# Oil and Gas Investor

MAY 2020


The U.S. industry seeks a path forward amid calamitous market forces.

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# Oil and Gas Investor

MAY 2020/VOLUME 40/NUMBER 5




SPECIAL REPORT: THE PATH FORWARD

Oil and Gas Investor

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## COLUMNS



## DEPARTMENTS



ABOUT THE COVER: In March, supply and demand dynamics for global oil were rocked like never before, with the coronavirus pandemic removing potentially tens of millions of barrels of usage per day from the markets and an untimely market share war between Saudi Arabia and Russia pushing millions of gallons of unneeded supply into the mix. With prices plummeting, U.S. independents look for answers. Illustration by Robert D. Avila.




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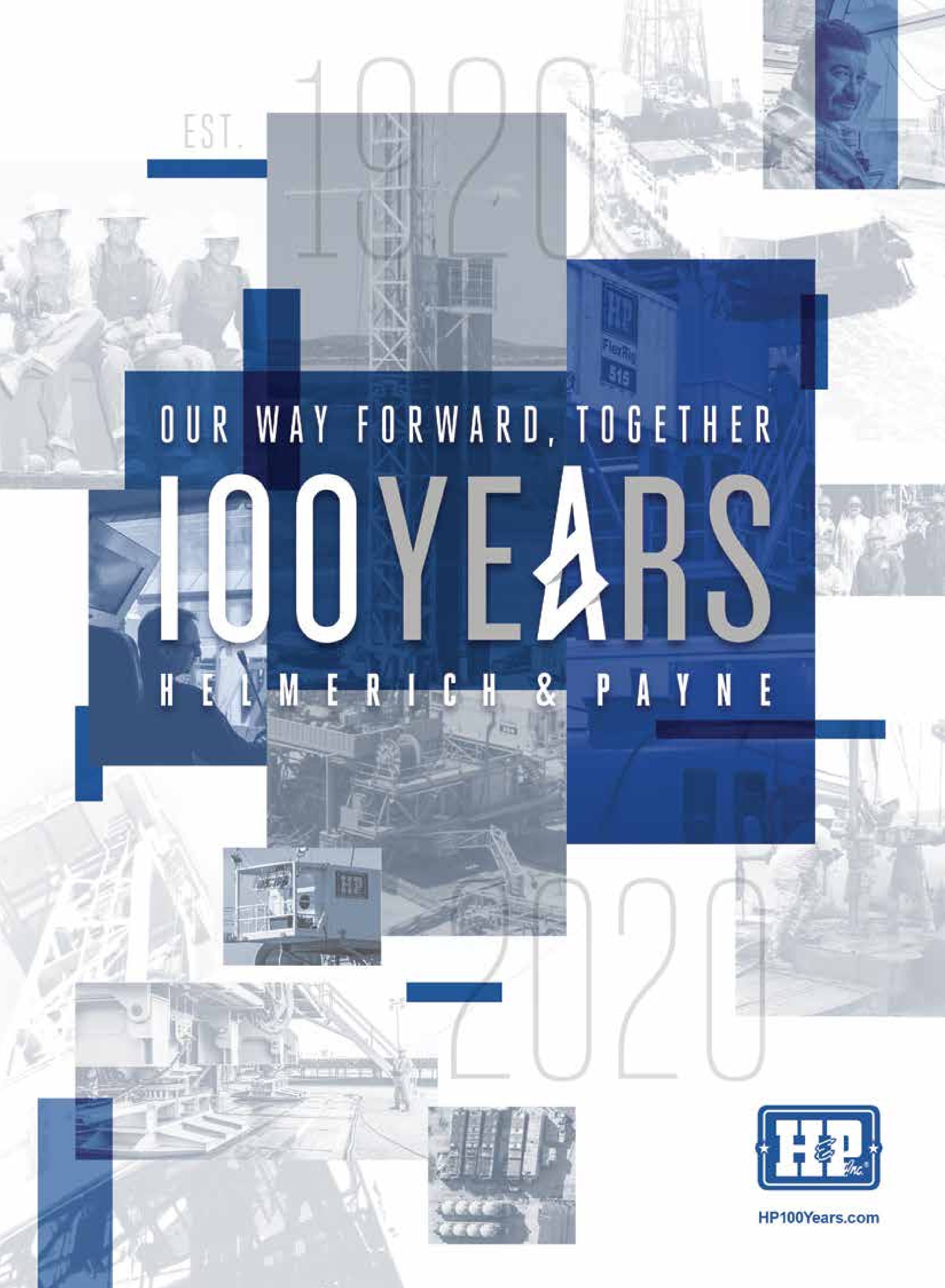
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## LATEST CONTENT

### Oil Price Plunge, Coronavirus Spur Tax Relief For Wyoming Producers
The Wyoming governor recently signed a bill to help oil and gas producers reduce severance and conservation taxes.

### Exxon Mobil Chops Spending By 30%
Exxon Mobil Corp. on April 7 throttled back a multiyear investment in shale, LNG and deepwater oil production and will cut planned capital spending by 30% this year as the coronavirus pandemic saps energy demand and oil prices.

### Occidental Petroleum Names New CFO In Management Shakeup
Occidental Petroleum Corp. did not provide a reason for the leadership change, but the CFO transition marks the second major management change at the oil and gas company recently.

### Oil, Gas Companies Stepping Up During Coronavirus Pandemic
The following is a sampling of companies in the oil and gas industry stepping up during the COVID-19 pandemic to help make a difference, including BP Plc, Chevron Corp., Petrobras and more.

### Dallas-based Tailwater Capital Closes Largest Fund To Date
Commenting on the current state of the oil market, Jason Downie, founding partner of Tailwater Capital, said he expects to see 'some of the most compelling buying opportunities' in many years.

### Where Will the Excess Glut Of U.S. Oil Go?
Excess supply has sparked a fresh dilemma among U.S. drillers, which are being asked to cut oil production as storage space fills up.

## ONLINE EXCLUSIVES

### Oil Trade Groups Release New Guidelines On ESG Reporting

Guidance provides framework for detailing sustainability efforts as environmental, social and governance (ESG) remains a key priority for many upstream oil and gas companies.

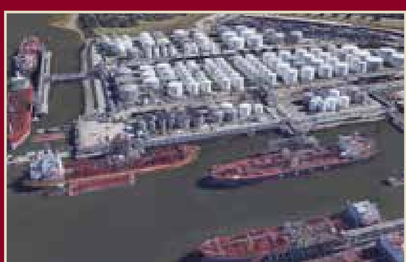


### Oil Industry Experts: Pandemic Impacts Not Just Dollars—Change, Too

Culture shifts as result of at-home workforce experience, staffing cuts and ESG priorities.

### As Shale Struggles, Crude Tankers Ply Oceans Of Cash

Even with very high day rates, the oil market contango means that floating storage makes economic sense.



## Videos

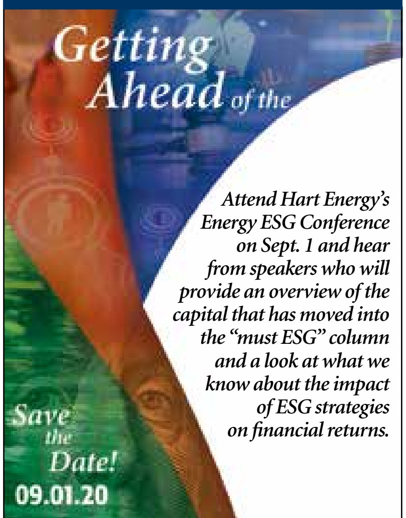

### Women in Energy: Brenda Schroer
Hear from Brenda Schroer, senior vice president, CFO and treasurer of Concho Resources Inc., and a featured 25 Influential Women in Energy honoree.

**www.HartEnergy.com/videos**

## What's Trending

1. Video: Tom Petrie's Take On OPEC+, Oil Prices, Production Cuts
2. Icahn vs. Hollub: Sound Decision-makers Don't Bet On Luck
3. Ring Energy Sells Itself Out Of Delaware Basin
4. May Crude Oil Futures Plunge Into Negative
5. Yuma Energy Files For Bankruptcy With Plans To Liquidate

## CONFERENCES

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# **2020** Hart Energy Events:

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BAKKEN AND ROCKIES
**Feb. 18-19**
**Denver, CO**
Colorado Convention Center
**20 Years in the Bakken**

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

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

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

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

**CO-LOCATED**
EXECUTIVE OIL CONFERENCE & EXHIBITION
CONFERENCE & EXHIBITION MIDSTREAM TEXAS
**Nov. 3-4**
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# WILL IT MATTER?

STEVE TOON,
EDITOR-IN-CHIEF

When last we spoke on this page, Saudi Arabia and Russia were launching their market share salvos to glut the market with oil to spite the other. This as the global economy listed sharply due to coronavirus fears and taking some estimated 20 million to 25 million barrels per day (MMbbl/d) out of demand. Now they're trying to put that supply genie back in the bottle. But will it matter?

Unfortunately, scant little. At least in the near term.

Our cover story in this issue analyzes the first wave of the COVID-19 induced demand destruction and OPEC+ instigated supply surge, but that is just the first chapter of this epic drama that will take months and likely years to unfold entirely. Realistically, the world needs to recover from the coronavirus before the oil markets are going to return to any kind of a semblance of yesteryear's prices led by renewed demand. And if the bug takes hold again for a round two, timing is anyone's bet.

The historic agreement between OPEC, Russia and a supermajority of other G20 nations in early April to remove some 10 MMbbl/d from global supply will serve to "flatten the curve," so to speak, to slow the flow before global storage options breach the brim. It was the breathtaking, unprecedented drop in demand as the world stayed home to stay safe that quickly turned the attitudes of spatting oil-producing nations from fight to flight, according to IHS Markit vice chairman Daniel Yergin in a statement.

"What facilitated the deal was the realization on the part of the major producers that they were not, in any event, going to be able to find markets for their oil at high production levels.

"What this deal does is enable the global oil industry and the national economies and other industries that depend upon it to avoid a very deep crisis," he assured. "Without this deal, the global industry would have run out of storage for the flood of excess oil in a few weeks and prices would have crashed, which would have also really hit financial markets. This restrains the buildup of inventories, which will reduce the pressure on prices when normality returns—whenever that is."

