee Parish at press time to, initially, drill a vertical test. Plans were to core some 350 feet of Chalk.

Charlie Goodson, president and CEO, saw vertical Chalk work in the 1970s in Texas and the horizontal effort in East Texas and western Louisiana in the late 1990s, predominantly by Chesapeake Energy Corp. and Union Pacific Resources Co.

In Chalk 1.0, the good verticals intersected natural fractures; they weren't fracture-stimulated. In 2.0, horizontals were deployed, also unstimulated. In 3.0 in South Texas and East Texas, the Chalk horizontals are being fracked to tap matrix porosity—that is, the oil trapped within the rock itself—along with connecting natural fractures and with economic success.

The 3.0 job is what PetroQuest plans for its 21,000 net acres that are east of EOG's Eagles Ranch in Avoyelles and Point Coupee parishes.

"In this area, there were a lot of oil shows in the lower portion of the Chalk as operators drilled through this section on the way to the Lower Tuscaloosa [known as Woodbine in East Texas]. It was always felt there was a lot of oil in place; we just didn't know how to effectively produce it," Goodson said.

"There were several dozen vertical wells that were drilled specifically for the Chalk, after they drilled through it for the Tuscaloosa Sand below."

In eastern St. Landry Parish and in Point Coupee Parish, EURs of wells with the Chalk as the primary objective ranged from less than 100,000 bbl to up to 500,000 bbl of oil. "The upper tier of those more than likely intersected natural fractures and made economic sense," Goodson said.

In the late 1990s, some of the unstimulated Chalk horizontals in western and central Louisiana produced up to 650,000 bbl of oil, "clearly indicating that, if you had decent matrix porosity and intersected natural fractures, things worked."

Far east in Livingston Parish, a Chevron Corp. vertical, Crown Zellerbach 7 #1, produced 291,000 bbl of oil and 357 MMcf of gas from the Chalk from 1980 through 1986 at about 16,300 feet, according to the state Department of Natural Resources.

Going fracked horizontal in the Chalk, without modern stage-placement technology, would have been challenging, Goodson said. That's largely why it's taken so long for operators to frack the Chalk.

"Without plugs and staging, it's understandable," he said. Meanwhile, shales have offered better investment odds, without the hit-or-miss drama. And gas prices began declining in 2012; oil prices, in the second half of 2014.

"That's how a lot of this stuff happens," Goodson said. "Right place, right time. And in the past, the Chalk was the wrong place or the wrong time."

The Chalk is fairly homogenous, with some fluctuations in porosity and content—oil, gas, water. "But a lot of it just boils down to people being focused on things they know they can do."

Learned from Karnes

In 2010, Anadarko Petroleum Corp. leased 250,000 acres in the Louisiana Chalk and drilled a few wells. It let the leases expire in 2014. Goodson said, "In retrospect, they appear to have been spot on in where they focused their efforts.

"But, unfortunately, they only drilled four modern horizontal tests and did not attempt to frack any of them."

At around that time, BlackBrush Oil & Gas LP announced a fracked, horizontal Chalk success in Karnes County, Texas, overlying the Eagle Ford.

Goodson said, "EOG in their infinite wisdom stepped in right behind [Anadarko] and picked up the exact same acreage with a plan to go in and frack."

PetroQuest followed, picking up its acreage for about $15 million in cash plus 2 million shares. Its leasehold is downdip of the Lower Cretaceous Shelf Edge, "which is one of the defining points in this play—not only by us but by many others."

The updip Chalk fairway was deposited in a shallower environment than the downdip fairway south of the Shelf Edge.

If the core analysis is positive, PetroQuest may return to the location to drill a lateral off the vertical. The earliest start would be in late 2019.

"A lot depends on what we see. If this is a tight sponge full of oil, obviously we will be moving a lot faster. We may want to see what others are doing," Goodson said.

"There is another well being drilled by EOG 1,500 feet downdip in our immediate area. Theirs seem to be permitted the same as ours—as a vertical to be cored.

"They may plan, with a much bigger pocketbook, to keep the rig on location, do a shorter evaluation on location and go ahead and drill their lateral. I don't know. They're the least likely to tell you what they're going to do." (*Editor's note: EOG was contacted for the article but did not respond.*)

PetroQuest's leasehold carries varied expirations. "We feel comfortable we can certainly maintain through the extension periods," Goodson said. Based in Lafayette since 1985, "we have known many of the landowners we have under lease for generations."

Other new eastern Louisiana Chalk wells are east of the Mississippi in what are known as the "Florida parishes," outside of PetroQuest's leasehold. (The term is derived from when this area of the state was part of Spain's Florida at the time of the Louisiana Purchase from France.)

"For us, the play has not matured as fast as most people thought," Goodson said. "Right now, the area in the Florida parishes is getting most of the attention."

Giddings vs. Eastern Chalk

Phil Martin, CEO of New Century Exploration LLC, has worked primarily in the Texas Chalk. The Louisiana Chalk is deeper and has a higher pressure gradient, he said.

"So there are some things there that more match the southern Giddings Field area in Washington County where Chesapeake, GeoSouthern Energy Corp. and others are making some big gas wells in the wet-gas window. That's a bit more similar to most of what's going on in Louisiana."

An advantage in Louisiana is that the leasehold is relatively inexpensive, Martin said. "PetroQuest reportedly got around 25,000 acres for $700 an acre." ConocoPhillips' roughly 225,000 net acres were leased at less than $1,000 an acre.

Also, the Louisiana Chalk makes sweet oil, extensive infrastructure is pre-existing "and it's pretty close to refineries, so you're getting premium takeaway prices."

The Louisiana Chalk sits in four fairways—all associated with proximity to the shelf edge. The most updip is the Back Reef Shelf; it's historically somewhat less productive and doesn't have as many fractures.

"But it's a very active target right now because it is what is being extended from East Texas," Martin said. The popular play in East Texas currently focuses on areas with favorable matrix porosity, "drilling in quieter areas where you don't have as many natural fractures and going in and making your own fractures.

"That's what's been going on in Texas, while

An advantage in Louisiana is that the leasehold is relatively inexpensive, said Phil Martin, CEO of New Century Exploration LLC.

Below, the green outline indicates where the Chalk and Tuscaloosa may have potential as a stacked play. The blue line indicates the Lower Cretaceous Shelf Edge. Most recent Chalk activity has focused updip.

New Austin Chalk Wells

The eastern Louisiana Chalk play "is more of a petrophysical approach than a fracture-intersection approach," said Kirk Barrell, president of Amelia Resources LLC.

the abundant natural-fracture areas have been drilled up over the years. So the Back Reef Shelf trend would probably be more similar to the black oil portions of Giddings."

Moving south, the fractures increase, primarily due to draping over the Edwards Reef while also simply being deeper. The next fairway is the Near Fore Reef Shelf Slope.

"That's the trend EOG drilled in [with the Eagles Ranch]." It's the Gulf-side edge of the Lower Cretaceous Shelf Edge. "You do have faulting there more than you do north of the Shelf Edge, and that's primarily due to the extension of the deeper Tuscaloosa."

The fourth—and most downdip—is the Far Reef Lower Shelf Edge. "There's also some fracturing there, primarily due to subsidence and normal fault movement."

Water cut

Martin said, "The notable part of the [Eagles Ranch] IP and the production is it's about 70% water cut, and that's not good."

In Giddings, water cut can be up to 40%; in some places, up to 50%. Sometimes, it can be a result of gel fracks fracking out of the main zones or out-of-zone placement, "so some of that water isn't Chalk water saturation; it could be coming in out of other zones. The bottom line is you're producing wherever that water comes from.

"It may be what happened with the EOG well. But that's pretty high water cut. I don't think that will happen across the play."

The EOG well "also had a very severe decline rate," producing about 54 bbl/d in March. "That well is almost certainly sub-economic at today's oil prices," Martin said.

The frack job used more than 2,500 pounds of proppant and 53 bbl of fluid per lateral foot. "They did give it a nice frack."

As for rock properties, the Eagles Ranch Chalk and the Texas Chalk both have high resistivity. Total organic content varies but is generally above 2%; matrix porosity, from 3% to almost 10%; permeability, from 0.02 to 1.2 millidarcies.

"Basically, you need to combine matrix porosity and natural fractures and then use a nice, big, almost Eagle Ford-style frack to connect those natural fractures and squeeze more oil out of those rocks," Martin said.

"I expect we're going to see some localized success and probably some that don't work out as well—if low oil prices don't kill development off first."

'Saturated and thick'

Kirk Barrell has sold some 135,000 acres of leasehold prospective for eastern Louisiana Chalk—one of the buyers was ConocoPhillips, which picked up 85,000 net acres for $87 million—and has about 400,000 remaining.

A New Orleans-based geologist, Barrell is president of Amelia Resources LLC and drilled the Tuscaloosa sands for Amoco Corp. in the early 1990s. In early 2017, he did an extensive regional analysis of the Chalk from Mexico to Mississippi.

The eastern Louisiana Chalk play "is more of a petrophysical approach than a fracture-intersection approach," Barrell said.

The new Chalk play in southwestern Giddings Field that is having success was a "graveyard of dry holes" in the unfracked, horizontal 1990s. "Chalk 3.0 is trying to find the highest matrix porosity you can find that's saturated and thick."

In the eastern Louisiana Chalk, data are available. About 700 wells penetrated it while heading to the Tuscaloosa sands. With all of that log data, "you can do an evaluation and determine where your thickest saturation and highest porosities are."

The far eastern Chalk is its own source rock, he added, while the oil in the Texas Chalk is mostly sourced from the Eagle Ford. "In the early '90s, when I was with Amoco, we did a lot of oil-typing and confirmed the Austin Chalk in that core Tuscaloosa Trend area is a source rock.

"So it fits in the unconventional model of finding the best TOCs [total organic content] and best porosity and putting a high-proppant frack on it."

The eastern Chalk was deposited about 89 million years ago; the Tuscaloosa Marine Shale (TMS), some 700 to 800 feet below, about 93 million. "The same conditions that caused the TMS hydrocarbons to cook to the right level did the same thing for the Chalk. Each was cooked at the right temperature at the right time."

Water cut varies widely, he said. Barrell finds it changes west of Avoyelles Parish. Masters Creek, for example, made an average of 12 bbl of water per bbl of oil for a total of 311 MMbbl of water.

He has no doubt that smaller operators are waiting for bigger-balance-sheet operators to crack the code in the far eastern Chalk. "Now the lease clock is ticking in all of the cases." Most lease terms are for three years with options for three-year extensions.

Marathon in Masters Creek

As for the western Louisiana Chalk, some operators "were planning on piggybacking on Marathon [Oil Corp.'s] program," Barrell said.

Marathon leased some 240,000 acres for less than $900 an acre. Registered with the state as Southwind Oil & Gas LLC, it temporarily plugged its Crowell LM 30 #1 at total depth of 15,534 feet and TVD of 15,508 feet in December.

Barrell said, "Marathon experienced significant problems with the high formation pressures and never was able to drill the lateral portion of the well." The hole is in Masters Creek Field in southeastern Rapides Parish. Marathon has a permit for a second well, Crowell LM 30 #2, on the lease.

Barrell said, "Marathon's challenges have really cost [these other operators] a year on their lease clocks."

Also in the western Louisiana Chalk, Lime Rock Partners-backed Prime Rock Resources LLC has signed a joint venture with privately held New Dawn Energy LLC to develop some 120,000 net acres from the Texas border to Rapides and Evangeline parishes. The leasehold is primarily in Masters Creek Field.

They expect to acquire additional leasehold, they reported in June. Prime Rock has more than 100,000 net acres in Central Louisiana; New Dawn owns more than 270,000 net acres of minerals in western Louisiana, including more than 150,000 net acres over the Chalk.

'Technically strong'

Compared with deeper, TMS attempts earlier this decade, Barrell said, "I feel we have much better operators leading the charge this time. They're operationally strong, technically strong and fiscally strong.

"We're going to have a much better start. And ConocoPhillips, EOG and Marathon, they're all very active in these same-age formations in South Texas. They have a lot of experience with same-age rock and same type of rock. That's a major plus."

Barrell would like to see the new far eastern Chalk play become a stacked play for Chalk and Tuscaloosa, as they're only about 750 feet apart. Australis Oil & Gas Ltd. continues to attempt the TMS in southern Mississippi, having picked up leasehold from Encana Corp., which discontinued its effort.

"While [Australis] struggled operationally, they did have success with two wells—both full-length laterals," Barrell said.

J.P. Morgan large-cap E&P analyst Arun Jayaram reported in May that, after three months of production, one of the Tuscaloosa wells had made some 86,000 bbl; the other, after 19 days online, had averaged about 1,100 bbl/d. Lateral lengths are about 6,800 feet.

Two other wells didn't work out, Jayaram wrote, "supporting how the current perception of the [TMS] play continues to be hit or miss."

Barrell said, "They're still using Encana's 2014 frack design just to prove they can replicate that, but we're getting 1,450 barrels of oil equivalent per day out of these recent TMS wells."

Stacking wells could be "intriguing for the economics, and EOG has leased all the way into Mississippi," Barrell added. "It's obvious they have some TMS interest."

Based on the fact that EOG drilled Ironwood in 18 days for Chalk above Tuscaloosa, averaging more than 1,000 feet a day, "EOG has proven that a TMS well could be drilled in 19 days," since the TMS is just another 700 feet below the Chalk, he said.

'Pulling the trigger'

Bryan Hanks' Lafayette-based Beta Land Services LLC has led land acquisition for clients across several shale plays, including the Haynesville. While there has been considerable leasing in the far eastern Chalk, he has inquired as to the dearth of drilling activity among smaller operators.

"Everybody has a twist or a story," Hanks, Beta's president, said. "They are reconfiguring the rig or going with a different [internal] team. There are a lot of plans, but nobody's pulling the trigger."

Devon Energy Corp., which has leasehold east of the Mississippi River, replied to *Investor* that it is too early to comment. In the western Louisiana Chalk, Marathon said it's still in early stages.

Marathon chairman, president and CEO Lee Tillman said at IHS Markit's CERAWeek earlier this year, according to Bloomberg, "If [the Louisiana Chalk] works—and that's still a question—that kind of investment gives you the opportunity to create outsized, full-cycle returns because your entry cost is so low.

"If we're successful, that's a basin-opening opportunity."

Also having leasehold for Louisiana Chalk is Cimarex Energy Co. According to J.P. Morgan's Jayaram, Cimarex has some 130,000 net acres in the Louisiana Chalk with all but about 9,200 picked up in 2018.

"We note the company is currently in a watch-and-see mode, likely observing the results of ConocoPhillips and EOG first before deploying incremental capital dollars to the play," Jayaram wrote. "We also note a very similar phenomenon for Devon."

John Lambuth, Cimarex senior vice president, exploration, said in an earnings call in February that "we have been able to accumulate a very nice acreage position in Louisiana, and we are actively pursuing an exploration idea there."

He added that, if there are good results, "at some point, then we'll speak more to it."

Jayaram reported earlier that month that another leaseholder's presentation showed Cimarex's position to be east of the Mississippi River in Livingston Parish.

This spring, Hanks said, some plans on private land underlying the Morganza Spillway path in central Point Coupee Parish may have been postponed while leaseholders expected the Mississippi River control structure to be opened to relieve flooding. At press time, the opening was postponed indefinitely.

Election year

Some potential drillers are awaiting results from the Louisiana gubernatorial race, which will be decided this fall. The incumbent, John Bel Edwards, has supported "legacy lawsuits."

"It's just such an obstacle to get over," said Hanks, who is a past chairman of the Louisiana Oil & Gas Association and continues to serve on its executive committee. "He truly believes in these legacy lawsuits: When you buy a property, you inherit everything that ever happened on that property."

Other than this, Edwards has been engaged in supporting oil and gas industry growth, Hanks said.

Amelia's Barrell said that, with the Haynesville play in northwestern Louisiana reemerging, a new Louisiana Chalk play presents an opportunity to further generate some positive economic results for the state, particularly as the Gulf of Mexico industry remains depressed.

While there has been considerable leasing in the far eastern Chalk, Bryan Hanks, president of Beta Land Services LLC, has inquired as to the dearth of drilling activity among smaller operators.

> "Chalk 3.0 is trying to find the highest matrix porosity you can find that's saturated and thick."
>
> —Kirk Barrell, Amelia Resources LLC

"So let's hope that [whoever wins] is industry-friendly and wise enough to understand the potential impact of the upside [of oil and gas development]."

Beta's Hanks said that, meanwhile, operators with undeveloped leaseholds "have to develop those investments. They're going to have to deal with it one way or another, especially if [Edwards] gets reelected."

'Chess moves'

ConocoPhillips responded that it couldn't provide an interview at this time. Chairman and CEO Ryan Lance said in a press conference after the company's annual meeting in May that it wanted to finish its initial four-well program before discussing it further, according to an S&P Global report.

"We probably won't have results until later in the year," he told S&P Global, adding that the company is "still optimistic."

The operator's May investor presentation cites the Louisiana Chalk play as "leveraging learnings from Lower 48 unconventional plays, including updated completion designs."

J.P. Morgan's Jayaram reported that EOG has created 33 2,000-acre drilling units in West Feliciana Parish east of ConocoPhillips and in the updip window. (EOG's Eagles Ranch well is downdip, south of the Shelf Edge. Brunswick is as well. Ironwood is updip.)

He added that ConocoPhillips and EOG have applied for about 18 permits each in the two Feliciana parishes, "with a majority directly offsetting one another."

Also, "in addition to EOG bulking up its permit backlog, ConocoPhillips appears to have made a similar pivot and—although the first well test that we came across from ConocoPhillips was negative—the company's permitting chess moves as of late certainly make us believe that incremental technical data and learnings from that first well have influenced them on future permitting actions.

"And we do not expect EOG to be left out."

Geaux Louisiana Chalk

PetroQuest's Goodson said, "Regardless of whether or not we have leasehold in all segments of the play, we are hoping for success across the trend. This may be 'South Louisiana's Haynesville.'"

In all of South Louisiana in June, there were only four active rigs, he said. Since the Jennings Field discovery in 1901, "it has never been this inactive" in South Louisiana. The revival of the Haynesville rig count in North Louisiana is very encouraging for the state, and Louisiana oil and gas production's access to markets is a distinct advantage.

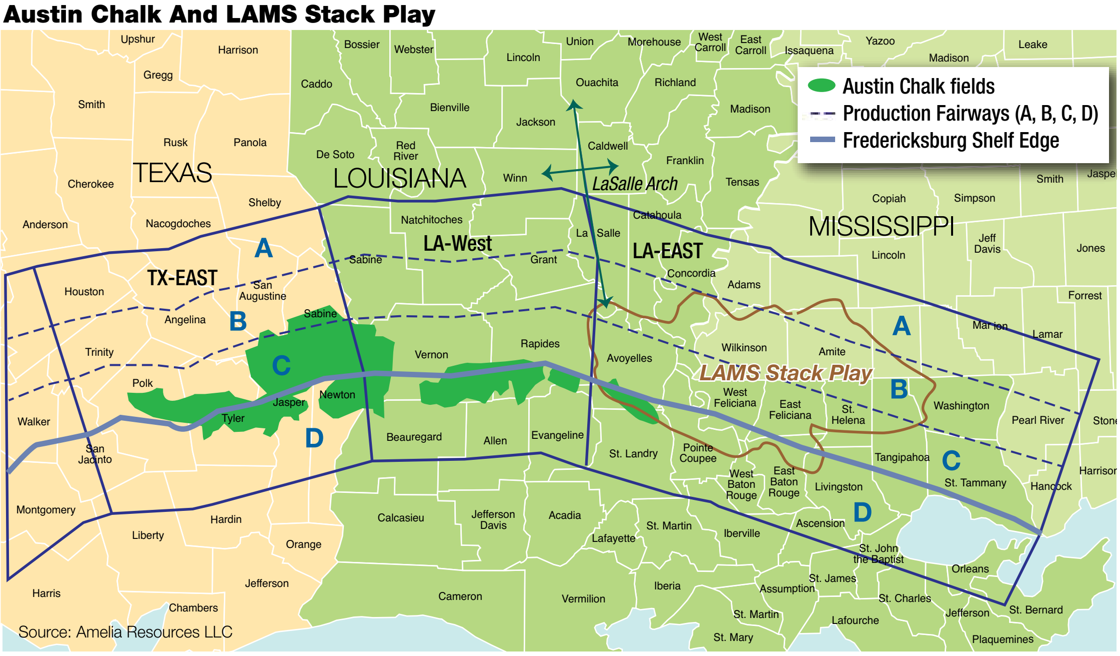
"The Haynesville is, by pipeline, less than one day from the largest hydrocarbon-processing center in the world, stretching from Corpus Christi, Texas, to Mobile, Ala., with the bull's eye for LNG 100 miles due south around Lake Charles.

"If the Louisiana Austin Chalk works, our acreage begins 5 miles from the Mississippi River 'as the alligator swims,' as we say. Just downstream another 10 miles begins refinery row, all the way to the Gulf of Mexico and the benefits of LLS [Louisiana Light Sweet] pricing.

"We have access by truck and pipeline and have heard about thoughts for a barge terminal on the river, which could also be a receiving point for barge loads of frack sand, which will be needed in massive quantities.

"Bottom line, everyone in Louisiana is rooting for Austin Chalk 3.0 to be an economic success." ☐

Austin Chalk And LAMS Stack Play



Most past Chalk production has been from just updip or just downdip of the Lower Cretaceous Shelf Edge (blue line). Most of the economic Chalk production in the past has been made in Texas and in western Louisiana.

FIVE STATES
www.fivestates.com

Upstream Non-Op
Working Interest Buyer

$3-50MM
Transactions

Core Focus Areas
Permian | East TX | Midcon | Rockies
Proved, High R/P, Low Lifting Costs

Gary Stone | EVP Engineering | (214) 560-2584

www.fivestates.com

NOBLE ROYALTIES, INC.

America's #1 Family Land Heritage Option

WE ARE BUYING.

CURRENTLY EVALUATING ASSETS $5MM-$500MM

CHASE MORRIS
cmorris@nobleroyalties.com

THOMAS DENTON
jtdenton@nobleroyalties.com

OIL, GAS AND DECARBONIZATION

Big gains in energy exports fuel commitments to address climate change.

ARTICLE BY
GREGORY DL
MORRIS

PHOTOS COURTESY
UNIVERSITY OF
OKLAHOMA

In the competition for markets, the U.S. oil and gas industry has turned the world upside down, surging to place among the top three countries in exports just a few years after re-entering the deepwater trade. In terms of coming to grips with the urgency of addressing and mitigating climate change, however, the gains have been much more modest. The industry must improve its position in the competition for capital and positive public sentiment. Speakers at the annual Energy Symposium held by the Price College of Business at the University of Oklahoma lauded the energy industry for its business accomplishments and exhorted leaders to step up environmental efforts by citing evidence that sustainable business is profitable business.

"The resource is there as long as we extract it in an environmental and economical way," said opening speaker Dr. Mark Zoback, professor of geophysics and director of the Stanford Natural Gas Initiative at Stanford University. "There is almost unlimited potential even if we are only drilling in areas where we are already allowed," said Zoback. "Recovery of tight oil is still in the single digits [as a percentage of oil in place]. Tight gas is a little better. For the $77 billion invested, we are doing a bit better [than at the start of the shale era], but we have a long way to go."

There was a strong, if unspoken, implication that the global energy market could move into oversupply. More producers of more molecules will be chasing demand growth that is changing quickly and, in some cases, already facing limited growth.

"The oil and gas industry is in the era of decarbonization," said Zoback. "The new abundance of natural gas is an immediate opportunity to decarbonize the power-production sector." While most of the decarbonization attention is on reducing the use of coal and oil to generate electricity, Zoback noted the important potential in heat, not just light.

"Thermal fuels are a significant matter in the developing world," he said. NGL, especially propane, is a significant opportunity to replace

The University of Oklahoma's Price College of Business held its annual Energy Symposium in April. From the left, Melanie Kenderdine, Wes Mitchell, Brian Moddelmog and Mike Ming.

"The oil and gas industry is in the era of decarbonization," said Dr. Mark Zoback, professor of geophysics and director of the Stanford Natural Gas Initiative at Stanford University.

wood, charcoal and dung as a fuel for cooking and heating.

"The importance of the industry is carbon capture and storage [CCS]. CCS should not be overlooked," Zoback added.

Looking more closely at decarbonization of electrical power, Zoback stressed the danger, and potential: "There is 300 gigawatts of coal-fired generating capacity under construction across Asia. To put that into context, that is equal to all the coal-fired plants operating in the U.S. That means that even if we shut all of our coal-fired plants tomorrow, it would only be a net zero for emissions as the plants in Asia come into service."

Stepping into the vanguard

It might be surprising that so much new coal-fired generation is being built, given all the gas being produced, and the boom in deepsea LNG. But LNG into India is going for about $7 per million British thermal unit (MMBtu), and coal is costing less than $3/MMBtu.

"However, there are 4 million deaths worldwide a year from indoor air pollution," he said. "In the developing world that is caused primarily by burning wood or dung for fuel and heat. So [nations have to] account for the health and the quality of gas over traditional fuels. What carbon price does that take? About $22 a ton."

Even without a formal global carbon price, there is already action on that front. "India is providing 10 million propane canisters around the country," said Zoback.

All of those efforts are necessary but not sufficient, said Zoback and other speakers through the course of the symposium. "The only way to reduce CO_2 is carbon capture and storage," Zoback stressed. "Green energy only reduces the rate of increase in carbon emissions." He again cited California, which has been vocal about decarbonization. "If California is going to meet its goals, it is going to need lots of natural gas, high standards for automobile emissions and CCS."

And that is where the oil and gas industry can be in the vanguard. "The current estimate for CCS is 30 million tons a year injected as a super-critical fluid and sequestered," said Zoback. "The infrastructure required to do that is equivalent to the [scale and volume] of the global oil industry. The only realistic pathway to sequester that much carbon is to inject it into depleted formations. The infrastructure is in place, and the pore space is being created every year."

Just as the roots of a tree reflect its branches, Zoback's vision for the sustainable hydrocarbon industry is equivalent volumes of oil and gas out and CO_2 in. "We know where it can go, and we know what we need to do."

The first steps in that direction are being taken. Occidental Petroleum Corp. is already the largest consumer of CO_2 in the country, said Hilary Moffett, senior director of government affairs. The company consumes 2.6 billion cubic feet per day (Bcf/d), or 50 million tons per year of CO_2 for EOR.

The company has invested in 1.6 megawatts of solar power at its producing field near Goldsmith, Texas, and has a joint venture with White Energy in biofuels. Occidental has also invested in direct carbon capture, an eponymous project in Squamish, British Columbia, just up the coast from Vancouver. "This pilot plant with Carbon Engineering [Ltd.] opens a pathway to a carbon-neutral or even carbon-negative barrel of oil," said Moffett.

The panel underscored the tone set by earlier remarks that natural gas is an essential part of the decarbonization equation, especially in the developing world. "At the Energies Futures Institute [EFI], we are very focused on deep decarbonization," said Melanie Kenderdine, former director of the energy policy office at the Department of Energy and former executive director of the energy initiative at Massachusetts Institute of Technology. She is currently a principal at the EFI.

That focus comes naturally. "When I was in the Clinton administration, gas was viewed as a very green fuel. A lot has changed since then. My view now is that gas and renewables should work together. Even large-scale wind and solar will result in periods that require large-scale backup options."

Kenderdine showed historical data indicating that there have been periods as long as 10 days in which the wind did not blow sufficiently to meet base demand in some regions. That may be mitigated by utility-scale storage, but only after significant time and investment. In the major North American regional wholesale markets, actual storage available today is measured in hours, not days.

"California Independent System Operator has a bit of storage for 14 hours," said Kenderdine, "but most of it is only 4. PJM [the ISO for Pennsylvania, New Jersey and Maryland] has storage for only about an hour. When you are talking about 10 days with no wind, you either need 10 days of storage, or 10 days of fuel."

Wes Mitchell, manager of supply and trading for Cheniere Energy Inc., concurred, offering his perspective from the trading desk. "Five to seven years ago an energy trader would only discuss wind output at a cocktail party, to demonstrate knowledge. Now [the ability to understand wind output] is essential. On peak days the U.S. has 60 gigawatts of wind energy. That is the equivalent of 120 nuclear power plants. But the next day that might be only 30 gigawatts. That's like 60 nuclear plants being lost from one day to the next."

He hastened to add, "You never hear about that, which is a demonstration of a market that is working. Gas is there to back it up. It is fascinating to see the volatility in wind output and the ability for gas to fill it."

Balancing gas demand and LNG

The larger question is whether storage is the enabling technology to arrest climate change. Kenderdine does not believe so. "We do need breakthrough technology, but I don't see that happening by 2030. I only see incremental improvements by then. We need the breakthrough technology by 2050 to meet the climate change goals by then. That could be direct capture. Or hydrogen—from electrolysis, not from steam reforming."

While acknowledging that LNG exports have gone to a wide range of countries, with more being added every year, Kenderdine cautioned that "69% of LNG exports go to other OECD countries." OECD has 37 member countries and is broadly taken to represent the industrialized nations of the world. That reality of exports mostly to other "Western" countries throws some shade on the idea that cleaner-burning gas will quickly and easily displace coal for power generation and perhaps even wood for cooking and heating in developing countries.

Back at the export end of the tanker voyage, the number of liquefaction terminals is growing, with more planned. "There are massive new projects," said Cheniere's Mitchell, "and I am talking just about the ones that are actually under construction or approved by the Federal Energy Regulatory Commission, not ones that have not yet gotten to final investment decision." One came into service last year, two more are due this year, with two more approved. Meanwhile, the price for LNG in Asia has tumbled.