That's not to say there won't be near-term pain. Yergin's colleague Roger Diwan noted, "On a global basis, these cuts remove the specter of an aggressive price war and lower the likelihood that global tank tops will be breached but does not solve the distress physical markets are likely to face in May and June."

Bernstein analyst Neil Beveridge projects a near-term oversupply of 13 MMbbl/d in second-quarter 2020, "which will test inventory limits and could push prices back to US$20/bbl or below," he said in an April 13 report. "Even with SPR [Strategic Petroleum Reserve] filling and Chinese stockpiling (combined 500 MMbbl), we still expect that OECD inventories could build by a further 500 MMbbl, which would take storage utilization to record levels."

In a report April 12, Citi's Ed Morse said he also feels sallow regarding bloated inventories and near-term prices.

"However large and credible the combined OPEC+ and G20 cuts, the main problem is timing; it's simply too late to prevent a super-large inventory build of over 1 billion barrels between mid-March and late May and to stop spot prices from falling into single digits," he said. "With these combined cuts unfolding only in May (affecting delivery in June and July), front-end contangos should widen again and prompt prices should fall, triggering further involuntary production cuts."

So it gets worse before it gets better. Citi's forecast for Brent to average in the second quarter? $17.

However, there is a light at the end of the pipe. Morse said the too-little-too-late April OPEC+G20 agreement, while ineffective near term, should "rapidly" help markets to rebalance going into the third quarter, "and with our expected demand rebound, should facilitate a rapid change from a massive inventory build to a massive inventory draw, supporting prices for the rest of the year."

Those prices: $35 Brent in the third quarter ($33 WTI) and $45 in the fourth quarter ($42 WTI).

But it doesn't stop there. "If OPEC+ fully complied with proposed cuts, through to 1Q21, this would likely tighten markets significantly, driving oil prices into the $60s and even $70s in 2021," Morse said. But that optimism is likely to be tempered if Russia and OPEC raise production as second-half 2020 inventories draw down and prices recover. With that caveat, Citi calls for an average of $56 Brent in 2021 and "seeing the $60s at times," with WTI averaging $52.

So will the deal matter? Bernstein's Beveridge said the OPEC+ commitment to cut production by 6 MMbbl/d for a full two years out shows "the era of supply side price management is not over. If demand returns to normal levels in 2021, this could lead to sharply higher prices if compliance holds."

Eventually it will matter.


# Can Management Deliver?

In an environment of economic uncertainty and lower oil & gas prices, the success of your loan or equity investment depends on one thing - the ability of management to navigate through treacherous waters. Unfortunately, reserve reports and stress tests seldom provide the insight and answers you need to answer this most fundamental question.

## Our Analysis Will

The Performance Analytics Group specializes in analyzing all aspects of oil & gas performance - from individual fields to entire companies. Using both lookbacks and performance analytics, we can answer this question with a very detailed, yet clear and insightful report.

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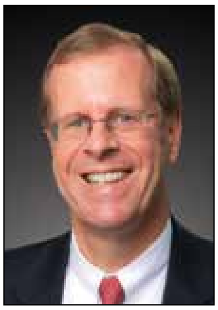
# ANXIETY OVER INVENTORY



CHRIS SHEEHAN, CFA
SENIOR FINANCIAL ANALYST

Rarely has there been as many moving parts in the global crude market. How much demand for oil has been really destroyed by the coronavirus pandemic? How much oil has Saudi Arabia really loaded onto crude carriers in hopes of buyers? If there were a resolution of the price war between Saudi Arabia and Russia, would it simply help sentiment—and offer little real solution?

There's no way crude and product inventories held in storage won't continue to rise, barring an overnight cure for the coronavirus. The fear is that storage—whether floating, coastal or landlocked—will be filled to tank tops in the near term. The hope is that by reaching a deal on global production, the date for maxing out storage will be pushed out to allow the world economy more time to get back on its feet.

There's no shortage of estimates of oil demand destruction or the timing of inventory builds to fill storage.

Analysts' estimates of peak demand losses for a time ran around 20 million barrels per day (MMbbl/d) but jumped as high as 26 MMbbl/d in a late March interview by Jeff Currie, global head of commodity research at Goldman Sachs. Ryan Sitton, the Texas Railroad Commissioner, carried an estimate of 18 MMbbl/d, but he raised it to 22 MMbbl/d to 24 MMbbl/d after U.S. jobless claims surged to 6.65 million, setting a new weekly record, in early April.

Although details are few, a proposal for a 10 MMbbl/d cut in oil production has been aired by President Donald Trump with Saudi Arabia Crown Prince Mohammed bin Salman, who in turn contacted Moscow. In addition, commissioner Sitton spoke earlier with Russian oil minister Alexander Novak, calling for "an unprecedented level of international cooperation" in the wake of the coronavirus impact on oil.

Pioneer Natural Resources Co. and Parsley Energy Inc. sent a letter to the Texas Railroad Commission in which they asked for "fairness" in production cuts as part of a plan to help stabilize oil prices worldwide.

Without such action, the independent sector, currently comprising 74 firms, might see 64 of their number fall by the wayside, leaving just 10 producers with strong balance sheets, according to Pioneer CEO Scott Sheffield. The remaining 64 would be weighed down with debt-to-EBITDA ratios of about 5x, levels that would make them financially unattractive as takeout targets, he said.

Sheffield argued that it was not in the strategic interests of the U.S. to return to the days when the U.S. depended on imports from the Middle East for 60% of its crude oil needs.

While commissioner Sitton said production cuts as high as 20 MMbbl/d to 25 MMbbl/d would be needed to balance the global market, lower cuts could also play a role. If 10 MMbbl/d of production cuts were able to "extend the life of intermittent storage" to, say, four months versus a previously expected two months, that would buy additional time for a recovery in demand by the global economy.

But according to an early April report by Citi, moves to cut production may be coming "too little, too late."

"What's required is a good 10 MMbbl/d immediate reduction in oil supply that is needed to prevent inventories globally from reaching tank tops," according to the report. The Citi analysis assumed a drop in global demand of nearly 16 MMbbl/d on average for the second quarter, peaking at 18.5 MMbbl/d in the eight weeks through the end of May, it said.

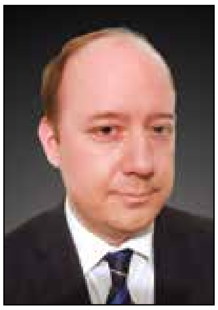
A critical question is how much of the cuts materialize on a voluntary basis, and how much they occur due to forced shut-ins as producers are simply unable to sell their production.

Among key producers, "Russia will be forced to cut output by at least 1 MMbbl/d due to a combination of lost condensate production from lost natural gas sales and export bottleneck," said Citi. "Saudi Arabia, in the midst of a period of allocating sales to clients, looks likely to be confronting a market that might want—at any price—no more than 6.2 MMbbl/d, 1 MMbbl/d lower than March levels."

In addition, "while the U.S. looks likely to be seeing a production drop of 1.0 MMbbl/d, it is unlikely to occur before the end of the third quarter," added Citi.

As lost demand deepens, much will depend on these market forces in determining an approximate time for reaching tank tops. Forecasts vary, but some say storage could be brimming as soon as the end of May.

# OIL SOAKED



DARREN BARBEE, SENIOR EDITOR

Welcome to Thunderdome, raggedy man. Turns out the oilpocalypse isn't a brutal fight to fuel up Mad Max's V8 Interceptor. In this twisted reality, there's plenty of crude. Just no toilet paper.

Adding to our new surreal existence, the COVID-19 pandemic has sidelined professional sports and forced the cancelation of the Scripps National Spelling Bee, leaving ESPN to air a spelling bee rerun. (Spoiler alert: a kid won.)

Other things in short supply: M&A, capital and common sense.

Transactions activity, which was already muted to begin the year, went into radio silence as the pandemic and the oil price war sent oil tumbling to its lowest level in 21 years. Enverus said in April that deals will likely restart in earnest after crude prices stabilize.

That future price is likely to be low. Asset packages on the market have already fallen to about $5 billion in expected value, Enverus said. And with debt maturity dates ticking closer, the industry's next great flood may be distressed assets.

Some have celebrated the OPEC+ deal to cut production by nearly 10 million barrels a day to end a resoundingly dumb price war. Chief combatants Saudi Arabia and Russia decided to play chicken without realizing they, too, were in the pot. Still, credit and all-around kudos to OPEC+, which prevailed in forcing itself to agree to its own terms of surrender.

Many people are noting that President Donald J. Trump said on Twitter that he was involved in the OPEC+ negotiations "to put it mildly."

With the pandemic still rampaging worldwide, however, the oil and gas industry remains at the mercy of the virus. As one Twitter user noted in April, demand destruction may be a solid name for a rock band, but by every other measure it's uniformly awful.

Paul Sankey, managing director at Mizuho Securities USA LLC, wrote in a commentary that the demand destruction "is so dramatic that supply management is moot for the month of April. … This overhang will take years to work off. The OPEC meeting gave you that answer, setting cuts through April 2022."

But Ann-Louise Hittle, vice president of Macro Oils at Wood Mackenzie, said that even if the OPEC+ deal is poorly implemented, it would still make a substantial difference in the market.

"We expect the second half of 2020 to show an implied stock draw, in contrast to the record-breaking oversupply of the first half of 2020," Hittle said. "That will support and lift prices significantly. The market will recognize this once the storage builds slow this quarter and start drawing down in the second half."

Will it be enough? Goldman Sachs analyst Damien Courvalin said in an April report he doubted so. Despite a rally in prices after the OPEC+ agreement, WTI could sink back to $20/bbl.

"Ultimately, the size of the demand shock is simply too large for a coordinated supply cut, setting the stage for a severe rebalancing," he said.

Roger Diwan, vice president of financial services at IHS Markit, likewise said the supply cuts resolve the price war (for now) and spare the U.S. from a "catastrophic price scenario" that would have wiped out many E&Ps.

"But this improved scenario will not change the fact that the production decline unfolding in the United States will be in the same range as the forced shut-ins or cuts agreed [to] by Russia and Saudi Arabia," Diwan said in a April 13 report.

Regional benchmarks and wellhead prices will continue to show further discounts and are likely to force shut-ins above and beyond the supply agreement, Diwan said. Declining production of 3.7 million barrels per day in the U.S., Canada and other producers reflect these "distressed economics."

In the here and now, energy companies' default risk is rising. As of April 13, the energy sector's default rate was 9.9% following the bankruptcy of Whiting Petroleum Corp., according to Fitch Ratings. The default rate could reach 17% by year-end.

E&Ps on Fitch's watch list collectively hold $18.3 billion in debt, and most have upcoming interest payments in the next 60 days. Chesapeake Energy Corp., California Resources Corp., Denbury Resources Inc., Unit Corp. and Bruin E&P Partners are among companies facing potential defaults.

Diwan, speaking about the differentials between global benchmarks and physical prices, said the disparity speaks to "dual reality of hope and despair."

This may well be a year of reckoning for the industry. But to paraphrase Winston Churchill, never flinch, never weary, never despair. Or as Max would put it, "survive."

# EVENTS CALENDAR

*The following events present investment and networking opportunities for industry executives and financiers. These dates are effective as of April 15, and many are changing due to the impact of the coronavirus.*

| EVENT | DATE | CITY | VENUE | CONTACT |
|---|---|---|---|---|
| **2020** | | | | |
| Offshore Technology Conference | Canceled: May 4-7 | Houston | NRG Park | 2020.otcnet.org |
| Louisiana Energy Conference | May 27-28 | New Orleans | online | louisianaenergyconference.com |
| CIPA Annual Meeting | June 4-7 | Santa Barbara, Calif. | TBA | cipa.org |
| AAPG Annual Conv. & Exhibition | June 7-10 | Houston | George R. Brown Conv. Center | ace.aapg.org/2020 |
| IPAA Annual Meeting | Canceled: June 29 | Newport Beach, Calif. | Pelican Hill | ipaa.org |
| Unconventional Resources Tech. Con. | July 20-22 | Austin, Texas | Austin Convention Center | urtec.org/2020 |
| Petroleum Alliance of Okla. Annual Meeting | July 27-30 | Las Colinas, Texas | Four Seasons | thepetroleumalliance.com |
| Western Energy Alliance Annual Meeting | July 29-31 | Tabernash, Colo. | Devil's Thumb Ranch Resort | westernenergyalliance.org |
| Summer NAPE | Aug. 12-13 | Houston | George R. Brown Conv. Center | napeexpo.com |
| EnerCom The Oil & Gas Conference | Aug. 16-19 | Denver | Westin Denver Downtown | theoilandgasconference.com |
| The Energy Summit | Aug. 17-19 | Denver | Sheraton Downtown Denver | coga.org |
| TIPRO Summer Conference | Aug. 19-20 | San Antonio | Hyatt Hill Country Resort | tipro.org |
| **Energy ESG Conference** | **Sept. 1** | **Houston** | **Omni Galleria** | **energyesgconference.com** |
| **DUG Permian/DUG Eagle Ford** | **Sept. 8-10** | **San Antonio** | **Henry B. Gonzalez Conv. Center** | **dugpermian.com** |
| **DUG Midcontinent** | **Sept. 22-24** | **Oklahoma City** | **Cox Convention Center** | **dugmidcontinent.com** |
| **DUG Haynesville** | **Oct. 13-14** | **Shreveport, La.** | **Shreveport Convention Center** | **dughaynesville.com** |
| **A&D Strategies and Opportunities** | **Oct. 27-28** | **Dallas** | **Fairmont Hotel** | **adstrategiesconference.com** |
| **Executive Oil Conference/ Midstream Texas** | **Nov. 3-4** | **Midland, Texas** | **Midland County Horseshoe Pavilion** | **executiveoilconference.com** |
| **DUG East/Marcellus-Utica Midstream** | **Dec. 1-3** | **Pittsburgh** | **David L. Lawrence Conv. Center** | **dugeast.com** |
| Privcap Energy Game Change | Dec. 1-2 | Houston | Houstonian Hotel | energygamechange.com |
| **Veterans In Energy Luncheon** | **Dec. 3** | **Houston** | **The Westin Memorial City** | **impactfulveteransinenergy.com** |
| **2021** | | | | |
| IPAA Private Capital Conference | Jan. 21 | Houston | JW Marriot Houston | ipaa.org |
| NAPE Summit | Feb. 8-12 | Houston | George R. Brown Conv. Center | napeexpo.com |
| CERAWeek by IHS Markit | Mar. 1-5 | Houston | Hilton Americas-Houston | ceraweek.com |
| **DUG Bakken and Rockies** | **Mar. 25-26** | **Denver** | **Colorado Convention Center** | **dugrockies.com** |
| **Monthly** | | | | |
| ADAM-Dallas/Fort Worth | First Thursday | Dallas | Dallas Petroleum Club | adamenergyforum.org |
| ADAM-Greater East Texas | First Wed., 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 Bill Walter at bwalter@hartenergy.com.*
*For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com/events.*


NORTHERN
CLOSES DEALS
$52 MILLION
SALT CREEK OIL+GAS
Salt Creek Oil & Gas
Closed June 2018
$152 MILLION
PIVOTAL PETROLEUM PARTNERS
Pivotal Petroleum
Closed Sept. 2018
$305 MILLION
W Energy Partners
Closed October 2018
$310 MILLION
FLYWHEEL ENERGY
Flywheel Bakken, LLC
Closed July 2019
Northern Oil & Gas has executed on over 150 transactions for $850+ million in value since 2018. We continue to seek high quality Williston Basin non-operated production, leasehold and minerals of any size and scale.
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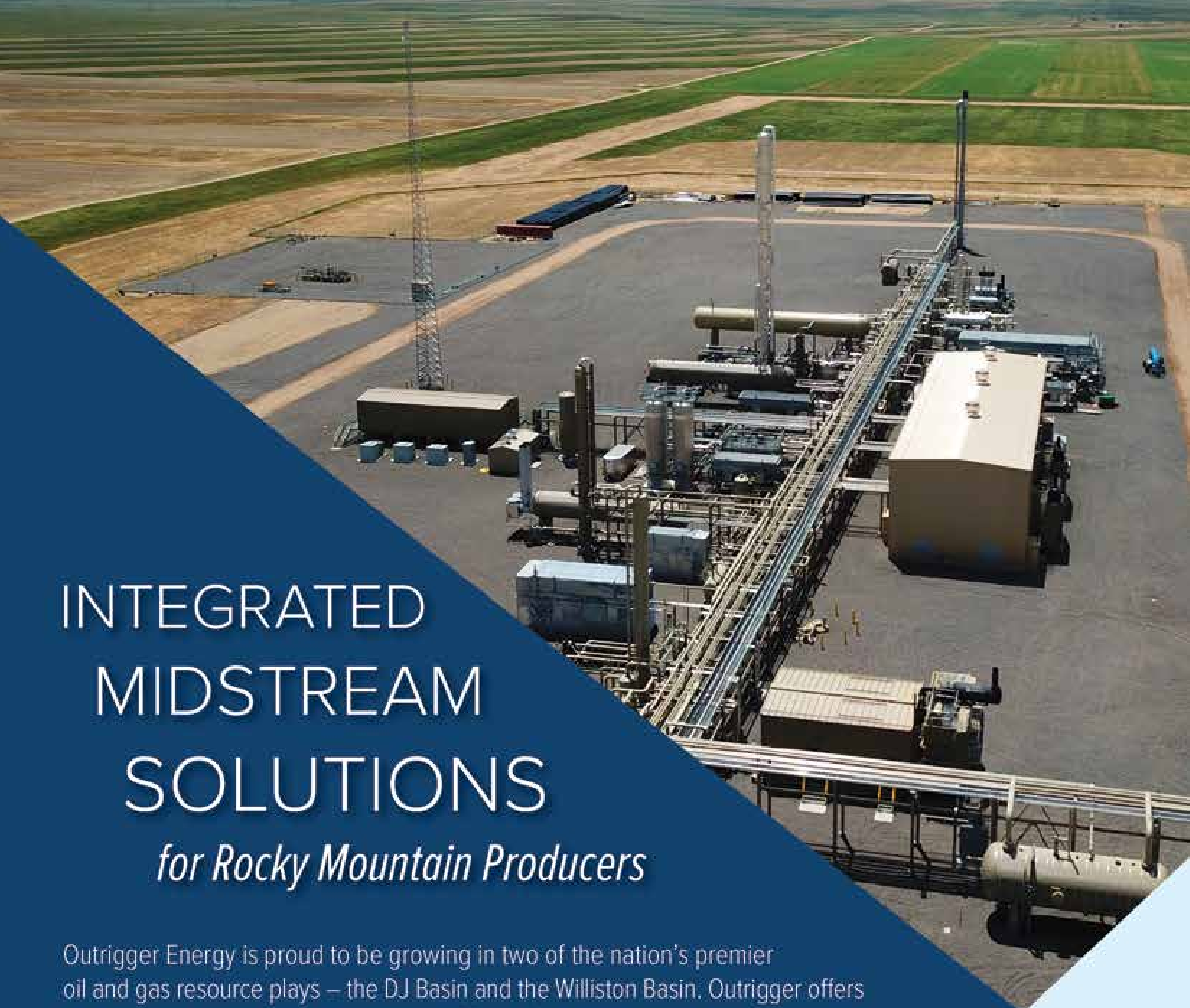


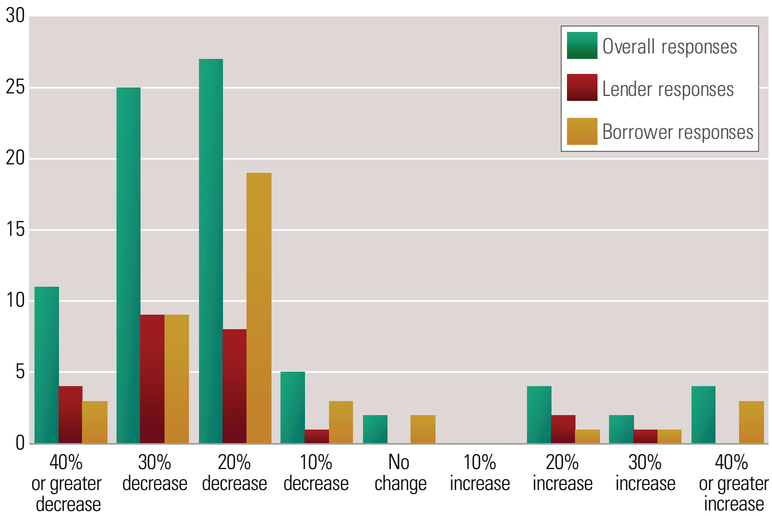
### Banks contend with deep impact on borrowing; price decks

People search for certainty in times of turmoil, but predictions, polls and surveys about oil price decks and borrowing bases fluctuated throughout February and March as experts grappled with rapidly changing conditions due to the COVID-19 pandemic and the oil price crash. Both factors have had a deep impact on what E&Ps and their lenders expect compared to what they thought last fall.