"We need the breakthrough technology by 2050 to meet the climate change goals by then," said Melanie Kenderdine, principal at the EFI.

"We need investment in the midstream," said Wes Mitchell, manager of supply and trading for Cheniere Energy Inc. "It is one thing to have a beautiful world-class terminal, and a whole other thing to get gas to it."

By the time its 6th train is in service at Sabine Pass, and the second at Corpus Christi, Cheniere will have about 8.5 Bcf/d of liquefaction. That is roughly 10% of the entire U.S. gas market and roughly as big as the entire Canadian market.

"We are now looking at the second and third waves of LNG facilities," said Mitchell. While he confirmed some projects have sound financials, he added, "It is difficult to see projects that are just extrapolations of current growth rates taken out 10 or 20 years. We could be looking at 20 to 25 Bcf/d of waterborne gas out of the U.S. That final five is going to be a challenge to think about. How are they going to get the gas, and how are they going to get it to the Gulf Coast?"

That raised the question of other LNG exporters keen to get in on the boom, particularly the flurry of interest in floating liquefaction vessels. "The lead opportunity outside the U.S. is Qatar," said Mitchell. "There will be opportunities for gas economies worldwide, and not necessarily in LNG.

"China now produces half of the gas they need and is developing more. That is on our radar. Also, liquefying gas is hard. Doing it on a ship with dramatically condensed engineering is even more so. It will be interesting to see how that works, to see how these floating units do on reliability standards."

Brian Moddelmog, vice president of strategic origination at Calpine Corp., noted dryly that "this past winter New England had to

Regardless of the region, "it is very important for renewables and gas to work together," said Brian Moddelmog, vice president of strategic origination at Calpine Corp.

import LNG—at $12 per Mcf [thousand cubic feet]." Calpine is one of the largest utilities in the country, with 28,000 megawatts of generating capacity primarily in California, Texas and New England. That capacity is primarily gas-burning, consuming about 2 Bcf/d of gas.

"California is a proxy for what we should expect to see in other parts of the country," said Moddelmog. "If we can agree on that [model], the market design [for natural gas] becomes the next issue."

The volumes in domestic pipelines are very much on the mind of LNG exporters. "We need investment in the midstream," Mitchell stated flatly. "It is one thing to have a beautiful world-class terminal, and a whole other thing to get gas to it. We look for consistency, and we wonder how the midstream is going to support 50 million tons a year of exports, and 100, and 150. What is missing in the big conversations about LNG is the importance of the midstream."

Sounding dire, Mitchell elaborated, "We cannot get incremental pipes built, if we can't get greenfield or even brownfield pipes, if all we are left with is looping and compression on existing lines, then the Marcellus will only have a limited role in U.S. LNG exports over the next decade."

Price ranges and fluctuations are the essential variable for all energy projects. While global oil markets are well established, as are regional gas markets, LNG is in its early days. "Contract terms are literally evolving as I sit here in this chair," said Mitchell.

He explained that traditionally, LNG was priced against an oil index at 6:1 because of the relative Btu value of crude and gas. "That was always mathematical, not actual," he stated. As LNG has become a global commodity, it is in the process of developing real price balances based on delivered costs and competition from other fuels.

"Today LNG prices in Asia have nothing to do with oil prices," said Mitchell. "There is dealing based on price options and destinations.

"The importance of the industry is carbon capture and storage [CCS]. CCS should not be overlooked."

—Dr. Mark Zoback, Stanford University

Is LNG priced against oil? Yes. Against Henry Hub? Yes. Against Rotterdam coal? Yes. Eventually LNG will be priced on its own merits."

Kenderdine noted a fast-approaching inflection point. "Based on LNG projects currently in service or being built, not just project announcements, the volume of LNG worldwide will approximate the total pipeline volumes in the world by 2020 if all those projects are completed."

Renewables and gas collaborate

Regardless of the region, "it is very important for renewables and gas to work together," said Moddelmog. "Electricity is the easiest to decarbonize. It is not easy per se, but the easiest sector because the others are more difficult. [The] industry is extremely difficult because there are no alternatives for process heat. Transportation is a matter of consumer decisions. There is also consumer resistance in the building sector."

For example, commercial kitchens and most consumers want gas stoves. They don't like to cook on electricity.

Even having said that the power generation sector is the easiest, Moddelmog added, "In California, 49% of the generation is gas-fired. Getting to the goal of 60% renewables by 2030? That is a lot."

Kenderdine emphasized a different set of ratios. "Decarbonization of electricity is important, but in California, [that sector] is only 16% of emissions. The largest sector by far is transportation, followed by industrial, followed by buildings. The focus on electricity is important, but that is not going to get us to our emissions goals, certainly not by 2030. And in the meantime we have to worry about reliability."

Returning to an idea she mentioned earlier, Kenderdine advocated reusing fossil-fuel facilities to support renewable energy. For example, that could mean using the existing natural-gas distribution system to carry "renewable gas" from agriculture, or as a way to move hydrogen to augment gas-fired combined-cycle generation.

There are several advantages to blending green energy into the existing infrastructure, most obviously, the facility and economy of not having to make major new capital investments.

"Oil and gas companies have a fiduciary responsibility to protect their infrastructure," said Kenderdine. "We need to understand that."

Still, she chastised the industry on the same point. Acknowledging that companies have been unwilling to abandon assets, Kenderdine added, "that unwillingness has delayed a response to the existential threat of climate change. Anything we can do to stop creating immovable objects is critical." □

CALIFORNIA
RESOURCES CORPORATION

ENERGY FOR CALIFORNIA BY CALIFORNIANS

Operating in the fifth largest economy in the world, California Resources Corporation (CRC) is California's largest independent oil and natural gas exploration and production company dedicated to alleviating the state's chronic dependence on imported energy. We take our leadership position seriously as we advance policies that increase the state's energy supply, environmental quality and economic mobility. This means we:

- Participate in an "All-of-the-Above" approach to provide energy that is affordable, reliable and critical to our local economy and our state.
- Serve as a key economic engine in California by providing high-wage jobs and a path to the middle class for a diverse and empowered workforce.
- Share and endorse the state's commitment to conserve natural resources and protect our environment while providing localized solutions for sustainable future energy.
- Deliver value to all of our stakeholders by managing our business in a disciplined manner, while extending CRC's expertise throughout our operations to ensure excellence in everything that we do.
- Promote the safety, health and protection of people, the environment and our communities as our top priorities while operating under the world's most stringent regulations.

crc.com

CHESAPEAKE'S SAND STRATEGY

Chesapeake Energy Corp. is cutting costs and shaving nonproductive time by opting to self-source sand instead of using third-party suppliers.

ARTICLE BY
VELDA ADDISON

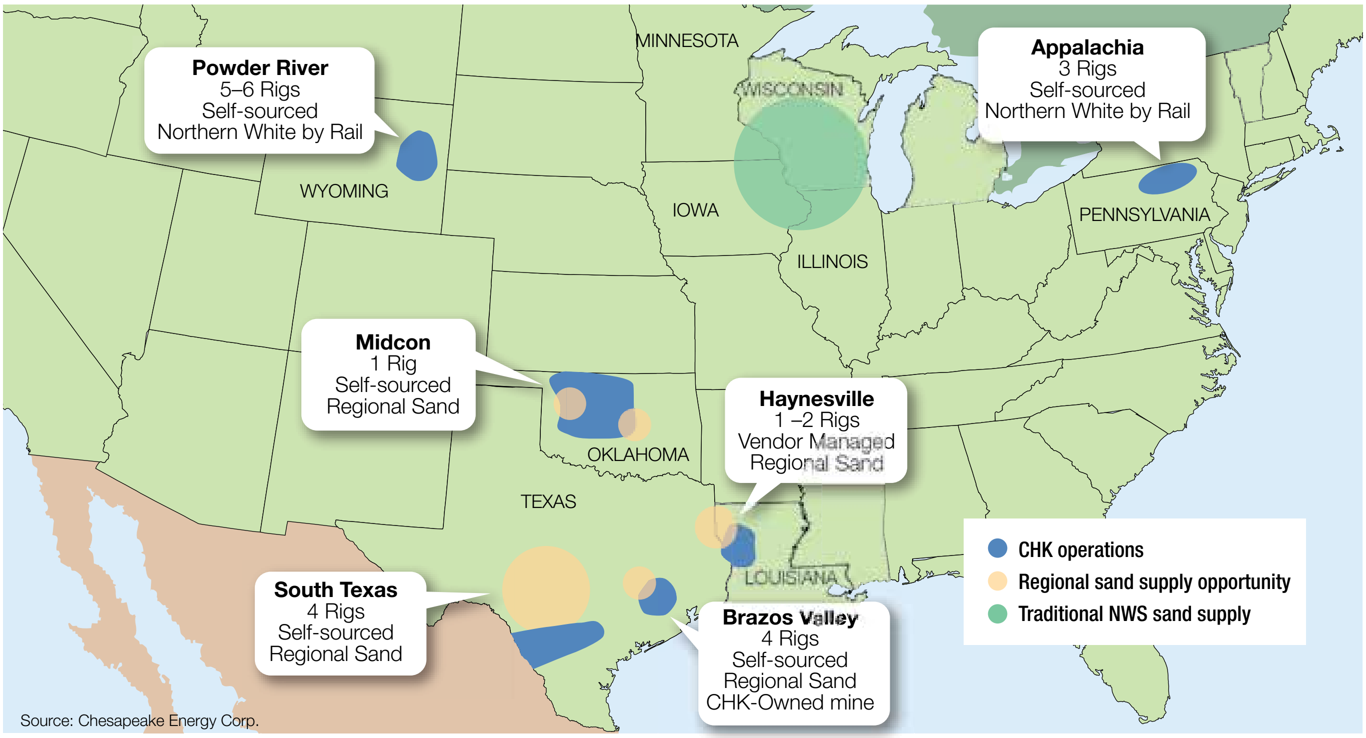
For a company that pumps about 4 million tons of sand per year—enough to fill Oklahoma City's Chesapeake Arena six times—it's no wonder that thoughts turned to self-sourcing when free-cash-flow neutrality and reducing debt were goals.

"We have saved over this last year $100 million by supplying our own sand. That's massive for us," Jason Pigott, executive vice president of operations and technical services for Chesapeake Energy Corp., told attendees at Hart Energy's DUG Sand conference in April. Added benefits included reducing nonproductive time (NPT) by 92% in the last few months with no negative impact on production, he said.

The accomplishments didn't require adding another division to the company's supply chain group as he originally feared. They came by adding two people with expertise to the organization, forming valuable partnerships and lots

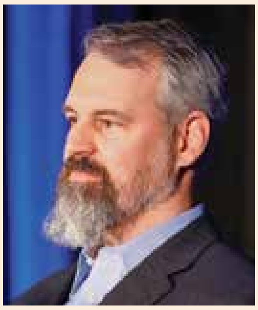
"We have saved over this last year $100 million by supplying our own sand. That's massive for us," said Jason Pigott, executive vice president of operations and technical services for Chesapeake Energy Corp.

Chesapeake's Sand Supply Locations



Frack Sand Forecast

Frack sand demand could reach 107 million tons in 2019, and a lot of it is coming from the Permian Basin.



Todd Bush, principal, Energent Group

"We expect about 40% of that [demand] to be in the Permian and then increasing the Permian Basin's activity in 2020, moving to close to 45%," said Todd Bush, principal at Energent Group, at the DUG Sand conference in April.

Bush noted that when you think about frack sand demand, you have to think about its key drivers: proppant per foot, lateral lengths, horsepower and what's happening with the number of frack crews.

"Every grain of sand has to be pumped through some of the horsepower that's out there in the field. So we're actively watching what the crew count is doing, what the supply and demand of horsepower is doing to then show those constraints within our frack sand forecast," Bush said.

Energent is tracking 145 frack crews in the Permian, accounting for 38% (383) of frack crews right now. By tracking the frack crews, Bush said, the firm is able to see what the cycle times look like.

"One thing that we're watching closely are all the [sand] mines that are coming online, where they're located and what that means for cycle time and costs," said Bush.

About 23 sand mines are scheduled to come online in 2019, resulting in 80 million tons of frack sand supply, he said.

In the Permian, "we're looking at more in the 42- to 45 million tons of frack sand demand for 2019, and with the locations of the mines within that central Midland-based scenario, you get pretty good access to any side of the Permian," Bush said.

"This essentially gives you about an hour, hour and a half drive toward any area within the Delaware Basin or within the southern Midland Basin. … This is a good presentation of what it takes to drive from mine to the well site."

—Brandy Fidler

of planning. Pigott said the company's sand story is universal to everyone in the E&P business.

The story was shared as operators continue to focus on costs and efficiency as they try to add value from unconventional oil and gas assets in the U.S. Chesapeake is cutting costs and shaving nonproductive time by opting to self-source sand instead of using third-party suppliers.

With assets in the Powder River Basin, Midcontinent, Marcellus, Haynesville and the Eagle Ford, among other spots, the company does not take a one-solution-fits-all approach when it comes to sand sourcing. In the Powder River and Appalachia, for example, northern white sand by rail is self-sourced, while regional sand—also self-sourced—is used in the Midcontinent, South Texas and Brazos Valley. The company uses regional sand in the Haynesville, but it is vendor managed.

For Chesapeake, the number of rigs running is a factor in determining whether to self-source in a basin. In the Haynesville, for example, the company runs one to two rigs, compared to four each in South Texas and Brazos Valley.

"If you've got one rig, it's [self-sourcing] probably not going to be for you. … You have to have mass to make it work," he said.

A hybrid strategy is something companies should think about if they are considering self-sourcing, taking into account the location of sand mines, which facilities can handle spikes in demand and trucking expenses, according to Pigott.

Another big consideration is an obvious one—reservoir properties, along with the potential impact on EURs and completion designs.

Chesapeake began testing regional sand in 2013, looking at the supply of Northern White, Pigott said, adding "it never quite worked out" as market conditions prevented a full transition. But the opportunity surfaced again five years later, in 2017, as regional sand mines came onstream, prompting Chesapeake to carry out regional sand testing in various assets to determine the impact of regional sand use on production.

"We felt comfortable that regional sand in an area like the Eagle Ford was not going to be detrimental to our production. So that caused us to make that shift," Pigott said.

By mid-2018, Chesapeake was decoupling its frack services and lining up partners for logistics and sand. The company started its direct-sourcing transition in fourth-quarter 2018, pumping regional sand and managing final mile transport, he said.

The change has resulted in 50% cost savings vs. traditional northern white sand and a 92% drop in sand-related NPT, according to Pigott, who called it a game changer for the company.

"As we've gone to this micro supply chain, it's a lot of clarity," Pigott said. There have been times when a vendor would say it was waiting on sand while down fixing pumps, he said, noting you couldn't really tell whether time was needed to fix pumps or for sand to arrive. "Now they are no longer waiting on sand. … We have clarity into what's really going on."

It also helps that Chesapeake acquired the Burleson Sand Mine as part of its purchase of WildHorse Resource Development Corp. that closed in February.

"We are not only supplying sand; we are operating a mine," Pigott said. "That mine is up and running today. It supplies about half our sand."

Meanwhile, other vendors in the region supply the rest. "Those things are really moving the costs down," he said.

Session moderator Richard Mason, chief technical director for Hart Energy, pointed out the evolution taking place within the industry. "We've gone from an industry where we have specialized E&Ps, specialized service companies. Are we going back to a vertically integrated industry?" he asked.

For Chesapeake, "the big thing is clarity," Pigott responded. "Everybody was taking a slice of the profit and getting margin along the way. When we started to decouple, we knew exactly what sand costs. … Are we going to decouple everything? No, but when you're pumping 8 billion pounds of sand, that's a big ticket item that you may want more clarity into." □


2018 STATISTICS
1,023 ATTENDEES
21 SPEAKERS
95 SPONSORS
116 EXHIBITORS
Celebrating 25 Years
PLAYS COVERED: WOLFCAMP, BONE SPRING, AVALON, DEAN, JO MILL, SPRABERRY, CLEARFORK AND SAN ANDRES
THE CENTER OF THE ACTION:
The Market's Shining Star
EXECUTIVE OIL
CONFERENCE & EXHIBITION
Nov. 4, 2019
Golf Tournament
Nov. 5-6, 2019
Conference & Exhibition
Midland County Horseshoe Pavilion | Midland, TX
Confirmed Speakers:*
Staale Gjervik
President
XTO Energy Inc.
Mike Ford
CEO
Caza Oil & Gas LLC
*Speakers being confirmed daily.
Nov. 5, 2019: Executive Dinner
Honoring Jim Henry, Founder, Henry Petroleum; Founder, Henry Resources
Midland Country Club | Midland, TX
Presented by:
HARTENERGY
Hosted by:
E&P
Oil and Gas Investor
MIDSTREAM
REGISTER TODAY at ExecutiveOilConference.com

PRENG & ASSOCIATES
The Global Energy Search Leader

THE MOST RESPECTED EXECUTIVE AND BOARD SEARCH FIRM IN ENERGY

Preng & Associates is the world's leading executive search firm totally dedicated to the energy industry. Over our thirty-eight years, we have assisted more than 700 management teams and Boards attain exceptional talent who have delivered long-term value.

After nearly four decades of specializing in energy and natural resources, our consultants:

- Completed more than 3,500 search assignments in 70 countries.
- Generate more than 80% of our business from repeat clients.
- Believe loyalty and experience is invaluable to the executive search process.

Houston Office:
2925 Briarpark Drive
Suite 1111
Houston, Texas 77042
Tel: +1 (713) 266-2600

Chicago Office:
560 Frontage Road
Suite 300
Northfield, Illinois 60093
Tel: +1 (713) 243-2650

London Office:
42 Brook Street
Mayfair
London, England W1K 5DB
Tel: +44 (0) 20-7958-9445

www.preng.com

NATURAL GAS HITS THE ROAD

When shale gas first took off, natural gas vehicles became the next big source of demand. How much progress has been made?

ARTICLE BY
LESLIE HAINES

This summer, UPS Inc. announced a historic, seven-year deal with Clean Energy Fuels Corp. The package delivery company said that through 2026, it will buy 170 million gallon equivalents of renewable natural gas (RNG).

This is the biggest purchase of RNG in American history, and that makes sense, given the size of the UPS fleet and its commitment to reduce emissions—UPS has set a goal of alternative fuels constituting up to 40% of its ground fuel consumption by 2025. The company has 6,100 vehicles worldwide that now use either CNG or LNG. It also uses propane and has hybrid and electric vehicles.

Bravo UPS; this is great news for the environment—experts say heavy-duty trucks and buses are the No. 1 source of emissions in urban areas. But note that all of the gas fueling UPS trucks is not coming from wells drilled by the nation's natural gas producers. Instead, it is RNG, which is gas derived from methane emitted by landfills, dairy and hog farm waste and other renewable sources.

"There are 2,000 stations across the country today for CNG and LNG vehicles," said Daniel Gage, president of NGVAmerica.

Clean Energy Fuels, a company built on championing natural gas for vehicles, sells both gas from wells and from RNG. As of December 2018, the company served roughly 1,000 fleet customers operating some 47,000 natural gas vehicles (NGVs). To do this it owned, operated or supplied 530 natural gas fueling stations in 43 states and four provinces in Canada.

The brainchild of oilman and billionaire energy investor T. Boone Pickens and current CEO Andrew J. Littlefair, Clean Energy Fuels was incorporated in 2001 based on some predecessor companies Pickens owned. It went public in 2007, and is based in Newport Beach, Calif. In 1997, Pickens had founded Pickens Fuel Corp., the predecessor company to Clean Energy. Then, Pickens was noted for the Pickens Plan, his $100 million campaign to end America's dependence on OPEC oil. He traveled the country urging that all heavy-duty trucks convert to natural gas.

As the shale gale took off, he and several other gas producers later founded America's Natural Gas Alliance in 2009, which merged into the API in 2015. This occurred when the natural gas shale plays were being unveiled at a fast clip—first the Barnett, then the Fayetteville, the Haynesville, the Marcellus—and the land grab in them was at its height. E&P executives extolled the enormous potential benefits of the huge gas resources that lay before them.

Shale gas production tripled between 2007 and 2011 and by July 2012 it had risen to nearly 70 billion cubic feet a day (Bcf/d). The growth continues today as associated gas from the Permian Basin competes with production growth still seen in the Marcellus Shale. Today the U.S. produces more than 88 Bcf/d of gas and is exporting about 6 Bcf/d.

In an interview with Forbes in 2011, the late Chesapeake Energy Corp. founder and CEO Aubrey McClendon, one of the industry's most vocal advocates of natural gas, said, "… I look forward to the day when Americans can fill up on American natural gas rather than OPEC oil and at half the price of OPEC oil, and at great benefit to the American environment."

Since then, Clean Energy Fuels has built the biggest network of both public and private natural gas stations in North America, and during the past five years it has seen sales of Redeem, its trademarked RNG fuel, skyrocket. In the first quarter of 2019, the company said total gas volumes increased 12%, but Redeem volume increased almost 90%; that's *before* its recent agreement with UPS was in place. Last year, it inked a deal to buy biomethane gas from BP Plc, and it also has a deal with Total.

NGVs today

With such an abundance of natural gas supply available, and many ardent supporters of its use, just how much natural gas is the nation's vehicle fleet using instead of diesel or gasoline? Natural gas vehicles have continued to grow in popularity as more municipalities and companies owning large vehicle fleets, whether trucks or buses, continue to work on reducing fossil-fuel emissions.

Worldwide, about 27 million vehicles are fueled by natural gas, but adoption of NGVs in the U.S. seems to have slowed. In the U.S., some 175,000 to 185,000 NGVs are in use:

11,000 are buses, 17,000 are waste trucks, 5,500 are school buses used in 150 school districts. (Data includes all land-based vehicles, including two-wheelers, off-road and vehicles that have been converted to natural gas.)

"We are a mature technology, and all the kinks have been worked out. We are commercially proven and ready. There are 2,000 stations across the country today for CNG and LNG vehicles," Daniel Gage, president of NGVAmerica, told *Investor*.

In the U.S., the light-duty market (mostly cars and taxis) is focused on transitioning to electricity rather than natural gas, whereas the heavy-duty fleet (long-haul freight trucks and construction equipment) is moving toward using more CNG, LNG or RNG.

LNG is more popular and efficient for high-horse-power uses like long-haul trucking and marine applications, Some 11,000 freight haulers run on either CNG or LNG.

CNG appears to be cheaper and easier for buses and taxis. About 60% of all waste or trash trucks run on natural gas, with Waste Management owning the largest such fleet with over 6,000 NGV trucks—plus, it recycles trash from landfills to make its own RNG.

Competition arises

Meanwhile, U.S. school districts now have over 17,000 propane-powered buses, and Texas alone has over 3,000 propane buses, according to the Propane Council of Texas and its national parent, the Propane Education & Research Council.

However, the rise of electric vehicles (EVs) that can be charged, or powered by batteries, does pose a threat to NGVs in the arena of public opinion, Gage said, because EVs are thought to be less polluting than NGVs. "The electricity supporters have done a good job of convincing the public that EVs are better, but that is just not the case.

"Electric vehicles today are where natural gas vehicles were 20 years ago. The reality is they are just not there yet and are still too expensive. If anyone's driving an electric vehicle, it's an experiment or a demonstration," Gage told *Investor*. "We've got to get the battery costs lower; they are just not affordable for most private or municipal fleets right now."

Gage cited some advantages NGVs have over EVs. "A natural gas engine is cleaner than anything else available now, and is 90% cleaner than the cleanest diesel engine available today," he said. NGVs are able to be refueled faster than EVs at a charging station, he added.

In July, the city of Toronto, which operates North America's largest bus fleet after New York and Los Angeles, said it would transition to all electric buses as soon as possible, bypassing CNG.

About a third of North America's transit buses run on CNG or LNG. "It is our contention that this percentage is peaking and will begin to gradually decline as EVs increasingly take share," said a new report by Raymond James. "However, diesel is still the mainstay of bus fleets, accounting for 40% of the total. Toronto is a case study of how some transit agencies are shifting directly from diesel to EVs, i.e., bypassing natural gas altogether."

Even though there is competition from other fuel sources, the use of NGVs continues to grow. The Energy Information Administration says that in 2018, NGVs consumed about 43.4 Bcf, up from 22.8 Bcf in 2005. And, about 50 companies in the U.S. manufacture 100 models of natural gas-burning engines and vehicles. □

The ports of Los Angeles and Long Beach require trucks and dock equipment to use natural gas or electricity to reach zero emissions by 2035.

Don't settle for close enough

Rextag GIS data sets deliver more miles, better accuracy

Find out why over 80% of top producers and pipeline operators rely on Rextag GIS data sets for mapping and asset intelligence. No other data provider can match the volume and accuracy of these carefully curated databases. Monthly updates ensure up-to-date information – and precise data supports greater efficiency.

For more information, visit Rextag.com or call us at 1-619-564-7373.

HARTENERGY

REXTAG

REXTAG.COM

Copyright 2019 Rextag, a Hart Energy company. All rights reserved.

SPAC CHALLENGES

Many private energy companies have sold to special purpose acquisition companies to monetize their investments. However, transacting with a SPAC has presented some unique challenges.

ARTICLE BY
TROY HARDER,
JASON JEAN AND
JARED BERG

In the past three years, special purpose acquisition companies, or SPACs, have enjoyed a surge in popularity, with a noticeably large proportion targeting the exploration and production, midstream and oilfield service sectors. Though several of these energy-focused SPACs have announced or closed transactions, at the time of this writing, we counted 10 energy-focused SPACs with around $2.6 billion in available capital that are still seeking a transaction.

The SPAC structure is popular, but it presents challenges to sellers when they transact with a SPAC. There are several reasons why SPACs have had an increasingly difficult time finding a transaction in the last six months.

What is a SPAC?

SPACs are formed and supported by a sponsor, typically consisting of a private-equity firm or other institutional investor that usually recruits a management team composed of well-known executives with experience managing large companies in the SPAC's area of focus. For example, private-equity firms Riverstone Holdings, NGP Energy Capital, Kayne Anderson Capital Advisors LP, TPG Global LLC and Apollo Global Management LLC have each sponsored SPACs. A SPAC completes its IPO on the strength of its sponsor and management team. It then seeks a business opportunity using its IPO proceeds and its publicly traded stock as transaction consideration.

In its IPO, a SPAC typically will issue units to the public for $10 each. These units consist of one share of common stock and one-third or one-half of a warrant to purchase one share of common stock at $11.50 per whole warrant. Shortly after the IPO, the warrants can be traded independently from the common stock. Along with the units issued to the public in the IPO, SPACs usually also issue "founder shares" to the sponsor and to certain members of the SPAC's management team. The founder shares are a separate class of stock from the class issued to the public in the IPO and usually convert automatically into a significant percentage of the publicly held class of outstanding common stock of the SPAC when the SPAC closes its first acquisition.

Because the investment is purely speculative at the time of the IPO, SPAC stockholders have a number of protections that help to hedge their investment risk. A SPAC generally has only two years following its IPO to close its first acquisition before the SPAC expires. During that time, the IPO proceeds are held in trust. The IPO proceeds are only released from trust in connection with the closing of the SPAC's first acquisition, provided that the closing occurs prior to the SPAC's expiration or, absent such an acquisition, in connection with the SPAC's redemption of its public stockholders for cash at the SPAC's expiration.

In connection with the SPAC's first acquisition, SPAC stockholders have the right to compel the SPAC to redeem their common stock for their proportion of the IPO proceeds held in trust. Additionally, stockholders generally have the right to approve or reject the acquisition.

SPAC stockholders are not required to vote against the acquisition to redeem their common stock, and they are entitled to keep the SPAC warrants they received in the IPO regardless of

Selected SPAC Offerings

Priced	Exchange/Ticker	Proceeds Raised $MM	Company	Offer Price ($)	Last Trade	Last Trade Date	SPAC Acquisition Completed Y/N
09-Mar-17	NASDAQ: MPACU	325.00	Matlin & Partners Acquisition Corp.	10.00	10.00	26-Oct-18	Y
10-Apr-17	NASDAQ: VEACU	552.00	Vantage Energy Acquisition Corp.	10.00	10.19	15-Apr-19	N
11-May-17	NASDAQ: NESRU	210.00	National Energy Services Reunited Corp.	10.00	9.99	02-Jun-17	Y
29-May-18	NASDAQ: TDACU	201.00	Trident Acquisitions Corp.	10.00	10.45	04-Jun-19	N
27-Jun-18	NASDAQ: HCCHU	55.00	HL Acquisitions Corp.	10.00	10.53	03-Jun-19	N
15-Nov-18	NASDAQ: AMCIU	221.00	AMCI Acquisition Corp.	10.00	10.20	03-Jun-19	N
		1,564.00					

Source: Dealogic

their vote and regardless of whether they compel the SPAC to redeem their common stock. Accordingly, SPAC stockholders are able to shed almost all of the potential downside of the post-acquisition business while still retaining a portion of the potential upside. These stockholder protections make transactions with a SPAC uniquely challenging from a seller's perspective, as discussed in greater detail below.

Recent surge in SPACs

In 2017, there were a total of 32 SPAC IPOs, with that number jumping to a record of 45 in 2018, the highest number since 2007. Several of these SPACs are focused on the energy industry.

The rise in the number of energy-focused SPAC IPOs coincides with a sharp decline since 2014 in the number and dollar size of traditional IPOs of energy companies. In 2014, 29 energy-focused IPOs closed, raising an aggregate of $11.6 billion. Since the oil price downturn in 2014, capital markets have generally been less receptive to energy companies, particularly those attempting an IPO. As a result, there have been only 35 energy company IPOs, raising an aggregate of $11.7 billion, in the four full years since 2014. With public capital markets generally unavailable to private energy companies, these companies, many of which are backed by significant private-equity investment, must find other avenues to monetize their investments. SPACs have stepped into this void in significant numbers.