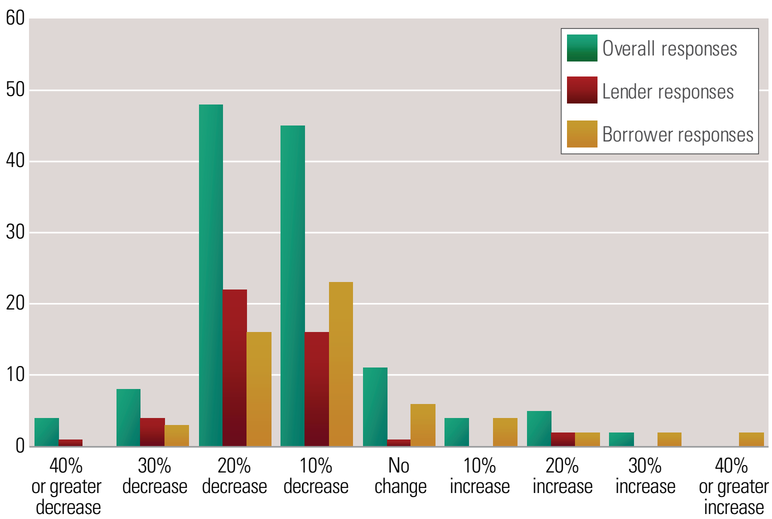
Haynes and Boone law firm in Houston had to conduct its 11th annual survey of borrowing base expectations more than once in response, first getting answers between Feb. 24 and March 7, then again between March 8 and March 25.

The 207 respondents included E&P executives who made up 46% of the answers, while financial providers such as lending banks and private-equity firms were 34% of the total.

**% Of Respondents That Expect Borrowing Bases To Change In Spring 2020 As Compared To Fall 2019***




*The responses above were provided from March 8-25 (after the commencement of the Russia–Saudi Arabia oil price war and acceleration of COVID-19 concerns in the U.S.).




*The responses above were provided from Feb. 24 to March 7 (prior to the commencement of the Russia–Saudi Arabia oil price war and acceleration of COVID-19 concerns in the U.S).

Source: Haynes and Boone

"A sizable majority of respondents expect borrowing bases to decrease by at least 20% in response to the recent freefall in commodity prices, and 45% of respondents expect even deeper cuts, of 30% or more," the firm said in early April.

"In contrast, the largest share of respondents, 40%, in the firm's fall 2019 survey said they expected borrowing bases to decrease by only 10% during the redetermination season."

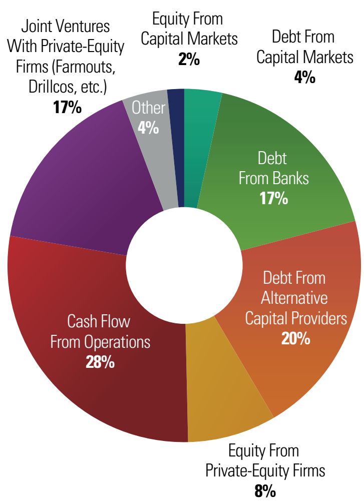
Producers entered this downturn relatively well-hedged, the firm said, "raising a question about whether producers will keep these hedges in place to preserve cash flow, or immediately monetize them to enhance liquidity."

Producers are expected to use cash flow from operations as their primary sources of capital in 2020, followed by debt from alternative capital providers as the next likeliest source of capital.

"When compared to the fall 2019 responses, survey participants who see private equity as a source of E&P capital have dropped by nearly 50%," said Kraig Grahmann, head of Haynes and Boone's energy finance practice group.

In a separate survey, the law firm asked leading banks about their oil and gas price decks to be used for borrowing bases or reserve-based loans. Haynes and Boone first asked participating banks in mid-February and reached out to them again in

**Where Producers Plan To Source Capital From In 2020***




*Respondents could select more than one option. We collected 578 responses. The figures in the chart above indicate the percent of total responses for each option.

Source: Haynes and Boone

March—after the announcement of price cuts by Saudi Arabia. This allowed the banks the opportunity to revise their price decks that had been submitted prior to the crash.

Some of the key takeaways included:

- The average base case for the oil price post-crash is 15.6% lower than the fall 2019 base case; and
- The average base case for gas post-crash is 12.3% lower than the fall 2019 base case.

"The firm initially sent out survey questions in mid-February but then reached out again to industry professionals in early March to ask them if they wanted to revise their predictions in light of the OPEC price war and growing concerns about the coronavirus. The latter responses were far more pessimistic," Grahmann said.

Twenty-one banks responded. The post-crash mean oil price they cited was $32/bbl for the base case. Their pre-crash mean for the base case was about $48. By 2023, they now expect the mean to be $42.

"The rapid deterioration in market conditions that started on March 8, 2020, had an immediate and deep impact on predictions about future borrowing capacity," Grahmann said. Buddy Clark, co-chair of the firm's energy practice, noted the significant drop in value of oil and gas collateral since commodity prices fell. He also noted that the turmoil might give bankers an excuse to postpone the borrowing base redetermination season, although he gave no time frame for the delay.

*—Leslie Haines*

## Hedge protection good for some, not for others

A market flooded with cheap oil coupled with the demand-destroying coronavirus is forcing unprecedented headwinds on E&P companies and exposing those not protected by hedges on produced volumes. Hedging offers a degree of protection in volatile oil and gas markets, providing a source of reliable liquidity assisting operators, some of which are adrift in truly uncharted waters.

According to a joint report by the recently-united Enverus and RS Energy Group teams, 2.5 million of aggregate 2020 oil-hedge volume among publicly traded North American E&Ps are set at an effective hedge price above $50 WTI. Most oil-weighted E&Ps have hedged between 25% and 90% of anticipated oil production for the year. Enverus estimates the value of these financial-derivative assets (in conjunction with gas and NGL hedges) exceeds 10% of respective enterprise values for the majority of E&Ps.

"Most North American E&Ps have some sort of policy to hedge at least some of their volumes for a certain period, but each policy is unique," said Andrew McConn, an analyst with Enverus. "Some refrain from hedging altogether, opting for complete exposure to market prices. There is an argument for doing that. But most wish to mitigate at least some of their exposure to the main risk-facing E&Ps—commodity prices. And those hedge programs are exactly for times like this—to insulate companies from big market shocks, which are always a possibility."

For example, U.S. independent Devon Energy Corp. has hedged about 80% of its estimated 2020 crude production at an average floor price of nearly $45 WTI. Smaller, Permian-focused Laredo Petroleum Inc. currently has 100% of its estimated 2020 oil production hedged with 7.2 MMbbl swapped at over $59 WTI and 2.4 MMbbl swapped at about $63 Brent.

Apache Corp., which had no hedges in place for 2020, has added near-term oil hedges to protect 2020 cash flows from further price deterioration. Those deals were made at less favorable terms, mid-$20 WTI for fixed swaps through September on over 110,000 bbl/d in addition to three-way collars over the balance of the year covering over 40,000 bbl/d. A similar hedging strategy for Brent crude was also consummated, covering lower volumes.

"If you hedged two months ago you're in a much better position than two weeks ago," McConn said. "I think it is fair to say that the vast majority of companies are going to be very reluctant to hedge at today's strip. But even with the strip reflecting $30 oil for the rest of the year, there is still downside risk. It can go lower."

However, the Enverus/RS Energy report also reveals hedged oil volumes decline by 85% after 2020. If oil prices fail to recover by year-end, 2021 could prove even more challenging for E&Ps than 2020.

"The oil market really needs to find the path to recovery by the end of the year because the whole sector is just more exposed to market prices going into next year," said McConn. "There are a lot of E&P businesses that fundamentally do not work at $30, so most companies will be very reluctant to hedge at such prices."

*—Blake Wright*

## Oil price plunge to crush E&Ps' free-cash-flow goals

The ability for E&P companies to generate free cash flow is expected to be severely hampered by the plunge in oil prices, according to a recent Rystad Energy report, which projects free cash flow will drop to zero if oil prices remain at $30/bbl.

"This is probably where we are heading in the coming months, which will be extremely difficult for E&P companies," Per Magnus Nysveen, Rystad Energy's senior partner and head of analysis, said during a webinar on March 18 discussing the findings of the report focused on the coronavirus' impact on oil markets.

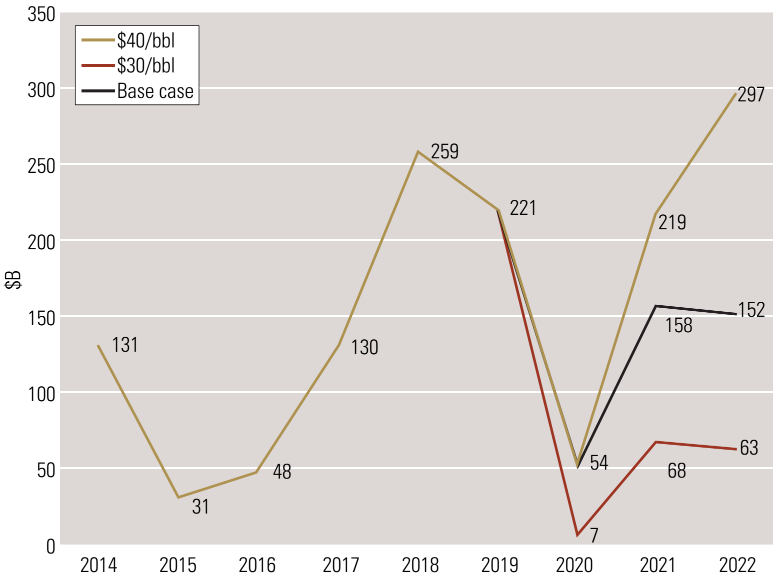
After a double whammy delivered by COVID-19 and a price war between Saudi Arabia and Russia, global oil prices have lost half their value in March. On March 18, WTI crude fell a staggering 24% to $20.37/bbl—its lowest level since February 2002.