SPACs present an attractive counterparty for a private energy company because they have both available cash and a public-equity currency. Additionally, the SPAC's sponsor is incentivized to consummate an acquisition in order to create value in its "founder shares." This creates ability and motive for the SPAC to transact at higher valuations that are difficult to match for other prospective buyers. For many potential sellers, these high valuations have outweighed the challenges associated with a SPAC transaction.

SPAC transactions

SPAC stockholder protections present challenges when transacting with a SPAC that differ from those of a typical merger or acquisition.

As mentioned, SPAC stockholders are entitled to redeem their common stock in connection with the SPAC's first acquisition. To facilitate this, the SPAC is required to prepare and file a lengthy public disclosure document that complies with Securities and Exchange Commission disclosure requirements and the terms of the SPAC's organizational documents. These filings are labor-intensive, time-consuming and expensive to prepare.

If SPAC stockholders redeem their common stock, the amount of cash available for dis-

Although a reduced price is not desirable for the seller, the seller will have spent significant time negotiating the terms of the transaction with the SPAC and may feel compelled to continue with the SPAC.

tribution to the seller will be reduced. SPAC stockholders are not required to make their redemption election until very near closing of the SPAC transaction.

The potential for redemptions and the uncertainty about the amount of redemptions puts the SPAC as the buyer and the seller in a position where they end up negotiating deal terms with incomplete information. Excessive redemptions can result in the transaction failing to close, or the seller agreeing to replace a portion of its cash consideration with SPAC equity consideration to achieve a closing. The specter of excessive redemptions also presents the SPAC with an opportunity to renegotiate the transaction price with the seller even after the SPAC and the seller have signed a definitive agreement.

Because the SPAC IPO proceeds are held in trust, break-up fees are not available to compensate the seller for transaction risk and the cost of the seller's lost opportunities. A seller can negotiate for the sponsor to make up some of the cash shortfall created by redemptions, but a sponsor backstop is often an incomplete solution in the face of overwhelming redemptions.

Depending on the size of the transaction relative to the amount of the SPAC's IPO proceeds held in trust, the SPAC may engage in offerings known as private investments in public equity, or PIPEs, to raise additional cash prior to signing a definitive agreement with the seller. The PIPE transactions would close and fund immediately prior to the SPAC closing.

Typically, the SPAC will not pursue PIPE transactions until the definitive agreement with the seller has been fully negotiated, but not yet signed. If the PIPE transactions do not attract enough investment, the SPAC and the seller may need to renegotiate the transaction price. Essentially, like the SPAC stockholder redemptions, PIPE transactions act as a "market check" on the SPAC's transaction price.

Although a reduced price is not desirable for the seller, the seller will have spent significant time negotiating the terms of the transaction with the SPAC and may feel compelled to continue with the SPAC rather than invest the time and money necessary to seek out an entirely different buyer. Even if the PIPE transactions attract enough investment, the seller is now exposed to third-party performance risk (i.e., the risk that the PIPE investors do not fund at closing).

Even if the SPAC has enough IPO proceeds held in trust and funds from PIPE investments, if applicable, to close the transaction with the seller on the terms originally negotiated, excessive redemptions can leave the post-closing business with less liquidity than anticipated, which, among other things, may adversely impact the SPAC's stock performance following closing.

The aftermath of a SPAC transaction

Once a SPAC transaction closes, the seller will have investment risk if it received SPAC equity in the transaction. The SPAC equity that the seller receives in the transaction may be subject to a contractual lock-up, or the seller's position may be too significant to liquidate quickly. This means the seller may have to bear the risk of its investment in the SPAC for an extended period.

Most SPAC transactions experience a year or more of high trading volatility and depressed stock prices following closing. In fact, more than 60% of the energy companies acquired by SPACs since 2016 are trading at prices below the SPAC's stock price at the time the transaction closed. This suboptimal post-closing trading can be caused by a number of factors, including sell-offs by short-term institutional investors and the trading overhang created by "founder shares" and warrants.

In an environment where traditional capital markets are insufficient to provide liquidity events for private energy companies, SPACs serve an important function. Currently, around $2.6 billion in available capital resides in energy-focused SPAC trust accounts. However, the challenges described here and the historically weak trading price for energy-focused SPACs following closing should give any seller pause.

In addition to transaction price, sellers should consider how they can structure their transaction with a SPAC to address these challenges and insulate themselves, to the extent possible, from investment risk in the SPAC's equity. ☐

Troy Harder is a partner at Bracewell LLP and advises clients in corporate and securities law, with an emphasis on corporate finance transactions. Jason Jean is a partner and has experience in advising public and private businesses, including private-equity investors, in the financial service sector, upstream and midstream energy sector, and other sectors. Jared Berg is an associate and works with privately and publicly held companies, as well as their private-equity investors, in mergers, acquisitions and general corporate matters.

HIGHLIGHTED TRANSACTIONS:

Gulf Coast Texas Non-Operated Investor **$4,500,000** **Acquisition & Development Facility** **2019**	West Texas Operator **$3,000,000** **Acquisition Facility** **2019**	Utah Non-Operated Investor **$7,000,000** **Acquisition Bridge Loan** **2019**	Gulf Coast Operator **$1,500,000** **Acquisition & Development Facility** **2019**
Gulf Coast Operator **$4,500,000** **Acquisition & Development Facility** **2019**	Louisiana Operator **$1,350,000** **Acquisition Term Loan** **2018**	East Texas Operator **$250,000** **Development Bridge Loan** **2018**	Gulf Coast Texas Operator **$1,250,000** **Acquisition & Development Facility** **2017**
South Texas Operator **$2,000,000** **Acquisition & Development Facility** **2017**	South / East Texas Operator **$3,000,000** **Acquisition & Development Facility** **2017**	Central Texas Operator **$1,500,000** **Acquisition & Development Facility** **2017**	East Texas Operator **$3,500,000** **Acquisition & Development Facility** **2017**

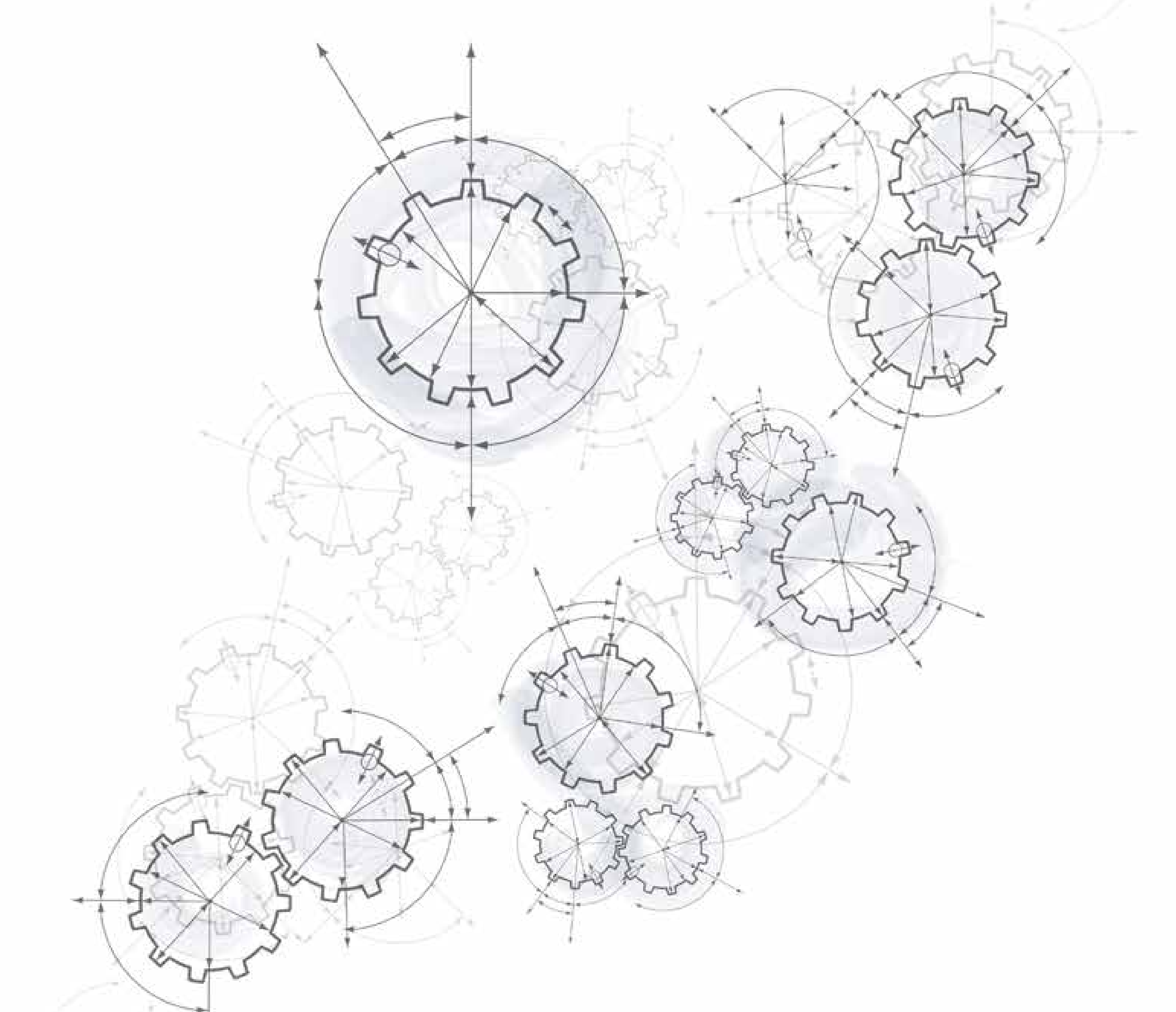
Abhishek Kumar
Principal
(512) 853-0069 (direct)
ak@productionlending.com

Ryan W. Childs
Principal
(978) 828-1788 (direct)
rw@productionlending.com

10497 Town and Country Way, Suite 700
Houston, TX 77024
(832) 895-1086

productionlending.com

Competitive, Structured, and Fair Sale Processes for Oil and Gas Assets that Consistently Work



The Continuous Oil and Gas Marketplace for Sealed Bid and Negotiated, Auction, Federal and State Lease Sales

ENERGYNET

Your Trusted Advisor for 20 years

HOUSTON | DALLAS | DENVER | OKLAHOMA CITY | MIDLAND

877-351-4488 | EnergyNet.com

Member FINRA. Investments in oil and gas properties involve substantial risk including the possible loss of principal. These risks include commodity price fluctuations and unforeseen events that may affect oil and gas property values.

A&D Watch

EDITED BY
DARREN BARBEE

Comstock's Haynesville Blitz Scores $2.2 Billion Deal

COMSTOCK RESOURCES INC. is set to improve its field position in the Haynesville, saying it would become the play's leader with the acquisition of private E&P **Covey Park Energy LLC**.

In a joint statement on June 10, the companies announced an agreement for Comstock to acquire Covey Park in a cash and stock transaction worth roughly $2.2 billion. The transaction also includes the assumption of outstanding debt and the retirement of existing preferred units for a total of $1.1 billion.

Comstock plans to fund the acquisition through a combination of debt under its revolver and an investment from its largest shareholder, billionaire and Dallas Cowboys owner Jerry Jones.

Analysts with **Tudor, Pickering, Holt & Co.** (TPH) said that when combined with Covey Park, Comstock will be the largest Haynesville operator at 293,000 net acres.

"We continue to see the need for additional industry consolidation of the basin to gain meaningful scale," the TPH analysts said in a research note on June 10.

Covey Park is a Dallas-based private independent with properties in the Haynesville and Bossier shale plays of North Louisiana and East Texas. The company was founded in June 2013 as a partnership with private-equity firm **Denham Capital** and is led by John Jacobi and Alan Levande. The company attempted to launch an IPO that ultimately fizzled.

Comstock CEO M. Jay Allison said the transaction follows a year of evaluating several potential targets in the Haynesville Shale. He noted, that with Covey Park, he believes they have found the "perfect merger partner."

"This merger is an excellent fit with our existing acreage and continues our strategic plan of creating significant scale and resource depth in the Haynesville Shale. ... In integrating Covey Park, we plan to focus on operating efficiency and having a combined drilling program that provides for substantial free cash flow to achieve our goal of reducing our leverage," Allison said in a statement.

Pro forma the Covey Park acquisition, Comstock expects its position to total roughly 374,000 net acres with over 1.1 billion cubic feet equivalent per day (Bcfe/d) of net production. In the Haynesville, the company said it will have about 2,000 net drilling locations, including roughly 1,300 net locations with lateral length over 5,000 feet.

The deal pushes Comstock further down the gas cost curve, according to Greig Aitken, director of corporate analysis at global natural resources consultancy **Wood Mackenzie**.

By acquiring Covey Park, Aitken said Comstock will gain access to the three best parts of the Haynesville: the Caspiana Core in Louisiana, the Shelby Trough in East Texas and the emerging Carthage sweet spot.

"Before the deal, Comstock's best acreage was confined to Louisiana, but inventory was limited," Aiken told *Investor*. "Adding acreage—specifically around Carthage—should have been a big driver for Comstock."

He also called the Shelby acreage a "jewel" with low breakevens, according to Wood Mackenzie analysis. The Covey Park deal comes roughly a year after Comstock, based in Frisco, Texas, teamed up with Jones.

Last year, Jones rolled his and his family's interests in the 424 Bakken-producing wells into the Haynesville gas producer in exchange for 88.6 million—about 84%—of outstanding shares. The transaction closed in August 2018.

"I am excited to provide the funding and to team up with Denham Capital to combine the two companies to create the basin leader in the Haynesville Shale," Jones said in a June 10 press release. "This combination is another step toward completing my vision to create an industry-leading natural gas company."

Jones will remain the company's largest shareholder following Comstock's acquisition of Covey Park with 75% ownership interest and a cumulative investment of $1.1 billion. He also agreed to invest an additional $475 million in cash for 50 million newly issued shares of Comstock stock and $175 million of newly issued shares of perpetual convertible preferred stock.

Additionally, Denham Capital is set to become the second-largest shareholder of Comstock as a result of the transaction with roughly 16% common stock ownership interest.

As part of the acquisition agreement, Covey Park's equity owners will receive $700 million in cash, $210 million of a newly issued perpetual convertible preferred stock and about 28.8 million shares of newly issued

Comstock stock at $6 each.

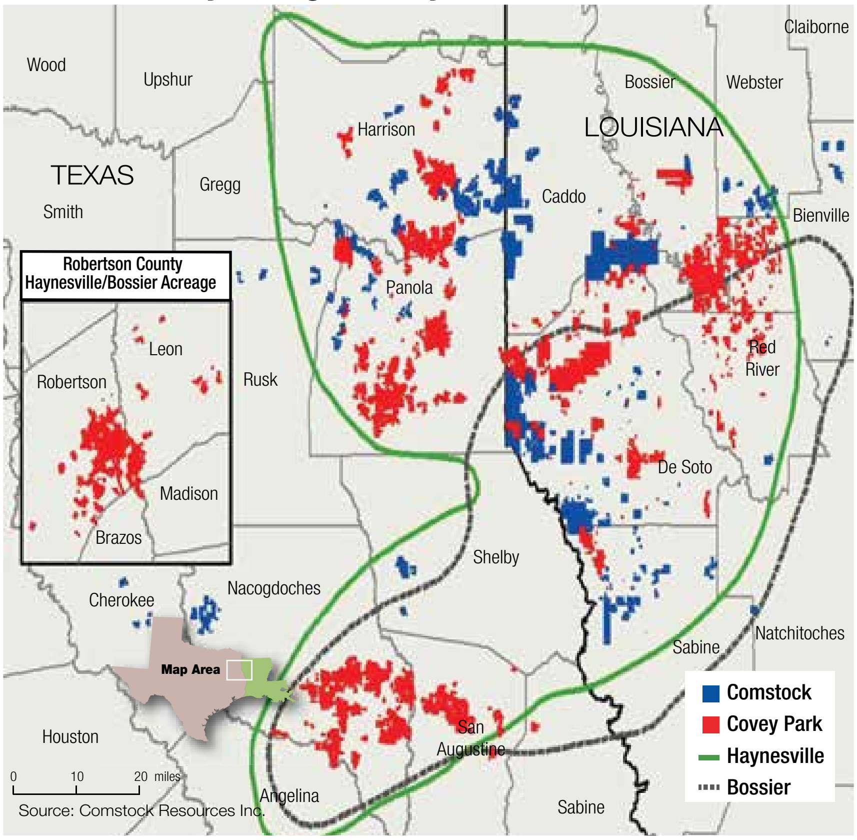
At the expected July 31 close of the Covey Park acquisition, Comstock will continue to be led by Allison. The company's leadership will also include representation from both management teams, according to the companies' joint release.

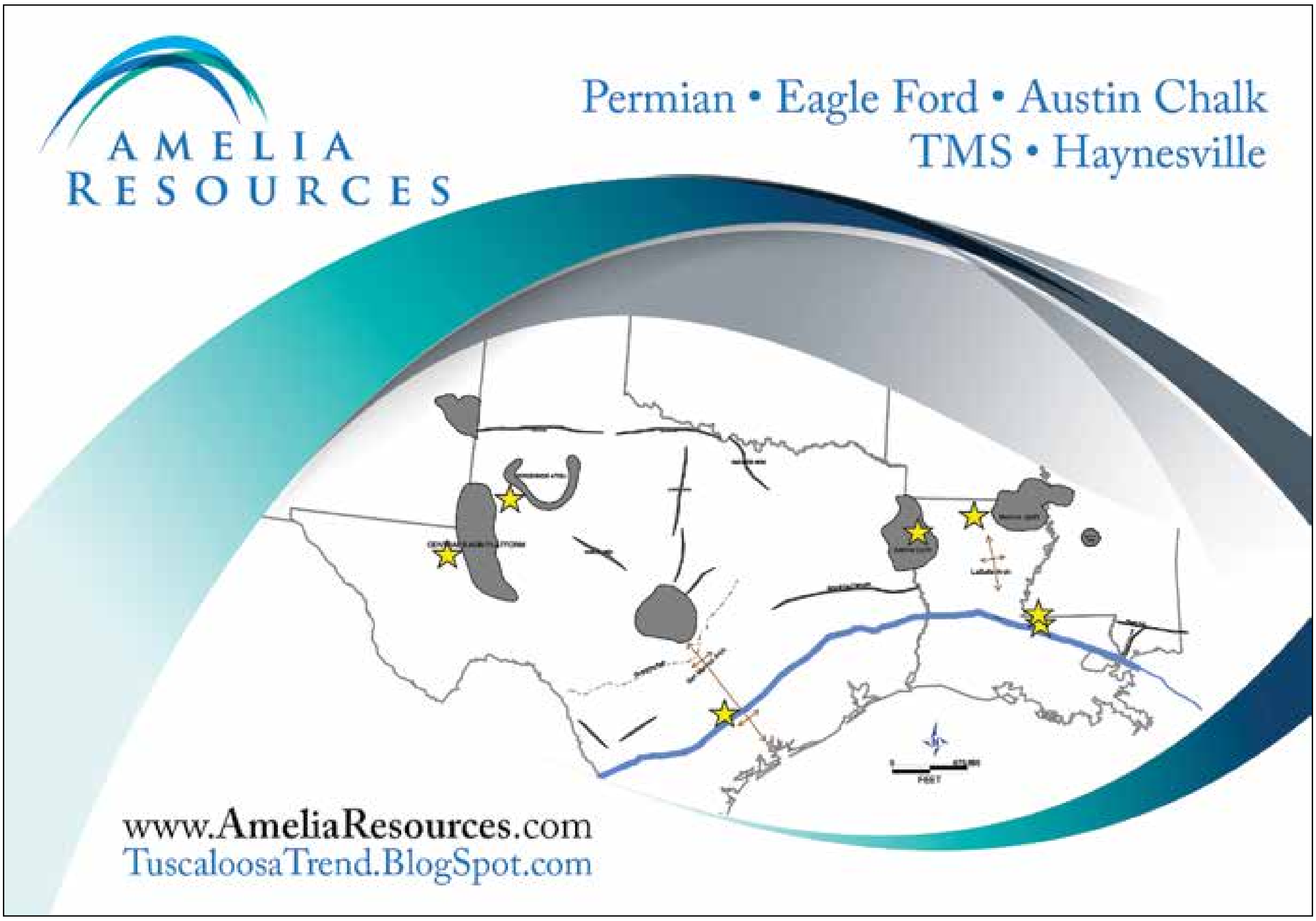
Also in connection with the transaction, Comstock appointed **BMO Capital Markets** to arrange an amended and restated $2.5 billion bank credit facility with an initial borrowing base of $1.575 billion and a maturity of five years from closing. The company plans to elect to set the borrowing base at $1.5 billion at closing.

Wells Fargo Securities LLC is lead financial adviser to Comstock for the transaction. **BMO Capital Markets** is also acting as a financial adviser to the company. **Locke Lord LLP** is the company's legal adviser. **BofA Merrill Lynch** and **Barclays** are lead financial advisers to Covey Park. **Citigroup Global Markets Inc.** and **Goldman Sachs & Co. LLC** also provided financial advice to Covey Park. **Vinson & Elkins LLP** is the company's legal adviser led by partners Doug McWilliams and Shamus Crosby.

—Emily Patsy

Comstock-Covey Acreage Overlay





Helping You Protect Your Investment
For More Than 30 Years

Holland SERVICES

America's Land Company

www.hollandservices.com

Denver • Fort Worth • Houston • Midland • Oklahoma City • Southpointe

Chisholm, Gastar Agree To Midcontinent Merger

MONTHS AFTER EMERGING from bankruptcy, **Gastar Exploration LLC** has agreed to merge with a fellow private operator in the Oklahoma Stack play, **Chisholm Oil and Gas LLC**.

The private-equity-backed companies unveiled the strategic combination for undisclosed terms in a joint press release on June 19. The combined company is set to operate under the Chisholm Oil and Gas name and be headquartered in Tulsa, Okla., following the completion of the transaction slotted for third-quarter 2019.

Together, the companies expect to become a leading Stack E&P with net production of about 20,000 barrels of oil equivalent per day (boe/d). Combined, the companies' acreage position will total roughly 165,000 net acres, primarily in Kingfisher County, Okla.

Chisholm was formed in 2017 with backing from funds managed by certain affiliates of **Apollo Global Management LLC** and management. That same year, Chisholm, based in Tulsa, closed its first acquisition in the Stack comprising 53,000 acres in Kingfisher County. The acreage was also in the same area where Gastar had purchased assets for $51.4 million earlier in 2017.

Gastar began building an acreage position in the Midcontinent area in 2012. The Houston-based company ultimately established a position within the Stack play in Kingfisher, Garfield, Major and Blaine counties, Okla.

Once a publicly traded E&P, Gastar has more recently faced financial hardships that included seeing its stock delisted from the NYSE American Exchange due to an abnormally low trading price, according to a company release from September 2018. Roughly a month later, Gastar filed for Chapter 11 bankruptcy.

In October 2018, the company said it had reached a deal on a debt-restructuring agreement with its private-equity owner and largest creditor, **Ares Management LLC**. The restructuring, completed in January, eliminated more than $350 million in liabilities from Gastar's balance sheet.

Prior to its bankruptcy, Gastar halted its drilling and completions operations in August, including a one-rig drilling program targeting the Osage and Meramec formations. The company had also previously anticipated completing five drilled but uncompleted wells in the second half of last year.

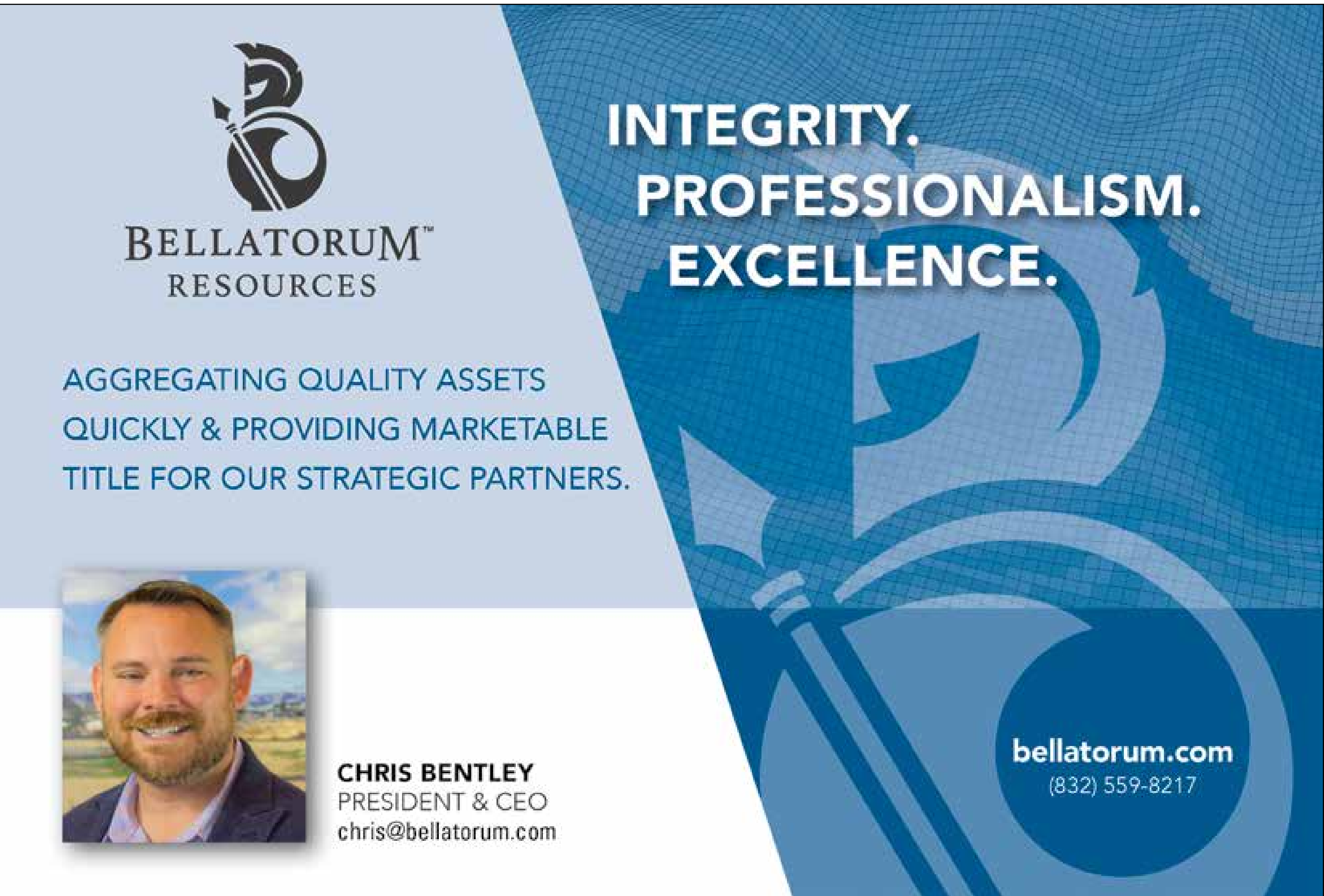
Chisholm is currently running three rigs and has a dedicated frack crew on its acreage, the company said. Chisholm also holds ownership stakes in **Great Salt Plains Midstream Holdings LLC** and its saltwater disposal subsidiary, **Cottonmouth SWD LLC**.

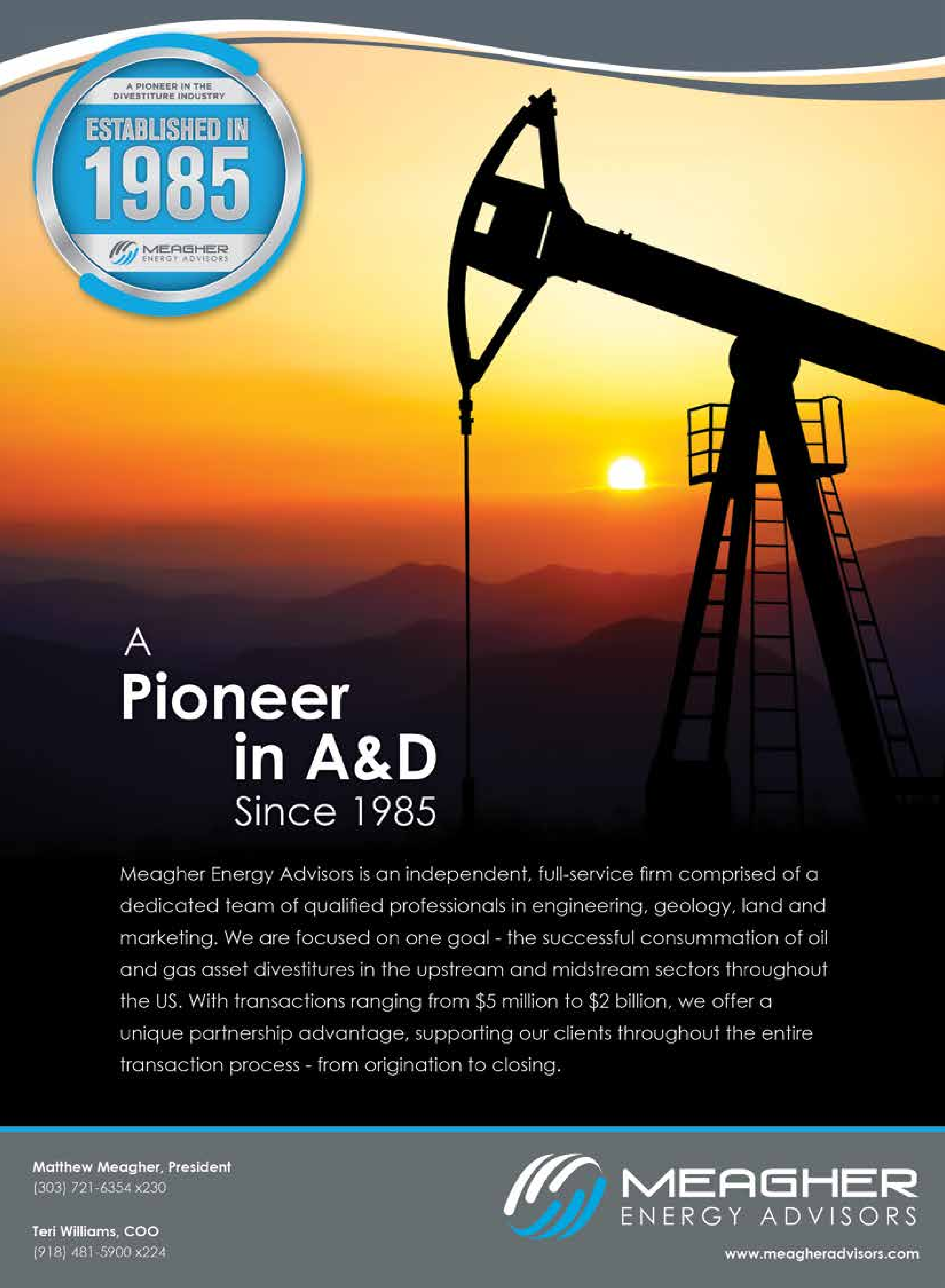
For the transaction, Chisholm received financial advice from **Citigroup Inc.**, **Vinson & Elkins LLP** and **Paul, Weiss, Rifkind, Wharton & Garrison** were the company's legal advisers. **Evercore** and **Tudor, Pickering, Holt & Co.** provided financial advisory services to Gastar. **Kirkland & Ellis** served as Gastar's legal adviser.

—*Emily Patsy*

Chisholm, Gastar Merger Overview

Net production	~20 Mboe/d
Net acres	~165,000
Expected close	3Q2019
Headquarters	Tulsa, Okla.




A PIONEER IN THE DIVESTITURE INDUSTRY
ESTABLISHED IN 1985
MEAGHER ENERGY ADVISORS
A Pioneer in A&D Since 1985
Meagher Energy Advisors is an independent, full-service firm comprised of a dedicated team of qualified professionals in engineering, geology, land and marketing. We are focused on one goal - the successful consummation of oil and gas asset divestitures in the upstream and midstream sectors throughout the US. With transactions ranging from $5 million to $2 billion, we offer a unique partnership advantage, supporting our clients throughout the entire transaction process - from origination to closing.
Matthew Meagher, President
(303) 721-6354 x230
Teri Williams, COO
(918) 481-5900 x224
MEAGHER
ENERGY ADVISORS
www.meagheradvisors.com

Encana Sells Newfield Leftovers

ENCANA CORP. is selling off its Arkoma Basin position as the Calgary, Alberta-based company continues to digest the slew of assets it acquired earlier this year from its multibillion-dollar deal for U.S. independent **Newfield Exploration Co.**

Encana said it sold about 140,000 net acres of leasehold in Oklahoma to a buyer, which the company did not disclose, according to a July 8 release. Production from the assets is currently about 77 million cubic feet equivalent per day, 98% of which is natural gas.

Encana said it will receive $165 million cash from the Arkoma exit, which is in line with estimates made by analysts with **Tudor, Pickering, Holt & Co.** (TPH) in a research note on July 8. The TPH analysts also noted that the Arkoma sale represents the second Newfield legacy asset to be let go by Encana.

In early June, Encana said it will exit its China operations through an agreement with its partner the **Chinese National Offshore Oil Corp.** The company had acquired the assets comprised of a production-sharing contract offshore China from Newfield, which had been active in the South China Sea since 2005.

Encana's purchase of Newfield that closed in February also included positions in the Uinta and Williston basins but most notably within the Stack and Scoop plays of the Anadarko Basin.

According to the company's website, Encana's core growth assets are the Anadarko, Permian Basin and Montney.

"Pre-deal leverage looks manageable [at TPH estimates 1.7 times year-end 2020 ND/EBITDA] at current strip, and further improvement could come if the noncore Uinta and Williston are similarly monetized [TPH estimates about $1.4 billion to $1.5 billion], but we remain sidelined pending longer-term operational results" in the Midcontinent, TPH analysts wrote of Encana's Arkoma sale.

Proceeds from the Arkoma sale will be directed to the company's balance sheet, according to Doug Suttles, Encana's president and CEO.

"Along with our recently announced agreement to exit China, this transaction shows our commitment to realize value from noncore assets," Suttles said in a statement on July 8.

Encana expects to close the sale in third-quarter 2019. **CIBC Griffis & Small** provided advisory services to Encana for the transaction. **Davis, Graham & Stubbs LLP** was the company's external legal counsel.

—Emily Patsy

E&P's 2020 Energy Innovators Program:

Recognizing Today's Technology Influencers

Recognize your colleagues or employees by nominating them for *E&P* magazine's Energy Innovators program. Emerging visionaries, technical leaders, accomplished reformers, entrepreneurs and disrupters – Hart Energy is seeking nominations worldwide for those who deliver innovation and efficiency in your organization and the industry.

This new program recognizes the up-and-coming talent and diverse nature of today's oil and gas workforce. How? By shining a spotlight on individuals actively engaged in research, technology management, and product or service applications. Each nominee should be deeply involved in the underlying innovation that sparks attention.

Companies and individuals are encouraged to nominate team members and leaders who distinguish themselves via exceptional efforts, passion or problem-solving as well as specific technical achievements. Nominees may deserve recognition for their potential impact on our industry's future.

CATEGORIES ARE:

- Geology & geophysics
- Drilling & well logging
- Well construction & completion
- Production & facilities
- Onshore field development
- Offshore exploration & operations
- Research & product development
- Data analytics, AI & machine learning
- Digital oilfield applications

NOMINATION IS ONLINE:

Visit HartEnergy.com/energy-innovators for details. Accompanying information should answer the question, "How has the nominee contributed?" Beyond resume and/or biographical data, describe specific technical differentiators or the impact this nominee has had on colleagues, your company, or the industry and its technologies.

Honorees will be selected and announced this fall and their individual profiles will be featured in a special supplement to *E&P*'s January 2020 edition. **But don't delay – nominations are open now.**

Visit **HartEnergy.com/energy-innovators** for details.

HARTENERGY

E&P

Oil Search Makes Last-Minute Alaska Deal

OIL SEARCH LTD. will expand its Alaska profile through a series of A&D transactions it recently entered into, including a $450 million acquisition to buy more interests in **Armstrong Oil and Gas Inc.**'s massive North Slope discovery.

Also, part of the deal-making included a transaction with Spain's **Repsol SA**. The transactions follow Oil Search's entry into one of the largest U.S. oil discoveries in decades made jointly in 2017 by Repsol and Denver-based Armstrong.

Initially, in February 2018, Oil Search acquired half of Armstrong's interest in the Alaskan discovery—named Horseshoe—for $400 million. The deal included a provision to buy Armstrong's remaining interests for $450 million.

Oil Search, Papua New Guinea's largest company and investor, had until June 30 to exercise the option. On June 29, just under the wire, Oil Search agreed to take the remaining Horseshoe interests.

Oil Search said in a news release that the deal's structure gave the company enough time "to develop a better understanding of the full Pikka Unit Nanushuk oil field potential and regional exploration opportunities."

Discovered in March 2017, Horseshoe Field is located in Alaska's Nanushuk Formation. The 1.2-billion-barrel oil find was the result of an exploration partnership between Armstrong and Repsol. The companies described the find as the "largest U.S. onshore conventional hydrocarbons discovery in 30 years."

Since the initial acquisition last year, Oil Search said, the Horseshoe discovery has the potential to be even larger based on 2018 drilling results conducted by **ConocoPhillips Co.**

In total, the exercised option comprises **Armstrong Energy LLC**'s remaining 25.5% interest in the Pikka Unit and 37.5% interest in the Horseshoe area, plus a further 37.5% interest in the Hue Shale leases and a 25.5% interest in other exploration areas in the Alaska North Slope.

Both transactions also include interest owned by **GMT Exploration Co. LLC**, another Denver-based independent.

"The acquisition of Armstrong/GMT's remaining interests allows Oil Search to maintain operatorship of a world-class oil development close to existing infrastructure, with material appraisal and exploration growth potential," Oil Search said June 29.

Oil Search said it will continue to work together with Armstrong in accordance with an area of mutual interest agreement that was entered into as part of the original March 2018 acquisition. The pair plan to review opportunities on the North Slope of Alaska outside the Pikka and Horseshoe areas.

Additionally, Oil Search entered into an asset swap transaction with Repsol on June 29 to align ownership interests across their now shared Alaskan assets. The swap will result in a net payment of $64.3 million to Oil Search.

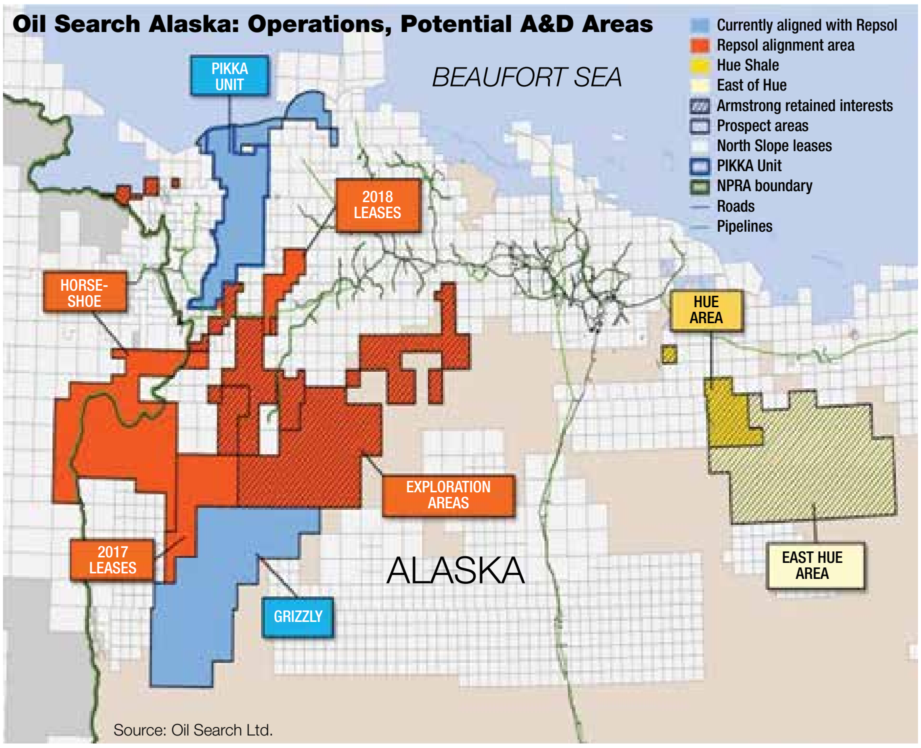
The company also plans to partially sell down its Alaskan assets and is looking to launch a formal divestment process of some of its interests. A sale is scheduled to conclude in first-half 2020, ahead of a final investment decision for the initial Pikka Unit Nanushuk development. Oil Search intends to retain a roughly 35% interest in its core assets.

Oil Search said the Armstrong option is scheduled to close in late August. The company will fund the acquisition from its existing corporate debt facilities, which are anticipated to total $1.2 billion.

Shearman & Sterling LLP advised Oil Search in connection with its exercise of the Armstrong option while concurrently transacting to align project interests with Repsol. The Shearman & Sterling team was led by partner R. Coleson Bruce, counsel Angie Bible and associates John Craven and Ryan Staine.

Gibson, Dunn & Crutcher LLP is advising **Repsol E&P USA Inc.** in its alignment transaction and project development arrangements with Oil Search. The Gibson Dunn transaction team is led by Houston partner Justin T. Stolte.

—Emily Patsy



A 1031 exchange or pay the taxes? Before you answer, talk to us. Since 1991 we've helped our energy clients use LKE's to successfully defer capital gains tax on over $35 billion of proceeds on large energy transactions. We've helped them regain control of their wealth. Our team is ready to do the same for you.

You can call on our expertise.

432.682.0292

www.petroleumstrategies.com

PETROLEUM STRATEGIES

Your 1031 Exchange Partner

W&T Offshore Buys ExxonMobil Gulf Assets

W&T OFFSHORE INC. will expand its position in the U.S. Gulf of Mexico (GoM) through a pending $200 million acquisition from **ExxonMobil Corp.**, W&T Offshore said June 27.

The Houston-based independent entered into a purchase and sale agreement with ExxonMobil to acquire producing properties offshore Alabama. The assets, located in the Mobile Bay area, produced roughly 19,800 net boe/d (25% liquids) in the first quarter of 2019.

W&T Offshore said the purchase will make it the largest operator in the Mobile Bay area within the eastern GoM. The acquisition, expected to close in August, consists of working interests in nine shallow-water producing fields and related operatorship plus an onshore treating facility.

Analysts with **Capital One Securities Inc.** estimate the price tag for the ExxonMobil acquisition equates to roughly 18% of W&T Offshore's enterprise value.

Overall, Capital One saw the deal as a slight positive for W&T Offshore as the transaction is set to increase cash flows with minimal expected capital spend on "an acquisition that is mostly centered on gas assets," the firm's analysts wrote in a research note on June 28.

Further, the analysts said that the added incremental volumes from the transaction represent about 50% of W&T Offshore's total production and 19% of the company's EBITDA.

In a statement, W&T Offshore chairman and CEO Tracy W. Krohn said: "We are pleased with this purchase of producing properties which meets all the criteria we have outlined in the past as necessary to drive increased shareholder value from acquisitions."

Krohn noted that the ExxonMobil properties are adjacent to W&T Offshore's current GoM operations providing the company with "the opportunity to recognize increased scale, rationalize operations and capture cost efficiencies to further grow cash flow.

"We believe this acquisition, with its long-life reserves, production and infrastructure, complements our ongoing strategy to recognize value for our shareholders through drillbit success, effective risk and cost management and joint-venture partnership," he added.

The transaction has an effective date of Jan. 1. W&T plans to fund the acquisition using available cash on hand and its revolving credit facility.

—Emily Patsy

19th ANNUAL

Energy Golf Classic benefitting KidLinks

Monday, October 7, 2019
Gleneagles Country Club · Plano, TX

Celebrating our 19th year, the KidLinks Energy Golf Classic provides companies with a way to make a difference in little lives everywhere as well as a direct avenue for generating positive community awareness about the independent energy industry. The Energy Golf Classic is also one of the most effective energy-specific networking opportunities of the year.

Join your colleagues at the energy industry's premier event benefitting our most precious resource— KIDS!

REGISTER TODAY!

www.KidLinks.org
817.268.0020

SPECIAL THANKS TO OUR COMMITTED SPONSORS*

SPECIAL EVENT SPONSORS

ASHER Resources Partnership

MEDIA SPONSOR

Oil and Gas Investor

NAMING SPONSORS

URBAN Oil & Gas Group LLC

Alliant

PIONEER Natural Resources

BBVA | Big E Drilling | Edge Natural Resources LLC | Enterprise Fleet Management
PetroCap LLC | PetroVen, Inc.

KIDLINKS

KidLinks is a 501(c)(3) nonprofit organization that provides healing, hope and happiness for children and families through therapeutic music entertainment and music therapy programs. For more than three decades, impacting more than 375,000 children and caregivers, KidLinks has provided healing experiences for the special needs of children through performing arts and media, funded therapeutic music initiatives, university-level music therapy training and free/low cost treatment programs for children in need. Funds raised directly support the growth of these direct services and the creation of content that can improve the daily experiences of hospitalized and special needs children when they need it most.

For more information on KidLinks, including services or news and events, please visit our newly redesigned website KidLinks.org or follow us on Instagram @Kid_Links.
supporters as of print deadline 07.01.19

ConocoPhillips Tacks On North Slope Acreage

CONOCOPHILLIPS CO. recently landed a deal with a private E&P for North Slope assets that further expands the Houston-based company's Alaskan footprint, which already totals more than 1 million acres.

In a deal on June 17, ConocoPhillips said it signed an agreement to acquire the Nuna Discovery located east of the Colville River and southwest of Oooguruk Field. Although the terms of the transaction weren't disclosed, ConocoPhillips said the purchase included 11 tracts covering 21,000 acres.

The seller, **Caelus Energy LLC**, is a privately held company headquartered in Dallas. The E&P is led by its founder and CEO Jim Musselman, who previously co-founded **Kosmos Energy Ltd.**

Last year, ConocoPhillips grew its position in the region with a deal for nonoperated interests in the western North Slope from fellow independent oil and gas company **Anadarko Petroleum Corp.** The $400 million bolt-on acquisition gave ConocoPhillips 100% control over 200 million barrels (MMbbl) of gross reserves and about 900 MMbbl of risked gross reserves.

In October 2016, Caelus unveiled a light oil discovery on the Alaska North Slope expected to hold at least an estimated 6 Bbbl of oil in place. The find, located on the company's Smith Bay state leases, was one of the biggest oil discoveries the North Slope had seen in several decades.

At the time, Musselman said the Smith Bay discovery has the "size and scale to play a meaningful role in sustaining the Alaskan oil business over the next three or four decades," but "fiscal stability going forward is critical for a project of this magnitude."

Musselman had similar exploration success at Kosmos. He led the Dallas-based company in the discovery of Jubilee Field offshore Ghana in 2007 while serving as chairman and CEO.

As for ConocoPhillips, the company and its predecessors have engaged in Alaska oil exploration for more than 50 years, according to its website.

The company ranks as Alaska's largest oil producer and one of the largest owners of state and federal exploration leases. Pro forma for the recent acquisition, ConocoPhillips' Alaska portfolio included nearly 1.3 million net undeveloped acres at year-end 2018.

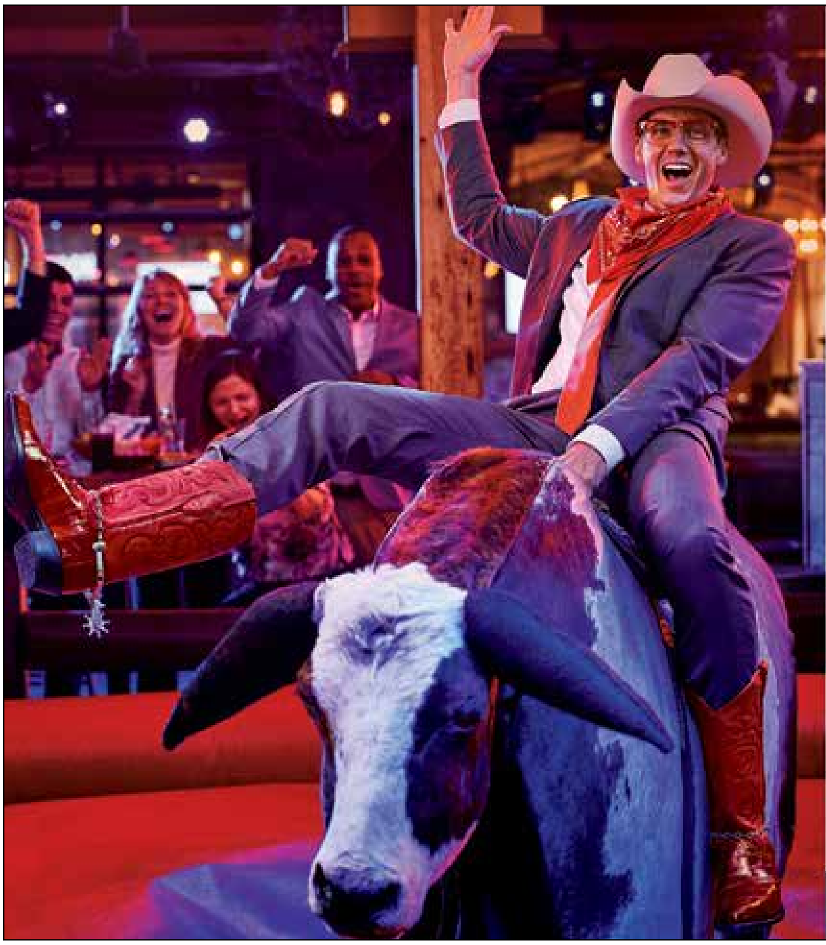
The acquisition from Caelus comprises 100% interest of the Nuna discovery. The transaction had an effective date of June 14. Completion of the deal remains subject to state regulatory approval.

The Nuna prospect was announced as a discovery in 2012. ConocoPhillips said the plans are for its Alaskan affiliate, ConocoPhillips Alaska, to appraise Nuna during the next several years with a goal toward making a final investment decision thereafter.

In a statement, Joe Marushack, president of ConocoPhillips Alaska, said: "This transaction represents an attractive addition to our expanding North Slope position and will allow ConocoPhillips to cost-effectively develop Nuna utilizing Kuparuk River Unit infrastructure."

Vinson & Elkins represented Caelus affiliate **Caelus Natural Resources Alaska LLC** in the transaction. The law firm's team was led by Danielle Patterson and Danny Nappier.

—Emily Patsy



Buck the competition.

You've got a good handle on the energy biz, but every advantage counts when the going gets rough. When you're looking to ride an unpredictable market to profitability, our driven, diligent pros can help you stay in the saddle and outlast the competition.

Everyone needs a trusted advisor. Who's yours?

BKD
CPAs & Advisors

bkd.com/energy | @BKDEnergy

MAKE BETTER DECISIONS WITH A GROUP SUBSCRIPTION

A group subscription to HartEnergy.com equips your team with daily intelligence to stay ahead of the competition.

The all new **HartEnergy.com** provides your business with daily intelligence about what is happening, why it matters and how it affects your company.

For as little as $1.48* per person a day

Your team can stay abreast of business trends, energy markets, A&D&M transactions, E&P news, technology, policy changes, midstream needs, and bridging the gap between oil and gas and renewables. And every issue of ***Oil and Gas Investor*** magazine (in a downloadable PDF) is included with each subscription.

Take advantage of introductory prices

Equip your team or your entire company with a license to **HartEnergy.com**. Multiple seats start with as little as two subscriptions.

To start your access right away or for more information contact:

Attrice Hunt
DIRECTOR
ahunt@hartenergy.com
713.260.4659

**Price is based on 10 seats at $540 per person per year*

HARTENERGY.COM

Your Daily Destination for Energy Information

Private Louisiana Austin Chalk Operators Enter JV

TWO PRIVATELY OWNED oil and gas companies agreed to jointly develop their assets in the red-hot Louisiana Austin Chalk play.

On June 12, **Prime Rock Resources LLC**, a **Lime Rock Partners** portfolio company, said it formed a joint venture (JV) with **New Dawn Energy LLC** for undisclosed terms. The JV will develop more than 100,000 net acres contributed by each company in central Louisiana targeting the Austin Chalk.

After a period of being largely written off, Louisiana's Austin Chalk play is experiencing a new era of popularity. Earlier this year, Charles Goodson, president and CEO of **PetroQuest Energy Inc.**, told Hart Energy's DUG Haynesville conference attendees that the Austin Chalk is currently in "its third wave."

Last year, several large E&Ps, including **ConocoPhillips Co.** and **Marathon Oil Corp.**, amassed nearly 600,000 acres in the Louisiana Austin Chalk as part of a resurgence.

An early mover, Prime Rock acquired over 100,000 net acres in central Louisiana targeting the emerging Austin Chalk play. The company also currently holds participating interests in the Permian's Delaware Basin in New Mexico.

Based in Midland, Texas, Prime Rock is funded with over $125 million of equity commitments from Lime Rock and management. The company was founded in April 2017 by Manny Sirgo and former executives from **Endurance Resources**, another Lime Rock-backed company focused in the Delaware Basin that sold to **Concho Resources Inc.** in late 2016.

New Dawn was another early mover in the Louisiana Austin Chalk. The Houston-based company, which formed in April 2015, built its position in the play through the acquisition of **LaBokay Natural Resources** in 2017.

In total, New Dawn owns over 270,000 net acres of mineral servitudes in the western parishes of Louisiana, including more than 150,000 net acres in the Austin Chalk trend.

Ghasem Bayat, who manages New Dawn as its executive vice president of E&P, said he believes the combination of the two companies' respective acreage positions in the Louisiana Austin Chalk creates "one of the premier positions in the entire trend.

"We expect this agreement to create significant value for both parties and look forward to working with Prime Rock to jointly develop and grow these assets in the future," Bayat added in a statement on June 12.

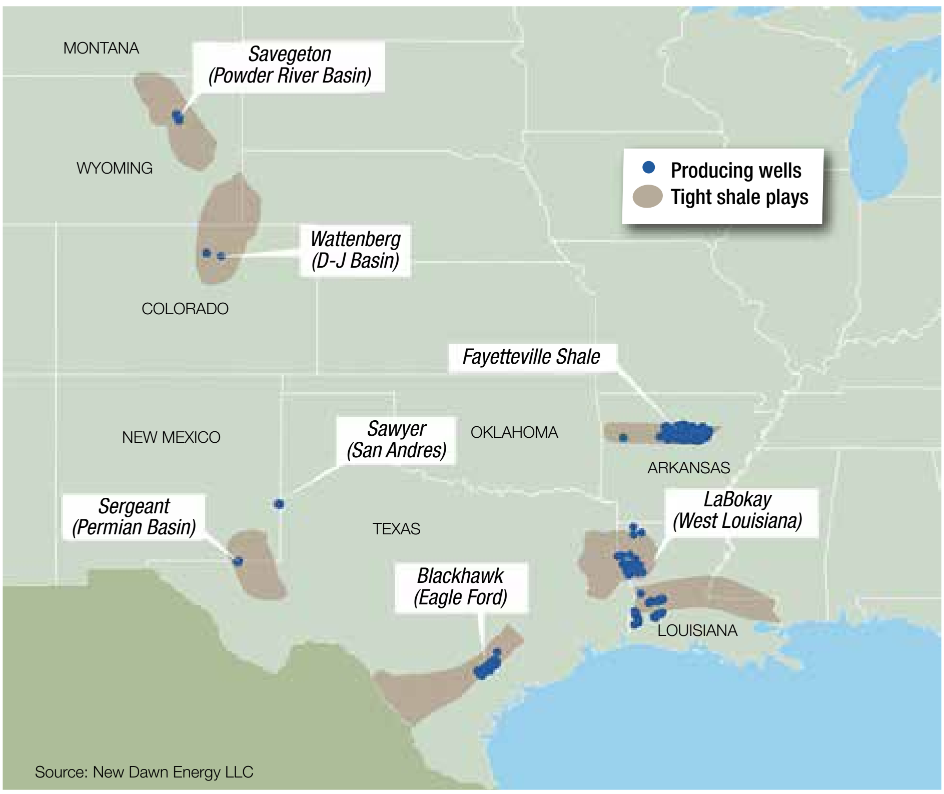
The development area in the JV agreement covers roughly 120,000 net acres in Allen, Avoyelles, Beauregard, Rapides and Vernon parishes, primarily in the legacy Masters Creek Field.

"We are excited about the potential benefits of applying modern drilling and completion technology in one of the most prolific legacy Austin Chalk fields in the entire trend," Sirgo, president and CEO of Prime Rock, said in a statement.

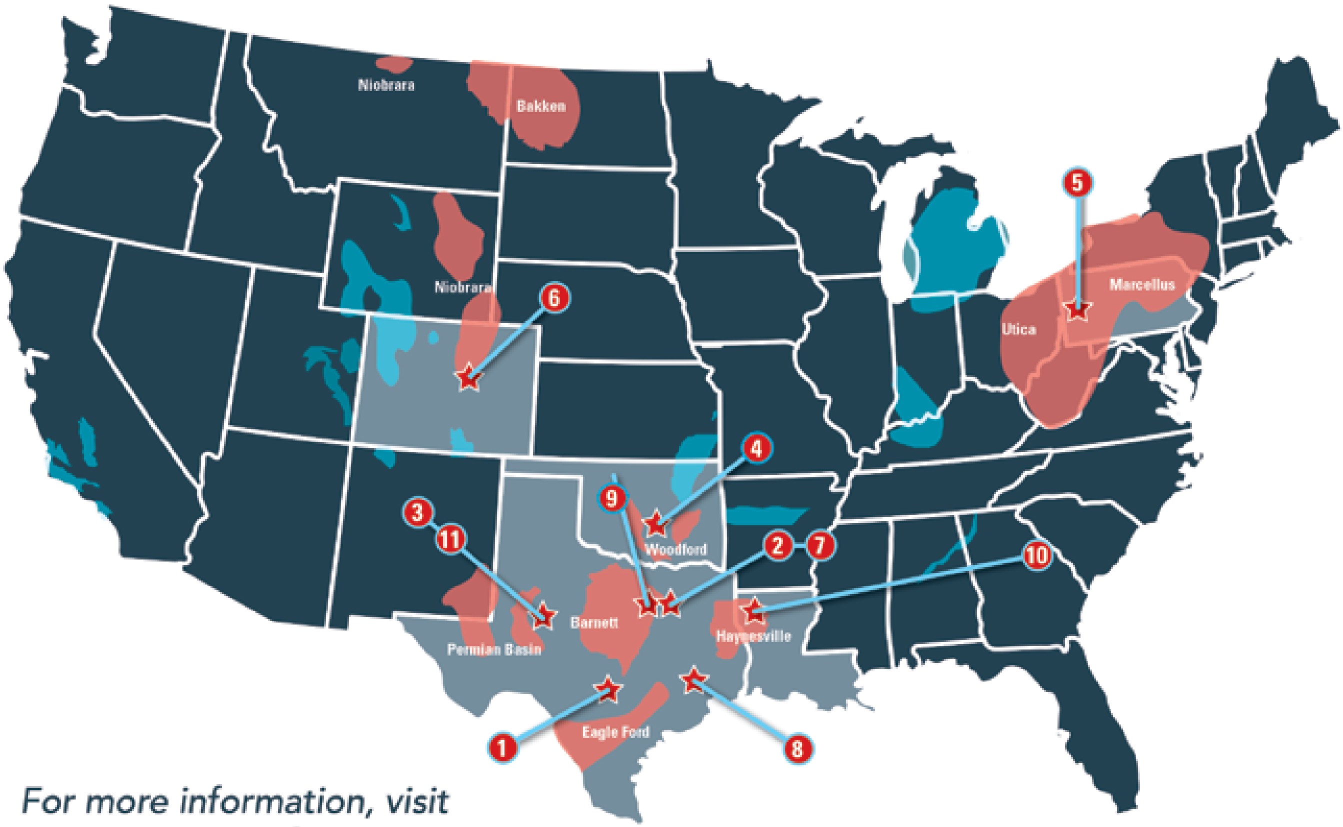
The companies expect initial development under the agreement to begin during the fourth quarter of this year. Also part of the JV agreement, the companies established an area of mutual interest in which they will work together to jointly acquire additional acreage, Prime Rock said.