U.S. shale producers are likely to face tough times ahead, with growth trajectory expected to close if WTI does not return to $40, according to the report by the research firm.

"With WTI below $30 per barrel or even lower, by the end of the year, we clearly see about 1 million barrels shaved out from U.S. shale production," Nysveen said.

Lower free cash flow of E&P companies will also negatively impact investment levels this year. Given an average Brent oil price of $40/bbl in 2020, global investments will fall by 8%. North America's shale industry

**Total Upstream Free Cash Flow From Public E&Ps For Various Oil Price Scenarios**




Source: Rystad Energy

will take the hardest hit, with investments falling by 25% in 2020.

Global final investment decisions for conventional projects during the first half of the year are also expected to be delayed.

In light of the current market conditions, the firm's revised outlook suggests that about $80 billion worth of capex projects will be sanctioned in 2020, stooping down to 2016 levels. The situation is not expected to improve until 2021.

Rystad predicts the coronavirus' impact on oil markets will worsen as world economies continue to lock down in hopes of preventing the spread of COVID-19, with global oil consumption expected to drop by almost 10 MMbbl/d in the coming months.

The figure by Rystad takes into account drastic travel restrictions, flight cancellations and self-quarantines, which are being heavily exercised in Europe and now in the U.S., as more cases of infected patients are being reported, Nysveen explained. If travel restrictions and quarantines continue, the impact on oil demand will be more severe during the next few months, he added.

The report also underlined that the actual impact on oil prices will be determined by global storage capacity, with the flood of oil supply from Saudi Arabia multiplied by the upcoming demand destruction. Implied stock builds could amount to as much as 1 Bbbl by summer, above the remaining capacity for crude and products in the entire supply chain.

"As such, production must halt when oil prices fall below a field's marginal cost of production, which ranges from $10 to $25 per barrel for fields globally," according the report.

*—Faiza Rizvi*

## Analysts are skeptical Exxon Mobil can perform as promised

You might assume that Exxon Mobil Corp., being the largest public U.S. oil company, and one that has paid a dividend for 37 straight years, would be mostly insulated from the oil price crash, but think again. The Institute for Energy Economics and Financial Analysis (IEEFA) is skeptical, saying the major's efforts may fall short.

And in late March, Moody's, which gives Exxon Mobil an Aaa rating, cited rising debt concerns when putting the company on negative outlook. Despite turbulence in the bond markets, the company borrowed an additional $8.5 billion to support its capex and dividend strategies.

"Even before this year's oil price dive, Exxon Mobil's planned assets sales faced a challenging market," according to the IEEFA report. "In 2019, the company anticipated $5 billion in proceeds from asset sales, but produced only $3.7 billion, well below target and about $1 billion below the company's 10-year annual average."

At its investor day conference in March, Exxon Mobil lowered its annual asset sales target from $5 billion to $3 billion per year through 2025. Yet even that goal may be unrealistically high in today's market, the group said.

"Exxon Mobil's failure to meet its cash targets for asset sales, particularly at a time of low oil prices, contributes to the company's poor cash flow. This is a significant contributing factor to Exxon [Mobil]'s deteriorating stock performance," said IEEFA financial analyst Kathy Hipple, lead author of the note.

Exxon Mobil isn't alone in its divestment plans, but the risk is that any sales, if they occur at all, may garner substantially less than anticipated, the report said. "Further, in the current environment where many companies are reducing capital expenditures, less money will be available for acquisitions. With weak, or potentially no, asset sale proceeds, Exxon Mobil will increasingly be forced to borrow to cover its dividend payments and capital expansion plans," Hipple said.

Over the past decade, the company's free cash flow has only covered two-thirds of the dividend. "Just last year, Exxon Mobil paid $15.3 billion to shareholders, while generating only $5.4 billion in free cash flows—leaving a $9.9 billion deficit that the company made up from other cash sources, including $5.4 billion in new long-term borrowing and $3.7 billion in asset sales."

Credit analysts increasingly cite Exxon Mobil's cash flow challenges as an area of concern.

*—Leslie Haines*

## How prepared are you for oil and gas price crisis?

Well-hedged oil and gas companies are best prepared to endure this downturn in the near term, but the longer the low price environment continues, the greater the likelihood that many in the industry won't survive, an analyst said.

"The hedges that are in place between $50 and $60, that is meaningful," said Bernadette Johnson, vice president for strategic analytics at Enverus, during a webinar on March 12. "That does provide some protection for the first part of the year. It's not going to save all these operators, certainly, and there are operators [in the Enverus analysis] that are not hedged."

But almost all of the hedges in place for the 63 operators studied begin to expire at the end of this year.

"Post-2020, that hedge protection starts falling off a cliff," Johnson said. "Even for the operators that are well-hedged, it's relatively short term, and the longer that these low prices persist, the more balance sheets that are in trouble."

Who should worry? Johnson boils it down to three questions:

- What is your debt-to-EBITDA ratio?
- How well hedged are you?
- How much debt do you have to roll over?

"If you are a Chevron [Corp.], if you are a ConocoPhillips [Co.] and you're sitting on a pile of cash, you can weather this storm longer, even if you're not as well-hedged," she said. "If you have a lot of debt to roll over, and your market cap just crashed by 50%, 90%, that's a significant challenge that a lot of these operators will have to overcome."

The plunge in price doesn't make it easy. Only a few areas in the Permian Basin and the Bakken Shale have breakevens that work at the current price level and those, Johnson said, are fairly well drilled out.

So far, she said, shale isn't dead because the market is working the way it is supposed to work. Prices are low, so operators are pulling back. When prices recover, they will return and add rigs quickly, which is what happened during the last recovery in 2017.

But is that the best strategy for an operator? That depends.

"If you decide to pull back right now as a U.S. operator, you're essentially betting on Russia and Saudi Arabia not being able to solve this very quickly," Johnson said. "It's game theory. If you pull the trigger too soon, even though you're covered, then this is resolved quicker than people are thinking, then you're at a disadvantage relative to your competitors."

But don't get your hopes up about a rapid rebound.

"Prices are not going to recover quickly," she said. "We're having a hard time seeing a lot of upside in 2020."

Those who still believe the shock of the March 9 meltdown will fade quickly will be forced to embrace reality by June, Johnson said, and then take drastic steps.

For those in the oilfield service (OFS) sector, well, duck and cover.

"The OFS market was having a tough time before the price collapse, just with the pullback in activity," she said. "We were running about 1,200 rigs in the U.S. back in November of 2018. By the end of 2019, we had cut that number by 25%."

Less activity means less drilling,

less need for services, pullback in rigs and pullback in crews. That was already happening.

"This really just exacerbates that," Johnson said. "If you look historically at what happens when prices first collapsed several years ago, it really is OFS that usually takes the hit first."

There are exceptions: Water-handling companies in certain areas of the Permian Basin may still do well. For most, however, tough times have arrived.

The longer-term outlook for 2022 to 2023 is brighter, though. Long-term demand trends for both oil and natural gas are increasing in the Enverus forecast. In that picture, shale plays can come back into money, and you can have rig counts return, Johnson said.

In an odd twist, this setback could be just what the oil and gas industry needs.

"This might be the type of event that helps shake loose capital markets," Johnson said. "If you think about it—a lot of these assets—what was the challenge before? Not a lot of transactions happening, not a lot of money in the space."

That could make it a good time to get back into energy if you're on the sidelines, she said. Johnson believes traditional investors will wait and see, but others might perceive a significant change in the market: the wide spread between bid and ask isn't so wide any more. Now you might see some transactions get done, she said.

*—Joseph Markman*

## 2020 M&A outlook: Analyzing Permian Basin consolidation

At the height of the U.S. shale boom, buying almost anything Permian-related seemed like a good investment. As the boom slowed, the Permian Basin retained a star rating. But today even the Permian requires a focused approach—how can investors play it today?

Overall, the outlook for M&A in the Permian Basin has shifted, according to a recent report from Bernstein Research updating the firm's thoughts on deal making opportunities in the basin.

In the past, the Bernstein analysts, led by Bob Brackett, suggested that small- to mid-cap Permian M&A "was a tough way to win," and the large-cap theme was preferable.

"That clearly worked for holders of [Anadarko Petroleum Corp] in 2019," according to the report. Anadarko Petroleum was acquired by Occidental Petroleum Corp. in a stock-and-cash transaction, which closed August 2019.

But the Bernstein analysts also said that going forward, the investment case for large caps "must rest on intrinsic, standalone business models, versus an M&A premium." This is based on analysis of 2019 full-year-results for the integrateds.

Bernstein looked at 36 public Permian E&P names last year and noted that of those:

- Three companies went bankrupt (EP Energy Corp., Approach Resources Inc. and Halcón Resources Corp.);
- Three were acquired (Anadarko Petroleum, Jagged Peak Energy LLC and Carrizo Oil & Gas Inc.); and
- Four were acquirers (Occidental Petroleum, Parsley Energy Inc., Callon Petroleum Co. and WPX Energy Inc.).

The firm's analysis showed that in 2019 the average deal size of 9,500 acres was little changed from the year previous. However, the median deal size fell significantly, to 1,300 acres, "and 90% of deals were below 25,000 acres."

The Jagged Peak and Felix Energy acquisitions were among the largest deals in acreage terms in 2019.

Developed, producing acreage continued to hold sway with a premium of 45% over that of undeveloped. As has long been the case, acquirers are seeking portfolio synergies via consolidation.

The Bernstein analysts identified WPX Energy, Occidental Petroleum and Halcón Resources (now known as Battalion Oil Corp.) as top targets for acquisition in the Permian Basin, while also noting there is still upside for some smaller names.

"Consensus EBITDA CAGR shows that even some of the cheaper names could grow quickly—the assets could be valuable to a suitor," according to the report. Bernstein sees "room for improvement for smaller companies" in total production and general and administrative costs via M&A. And looking at price to 2021 estimated cash flow, "there is an opportunity to buy up the cheaper players," the firm said.

Consensus EBITDA CAGR shows that even some of the cheaper names could grow quickly—the assets could be valuable to a suitor.

How can smaller players best position themselves given Permian M&A trends? "As a smaller player who could be an acquisition target, showing production is one of the most important elements."