—Emily Patsy

New Dawn Energy Asset Map



Future Hart Energy Events



For more information, visit
HartEnergyConferences.com

1 CONFERENCE & EXHIBITION DUG EAGLE FORD
Sept. 24-26, 2019
San Antonio, TX

2 A&D STRATEGIES AND OPPORTUNITIES CONFERENCE
Oct. 22-23, 2019
Dallas, TX

3 EXECUTIVE OIL CONFERENCE & EXHIBITION
Nov. 5-6, 2019
Midland, TX

4 CONFERENCE & EXHIBITION DUG MIDCONTINENT
Nov. 19-21, 2019
Oklahoma City, OK

5 MARCELLUS-UTICA MIDSTREAM CONFERENCE & EXHIBITION
Dec. 3-5, 2019
Pittsburgh, PA

2020*

6 CONFERENCE & EXHIBITION DUG ROCKIES
Feb. 18-19, 2020
Denver, CO

7 energycapital CONFERENCE
March 2, 2020
Dallas, TX

8 25 INFLUENTIAL Women IN ENERGY
March 4, 2020
Houston, TX

9 CONFERENCE & EXHIBITION DUG PERMIAN BASIN
April 6-8, 2020
Fort Worth, TX

10 CONFERENCE & EXHIBITION DUG HAYNESVILLE
May 19-20, 2020
Shreveport, LA

11 CONFERENCE & EXHIBITION MIDSTREAM TEXAS
June 2-3, 2020
Midland, TX

HARTENERGY
Conferences

**For a full list of our 2020 events, visit HartEnergyConferences.com*

Keane, C&J Energy Merger Creates Services Behemoth

PRESSURE PUMPERS C&J Energy Services Inc. and **Keane Group Inc**. agreed on June 17 to combine in what analysts are calling a "true merger of equals."

In the all-stock transaction, valued at roughly $745.7 million, the merger is set to create the third-largest pressure pumper in the U.S., better positioning the Houston-based companies to endure tough market conditions faced by the oilfield service sector.

Among pressure pumpers in the U.S., the merged companies will trail **Halliburton Co.** and **Schlumberger Ltd.** in terms of size, analysts with **Tudor, Pickering, Holt & Co.** (TPH) said.

Jim Wickland, research analyst with **Stephens Inc.**, noted during an industry event in Houston earlier this year that the oilfield service index was "dead flat" in February compared to its position 15 years ago, in 2004.

The challenged environment for oilfield service providers has led to calls for consolidation, and the C&J-Keane merger could be an indicator of consolidation heating up for the sector's pressure pumping industry, according to TPH.

"Consolidation [is] certainly nice to see, but we'll need more to notably enhance [the] pressure pumping industry structure," TPH analysts said in a research note on June 17 noting the transaction is a true merger of equals.

Combined, the companies have 2.3 million hydraulic fracturing horsepower (HHP) consisting of about 50 frack fleets, 158 wireline trucks, 81 pumpdown units, 28 coiled tubing units, 139 cementing units and 364 workover rigs. The combined company's footprint will also cover several of the most active U.S. shale plays, including the Permian Basin.

Additionally, the companies said the combination will provide for $100 million of synergies, which analysts with **Capital One Securities Inc.** called "compelling."

"The geographic overlap makes sense along with both having a higher-quality frack customer base than many of their peers," the analysts said in a June 17 research note.

C&J and Keane expect to complete the combination in fourth-quarter 2019. As part of the agreement, C&J shareholders will receive about 1.6 shares of Keane for each C&J share. Additionally, current C&J shareholders will receive a $1 cash dividend.

Shareholders of C&J and Keane will own roughly 50% of the new company. The enterprise value of the combined company is projected to be roughly $1.8 billion, including $255 million of net debt.

At closing, Keane CEO Robert Drummond will stay on as president and CEO of the combined company. Meanwhile, Patrick Murray, chairman of the C&J board of directors, will serve as chair of the combined company's board.

Citi is the financial adviser to Keane for the transaction. **Schulte Roth & Zabel LLP** is the company's legal adviser. A special committee of the Keane board is receiving financial advice from **Lazard,** and **Simpson Thacher & Bartlett LLP** is serving as the committee's legal adviser.

Morgan Stanley & Co. LLC and **J.P. Morgan Securities LLC** are the financial advisers to C&J, with Morgan Stanley as lead advisor. **Kirkland & Ellis** is the legal adviser to C&J.

—Emily Patsy

Great Golf for a Great Cause

Join us for the 24th annual

Small Steps Energy Classic

Monday, October 28, 2019
Champions Golf Club
and
Northgate Country Club

The Energy Classic is one of the principal sources of funding for Small Steps Nurturing Center, an accredited early childhood program in Houston's First and Fifth Wards dedicated to stopping the cycle of poverty through education and early intervention. Small Steps provides a comprehensive program that addresses the needs of both the children and their families.

In its 23 years, the Small Steps Energy Classic has raised more than $15.1 million in support of early childhood education. Last year alone, the Energy Classic raised $932,000 for the students of Small Steps Nurturing Center.

2019 Title Sponsors

DETRING ENERGY ADVISORS

EnCap Investments L.P.

WELLS FARGO

Sign up for a day of great golf at Northgate Country Club and Champions Golf Club, prior host to the U.S. Open, the Ryder Cup, and the PGA TOUR Championship, and future host to the 2020 U.S. Women's Open.

'19

Small Steps Energy Classic

To register, visit https://ssnc.org/events/energy-classic/registration/ today.
Contact Julianne Hickey at 713-236-0330 or jhickey@ssnc.org for more information.

TRANSACTION HIGHLIGHTS

BAKKEN

■ **Northern Oil and Gas Inc.** said July 2 that it closed its $310 million deal to acquire nonoperated Williston Basin assets from **Flywheel Energy LLC**.

The nonop-focused E&P, based in Minneapolis, acquired about 18,000 net acres, 100% HBP. Production from 86.9 net producing wells included in the acquisition was expected to reach about 6,600 barrels of oil equivalent per day (boe/d) during the second half of 2019.

Northern agreed to pay $165 million in cash, assume a $130 million, three-year senior unsecured note due 2022 and transfer roughly 5.6 million shares of Northern's common stock to Flywheel for the interests. Northern said it did not anticipate accessing the public equity or debt markets for the transaction.

APPALACHIA

■ **C Energy Corp.** agreed July 2 to sell subsidiary **Columbia Midstream Group** and its gas gathering and processing assets in the Appalachian Basin to **UGI Energy Services LLC** in a deal valued at US$1.3 billion.

UGI will pay the Canadian company roughly $1.3 billion for the U.S. midstream assets, which include four natural gas gathering systems and an interest in a company with gathering, processing and liquids assets.

The acquisition of the Columbia assets will help UGI Energy Services to achieve its goal of building "a midstream business of scale," said John L. Walsh, president and CEO of UGI.

"This transaction expands our midstream capabilities in the prolific gas-producing region of the Southwest Appalachian Basin and provides an initial investment into both wet gas gathering and processing," Walsh said in a statement July 2.

The five gathering systems owned by Columbia have capacity of roughly 2,675,000 million British thermal units and include 240 miles of pipeline located in the southwestern core of the Appalachian Basin, according to UGI.

The Columbia assets to be acquired by UGI Energy Services connect production to markets throughout western Pennsylvania, eastern Ohio and northern West Virginia, TC Energy said in its July 2 release.

ANADARKO BASIN

■ **Occidental Petroleum Corp**. is reportedly exploring the sale of the midstream MLP that the company is set to gain through its pending takeover of **Anadarko Petroleum Corp.**

Bloomberg first reported the possible sale on June 24, citing unnamed sources. According to the Bloomberg report, Occidental is working with a financial adviser to market half of Anadarko's interest in **Western Midstream Partners LP** and its general partner.

Proceeds from the rumored sale would be used to support its $57 billion acquisition of Anadarko Petroleum, which the companies agreed to in early May. The transaction, which was expected to close in the second half of 2019, comprises 78% cash and 22% stock plus the assumption of Anadarko debt.

PERMIAN BASIN

■ Coal producer **Alliance Resource Partners LP** said June 24 it will add to its growing position of oil and gas minerals in the Permian Basin through the multimillion-dollar acquisition of private-equity-backed **Wing Resources LLC**.

Based in Tulsa, Okla., Alliance is the second-largest coal producer in the eastern U.S.

Alliance said it agreed to acquire oil and gas mineral interests from Wing Resources and its affiliates for $145 million cash. Dallas-based Wing Resources is a Permian Basin-focused mineral and royalty acquisition company backed by private-equity firm **Natural Gas Partners**.

Wing's assets in the Permian cover more than 200,000 gross acres with interest in over 4,000 wells, according to the company's website. The assets are located throughout the Midland Basin and Delaware Basin of West Texas and New Mexico.

Alliance said the Wing acquisition adds roughly 9,000 net royalty acres in the Midland Basin. Wing's assets include 783 gross horizontal producing wells. The wells deliver an estimated 460 barrels of oil equivalent per day (boe/d) (70% oil, 14% NGL) net to the Wing interests. The assets also include 441 drilled but uncompleted wells and 279 permits.

■ **Development Capital Resources LLC** (DCR) has formed a multibillion-dollar Permian Basin joint venture (JV) that sets to deploy capital in the Wolfcamp shale play.

On June 19, DCR said it had agreed to invest up to $165 million in the JV for the drilling and development of the Permian's Wolfcamp Formation. As part of the agreement with an unnamed private operator, the company will participate in the JV as a working interest owner.

Backed by **Ares Management Corp.**, DCR focuses on participating in nonoperated JVs throughout the North American E&P industry. At the time of its formation in 2017, president and CEO Ronnie Scott said DCR, which has offices in Houston and Midland, Texas, had a "substantial amount of capital available" for investments that included but weren't limited to drilling JVs, nonoperated working interests and royalty participation.

■ **Callon Petroleum Co.** closed its sale of noncore Permian Basin assets on June 13 to Houston-based independent **Sequitur Energy Resources LLC**, with potential proceeds totaling $310 million.

The sale, announced in early April, comprised the company's Ranger asset located in the southern Midland Basin's Reagan and Upton counties, Texas, where Callon hasn't been as active.

The sale included 66% working interest in 9,850 net Wolfcamp acres. Callon said daily production averaged 4,000 boe/d, 52% oil, in February.

A subsidiary of Sequitur agreed to purchase Callon's Ranger asset for $245 million in cash. The agreement also included up to $60 million in contingent payments tied to oil prices during the next three years.

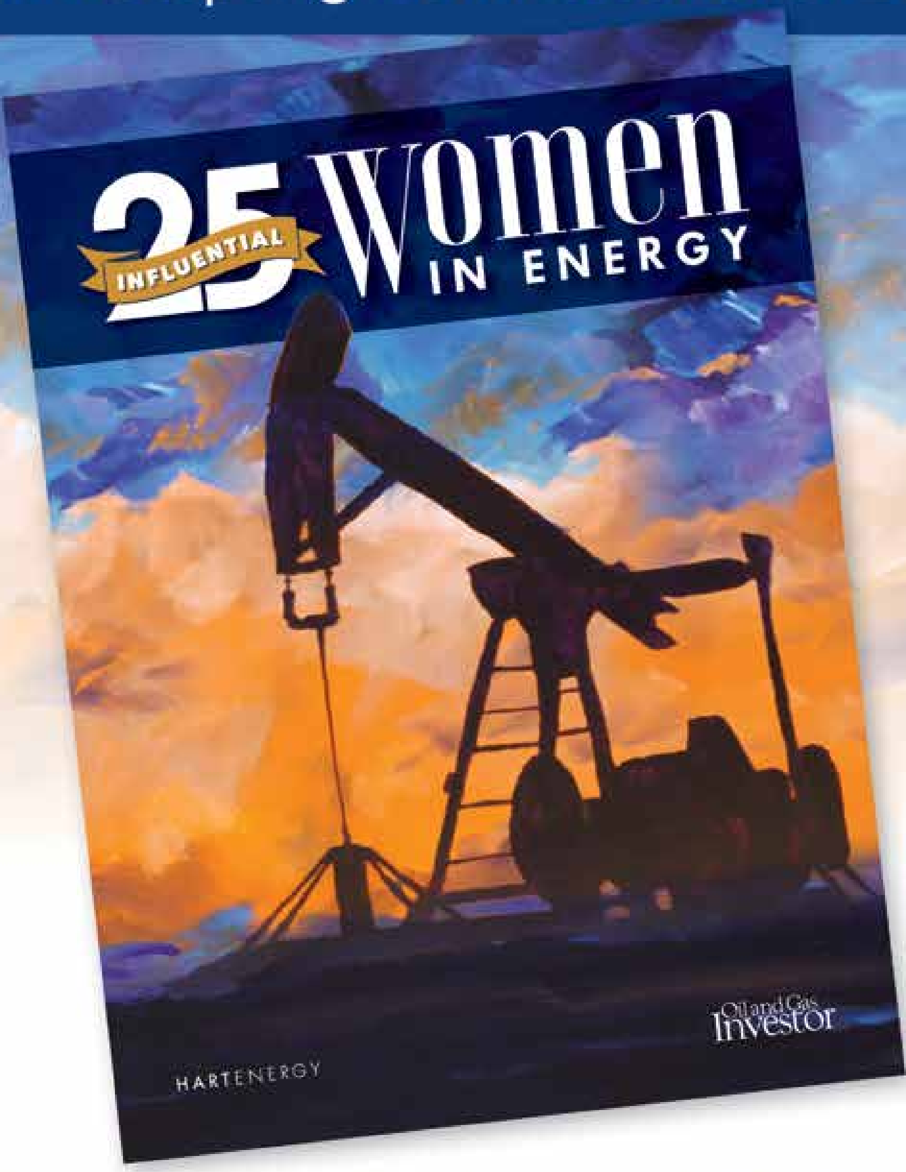
OKLAHOMA

■ **Glendale Energy Ventures LLC** and San Francisco investment firm **TPG Sixth Street Partners** said June 12 they had partnered to fund nonop acquisitions, including a $55 million acquisition of nonoperated interests in drilling pads located in Oklahoma's Stack play.

The partnership includes an initial $500 million in capital commitments. Remaining capital will be used to acquire and develop upstream oil and gas assets across the U.S.

Glendale is a private oil and gas company based in Houston. Led by industry veterans Brent Grundberg and Vignesh Proddaturi, the company focuses on de-risked U.S. onshore resource plays through asset-level acquisitions, drilling JVs and farm-ins.

Now Accepting Nominations for 2020



We invite you to nominate an exceptional industry executive for *Oil and Gas Investor*'s 3rd annual **25 Influential Women in Energy**. The nominees should represent those who have risen to the top of their professions, are currently active, and who have achieved outstanding success in the oil and gas industry.

A gala luncheon will be held for the selected honorees on Wednesday, March 20, 2020 at the Hilton Americas in Houston.

All honorees will be profiled in a special report that will mail to *Oil and Gas Investor* subscribers in March 2020.

The deadline for nominations is **October 1, 2019**

InfluentialWomenInEnergy.com

Oil and Gas Investor

HARTENERGY

WILDCATTERS' SPORTING CLAYS

IPAA

Thursday, September 19th
Elm Fork Shooting Sports
Dallas, Texas

*** 12 SHOOTING STATIONS ***
*** AWARDS * DOOR PRIZES ***

The seventh annual IPAA Wildcatters' Sporting Clays invitational is the premier oil and natural gas industry sporting clay tournament benefiting the industry and IPAA's Educational Foundation.

Secure a four-person shooting team today!
Contact Tina Hamlin at thamlin@ipaa.org or 202.857.4768.

www.ipaa.org/events

The IPAA Educational Foundation is a 501(c)(3) organization.

2018 SPONSORS

Matador · haynesboone · Lonestar · Medallion · P2 · Schlumberger · Stakeholder Midstream · Alliant · Approach · BASA

bvagroup · CWS · NOW · DTE Energy · Energy Finance Partners · Goodnight · Gray Reed · INTL FCStone · PLS · Texas Capital Bank · Ulterra

LET'S TAKE A POWDER

RICHARD MASON,
CHIEF TECHNICAL
DIRECTOR

How about some oil and gas love for the Powder River Basin?

After all, this stacked pay tight formation province was perennially branded as the last shale play standing. E&Ps have placed 2.6 million acres under lease split almost evenly between private and public companies. The largest privately held position—and the largest overall—is Anschutz Exploration Corp. with 460,000 acres straddling the Campbell/Johnson county line in Wyoming. Occidental Petroleum Corp. meanwhile picked up 445,000 acres via the Anadarko Petroleum Corp. acquisition. Anadarko previously planned two wells monthly in 2019 on a one-rig appraisal program.

Public players include EOG Resources Inc. at 400,000 acres, Devon Energy Corp. at 330,000 acres and Chesapeake Energy Corp. at 248,000 acres. For 2019, Devon will double Powder River activity to four rigs and one frack crew and add a Niobrara Shale appraisal program to its tight sand effort. Devon's Oklahoma City neighbor, Chesapeake Energy Corp., is transferring capital in 2019 from the Marcellus and Midcontinent to the Powder River Basin as it transitions a one-rig program from tight sand targets to source-rock Niobrara Shale.

Operators drilled 188 horizontal wells in 2018 with 23 rigs active (activity equivalent to Ohio's Utica Shale), primarily in Converse County, Wyo., with spillover into Campbell County, where higher GOR ratios reflect better thermal maturity. To date, operators have emphasized stacked pay tight sands charged from Upper Cretaceous source rocks. For example, 42% of horizontal wells since 2010 tested the regionally variable Shannon, Sussex, Parkman and Teapot formations, which are charged by the underlying Niobrara Shale. Another 37% of horizontal wells targeted the overpressured Frontier/Turner formations, which feature 30-day IPs of 2,000 barrels of oil equivalent per day (boe/d).

Operators had been appraising tight sand formations on the western side of the basin, where engineering efforts are focused on spacing and well density with the best wells producing more than 375,000 boe cumulative in the first year of production (oil cuts greater than 75%).

Now E&Ps are focusing on source rock. The Powder River's Niobrara Shale is up to 500 feet thick, while the Mowry Shale is a thinner (120 feet) and shallower resource that features multiple landing zones in economically viable acreage in the basin's eastern half.

E&Ps are witnessing a step change in well performance as they increase downhole intensity in the Niobrara and the Mowry. EOG, for example, reported four Mowry wells in 2018 with 30-day IPs above 2,050 boe/d on a 35% oil cut. Although one-year Mowry cumulative production averages less than 150,000 boe industrywide, EOG drilled the best well to date with nine-month cumulative production of more than 300,000 boe. The company told investors at the J.P. Morgan Energy Conference in June that the Mowry exhibits the highest profitability ratio in the company's premium well inventory thanks to lower well costs. Overall, EOG is targeting 40 net Powder River completions in 2019, double its Bakken program.

While big name public companies are active, don't overlook privately held firms. Anschutz Exploration will add a third rig to its program in fourth-quarter 2019 on the way to drilling and completing 28 wells this year. The company is moving from delineation and spacing tests in early 2019 to a well optimization focus by year-end. Anschutz is projecting 18,000 boe/d out of the Powder River by the first half of 2020, which would make the company cash-flow neutral.

Elsewhere, Ballard Petroleum Holdings LLC outlined a 40% drop in Turner and Parkman well costs following the 2014 peak for attendees at Hart Energy's DUG Rockies conference in May. Drilling optimization saves the company $1 million per well on four-well pads as Ballard transitions to longer laterals at a completed well cost of $5.9 million for the Parkman Formation and $7.5 million for Turner wells.

Operators have established Turner/Frontier economics. To date, those tight sand formations have provided the low-hanging fruit in the Powder River. E&Ps are now seeking economically sustainable productivity from the region's source rock shales through optimized completions, which increase productivity, while reducing well costs through water infrastructure and hydrocarbon takeaway capacity.

What's not to like? The Powder River is joining the Permian, the Midcontinent and Appalachian as a top-tier tight formation stacked pay target.

EASTERN U.S.

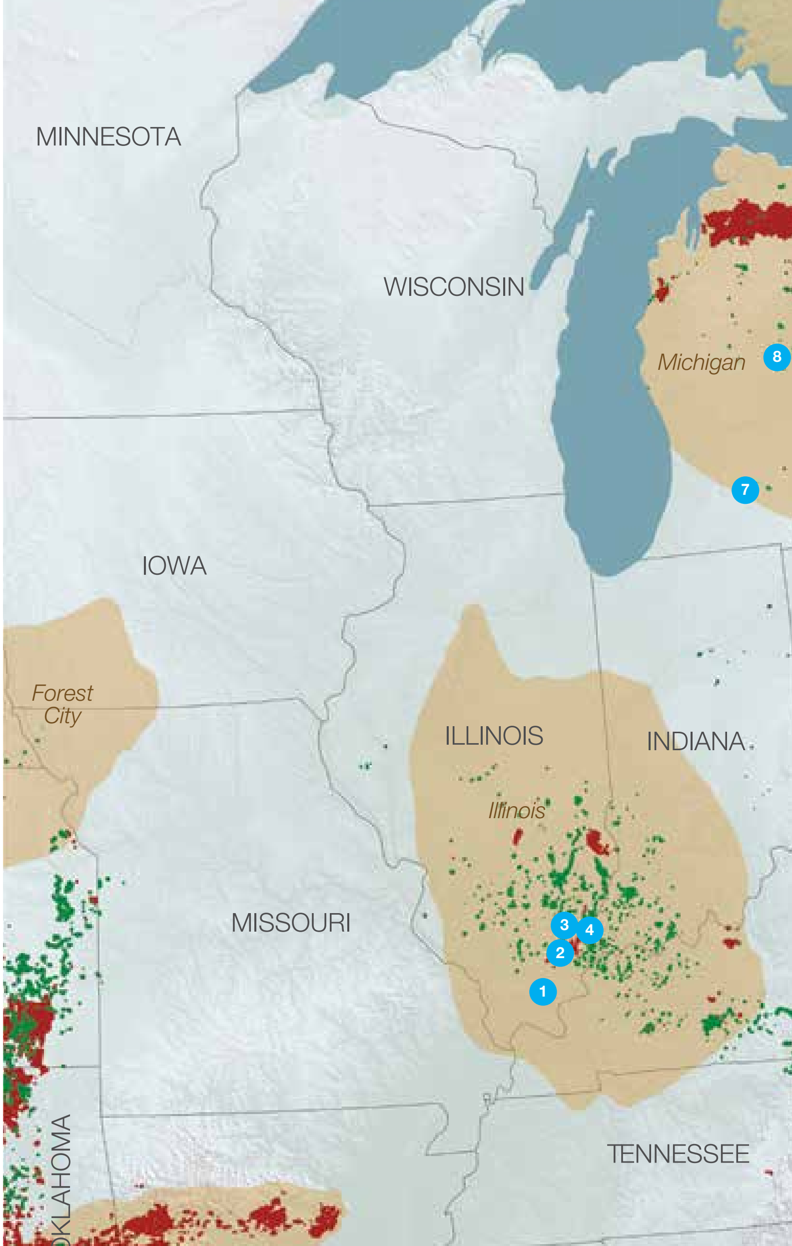
1 A deep, remote exploratory test in Hardin County, Ill., has been staked by ***John O. Schofield Inc.***, about 15 miles from the nearest oil production. The Carmi, Ill-based company's #1 Schofield-Hicks Dome has a planned depth of 12,500 ft. It is in Section 30-11s-8e and is targeting Granite Rhyolite Wash (Precambrian). The company had drilling plans in the area in late 2015, permitting an offsetting exploratory test, also named #1 Schofield-Hicks Dome. It had a planned depth of 12,000 ft, and the location was abandoned before drilling took place. Nearby drilling is at two wildcats—one in Section 30 at #1 H. Hamp, which was abandoned in 1953 at 2,948 ft, and #1 Missouri Portland Cement in Section 36, which was abandoned in 1978 at 370 ft. The only successful exploratory test in the county is at #1 A. Lane in Section 20-11s-10e that was tested in 1947 pumping an unreported amount of oil from the Lower Renault at 1,098-1,107 ft.

2 ***Dee Drilling Co.*** is drilling the first of two recently scheduled Aux Vases tests in Gallatin County, Ill. The #2 Brockschmidt has a planned depth of 3,100 ft and is in Section 35-7s-8e. The company's nearby #1 Charles Moye will be in Section 35 and also has a planned depth of 3,100 ft. The Mt. Carmel, Ill-based company's drilling program is designed to extend Omaha Field to the east. Gallatin County's Omaha Field was discovered in 1940, and reservoir production comes from numerous Mississippian pays, including Aux Vases at around 2,730 ft. ***Campbell Energy*** has drilled some of the most recent wells in Omaha Field, including #3 Patton in Section 33. It was completed in 2018 and was tested pumping 20 bbl of crude and 100 bbl of water per day through perforations ranging from Benoist Sand at 2,510 ft to McClosky Lime at 2,849 ft.

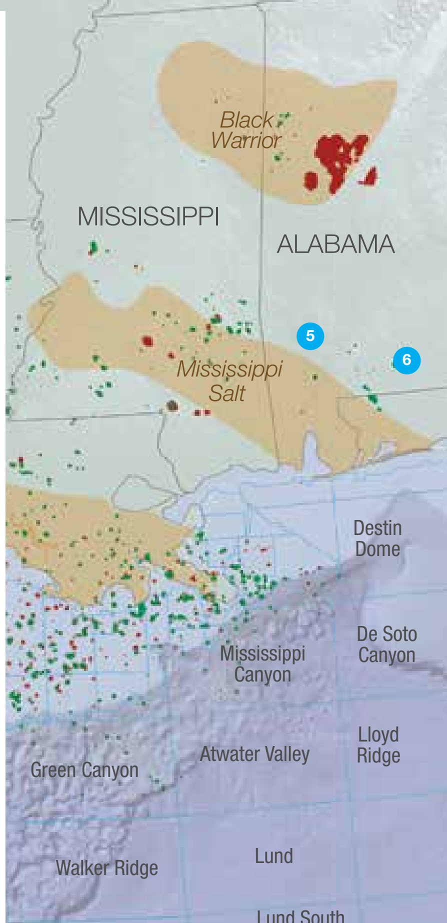
3 ***Countrymark Energy Resources*** has received a permit to drill a 4,999-ft Dutch Creek venture, #10 Bolerjack. The venture will be in Section 23-6s-8e in White County, Ill., in Roland Consolidated Field. Nearby Dutch Creek production is at #9 Downen, which was completed as an oil producer in 1982. Oklahoma City-based Countrymark is now the operator of that completion and has permitted a number of ventures in this part of the state.