Sellers should seek to be above in having more productive, developed acreage, while capable buyers would like to buy underdeveloped acreage and unlock value, according to the report.

Additionally, while it is attractive to sell to a major in terms of average price per acre, "A smaller producer would benefit from selling to a mid-cap or private E&P." The Bernstein analysis showed that selling to a larger public company offers 3.4x the spread between dollars per acre as compared with selling to a private-equity-backed or private company.

In the Midland Basin, public companies are contributing about 80% of the production, "but there are still opportunities to buy smaller players," the analysts noted. The publics hold an even greater share of production in the Delaware Basin.

With ownership in the Permian still diffused, and with crude price pressures looming, the analysts expect continued consolidation and acreage swaps.

*—Susan Klann*

## Oil crash poses extinction risk for some shale producers

With bankruptcy looming over energy companies in the wake of plummeting oil prices and soaring bond yields, executives across the shale sector are deliberating new ways of survival.

Although the long-term impact on demand prices is still unclear, the unprecedented uncertainty of the upstream sector is a strong indication that companies must act quickly in order to survive the storm, according to Basil Karampelas, managing director and head of the Houston office at advisory firm SierraConstellation Partners LLC.

"The prices of crude have collapsed to a point where it's hard to imagine any of the producers—even the most successful ones in the Permian—being able to generate substantial cash flows," Karampelas told Hart Energy.

The current state of the industry is very different compared to the price collapse in 2016, when a lot of companies were able to survive because of their hedging program. In contrast, he said the recent crash of the energy market is a twofold problem—low prices for sustained period of time and the grind down to the current price level, which is volatile, making hedging expensive.

"If you think of the world as a simple two-by-two matrix, with one dimension being price and the other being volatility, we are in the low-price, high-volatility quadrant which is the least desirable for an E&P company," he said.

Additionally, Karampelas sees no solace for gas producers either as the already-depressed natural gas prices have fallen to their lowest level in years.

"We have gone from an adjustment period to what could end up being as an extinction event particularly for oil and gas producers that are not well-capitalized," he said.

Karampelas expects the next three to six months will be "very turbulent" for the industry.

"We are already beginning to see of some bankruptcies and restructurings, which is going to create a lot of uncertainty and a real strain on the system," he said.

A large part of the industry will go into a "financial intensive care unit" over the next few months, he said. As a result, this will require negotiations between creditors, suppliers and customers to at least stabilize companies to a point where they can be restructured.

In order to survive the downturn, Karampelas said it's crucial that oil and gas companies focus on three themes—liquidity, objectivity and creativity.

"It's really making it through the initial critical period," he said, adding that liquidity will be the coin of the realm in the current environment. "Companies need to focus on what steps they need to take operationally, financially and strategically to maintain liquidity until the current environment improves. Near-term liquidity will provide stabilization that can hopefully allow companies to make informed decisions about their business without worrying about an extinction event," he said.

Oil and gas producers will need objectivity in terms of deciding a path forward.

"There is no room for any emotional attachment to assets or projects," he said. "Companies need to look gimlet-eyed at the reality of where they are and what works in this current environment. Being able to be objective and decisive will pay large dividends for companies."

Producers will also need to get creative, which Karampelas added is a necessity created by the current situation.

"Whether it means offering a discount to get aged accounts receivable paid or doing 'blend and extend' structures with vendors in order to stretch out purchasing and payables in order to maintain vendor relationships, creativity can be a tremendous help," he said.

With existing stretched balance sheets and lower margins, the price collapse will see refinancing and the restructuring of business models, where headcount cuts and bankruptcies will be inevitable, according to a recent report by Wood Mackenzie. Companies must drive efficiencies to extract the same or similar production for lower investment, defer the sanction of new projects and reduce activity levels and costs including short-cycle investment, exploration and operating costs, the firm said.

Several oil majors including Exxon Mobil Corp., Royal Dutch Shell Plc and Total SA announced significant spending cuts to protect their balance sheets from the oil price crash. Karampelas noted two reasons why oil majors are making these capex cuts, including maintaining some level of "attractive dividend."

"Secondly, and more importantly, I believe that there is going to be a tectonic shift in terms of oil majors moving into smaller and quicker payback period, focusing on projects that have higher near-term visibility and quicker payback and smaller capital investment per project, so they can be more nimble and flexible to deal with the volatility, which will last for at least the next year if not longer," he said.

*—Faiza Rizvi*

## E&P sector to face declines following cost cuts

Immediate moves by U.S. oil and gas players to slow activity amid unfavorable market conditions are expected to materialize as accelerated decline in U.S. Lower 48 supply by June or July, according to analysts.

"From a rig prospective you've already started to see significant laying off of rigs," John Coleman, principal analyst for Wood Mackenzie, said on a recent webinar.

The energy consultancy expects 37% of the rig fleet will be laid down, representing a drop of nearly 280 rigs from January 2020 levels.

The U.S. oil rig count saw its biggest weekly drop since March 2015 in the week to April 3 when drillers cut 62 oil rigs, according to Baker Hughes Co.'s report. The cuts brought down the total count to 562.

Wood Mackenzie forecasts the rig count will bottom out at about 480 in the third quarter and then stabilize. However, that "will not arrest U.S. supply decline but [would] stop acceleration of the decline," Coleman said.

The outlook was delivered as operators followed through on plans to drop rigs and completion crews to save money. Unknowing when the battle for more market share by Russia and Saudi Arabia along with lower global demand growth due to coronavirus will improve to lift commodity prices, capex cuts have been ongoing.

By the firm's estimates operators are reducing capex by 30% on average. This is on top of initial 2020 guidance indicating a 10% spending drop compared to 2019 levels.

"Analysis from our corporate coverage shows that year-on-year spending cuts of 41% are required across all cost categories including dividends to be cash flow neutral at $35/bbl in 2020," according to Wood Mackenzie.

Some companies—including Occidental Petroleum and Diamondback Energy Inc. among others—have already returned to the cutting room, Coleman said.

Lowering costs from efficiency gains or squeezing more from oilfield service margins, like the price downturn of 2014 to 2016, seem unlikely this time, he added.

"Even looking at things on a half-cycle basis, less than 10% of assessed resource in the Lower 48 space breaks even below $35 WTI," Coleman said. "On a full-cycle basis, none of it breaks even below $35 WTI."

"The message here is that incremental investment and capital deployment in the U.S. at today's prices is very much out of the money," Coleman said. "Now, that gets further complicated when you think about how producers are going to respond in terms of shut-ins and future activity as hedging enters the mix, which clouds the true economic response to what markets are trying to force."

He pointed out that the firm has seen single-digit realized prices regionally and at the wellhead across the Lower 48.

"Prices are already starting to push shut-in level economics," he said. "You'll start to see that really show up in supply declines starting in the summer months."

Determining when and where shut-ins happen, however, is difficult to forecast.

"It's not simply going below cash costs that drive a lot of those decisions," Coleman said. "There's a lot of regulatory or ancillary considerations around it."

These include leaseholder agreements, abandonment fees, and the ability to sustain some cash cost of production from a balance sheet perspective, he added.

As for exit rates, Wood Mackenzie anticipates a 900,000 bbl/d exit rate decline for December 2020 compared to December 2019 along with a 1 MMbbl/d decline from the expected peak, which Coleman said the firm believes occurred in February.

"Looking forward to 2021, the exit rate December 2020 to December 2021 is roughly an additional 500,000 [barrels per day] as we do expect price recovery into the back half of 2021 to marginally return rig additions back to the Lower 48 and arrest the rate of decline," Coleman said. "Certainly not returning the space to growth, but at least slow the rate of descent of the decline curves, for a lot of this supply."

*—Velda Addison*

## Where will the excess glut of US oil go?

Excess supply has sparked a new dilemma among U.S. oil producers already battered by an unprecedented demand loss due to the spread of the coronavirus.

Despite North America's storage system already nearing its limit, the oil market crash has plunged prices for physical delivery of several key crude grades to the lowest levels in decades. The result: Pipeline operators in

the U.S. have begun asking producers to voluntarily cut back production.

"Oil prices have come down to $22 per barrel but at the wellhead itself you're looking at $10 per barrel or less," Michael J. Blankenship, corporate partner at Winston & Strawn LLP, told Hart Energy. "What's happening now is when the producers are pumping out oil, they are looking for storage space since they cannot sell in the market."

The situation of the energy market—aggravated by the Saudi-Russian price war—is more severe than people had anticipated, Blankenship added.

Storage capacity is being quickly sold out, and as a result pipeline operators are asking producers of certain wells to cut back production. The U.S. Energy Information Administration said April 1 crude inventories in the U.S. rose the last week of March by 13.8 MMbbl to 469.2 MMbbl, which was the biggest one-week rise since 2016.

In early April, pipeline operators also began to ask suppliers to scale back output. Both Plains All American Pipeline LP and Enterprise Products Partners were reported by Bloomberg of having sent letters requiring customers to prove they have a buyer or place to offload the crude they are shipping. Blankenship said he expects more pipeline operators to join Plains in asking for output reductions.

In a similar development, Parsley Energy Inc. and Pioneer Natural Resources Co. called on the Texas Railroad Commission (RRC), which regulates energy for the state, to hold an emergency meeting and order oil production cuts, no later than April 13.

Ryan Sitton, a member of the Texas RRC, said on Twitter that pipeline companies are running out of storage space for oil as coronavirus-related lockdowns have caused demand to plunge. During a webinar on April 1, he also pointed out that the market is 21% oversupplied and if the current oversupply rate continues, global oil storage will be full in 72 days.

U.S. shale firms have been responding to the crisis by slashing the number of drilling rigs, reducing workforce and cutting capital spending, which according to Blankenship is the right thing to do.

"Producers are making the right decision by cutting 30% to 40% of capex," he said. "Even though some producers are hedged out 75% but the remaining 25% is not hedged and those are in negative margins right now."

According to Blankenship, U.S. shale producers need to also reevaluate their hedges and debt load to understand whether it makes sense to produce.

"[Producers] need to understand if they're not in the best area within the Permian, Bakken or any area of the country, it's going to be hard because there are no buyers of crude," he said. "On the flipside, gas producers are stronger because gas production will go down as the wells are shut-in and we could see gas prices go up in 2021."

To relieve some economic stress of producers that are forced to shut in oil wells due to lack of storage capacity, the U.S. Energy Department on April 2 announced a solicitation to immediately make 30 MMbbl of the Strategic Petroleum Reserve's oil storage capacity available to U.S. oil producers. The Department of Energy also intends to make an additional 47 MMbbl of storage capacity available thereafter.

Several other countries are struggling with storage capacity. According to industry reports, global oil inventories are estimated to be increasing at the rate of 25 MMbbl/d and storage capacity in pipelines, refineries, tank farms and vessels at sea is rapidly filling up.

With excess supply and slacking demand, major oil-producing countries like Nigeria, Brazil, Ecuador, Angola and Canada have only a few weeks of storage available before pipeline systems back up and production has to be curtailed, Reuters recently reported.

*—Faiza Rizvi*

## *Apache, Total score win with discovery offshore Suriname*

Apache Corp. and partner Total SA said April 2 the Sapakara West-1 well offshore Suriname has made a significant oil discovery, building on the success of their Maka Central-1 find.

Drilled to a depth of about 6,300 meters by the Noble Sam Croft drillship, the well hit hydrocarbons in multiple stacked Cretaceous-aged Campanian and Santonian targets.

The companies said test results indicate the shallower Campanian interval has 13 meters of net gas condensate and 30 meters of net oil pay. The deeper Santonian interval contained 36 meters of net oil-bearing reservoir.

The news sent shares of Apache up by more than 23% to $4.97 in trading early April 2, signaling a positive for the company that is facing tough times in U.S. shale.

"Based on a conservative estimate of net pay across multiple fan systems, we have discovered another very substantial oil resource with the Sapakara West-1 well," John J. Christmann, Apache CEO and president, said in a news release. "Importantly, our data indicates that the Sapakara West-1 well encountered a distinct fan system that is separate from the Maka Central-1 discovery we announced in January this year."

Suriname is among the most-watched exploration hotspots in the industry. Industry players willing to pursue offshore exploration, given today's challenging market conditions, could be at the beginning of another string of discoveries. Exxon Mobil and partners have made 16 discoveries on the Stabroek Block offshore Guyana, which is next door to Suriname.

Apache and Total's latest find comes about three months after Apache shared news that the Maka Central-1 well encountered oil and gas condensate in the Campanian and Santonian intervals.

Apache said it has identified at least seven play types and more than 50 prospects in the area it described as a thermally mature play fairway. The discoveries are located on the 1.4 million-acre Block 58, which is near Exxon Mobil's Haimara gas and condensate discovery well offshore Guyana.

"The results are once again very encouraging and confirm our exploration strategy in this region," Kevin McLachlan,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senior vice president of exploration for Total, said in a separate statement.

Plans are now for the drillship to search for hydrocarbons northwest and southeast of Sapakara West-1, looking for oil in upper Cretaceous targets in the Campanian and Santonian intervals. Apache said the reservoirs appear to be independent from the Maka and Sapakara discoveries. First up will be the Kwaskwasi prospect, about 10 kilometers northwest of Sapakara West-1, Apache said. Keskesi, the fourth exploration prospect on the block, will follow.

*—Velda Addison*

### Service providers to bear brunt of oil market crash

The global oilfield service (OFS) sector is expected to slash spending by $100 billion this year as oil prices continue tumbling to historic lows with the U.S. shale market being hit the hardest, according to a Rystad Energy analyst.

Many E&P companies have unveiled budget cuts to cope with the slump in oil prices—the bulk of which has been made by U.S. shale operators. On average, shale companies have revised budgets down by 30% this year. As a result of the curtailed activity, the number of well completions in the U.S. is expected to drop by 40% in 2020, Audun Martinsen, head of energy service research at Rystad, said during a webinar on March 27.

On the supply chain side, Martinsen explained that well-related services—which will experience 70% to 80% budget cuts—will feel the most pain. This includes land and offshore drillers, drilling tools and services, pressure pumping and completion services.

In a battle for market share, margins of the pressure pumping sector will also drop by 20% this year. Consequently, the average well cost could go down by 10% in all the major basins of the U.S., according to Rystad Energy forecasts.

Other sectors such as subsea, equipment construction and maintenance services are expected by Rystad to steer the downturn in a better way and run through long-term agreements. However, payment and execution will be delayed, Martinsen noted.

Rystad also predicted more than 1 million OFS jobs could be cut this year as projects are deferred and delayed, with onshore services bearing the brunt.

An estimated 5 million people are employed globally in the OFS sector. Contractors are predicted by Rystad to scale down by at least 21%. In the U.S. shale market, the situation could be worse for OFS providers, the firm said, with 30% expected layoffs.

SOURCE: LARRY1235/SHUTTERSTOCK.COM

The oil and gas industry is facing a historic slash in demand, as experts forecast crude consumption could fall as much as a quarter next month because of global lockdowns as the coronavirus pandemic continues to spread. Aviation and passenger vehicles—which constituted 34% of global oil demand in 2019—are the primary drivers of the global oil demand crash.

Page added that several countries in North America, Europe and Southeast Asia have imposed stricter measures, resulting in a large reduction in traffic. At this rate, oil demand was expected to possibly drop by 16 MMbbl/d in April.

However, the demand could bounce back relatively quickly once restrictions are lifted.

On the supply side, OPEC+ is expected to ramp up production by 3.5 MMbbl/d in May compared to February levels, which according to Page is a "dramatic increase given the crash in global oil demand." The increase in supply will be driven by factors such as Libyan production coming back online and Saudi Arabia increasing production.

In the U.S., if WTI could recover and maintain at $30/bbl, Page said oil production will begin seeing a significant decline by September. He predicts more than 1 MMbbl/d of U.S. production will be shaved off compared to 2019 levels. However, if the price drops to $20/bbl, the production decrease will be more dramatic and could begin as early as June. If the low-price levels continue until 2021, U.S. oil production will further decline by 1.9 MMbbl/d, he said.

In conclusion, the imbalance between overall crude supply and demand paints a very bearish picture, Page said.

"From February through July, we see significant builds in overall crude supply and crude demand, which we consider to be the 'mother of all market supply surpluses,'" he said. "There are significant downside risks in the second quarter with 5.8 MMbbl/d supply surplus, which is a significant build in stocks."

*—Faiza Rizvi*

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# WHAT IS THE 2020 *VIRTUA*LEC ?

Due to the impact on traveling and in-person meetings caused by the COVID-19 situation, our 2020 LEC will be held 100% online. It will feature a series of at least 10 presentations and discussions on Wednesday, May 27 and Thursday, May 28 that will address key domestic and international oil and natural gas industry developments.

***We are pleased to welcome back many of our popular speakers from past years who will provide their views on the current state of the energy industry.*** This knowledgeable group of industry participants and advisors will accept questions online from registered participants during their respective presentations. There is no cost to participate in the symposium but you must register through our website.

***We have already finalized our Conference plans for next year and our 2021 LEC will be held at the Ritz-Carlton, New Orleans May 25 -28, 2021 and hope you will mark your calendars to join us live and in-person then. Registration for 2021 will open later this year.***

Please visit www.LouisianaEnergyConference.com for an updated agenda and session times for our **2020 *VIRTUA*LEC.**

Each session will begin on the hour and last up to 60 minutes, with any related slides posted to the LEC website. We will maintain a recording of the presentations and Q&A for 60 days after the event concludes.

We currently have the following confirmed topics/presenters and expect to add others:

- JP Morgan – Scott Schnipper
  - The Unprecedented Shock to Global Oil Markets and the World Economy
- Jones Walker – Marshall Page, Dionne Rousseau and Asher Friend
  - The Ongoing Impact of COVID-19 in Energy and the Economy - A Regulatory, SEC and M&A Perspective
- Pareto Securities– Nadia Martin Wiggen
  - Pareto's View on Oil Prices and the Macro Outlook
- Deloitte - Jonathan Traub
  - Tax Policy in the Time of Coronavirus
- Enverus – Bernadette Johnson
  - Energy Outlook for 2H 2020 and 2021
- W. David de Roode and Lockton – W. David de Roode
  - ESG in the Energy Industry
- Seaport Global – Michael Schmidt
  - Seaport's Views on Public High Yield Securities and Private Debt Placements
- Simmons – Pearce Hammond and Mark Lear
  - Simmons' View of E&P and OFS in the Current Energy Environment
- Duff & Phelps – Jed DiPaolo
  - The Impact of Geopolitics on the Oil and Gas Industry

We thank all of our presenting firms for their participation and sponsorship of our 2020 ***VIRTUA*LEC.**

We are clearly living in an unprecedented time right now and Al Petrie Advisors wants to express our hope that you, your co-workers and all of your families and friends are safe and remain healthy.

Please contact us at info@LouisianaEnergyConference.com or 504-799-1953 if you have any questions.

The Al Petrie Advisors Team

AP+ AL PETRIE ADVISORS

# THE E&P SURVIVAL GUIDE

Amid a pandemic and a disastrously timed OPEC+ supply war, executives, analysts and consultants advise hedging strategies, keeping a close watch on markets and, potentially, rebuilding business plans from the ground up.

ARTICLE BY
DARREN BARBEE
AND
VELDA ADDISON

PHOTOGRAPHY BY
STEVE TOON

In April, the streets of the world's greatest cities emptied, offices and businesses shuttered, and humans huddled in their homes. The quiet grew, and the earth seemed to stand still.

It was the worst possible outcome for the oil and gas industry, which depends on all manner of movement—car and truck travel, airline flights, deliveries, logistics—for customers. By mid-April, as the coronavirus pandemic blazed through Europe and the U.S., the virus claimed 130,000 lives and restricted the movement of more than 300 million Americans. A supply war between Saudi Arabia and Russia only helped to further suppress oil prices.