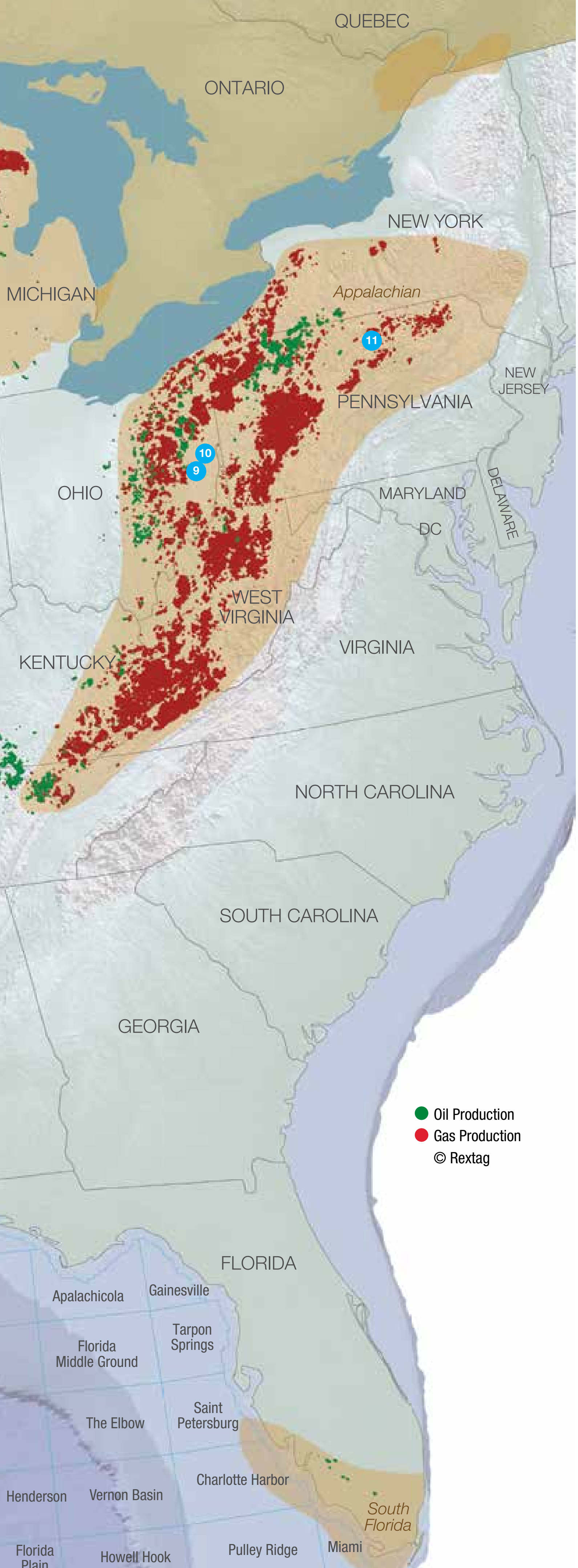
4 A 2,975-ft McClosky test has been permitted by ***T & B Production Co. LLC*** in Gallatin County, Ill. The well, #1-24 Lawler, will be in Section 20-8s-9e. It has a projected depth of 2,975 ft and is in Inman West Consolidated Field. Nearby recovery is to the southeast in Section 24 at a 2,990-ft well completed in 2017 at #1 Frey. The completion was tested pumping 41 bbl of crude per day from Aux Vases at 2,782-90 ft. Offsetting #1 Frey are two shallower Tar Springs oil wells drilled in 2000 to depths of 2,140 ft and 2,141 ft. T & B is based in Memphis.

5 ***Cobra Oil & Gas Corp.***, according to IHS Markit, is drilling an exploratory Norphlet test in a nonproducing part of Clarke County, Ala. The #1 Holberg 29-11 is in Section 29-7n-3e and has a planned depth of 14,900 ft. Numerous wildcats have been abandoned in the area, reaching depths of 6,000 ft or less. The nearest Norphlet wildcat is within 6 miles to the southeast in Section 7-6n-4e at #1 A.S. Johnson Trust 7-3, which was abandoned in 1989 at 14,190 ft. Smackover oil production in the one-well Perry Chapel Field is 6 miles southeast of Cobra's drillsite at #2 Bedsole Foundation 24-11 in Section 24-6n-3e. It was tested in 2011 flowing 172 bbl of crude, 84 Mcf of gas and 113 bbl of water per day from 14,040-14,346 ft. Cobra's headquarters are in Wichita Falls, Texas.



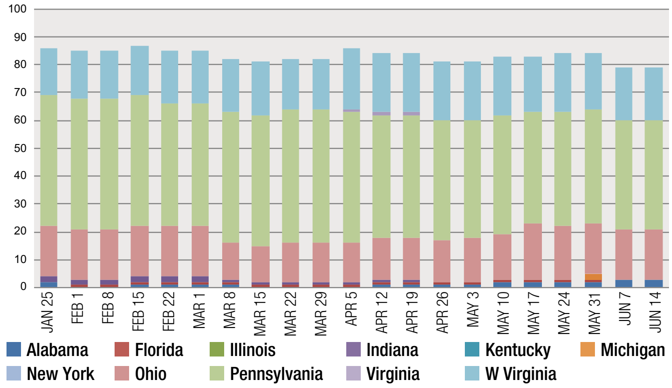
6 Dallas-based ***Ventex Operating Corp.*** is drilling a Smackover oil test south of oil production in Brooklyn Field. IHS Markit reported that the southeastern Conecuh County, Ala., venture, #1 Cedar Creek Land & Timber 23-14, has been spud, and the directional venture has a planned true vertical depth of 12,500 ft in Section 23-3n-13e. Nearby exploration is about 2 miles to the northeast at the company's #1 Cedar Creek Land & Timber 13-5 in Section 13. The directional Brooklyn Field test was drilled in early 2019 to 12,200 ft with 5 1/2-in. casing set on bottom. The expected producer has been perforated in Smackover at 11,915-11,920 ft with no other details available. Ventex operates one well in Brooklyn Field.





Eastern U.S. Rig Count

Jan. 25, 2019-June 14, 2019



Data compiled from Baker Hughes

7 Production casing has been set at a Trenton/Black River wildcat in Calhoun County, Mich., by ***Savoy Energy LP***. A directional sidetrack, #1-21A Traister, was drilled to 4,200 ft, and the company was running 5 1/2-in. pipe to an unreported depth. The original vertical hole was drilled to a planned depth of 3,900 ft. The expected oil producer is in Section 21-3s-8w. In nearby Section 34, the Traverse City, Mich.-based company's #1-34 Seymour was tested in 2018 pumping 48 bbl of crude per day from an undisclosed zone in the Trenton. The discovery was drilled to 4,035 ft. Savoy abandoned several Trenton/Black River tests in the area before successfully completing #1-34 Seymour.

8 Traverse City, Mich.-based ***West Bay Exploration*** has scheduled a Dundee Lime oil test in an attempt to extend Isabella Field to the north. The #1-27 Oaks will be directionally drilled in Section 27-15n-4w in Isabella County, Mich., with a planned true vertical depth of 4,150 ft. Isabella Field was opened in early 2010 with the completion of #1-35 Gepford in Section 35. It was tested pumping 480 bbl of 44-degree-gravity crude and 300 Mcf of gas per day from an openhole Dundee Lime zone at 3,763-67 ft. Additional Dundee Lime production in the area is to the east in Rosebush Field.

9 Oklahoma City-based ***Ascent Resources LLC*** has received permits to drill three Utica Shale wells in Jefferson County, Ohio. The Limestone Field wells will be drilled from a drillpad in Section 15-8n-3w. The #4H Ronald S SMF JF has a planned depth of 19,000 ft. The #2H Ronald S SMF JF has a planned depth of 20,000 ft. The #1H Ronald NE SMF JF has a planned depth of 23,400 ft.

10 IHS Markit reported that Oklahoma City-based ***Ascent Resources LLC*** completed a Utica Shale well in Jefferson County, Ohio, that produced an average of 36.3 MMcf of gas per day. The #1H Nolan is in Smithfield 7.5 Quad in Jefferson County, Ohio. The Gould Consolidated Field well, which was completed in a nearly 3-mile-long lateral, was drilled to 24,881 ft, 9,173 ft true vertical, and production is from perforations at 9,779-24,744 ft.

11 ***Chief Oil & Gas*** completed three Marcellus Shale wells from a pad in Section 7, Leroy 7.5 Quad, Leroy Township in Bradford County, Pa. The #1H SGL-12 K South Unit was drilled to 18,366 ft, 9,070 ft true vertical, and produced 22.9 MMcf of gas from perforations at 8,660-16,993 ft. The #2H SGL-12 K South Unit had a planned depth of 18,320 ft and was completed with a 7,632-ft lateral flowing 20.2 MMcf of gas per day. The #1H SGL-12 Hardy North was tested flowing 14.6 MMcf of gas per day from an 8,156-ft lateral. Additional completion details are not available. Chief's headquarters are in Dallas.

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.

GULF COAST

1 ***Chesapeake Operating Inc.*** completed an Eagle Ford producer in Briscoe Ranch Field in Dimmit County (RRC Dist. 1), Texas. The #4BH Big Wells South Unit 10 was tested flowing 35.4 MMcf of gas per day from perforations at 7,541-16,070 ft after acidizing and fracturing. It was drilled to 16,186 ft, and the true vertical depth is 7,128 ft. It is in Korn Valentine Survey, A-1179, and bottomed in Gallagher Dominic Survey, A-74. The discovery was tested on a 17/64-in. choke, and the flowing tubing pressure was 781 psi. Chesapeake is based in Oklahoma City.

2 In Karnes County (RRC Dist. 1), Texas, San Antonio-based ***GulfTex Energy III LP*** completed an Eagle Ford Shale well that initially flowed 2.978 Mboe per day (90% oil). The Eagleville Field well, #3HMZYK North Unit, is in Carillo Fernando Survey, A-64, and bottomed in William Toomey Survey, A-281. It was drilled to 15,237 ft, and the true vertical depth is 10,239 ft. Production is from perforations at 10,253-15,121 ft in a 4,868-ft lateral that was fracture stimulated. It was tested on a 22/64-in. choke with a flowing tubing pressure of 2,615 psi.

3 A horizontal Newark East Field-Barnett Shale well was completed by ***Texxol Operating Co.*** in Wise County (RRC Dist. 9), Texas. The Fort Worth Basin completion, #2H Gentry, was tested flowing 36 bbl of 48.8-degree-gravity oil, 1.583 MMcf of gas and 648 bbl of water per day. Production is from acid- and fracture-treated perforations at 6,888-10,598 ft. It was drilled to 10,715 ft and is in Lot 82, Matagorda CSL Survey, A-534. The lateral bottomed within 1 mile to the west in Lot 76. The true vertical depth is 6,809 ft. Texxol's headquarters are in Fort Worth, Texas.

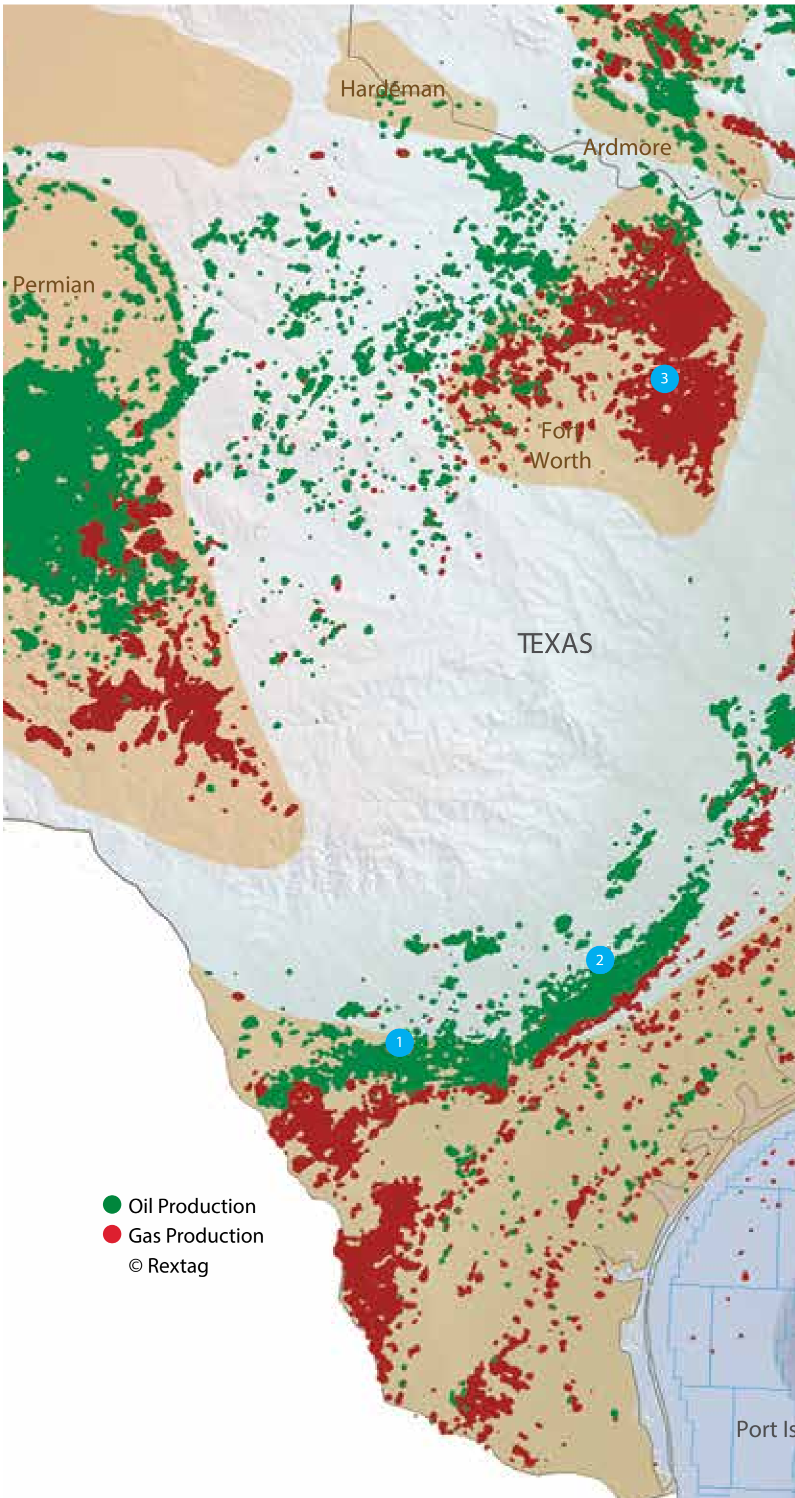
4 In Angelina County (RRC Dist. 6), Texas, ***BP Plc*** has completed a Haynesville Shale well in Carthage Field. IHS Markit reported that #4HB Rockies Gas Unit was tested flowing 9.557 MMcf of gas and 168 bbl of water per day from acid- and fracture-treated perforations at 16,362-23,700 ft. The horizontal gas well was drilled to 23,847 ft, 16,097 ft true vertical, and is on a 1,056-acre lease in the Sarah Odell Survey, A-494. The discovery bottomed about 1.75 miles to the south in John Berry Survey, A-100. It was tested on a 14/64-in. choke with a flowing tubing pressure of 11,653 psi and a shut-in tubing pressure of 12,266 psi. BP's headquarters are in London.

5 A Haynesville Shale discovery in Red River Parish, La., was tested flowing 15.084 MMcf of gas and 390 bbl of water per day. The Houston-based ***Tellurian Operating LLC***'s #2-Alt NRG 29-12-10H is producing from fracture-treated perforations at 12,978-17,567 ft. Gauged on a 17/64-in. choke, the flowing casing pressure was 9,104 psi. The horizontal Red River-Bull Bayou Field well is in Section 29-12n-10w and bottomed about 1 mile to the north. The total depth is 17,675 ft, and the true vertical depth is 12,550 ft.

6 Two Lower Cotton Valley completions were announced by ***Riviera Operating LLC*** in the Lincoln Parish, La., portion of Ruston Field. The wells were drilled from offsetting surface locations in Section 2-18n-3w, and both wells bottomed about 1 mile to the south. The #003-Alt J.P. Graham 2H flowed 21.119 MMcf of gas and 776 bbl of water through acid- and fracture-treated perforations at 11,259-15,825 ft. The flowing casing pressure was gauged at 4,029 psi on a 34/64-in. choke. It was drilled to 15,982 ft, 11,181 ft true vertical. The offsetting #004-Alt J.P. Graham 2H produced 21.191 MMcf of gas, 28 bbl of condensate and 717 bbl of water per day from acid- and fracture-treated perforations at 11,280-15,628 ft. It was tested on a 34/64-in. choke, and the flowing casing pressure was 4,993 psi. It was drilled to 15,800 ft, 11,083 ft true vertical. Riviera's headquarters are in Houston.

7 ***LLOG Exploration Co. LLC*** has permitted an appraisal test at the company's Leon prospect in Keathley Canyon Block 686. The #3 OCS G33341 is in the northeastern portion of the block, and area water depth is 6,200 ft. The venture is designed to delineate the 2014 Leon discovery on Keathley Canyon Block 642. Drilled by ***Repsol***, #1SS (BP2) OCS G33335 hit 492 ft of high-quality net oil pay in multiple Lower Tertiary sands. According to an agreement with Repsol, LLOG agreed to drill an appraisal well and take a 33% stake in the project. After the delineation drilling is completed, development options will be evaluated for the field.

8 ***Renaissance Offshore LLC*** has spud a development test in offshore Louisiana's Vermilion Block 369 Field Louisiana. The #1-A OCS G36201 is being drilled from the existing A platform in the eastern portion of the block. The development test will bottom to the southeast beneath Vermilion Block 385. Area water depth is 360 ft. Houston-based Renaissance Offshore filed a development plan for the area in 2018. According to the plan, two more tests are scheduled to be drilled from the platform, also bottoming beneath Block 385. The drilling rights to the Block 385 lease were acquired in March 2018. Vermilion Block 369 Field was brought online in 1980, with most of the reservoir's production coming from Pleistocene zones at 3,500-6,700 ft.

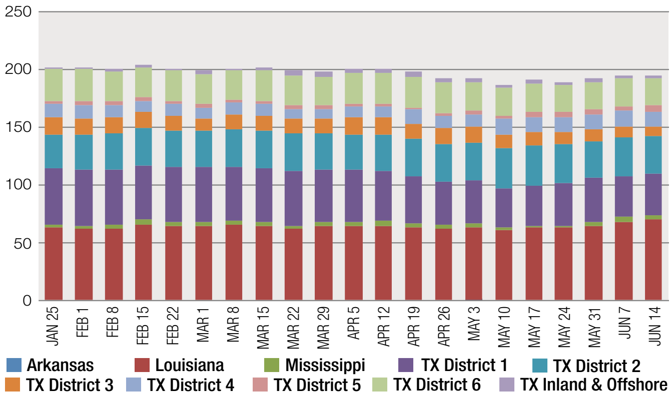


9 IHS Markit announced that ***Talos Energy LLC*** has logged 235 ft of pay in a Pliocene objective at the Bulleit exploratory test on Green Canyon Block 21 at #1 OCS G35385. The company was last reported drilling below 10,615 ft. Area water depth is 1,300 ft. Additional completion information is not currently available. Once drilling operations are complete, and pending the test results of the deeper main Pliocene objective, the discovery is expected to be tied back to the Houston-based company's existing A platform. Other Talos wells on Block 18 yield oil and gas from Pleistocene at 9,386-17,728 ft.

10 A development test has been scheduled by ***Walter Oil & Gas*** in South Timbalier Block 311 Field. The #4-A OCS G31418 will be drilled from the existing A platform in the northern half of the block and water depth in the area is 392 ft. The Houston-based company drilled the first well in the field in 2012 and recently added two wells to the two-block reservoir. In 2018, the #2-A OCS G24990 was drilled to 25,382 ft (21,520 ft true vertical) and bottomed to the south in Block 320. Through February 2019, it has produced 353 MMcf of gas and 59.379 Mbbl of condensate from Miocene perforations at 23,085-23,350 ft. The #3-A OCS G24990, which also bottomed in Block 320, was recently drilled to an unreported depth.

Gulf Coast Rig Count

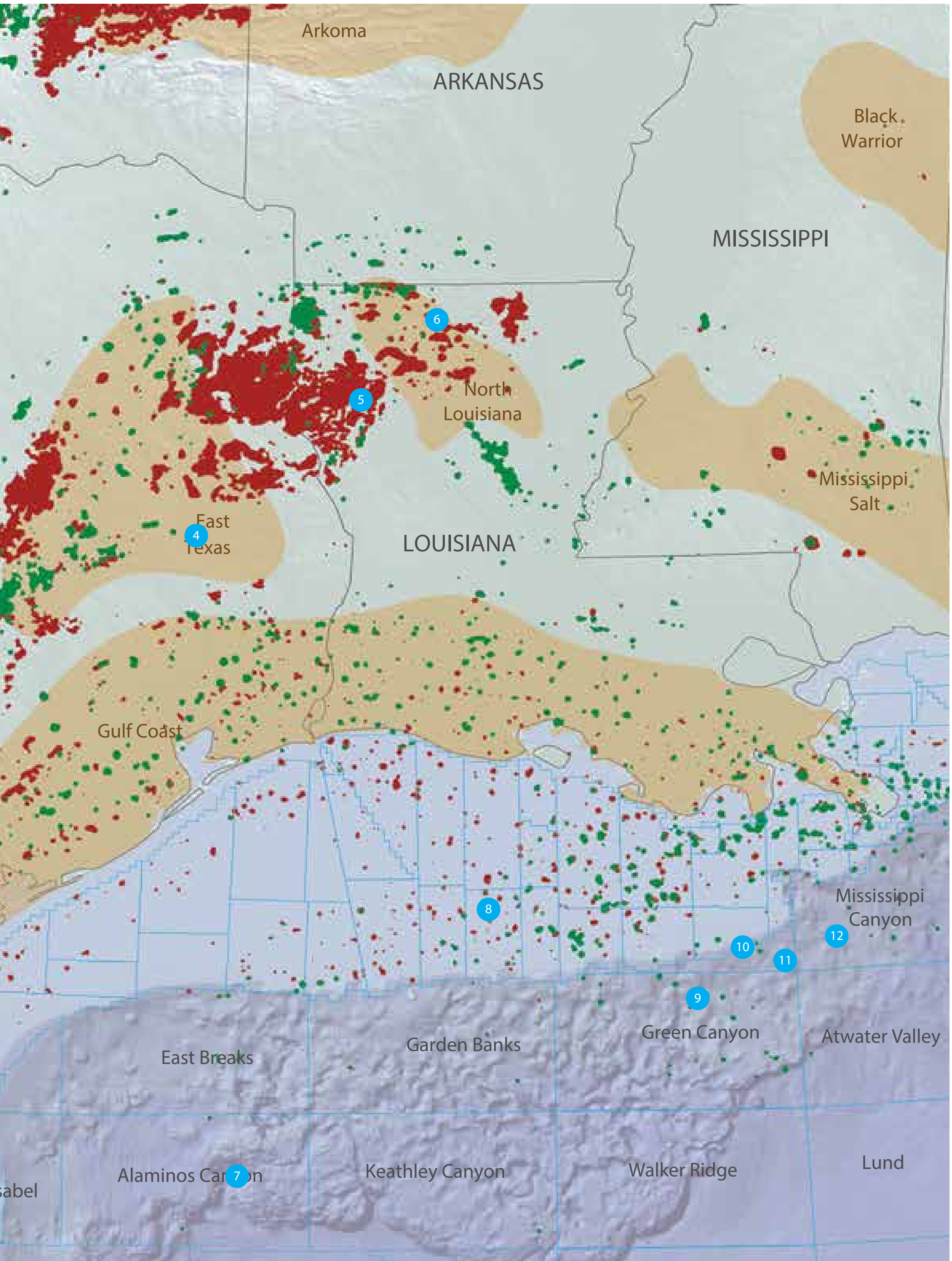
Jan. 25, 2019-June 14, 2019



Data compiled from Baker Hughes

11 An exploratory test has been permitted for ***LLOG Exploration***'s Spruance prospect at #1 OCS G35295. The venture will be in the southeastern portion of previously undrilled Ewing Bank Block 877. Water depth in the area is 1,572 ft. According to the prospect's 2016 exploration plan, a second exploratory test could be drilled on Ewing Bank Block 877. Nearby production is about 4 miles to the southwest at ***Eni***'s Morpeth Field (Ewing Bank Block 921), a Pliocene reservoir that was brought online in 1998. The last production from Morpeth Field was reported in August 2018. LLOG's headquarters are in Covington, La.

12 ***W&T Offshore*** completed a second well on Mississippi Canyon Block 800. Based on preliminary analysis of drilling and wireline logging results, the recoverable resource from #2SS OCS G18292 is expected to be in line with the pre-drill estimate of 7 MMboe. The total depth has not been disclosed. Known as the Gladden Deep discovery, first production from the completion is expected in late 2019. The offsetting #1SS (ST) OCS G18292 was drilled by ***Newfield Exploration*** in 2008 to 16,870 ft and is now owned by Houston-based W&T Offshore. W&T Offshore's field is the only producing reservoir in this part of the Mississippi Canyon area.



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 ***Oxy USA*** has completed three extended-lateral oil wells on a two-section lease, Section 27-22s-32e, in the Delaware Basin in Lea County, N.M. According to IHS Markit, #031H Taco Cat 27-34 Federal Com flowed 2.905 Mbbl of oil, 5.202 MMcf of gas and 4.853 Mbbl of water per day from a fractured-stimulated Wolfcamp zone at 11,982-22,029 ft. It was drilled to 22,168 ft, 12,205 ft true vertical, and bottomed about 2 miles to the south in Section 34. Tested on an 18/64-in. choke, the flowing casing pressure was 1,592 psi. The Los Angeles-based company has also completed two offsetting and parallel Second Bone Spring oil wells in Red Tank Field. The #021H Taco Cat 27-34 Federal Com flowed 2.557 Mbbl of crude, 2.62 MMcf of gas and 4.401 Mbbl of water daily from acid- and fracture-treated perforations at 10,699-20,791 ft. It was drilled to 20,904 ft with a true vertical depth of 10,848 ft. Gauged on a 20/64-in. choke, the flowing casing pressure was 801 psi. The #011H Taco Cat 27-34 Federal Com was tested through fracture-treated perforations at 9,445-19,621 ft. It initially produced 1.570 Mbbl of oil, 1.882 MMcf of gas and 3.201 Mbbl of water per day. It was drilled to 19,732 ft, 9,514 ft true vertical.

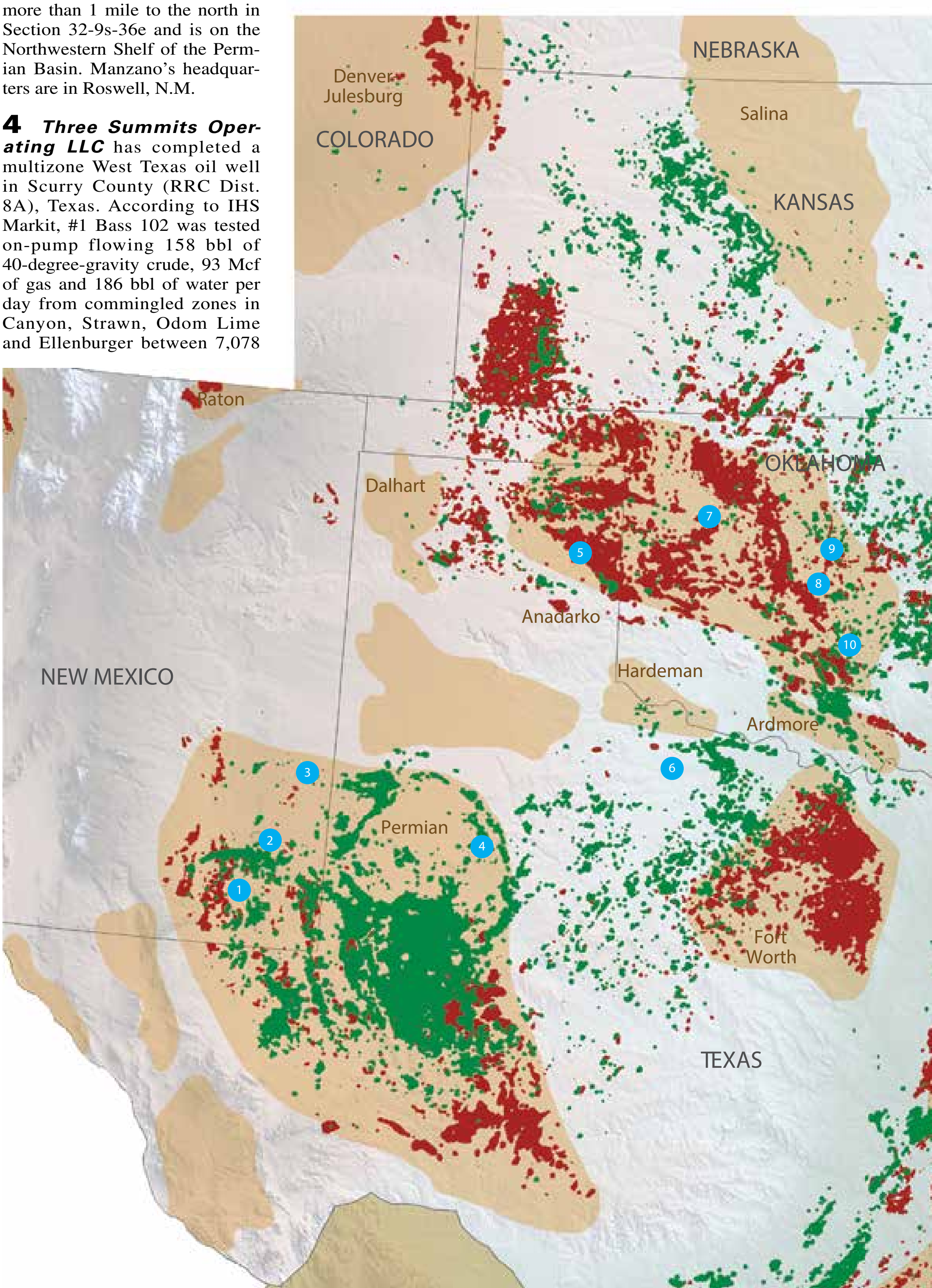
2 On the Carlsbad Shelf of the Permian Basin, a horizontal Lea South Field well has been completed by Midland, Texas-based ***Caza Oil & Gas Inc.*** in Lea County, N.M. The well, #001H Desert Rose 17-8 Federal Com, was drilled to 19,215 ft, 11,285 ft true vertical, in Section 17-20s-35e. Production is from fracture-stimulated perforations at 11,616-19,121 ft in Third Bone Spring. The initial flowing potential was 454 bbl of 36-degree-gravity oil, 501 Mcf of gas and 446 bbl of water per day. During testing on a 28/64-in. choke, the flowing tubing pressure was 580 psi. The lateral bottomed within 2 miles to the north in Section 8.

3 According to IHS Markit, the first horizontal well has been completed in Crossroads Field in Lea County, N.M. ***Manzano LLC*** completed #324H Crossroads West San Andres Unit flowing 61 bbl of 30-degree-gravity oil, 30 Mcf of gas and 2.197 Mbbl of water per day. Production is from acid- and fracture-treated perforations at 5,210-10,281 ft in San Andres. It is in Section 5-10s-36e and was drilled to 10,332 ft, 4,861 ft true vertical. The lateral bottomed more than 1 mile to the north in Section 32-9s-36e and is on the Northwestern Shelf of the Permian Basin. Manzano's headquarters are in Roswell, N.M.

4 ***Three Summits Operating LLC*** has completed a multizone West Texas oil well in Scurry County (RRC Dist. 8A), Texas. According to IHS Markit, #1 Bass 102 was tested on-pump flowing 158 bbl of 40-degree-gravity crude, 93 Mcf of gas and 186 bbl of water per day from commingled zones in Canyon, Strawn, Odom Lime and Ellenburger between 7,078 and 7,788 ft. The perforated intervals were acidized and fracture stimulated. The vertical Bass Field well is on an 80-acre lease on the Eastern Shelf of the Permian Basin and was drilled to 8,100 ft in Section 102, Block 3, H&GN Survey, A-1771. Three Summits' headquarters are in Dallas.

5 A ***Unit Petroleum Co.*** horizontal Des Moines Granite Wash well was completed in Section 68, Block M-1, H&GN Survey, A-1116, in Hemphill County (RRC Dist. 10), Texas. The #2 H Meek 6814 XL was tested flowing 6.65 MMcf of gas and 5.024 Mbbl of water per day. It was tested on a 128/64-in. choke and production is from a fracture-stimulated G interval at 15,192-21,111 ft. The shut-in and flowing tubing pressures were both reported at 1,414 psi. The Buffalo Wallow Field well was drilled north to a true vertical depth of 13,140 ft. It bottomed in Section 14, Block 4, AB&M Survey, A-1133. Unit is based in Tulsa, Okla.

6 A horizontal Caddo oil well has been completed by ***Brazos River Exploration LLC*** in a part of Throckmorton County (RRC Dist. 7B), Texas, which



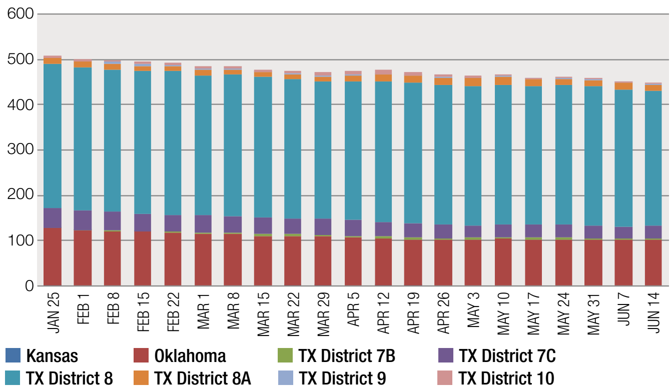
has seen little horizontal development. The #1362H Clark Ranch was tested on-pump flowing 60 bbl of 41-degree-gravity crude and 1.43 Mbbl of water per day from fracture-treated perforations at 5,808-8,604 ft. The Swenson Field well was drilled to 8,653 ft and is in Section 136, BBB&C RR Co Survey, A-1255. The true vertical depth is 4,425 ft. The lateral bottomed within 1 mile to the northwest in Section 111. Brazos River Exploration's headquarters are in Houston.

7 A Mississippian well was completed in the western portion of the Anadarko Basin Stack play by ***SandRidge Exploration & Production LLC***. The #2-18H Regina 1915 is in Section 18-19n-15w of Dewey County, Okla. It produced 500 bbl of oil, 1.4 MMcf of gas and 1 Mbbl of water per day during a test conducted according to a gas flaring application. The well was drilled north across the section to 14,918 ft. Further details are not currently available from the Oklahoma City-based company.

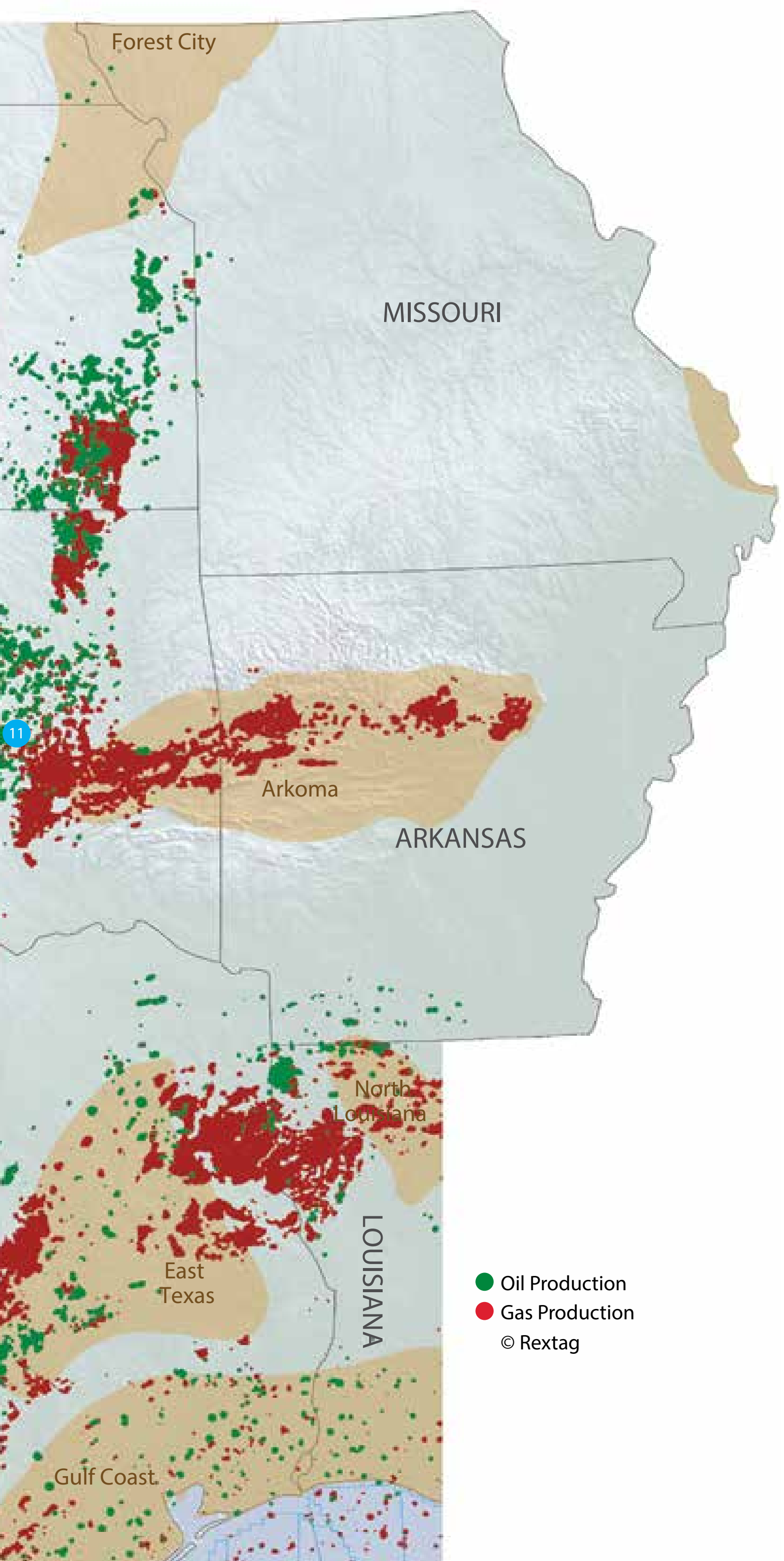
8 Houston-based ***EOG Resources Inc.*** completed a high-volume, oil-producing Tuttle Field East-Woodford well in Section 7-9n-4w in McClain County, Okla. The #0781 1H Nighthawk was tested flowing 1.667 Mbbl of 40-degree-gravity oil, 2.445 MMcf of gas and 4.814 Mbbl of water per day. It was drilled to 20,013 ft, 9,420 ft true vertical. The eastern Anadarko Basin well was tested on a 1-in. choke, and the flowing tubing pressure was 1,245 psi. Production was from a zone at 9,664-19,945 ft after acidizing and fracturing.

Midcontinent & Permian Basin Rig Count

Jan. 25, 2019-June 14, 2019



Data compiled from Baker Hughes



9 Oklahoma City-based ***Revolution Resources LLC*** reported completion results for the first of two horizontal Hunton redevelopment prospects drilled on a common pad in Oklahoma's Logan County. The #1BH Night King 1504 33-04 is in Section 33-15n-4w. It pumped 280 bbl of 40-degree-gravity oil, 380 Mcf of gas and 590 bbl of water per day from an openhole interval at 7,262-13,117 ft after acidizing. The lateral was drilled to the south about 1 mile to a true vertical depth of 6,709 ft. It bottomed in Section 4-14n-4w in Oklahoma County. The company has drilled and cased a 13,237-ft Hunton prospect with a parallel lateral 20 ft north on the pad at #2BH Night King 1504 33-03. No results are currently available.

10 Houston-based ***Marathon Oil Corp.*** completed a high-volume horizontal Springer Shale well in Stephens County, Okla. The #1-3-34SXH Papa Pump 0204 was drilled in Section 10-2n-4w. It was tested on a 16/64-in. choke flowing 2.091 Mbbl of 44-degree-gravity oil and 1.64 MMcf of gas per day with no reported water. It was tested after acidizing and fracturing between 13,245 and 21,633 ft. The Pearl Northeast Field well was drilled north across the Garvin County line to 21,800 ft, 12,601 ft true vertical, and bottomed in Section 34-3n-4w. According to IHS Markit, it has the third-highest reported initial oil production rate for all horizontal Springer wells in the southeastern Anadarko Basin Scoop play.

11 Preliminary test results from a horizontal producer drilled on a multiwell pad were announced by Tulsa, Okla.-based ***Trinity Operating LLC***. The #4-5H Zoe is in Section 5-7n-11e, of Hughes County, Okla. It initially flowed 5.64 MMcf of gas and 1.788 Mbbl of water per day. Production is from Mississippian at 5,320-5,404 ft and Woodford at 5,404-10,202 ft. It was tested after acid and fracturing treatments. The Horntown Southeast Field completion was drilled to the north to 10,731 ft, 5,404 ft true vertical.

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.

WESTERN U.S.

1 ***ConocoPhillips Co.*** has applied with the Bureau of Land Management for a drilling permit for a horizontal Frontier exploratory test on the western flank of the Green River Basin. If the permit is approved, according to IHS Markit, #17-1FH Double Whammy will be drilled in Section 17-22n-113w of Lincoln County, Wyo. The target depth and bottomhole location were not disclosed. Nearby production is about 1.5 miles to the south at the Houston-based company's #5-2H Lions Back Section 5-22n-113w, a horizontal Frontier wildcat drilled in 2018 with no details yet available. It was set up as a test of Frontier oil zones and drilled to the northeast to a proposed depth of 16,867 ft (11,490 ft true vertical) with a bottomhole location in Section 4-22n-113w.

2 Two high-volume horizontal Uteland Buttes (Lower Green River)-Uinta Basin producers were completed on a common drillpad by Houston-based ***Newfield Exploration Co.*** The drillpad is in Section 29-3s-1w in Duchesne County, Utah. The #2-29-3-1-29-32-1H Pekev UT produced 2.747 Mbbl of oil, 1.329 MMcf of gas and 3.305 Mbbl of water per day. Production is from a two-section lateral drilled southward to 18,330 ft with a true vertical depth of 7,775 ft. It was tested on a 36/64-in. choke after 41-stage fracturing between 8,608 and 18,330 ft, and the flowing tubing pressure was 1,507 psi. The #2-29-3-1-28-33-7H Pekev UT flowed 2.26 Mbbl of oil, 1.298 MMcf of gas and 630 bbl of water per day. Production is from a lateral drilled to the south-southeast to 18,558 ft with a bottomhole location in Section 33-3s-1w. It was tested on a 36/64-in. choke after 51-stage fracturing between 8,846 and 18,558 ft. The flowing tubing pressure was 1,197 psi.

3 ***Crescent Point Energy Corp.***, based in Calgary, has completed five horizontal Green River/Wasatch producers in Uintah County, Utah's Independence Field. The #4-18-19-3-1E-H3 Kendall-Tribal was tested flowing 400 bbl of 40-degree-gravity oil, 200 Mcf of gas and 747 bbl of water per day. The #4-18-19-3-1E-H3 Kendall-Tribal is in Section 18-3s-1e and is producing from a Wasatch lateral drilled to the south to 13,825 ft, 8,633 ft true vertical. It was tested on an 18/64-in. choke following 29-stage fracture stimulation between 9,194 and 13,797 ft. The #1-5-18-3-1E-UB Merritt was tested pumping 261 bbl of oil, 66 Mcf of gas and 1.242 Mbbl of water per day from a lateral in Wasatch. The rig was moved about 3 miles to the south to Section 7-3s-1e and completed #2-18-3-1E-H4 Kendall flowing 310 bbl of oil, 211 Mcf of gas and 703 bbl of water daily from a lateral in Uteland Buttes (Lower Green River). The #2-18-3-1E-WS Kendall was tested pumping 842 bbl of oil with 342 Mcf of gas and 983 bbl of water per day from a Wasatch lateral. In Section 19-3s-1e, #14-19-18-3-1E-H1 Kendall Tribal initially flowed 479 bbl of oil, 231 Mcf of gas and 1.331 Mbbl of water per day from a lateral in Wasatch.

4 IHS Markit reported that ***Aethon Energy Operating LLC*** completed a directional delineation test on the northern flank of the Wind River Basin that flowed 4.006 MMcf of gas and 4.147 Mbbl of water per day. The Fremont County, Wyo., well, #26-13 PKU (Powder Keg Unit), is in Section 26-37n-91w and was drilled to the northwest to 11,135 ft (10,965 ft true vertical). It was tested on a 56/64-in. choke after 15-stage fracturing between 7,598 and 11,033 ft. Production is from Fort Union between 7,598 and 9,592 ft and Lance between 9,628 and 11,033 ft. Aethon's headquarters are in Dallas.

5 Farmington, N.M.-based ***LOGOS Resources LLC*** has completed three horizontal Gallup (Mancos) producers from a drillpad in the San Juan Basin. The pad is in Section 7-23n-7w in Rio Arriba County, N.M. The #001H Federal 2307 07P Com flowed 927 bbl of oil, 3.993 MMcf of gas and 919 bbl of water per day. The Gallup lateral was drilled to the north to 12,397 ft (5,832 ft true vertical) and bottomed in Section 6-23n-7w. The #002H Federal 2307 07P Com flowed 775 bbl of oil, 1.244 MMcf of gas and 410 bbl of water per day. The lateral was drilled to the northwest to 13,863 ft (5,812 ft true vertical) and bottomed in Section 6-23n-7w. It was tested on a 61/64-in. choke after 40-stage fracturing between 6,400 and 13,769 ft. The #003H Federal 2307 07P Com flowed 799 bbl of oil, 4.306 MMcf of gas and 819 bbl of water per day. The Gallup lateral was drilled to the northwest to 13,441 ft (5,778 ft true vertical) and bottomed in Section 6-23n-7w. It was tested on a 49/64-in. choke after fracture stimulation in an undisclosed number of stages between 6,590 and 13,342 ft.

6 In Converse County, Wyo., ***Northwoods Operating LLC*** has completed a horizontal Frontier producer that initially pumped 840 bbl of 47-degree-gravity oil, 4.752 MMcf of gas and 1.032 Mbbl of water per day. The #11-W23-1FH Aspen is in Section 11-39n-75w and is producing from a two-section lateral in Frontier extending south-southwestward to 23,067 ft with a bottomhole location in Section 23-39n-75w. The true vertical depth is 12,872 ft. It was tested following 43-stage fracturing between 12,971 and 22,908 ft. Northwoods is based in Denver.

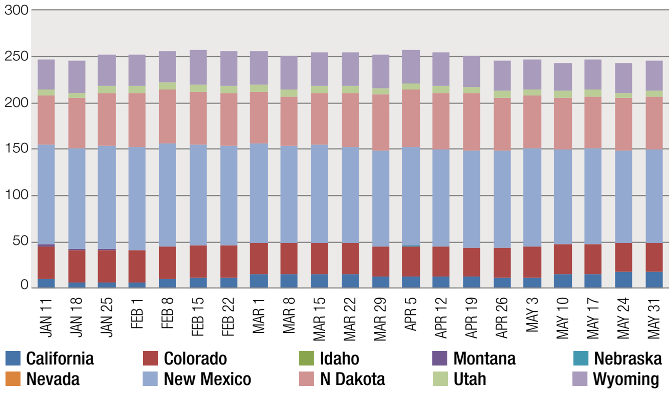
7 Denver-based ***Anschutz Oil Co.*** has completed two horizontal Turner producers in the southern Powder River Basin. From a drillpad in Section 27-35n-71w, #3571-27-34-14 TH Santana-Federal was tested flowing 1.018 Mbbl of oil, 1.793

MMcf of gas and 1.709 Mbbl of water per day from a Turner interval at 12,145-21,853 ft. It was tested after 35-stage fracturing. The lateral extends southward to 22,120 ft (11,815 ft true vertical) and bottomed in Section 34-35n-71w. The #3571-27-34-16 TH Meatloaf-Federal pumped 423 bbl of oil, 669 Mcf of gas and 1.184 Mbbl of water per day from a Turner interval at 12,061-20,950 ft after 32-stage fracturing. The lateral extends southward to 21,217 ft at a bottomhole location in Section 34-35n-71w with a true vertical depth of 11,767 ft.

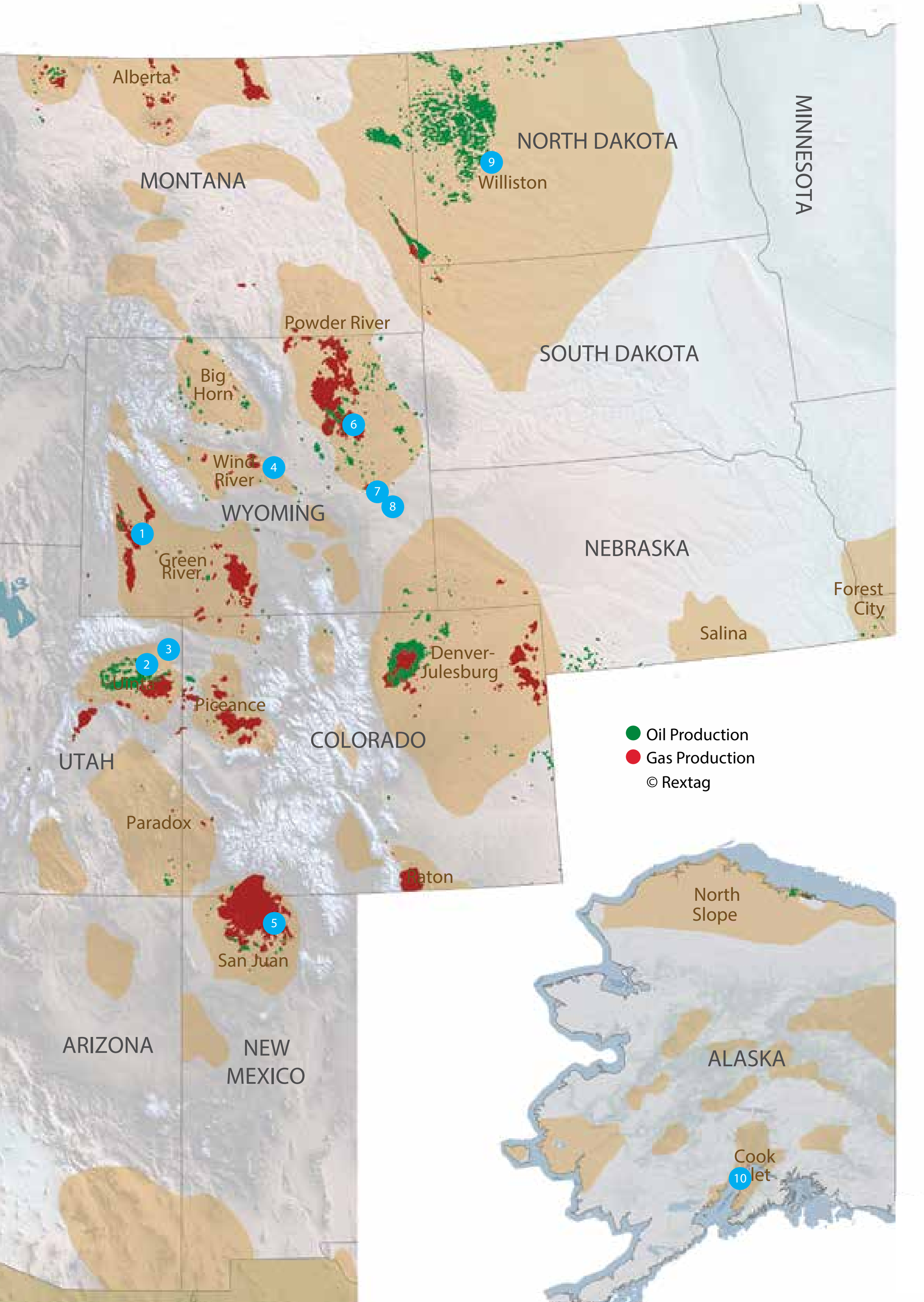
8 A high-volume Turner Sand well by ***Chesapeake Operating Inc.*** was tested flowing at a peak rate of 4 Mbbl of oil equivalent per day (75% oil). The Powder River Basin completion, #21H RRC 5-34-70 USA B TR, is in Section 5-34n-70w of Converse County, Wyo. It was tested on a 48/64-in. choke, and the well-head pressure was 2,000 psi. The well was drilled to the northwest to 21,838 ft and bottomed in Section 29-35n-70w with a true vertical depth of 11,377 ft. The horizontal Turner interval was fracture stimulated in an undisclosed number of stages.

Western U.S. Rig Count

Jan. 11, 2019-May 31, 2019



Data compiled from Baker Hughes

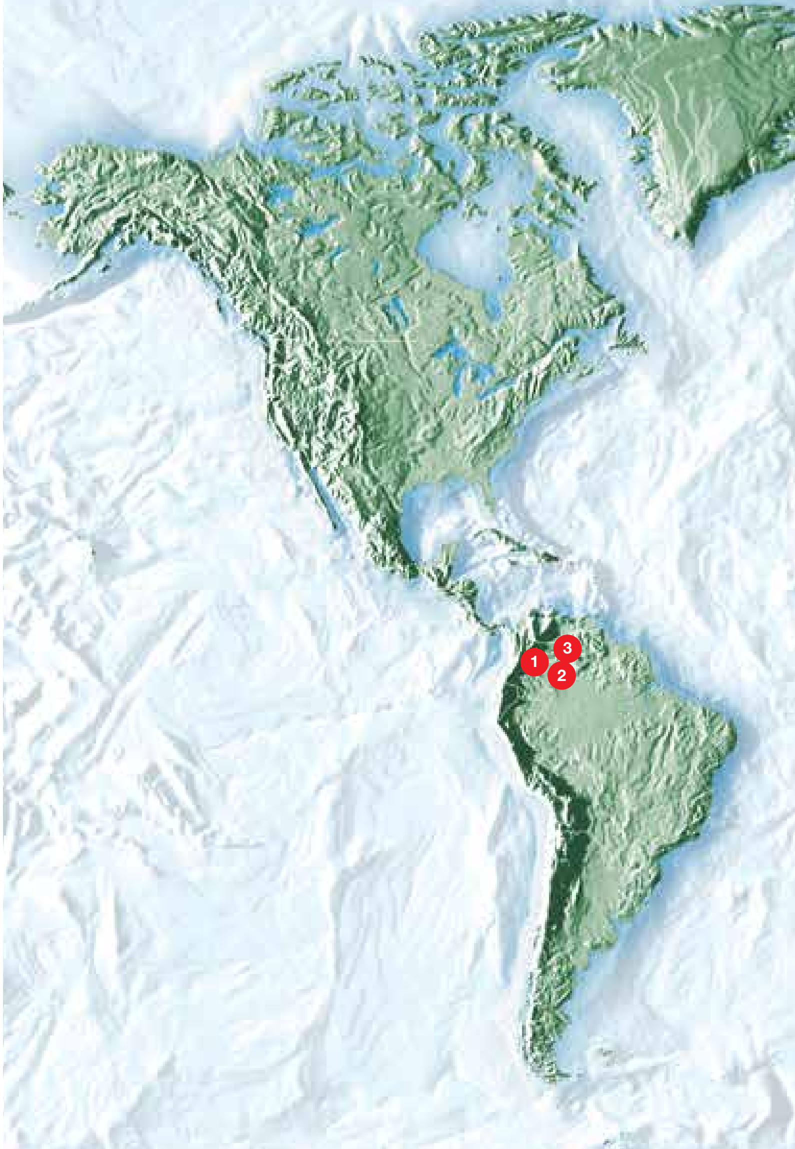


9 A Three Forks discovery initially flowed 8.887 Mbbl of 41-degree-gravity oil, 10.628 MMcf of gas and 5.541 Mbbl of water per day. ***Marathon Oil Corp.***'s #13-23TFH Lamarr-USA is on the Houston-based company's West Myrmidon McKenzie County, N.D. The completion is in Section 22-151n-94w, and production is from a lateral in Upper Three Forks extending from 11,164 ft eastward to 23,740 ft at a bottomhole location in Section 19-151n-93w that was drilled under the Missouri River. The true vertical depth is 10,787 ft. It was tested on a 1-in. choke following 57-stage fracture stimulation between 11,266 and 23,603 ft.

10 IHS Markit announced that the Alaska Division of Oil & Gas has approved Refigio, Texas-based ***Hilcorp Energy Co.***'s unit plan of operations to carry out its 2019 Granite Point drilling program in the Granite Point Unit (GPU). The Granite Point Platform (GPP) is in Cook Inlet marine waters. Hilcorp proposes to drill up to four sidetrack wells from existing wellbores at the GPP using the Spartan 151 or jackup rig positioned over the GPP. The proposed wells in sections 13 and 24-10n-12w, Seward Meridian, will be drilled to bottomhole depths between 7,000 and 16,000 ft. Rig mobilization is expected to begin by mid-June, and drilling and rig demobilization will conclude by mid-November.

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.

INTERNATIONAL HIGHLIGHTS



The Norwegian Petroleum Directorate estimates that more than half of the oil and gas that has not yet been discovered is in the Barents Sea. The rest is distributed between the Norwegian Sea and the North Sea. The opportunities are greatest in the Barents Sea, where vast areas have not yet been explored.

Two fields are currently producing in the Barents Sea, Goliat and Snøhvit. Goliat was proven in 2000, and production started 16 years later. The oil from Goliat is transported from the field by boat. Over the course of the years from 1980 to April 2019, 59 discoveries have been made in the Barents Sea.

The next field development in the Barents Sea is Johan Castberg and, as of today, the total undiscovered resources on the Norwegian Shelf are estimated at 4 billion standard cubic meters of oil equivalent. More than half of these resources are located in the Barents Sea.

Challenges that operators face include low air and sea temperatures, icing, long distances and limited infrastructure. However, the Gulf Stream ensures that the Norwegian part of the Barents Sea has little or no sea ice, and sea ice only occurs during parts of the year.

—Larry Prado

1 *Colombia*

Results from a Lower Magdalena Basin exploratory were announced by Calgary-based operator ***Canacol Energy***. The #1-Acordeon is in the VIM 5 block in Colombia. It was drilled to 8,500 ft and encountered more than 420 net ft of gross pay between 7,646 and 8,066 ft with an average porosity of 18% in Cienaga de Oro Sandstone. The well flowed 33 MMcf of gas daily during testing on a 60/64-in. choke with a flowing tubing head pressure of 1,476 psi. An appraisal well, #1-Ocarina, was spud from the same platform and will test the same Cienaga de Oro reservoir in a downhole location approximately 3,200 ft to the southeast and at a structural elevation approximately 400 ft up-dip of where the CDO reservoir was encountered at #1-Acordeon.

2 *Colombia*

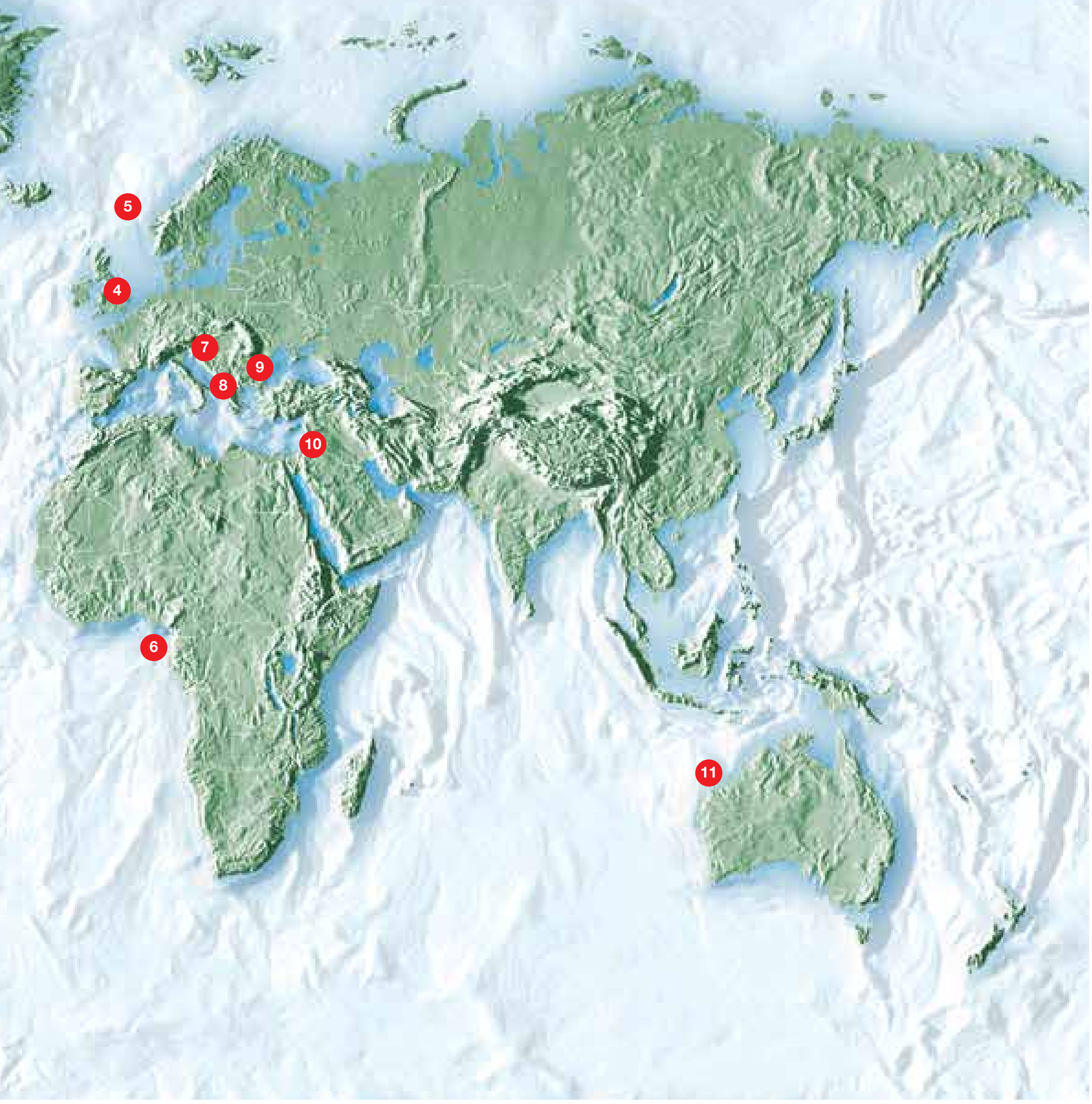
An oil discovery was announced by ***Arrow Exploration Corp.*** in the Llanos Basin. The #1-Rio Cravo Este is in the Tapir Block and was drilled to 10,000 ft and hit 103 ft of net oil pay (true vertical depth). It was perforated and tested over a 12-ft interval depth in C7 A Sand. The well averaged 613 bbl of 28-degree-gravity oil per day with a water cut of 46.5%. A peak oil rate of 1.172 Mbbl per day was recorded, and the well did not produce any gas during the test. Additional pressure testing is planned by the Calgary-based company.

3 *Colombia*

Parex Resources Inc. of Calgary announced the discovery of hydrocarbons in two formations at exploratory #1-Andina Norte in Colombia's Llanos Basin. The Capachos Block well has produced 3.406 Mbbl of light crude and 5.8 MMcf of gas per day. The discovery was drilled to 18,852 ft and producing from oil-bearing reservoirs in Guadalupe and Une. During testing, the venture produced an average of 2.892 Mbbl of oil and 4.6 MMcf of gas during a 12-hour period from Guadalupe with a wellhead pressure of 1,420 psi. From Une, the well flowed an average of 621 bbl of oil, 446 bbl of water and 1.5 MMcf of gas per day. Parex is the operator of the block and #1-Andina Norte with 50% interest in partnership, with ***Ecopetrol*** holding the other 50%.

4 *U.K.*

Operator ***Rathlin Energy*** announced preliminary results from appraisal well #2-A West Newton in PEDL 183. It was drilled to 2,061 m, and 28 m of core has been extracted from the primary target, Kirkham Abbey, with a net 65-m hydrocarbon-saturated sample including a significant liquids component, which correlates with results from discovery well #1A-West Newton. The well also encountered hydrocarbon shows within the deeper secondary target, Cadeby, which have proven to be consistent with #1A-West Newton. Prior to the drilling #2A-West Newton, a best estimate contingent resource indicated 189 Bcf of gas equivalent. An extended well test is planned to establish flow rates. Partner ***Union Jack*** holds a 16.665% interest in this license containing #1A-West Newton discovery well and #2-A West Newton.



Mountain High Maps® Copyright ©1993 Digital Wisdom, Inc.

5 *Norway*

Equinor announced an oil and gas discovery at an exploration well in Snadd Outer Outer/Black Vulture in offshore Norway production license 159B. According to the company, the well had two different reservoir targets—an upper drilling target containing 2-12 MMboe of gas and a lower target with an estimated volume of 1-48 MMboe recoverable. The #6507/3-13 Snadd Outer Outer/Black Vulture was drilled to 2,800 m to the first target, Snadd Outer Outer, where gas was proven. The well was then drilled to 3,200 m and hit oil at the second target, Black Vulture and well volume totals 3-60 MMboe before further delineation tests. Stavanger-based Equinor is the operator of PL159B, Block 6507/3, and the Snadd Outer Outer/Black Vulture well with 53% interest in partnership with ***Faroe Petroleum***, 32%, and ***Ineos***, 15%.

6 *Angola*

Another discovery was announced by Rome-based ***Eni*** in offshore Angola Block 15/06. An exploratory, #1-NFW Agidigbo, was drilled to 3,800 m and hit a single hydrocarbon column composed with a gas cap of about 60 m and 100 m of light oil. The hydrocarbons are contained in Lower Miocene Sandstones with good petrophysical properties. Based on current testing, there is an estimated 300-400 MMbbl of oil in place. The five commercial discoveries on the block are estimated to contain up to 1.8 Bbbl of light oil in place with possible upside. The Block 15/06 joint venture partners are operator Eni with 36.8421%, ***Sonangol*** with 36.8421% and ***SSI Fifteen Ltd.*** with 26.3158%.

7 *Hungary*

Aspect Energy announced an oil field discovery in Hungary. The Denver-based company and its partners ***Horizon Energy*** and ***TDE Services*** estimate that the new field will be able to produce 11 Mbbl to 14.2 Mbbl of oil per day. The company intends to drill 30 production wells in the new field and to build transport pipelines. Hungarian Horizon Energy will be the operator of the new field in partnership with TDE.

8 *Albania*

Results from an onshore Albania appraisal well were announced by Houston-based ***Shell Oil Co.*** The venture, #4-Shpirag, is in Block 4, and it was reported flowing light oil. A production test is planned, and commercially recoverable volumes of oil are still to be determined through further appraisal activity. The well was drilled to 6,101 m, and another appraisal well is planned at #3-Shpirag. A previous test at #2-Shpirag hit a light oil column of 800 m. According to the company, it is producing from a fractured carbonate reservoir in an equivalent geological setting to the Val D'Agri and Tempa Rossa fields in Italy. Shell is the operator of Albania's blocks 2-3 and 4 with 100% interest.

9 *Romania*

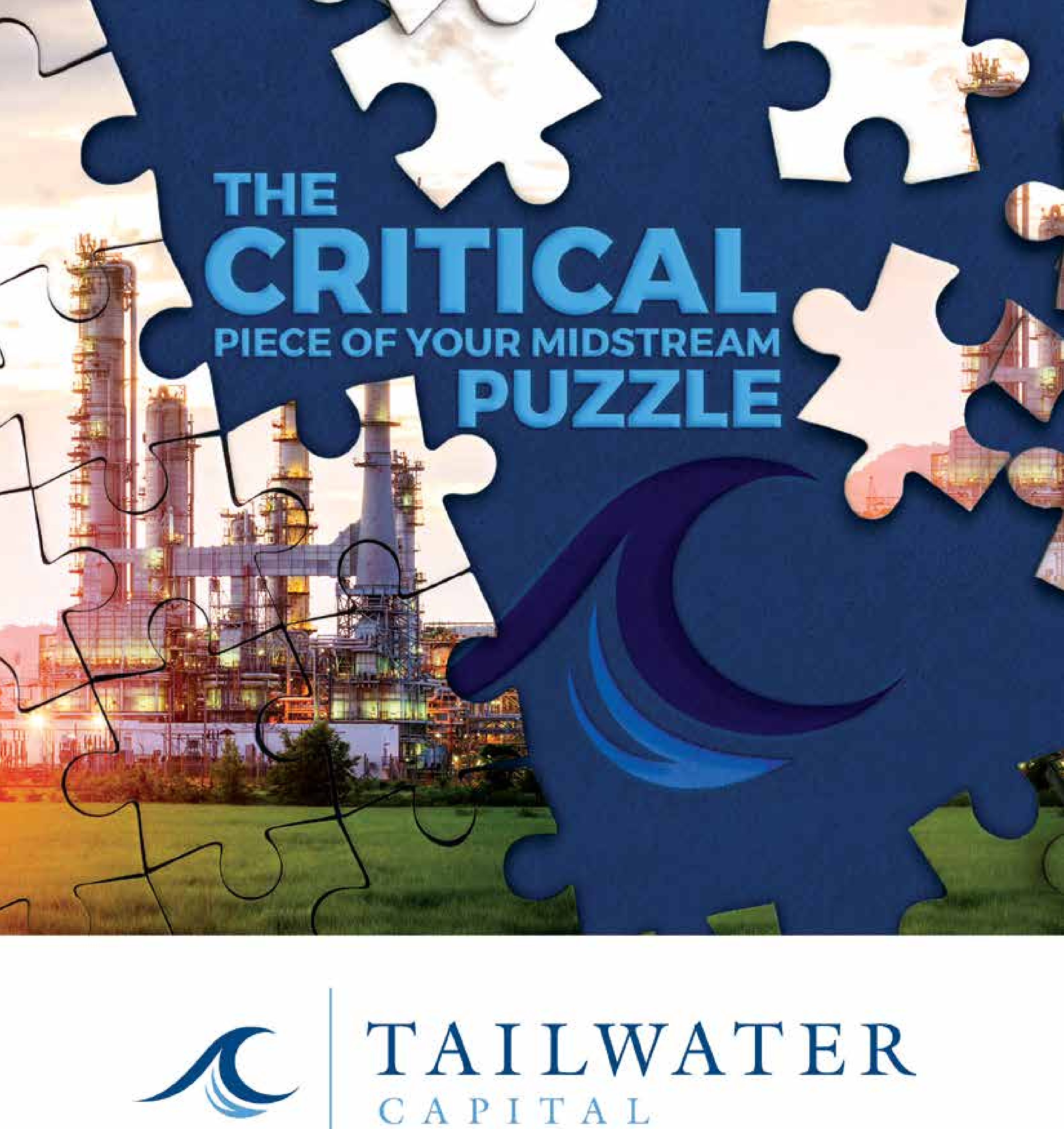
An exploration well is planned in the Bainet West Prospect in the EIV-1 Suceava Concession in Romania. ***Raffles Energy SRL*** has analyzed 2-D seismic data for the Bainet West Prospect where a previous exploratory, #1-Bainet, was drilled to 600 m and hit a 9-m reservoir with 8 m of net gas pay in a Sarmatian Sandstone reservoir. The two intervals tested within the main gas pay zone were perforated at 513.3-514.8 m and 516.3-517.3 m. The well produced 33 Mcf of gas per day during testing on an 8-mm choke. Bucharest-based Raffles Energy is the operator of the concession and #1-Bainet West well with 50% interest in partnership with ***Prospex Oil & Gas*** holding the remaining 50%.

10 *Jordan*

Jordan National Petroleum Co. has reported a gas discovery at a new well in Risha Gas Field in Jordan. According to the country's energy minister, the results in early assessment indicate that the well produced about 7 MMcf of gas per day. The venture will increase the production capacity of the field to 16 MMcf of gas per day, a 5% increase in Jordan's daily output. Jordan National Petroleum is based in Amman.

11 *Australia*

Sydney-based ***Santos Ltd.*** announced results from appraisal well #2-Dorado in the Bedout Basin, offshore Western Australia. The well was drilled downdip approximately 2 km from #1-Dorado and hit 85 m of net reservoir in Caley. The oil-water contact was intersected at 4,003 m with 40 m of net oil pay encountered. An additional 11 m of pay was found in Upper Caley Sands—preliminary analysis indicates this upper zone is oil-bearing, and additional testing is planned. An additional 32 m of net pay was found in the underlying Baxter and Milne sandstones, and there was no fluid contact. Wireline pressure testing has confirmed that all the reservoirs are in pressure communication with the equivalent intervals in #1-Dorado. Hydrocarbon and fluid compositions are similar to the light oils and gases that were sampled in #1-Dorado. The appraisal well was drilled to 4,573 m and is in 91 m of water in permit area WA-437-P. The well will be plugged and abandoned, and the rig will be moved to drill exploratory #1-Roc South. Partners in the venture are operator Santos and ***Carnarvon Petroleum***.



TAILWATER
CAPITAL

Growth Capital for the Energy Industry

JASON DOWNIE
Managing Partner

EDWARD HERRING
Managing Partner

DAVID CECERE
Partner

214.269.1183 | Email: info@tailwatercapital.com | **www.tailwatercapital.com**

CREDIT TAKES CENTER STAGE

While a host of factors have paralyzed energy equity markets—a slowing world economy, fears of trade friction and antipathy for energy equities in general—attention has shifted to the credit markets serving energy. A rally in the U.S. Treasury market sent the U.S. 10-year yield to sub-2% in late-June, and issuers took advantage of both low rates and an opportunity to extend maturities.

Apache Corp. priced $1 billion of senior notes in tranches of $600 million and $400 million. The former, due 2030, carried a coupon of 4.25% and were priced at a discount to yield 4.271%. The latter, which mature as far out as 2049, carry a coupon of 5.35% and are priced to yield 5.391%. Apache expects to use the proceeds to fund tender offers for various outstanding note issues.

In private credit, GSO Capital Partners, Blackstone's credit platform, announced the final closing of the GSO Energy Select Opportunities Fund II at $4.5 billion. Among the largest dedicated energy-focused credit funds in the market, GSO said it sourced commitments globally, including U.S. state, corporate and international pension funds, financial institutions, endowments, foundations and family offices.

"A fund of this size uniquely positions GSO to provide much-needed capital to the energy industry," said Rob Horn, senior managing director and co-head of GSO Energy.

A new partnership has been formed by TPG Sixth Street Partners and Glendale Energy Ventures with $500 million in capital commitments. The partnership will "use its flexible capital mandate to directly invest in the development and acquisition of upstream oil and gas assets," it said, adding it already had completed $55 million in acquisitions of nonop interests in the Stack play of Oklahoma.

Working with TPG Sixth Street's Houston-based energy team, Glendale will "provide capital solutions to operators by structuring investments in nonoperated and operated-by-others (OBO) acquisitions," the partnership said. Glendale focuses on acquisitions and investments in de-risked onshore resource plays and is led by co-founders Brent Grundberg and Vignesh Proddaturi.

"We believe there is more demand than ever for partnership capital to allow operators to achieve their full-scale development plans," said Grundberg.

—Chris Sheehan, CFA

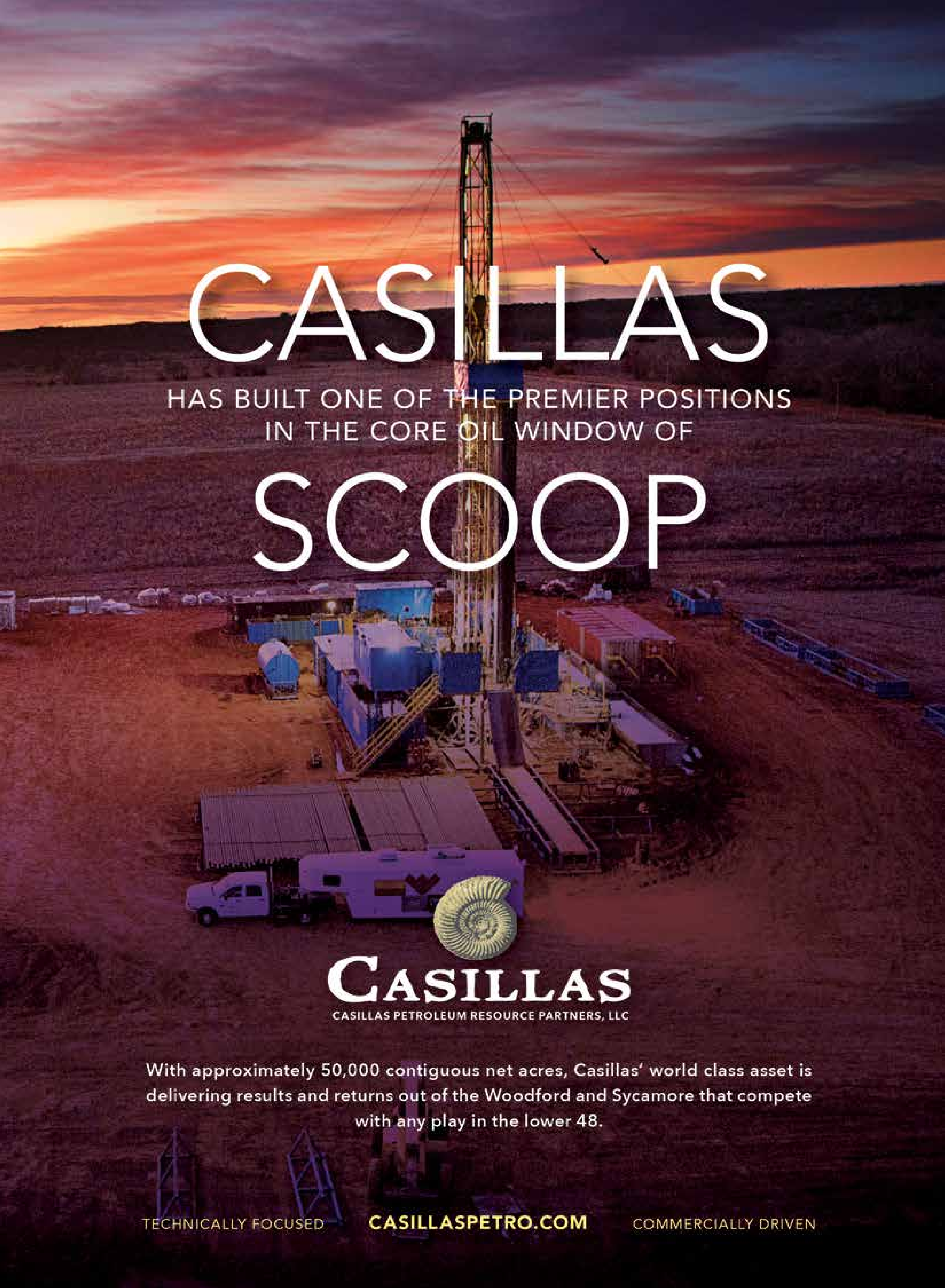
DEBT

Company	Exchange/ Symbol	Headquarters	Amount	Comments
GSO Capital Partners	N/A	New York	US$4.5 billion	Blackstone's credit platform announced the final closing of the GSO Energy Select Opportunities Fund II strategy at $4.5 billion. The fund will leverage GSO's scale, flexible capital base, strong brand and structuring expertise to capitalize on a favorable investing environment for its energy strategy, the company said. GSO has had a strong presence in the energy markets since 2005, committing approximately $13 billion in privately originated transactions.
Apache Corp.	NYSE: APA	Houston	US$1 billion	Apache is offering $600 million aggregate principal amount of 4.25% notes due 2030 and $400 million aggregate principal amount of 5.35% notes due 2049. Interest on the 2030 notes will be paid semi-annually in arrears on Jan. 15 and July 15 of each year, beginning on Jan. 15, 2020. Interest on the 2049 notes will be paid semi-annually in arrears on Jan. 1 and July 1 of each year, beginning on Jan. 1, 2020. The 2030 notes will mature on Jan. 15, 2030, and the 2049 notes will mature on July 1, 2049. It may redeem some or all of each series of the notes at any time or from time to time at the redemption prices calculated.
Glendale Energy Ventures; TPG Sixth Street Partners	N/A	Houston; San Francisco	US$500 million	TPG Sixth Street Partners and Glendale Energy Ventures LLC announced a new oil and gas investment partnership with an initial $500 million in capital commitments. The new partnership will use its flexible capital mandate to directly invest in the development and acquisition of upstream oil and gas assets across the U.S. Glendale will work closely with TPG Sixth Street's Houston-based energy team to provide capital solutions to operators by structuring investments in nonoperated interests and operated-by-others acquisitions. The partnership has already deployed funds with the completion of $55 million in acquisitions of nonoperated interests in drilling pads in Oklahoma's Stack play.

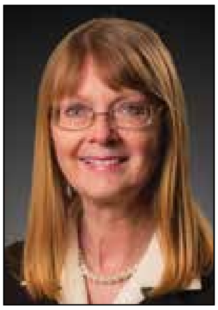
These deals and details on thousands more are available in real time in a searchable, sortable database at HartEnergy.com.

COMPANIES IN THIS ISSUE

This index refers to the pages of the story or news item in which the company is first mentioned. Advertisers are in boldface.


CASILLAS
HAS BUILT ONE OF THE PREMIER POSITIONS
IN THE CORE OIL WINDOW OF
SCOOP
CASILLAS
CASILLAS PETROLEUM RESOURCE PARTNERS, LLC
With approximately 50,000 contiguous net acres, Casillas' world class asset is delivering results and returns out of the Woodford and Sycamore that compete with any play in the lower 48.
TECHNICALLY FOCUSED
CASILLASPETRO.COM
COMMERCIALLY DRIVEN

NEEDED: LAZY CAPEX, SOME M&A



LESLIE HAINES,
EXECUTIVE EDITOR-AT-LARGE

The conventional wisdom that has guided investors for years is that old dictum: "Sell in May and go away," the implication being that equities usually trend sideways all summer and start to pick up in earnest in the fall, rising through the end of the year. The problem for us is, oil and gas investors went away way too early.

A lazy second half for drilling might get them to come back. Maybe some good M&A would help too.

It's said that no E&P company should be public unless it has at least $10 billion in market cap. People want scale. But whatever a company's size, the spreading desire—no, demand—is that producers slow down their spending pace and, by extension, cap oil and gas production growth. There is too much oil and too much gas. Not enough free cash flow.

While writing about Cabot Oil & Gas Corp., a Seaport Global Securities report said, "Our expectation is for management to address the giant elephant in the E&P room right now: the industry needs to slow down even more. Over the last two quarters, management has implicitly suggested that moderating its production growth in an effort to maximize ROCE [return on capital employed] and free cash flow was the direction the company was likely headed."

Analyst Paul Sankey of Mizuho Securities USA echoed the theme: "If we can foster capital discipline, we can collectively reduce U.S. oil supply growth that does not generate returns to justify the level of spending and growth. We have lowered our 2H19 oil price forecast by $5/bbl, still above strip at $70 Brent for the 3Q, but have also taken about $8/bbl off of next year and are now below strip for 2020. That is not positive for the sector.

"We do think that the best E&Ps can outperform this outlook by capital discipline and cash return growth, through higher multiples, but two-thirds of the oil group and oil services have a very problematic outlook here.

"To repeat, two-thirds of the group—those with higher breakevens and worse balance sheets—have an outright negative outlook into 2020, and until U.S. capital discipline reduces U.S. oil supply growth, there is too much oil. We believe … that Saudi does not want to cut more. On our balances, it may need to."

Based on conversations just before the second-quarter earnings deluge, Gabriele Sorbara, senior equity analyst at Williams Capital Group, said he thinks "the buy-side models are ahead of the sell-side in considering more modest growth going forward and utilizing strip pricing. Thus, on a net basis, margins and free-cash-flow generation/yield should be more attractive." Sadly, his universe of E&P companies is down 10% so far this year on average, significantly underperforming the 27.8% gain in the West Texas Intermediate oil price.

So yes, we all agree, keep spending within cash flow and cut capex if you can. But what else is an E&P company supposed to do? The pressure on publics is extreme in all commodity environments, good or bad, but especially now that investor sentiment has soured.

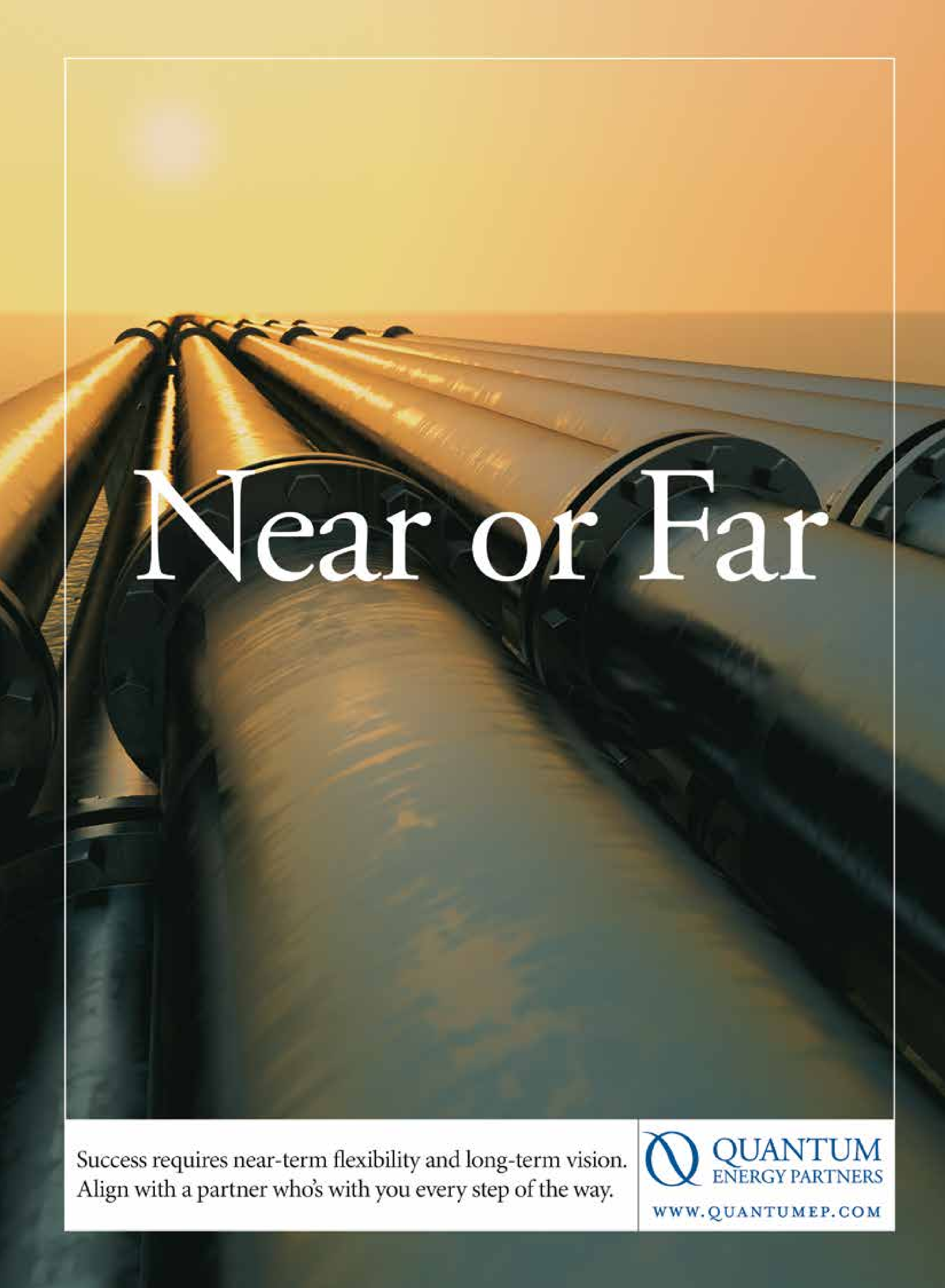
According to Guggenheim E&P analyst Subash Chandra, "Capital efficiency, rather than resource maximization or diversification, has become the primary M&A rationale in our view. Buyers have tended to be companies with supply chain and logistics competencies. These buyers can accrete value by improving the cash-flow profile of a resource without having to assume any EUR or inventory upside and … can manage large pads and minimize cycle times because of logistical advantages."

Cowen and Co. analysts revealed the conundrum recently, noting M&A activity within the E&P sector is trending about 82% below the five-year deal count average. "While investors clamor for consolidation, including activist campaigns, the multiple compression toward 5 times forward EBITDAX vs. 8 times just two years ago, and limited disparity in multiples, puts many management teams in a strategic bind, unless they merge with zero premiums."

Zero premiums? We know how that usually plays out.

Now, we have Callon Petroleum Co. and Carrizo Oil & Gas Inc. (which was under activist investor pressure) merging for scale. We have Comstock Resources Inc. snapping up the much larger Covey Park Energy LLC for the same. EQT Corp., already at huge scale, is under bold new management after a nasty fight.

A year from now, we'll know if these deals were worth all the angst. We'll know if consolidation, scale and slower growth are truly what it takes to attain profitability and free cash flow, grab investor attention and management kudos.


Near or Far
Success requires near-term flexibility and long-term vision.
Align with a partner who's with you every step of the way.
QUANTUM
ENERGY PARTNERS
WWW.QUANTUMEP.COM


America's Oil Champion:
Our formula for success.
Large, oil-weighted inventory
+
Lowest cost, most efficient operator
=
Significant Profit & Free Cash Flow
Oil is essential to the American economy, our security and our future. Fortunately, America is blessed with abundant supply. That's why, at Continental Resources, we have created an enterprise built to last. A company inspired and driven by the vision of its founder. We believe our large, oil-weighted domestic inventory, combined with our unique ability to be more efficient and more focused on producing low cost energy, is the winning formula for long-term and sustainable success. For us. For the industry. And for America. To learn more, visit clr.com.
Continental
RESOURCES