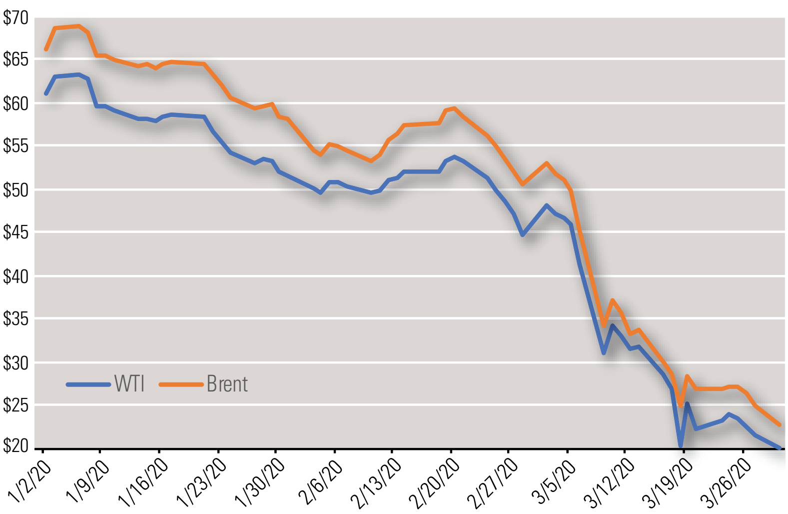
Whether weeks or months of shelter-in-place orders—and lessened energy demand—lay ahead, the implications for the oil and gas industry are dire. The dog-eared E&P survival guide for the year ahead has once more been dusted off, but there's no chapter for this. Generally, operators were responding rapidly through capex cuts, preparing for chaos and leaving all options on the table. And it may not be enough this time.

The swiftness of the March-April oil shock is unlike any that producers have faced before. In a matter of eight weeks, demand for oil was crushed, and prices skittered from $60/bbl to the low $20s.

The effects have been felt throughout all sectors of the economy, including hospitality, entertainment, travel and leisure. By early April, traffic through Transportation and Safety Administration checkpoints fell 94%—meaning 2 million fewer people traveled compared with the same time last year. Over New York, California and Texas, satellites tracking traffic showed declines of at least 50% each, according to Rystad Energy. In the U.S., jet fuel use is projected to fall by as much as 70% and gasoline by 50%, according to Regina Mayor, KPMG's global and U.S. energy sector leader.

Estimates for crude oil demand are growing increasingly bearish, said Mayor. Models showed demand falling by "20 to 25 million barrels per day, globally," Mayor said. "And those are now seeming to be pretty accurate. Just think about how our movements have changed for all of us."

**WTI/Brent Price Comparison ($/bbl, 1Q20)**




Source: Bloomberg

Industry leaders, consultants, analysts and executives say maneuvering through the crisis will require looking beyond the immediate aftermath of the price crash, which led to slashing capex and layoffs.

Harold Hamm, chairman of Continental Resources Inc., said the oil and gas industry has plenty of practice with business cycles and that the survival instincts of producers will kick in. "I think cutting back as much as you can, as quickly as you can and preserving cash and your liquidity is very important," he said. "And that's what everybody will strive to do."

Jeffrey Currie, an analyst at Goldman Sachs, wrote on March 30 that carbon-based industries such as oil production have historically served as the cornerstone of social interactions and globalization—and those must be shut down to defend against the virus.

"Oil has been disproportionately hit, likely more than 2x economic activity, with demand this week down an estimated 26 million barrels per day or [about] 25%," Currie said.

Unlike other industries, oil and gas producers are fighting a two-front war: demand destruction by the pandemic and the OPEC+ price war that has already unleashed a glut of oil on an already supersaturated market.

An angry Hamm said he is working with U.S. Sen. Jim Inhofe, R-OK, to place sanctions on the two countries for potential excessive dumping of oil into global markets. It's unclear whether a late-breaking agreement by OPEC+ to curtail production by nearly 10 MMbbl/d would alter Inhofe's response.

"The ironic thing is the U.S. [military] is over there [the Middle East] actually … protecting their physical and national security interests at the time that they choose to do this and undermine ours," Hamm said.

Hamm said a countervailing duty of as much as $25/bbl could be imposed, though the American Petroleum Institute is generally opposed to tariffs. Hamm said that Saudi Arabia and Russia miscalculated "the ire of everyone here in this country" as they drove supplies up and prices down.

"The Saudis … didn't just ramp up their production to two and a half million barrels," he said. "Actually, what they did was ramp up production and empty their tanks. So, they wanted double the impact on the market, and they've done that."

Even without the added pressures from the price war, Rystad forecast on April 1 that global demand in 2020 would contract by 6.4% because of the pandemic—about 2.5 billion barrels fewer than in 2019.

E&P executives, analysts and advisers urged upstream oil and gas producers to adjust to the reality that the pain will be long term. Even a truce between the oil price war between Saudi Arabia and Russia "is a little bit akin to spitting in the wind," said Ian Nieboer, managing director at RS Energy Group.

Nieboer said what's to come for upstream oil and gas producers amounts to a "buffet of bad choices."

## SHUT OUT

Permian Basin operator Triple Crown Resources LLC is keeping watch, ready to weather the pandemic storm and the oil price war, CEO Ryan Keys said. But the way forward for most E&Ps will be treacherous.

Several analysts predicted that operators may shut in wells as a pandemic drastically undercuts demand for oil.

"My team is prepared and knows exactly what to do and at what prices or physical constraints, down to the individual well," Keys said. "I don't think many E&Ps are doing that, so I think the inevitable production curtailment—whether by force majeure or by economics—is going to be a disaster for many operators."

Several analysts predicted varying degrees of shut-in production as prices fall and crude oil storage becomes scarce. Rystad Energy predicted that a third of U.S. storage capacity will be filled in April.

"Shut-ins are coming, and they are likely to be big," Enverus said in an April 8 report.

In Texas, Pioneer Natural Resources Co. and Parsley Energy Inc. petitioned the Texas Railroad Commission (RRC) to impose regulations curtailing oil production by May. A hearing on the matter was set for mid-April. Any production curtailments would be significant as Texas is the nation's largest producing state, accounting for 41% of U.S. oil production in 2019 and 25% of natural gas.

So-called proration, first implemented on a voluntary basis in Texas in 1927, would limit state oil production based on market demand that causes physical waste. Pioneer and Parsley argue in a motion for a hearing that the RRC should determine whether oil is being wasted or is in reasonably imminent danger of being wasted. The companies cited a lack of storage and low oil prices to suggest as much as 7 million barrels per day of oil production could be shut-in or not produced.

For shale producers, decisions to shut in production will likely involve a complex equation including price, long-term well performance, lease commitments and regional price and demand sensitivities, Goldman Sachs analysts said in an April 3 report.

Analysts at Morgan Stanley and Wood Mackenzie have said they have already seen signs of wells being closed.

"We've already seen confirmed cases of that occurring in the Eagle Ford [Shale] that some of my clients have said to us and is most likely happening to some small degree in other regions," John Coleman, principal analyst at Wood Mackenzie, said during an April 2 webcast. "I think it's not going to be as simple as high-cost regions are going to be the ones that shut in. It's going to happen across the board, and it's going to be on an operator specific basis, based on how much pain they can sustain."

Regina Mayor, KPMG's global and U.S. energy sector leader, said her clients are looking more toward deferring wells or slowing production without harming production curves.

"Shutting in production is a tool of last resort," she said. "That's not to say that you won't see some [operators] do it. I just don't see that as being a big lever that ends up coming into play."

However, the market was signaling by late March that low prices could go beyond laying down rigs.

Bernstein Research noted that oil prices in the low $20s require "significant shut-ins to avoid inventories overflowing." At prices of $25/bbl, low-producing vertical wells with high unit costs are uneconomical, Bernstein analyst Bob Brackett wrote in a March 27 report. About 120,000 such wells are found in the Permian, with about a quarter owned by Occidental Petroleum Corp., Apache Corp. and Pioneer Natural Resources.

In early April, Ryan Sitton, one of three RRC commissioners, said some Permian producers were "beginning to get offers at $6 per barrel" net, after differentials and transportation costs.

Keys said that at wellhead prices of $5/bbl few Permian wells would generate profitable margins, "and about half of the production in the basin would be getting negative margins. So negative cash flow."

"When I talk about shutting in, there are a lot of people who tell me I shouldn't be telling them what to do," Keys said. "That's not what I'm saying. If someone operates their assets at negative margins—thereby causing irreparable damage to their balance sheets—for long enough, out of stubbornness or ignorance, that's obviously their choice. But I'd have to ask them the same thing if they were punching themselves in the face: why are you intentionally hurting yourselves?"

Keys said that if enough operators continue producing assets at negative margins, the rest of the industry will suffer.

"We all need to remember we are producing a commodity," he said. "I think over the past six to eight years, we collectively forgot that."

**Taking a toll**

Since the beginning of humanity, germs have taken their toll. But "we have developed resisting power; to no germs do we succumb without a struggle," H.G. Wells wrote in "The War of the Worlds."

The same could be said of oil companies and down cycles. But after years of cutting costs, bankruptcies, price wars and Wall Street apathy, the mood among executives was grim in April. Some suggested M&A would simply speed up consolidation already underway. Others said they would monitor and react to the new developments day by day. And a few advocated a hard reset.

But Hamm wonders how long the economy can remain at a standstill.

"Whether it lasts 60, 90 days, whatever, before people go back to work, our economy, in my opinion, cannot afford to be shut down like it is today for over three months," he said. "I just don't see that being possible."

The nonpartisan Congressional Budget Office (CBO) on April 2 reported that the unemployment rate is expected to exceed 10% in the second quarter, reflecting 9.9 million unemployment claims reported from March 27 through April 2. The CBO "expected the effects of job losses and business closures to be felt for some time" with an unemployment rate of 9% by the end of 2021.

Mayor said her clients are overly pessimistic as storage fills and demand dwindles.

"The mood is very grim, and it's grim across the board: upstream, downstream, independent, integrated," she said. "I don't see really anyone seeing this as an opportunity."

So far, Mayor said, companies have been enacting short-term measures, including slashing capital spending and operating expenses and shoring up liquidity and access to debt.

"Some are better able to do that than others," she said. "I think some have started to take on workforce reduction and others have sacrificed the almighty dividend."

Producers instinctively plowed down previous spending plans, with Tudor, Pickering, Holt & Co. anticipating an overall 50% cut in oil and

***"Cutting back as much as you can, as quickly as you can and preserving cash and your liquidity is very important," Harold Hamm, Continental Resources chairman, said.***

***"[E&Ps] have to start literally from a clean sheet of paper because just trimming off the edges and even cutting into the muscle isn't going to be enough to deal with the fact that we went from a $60 price environment to the low $20s in the span of eight weeks," said Regina Mayor, KPMG global and U.S. energy sector leader.***

gas capex. Among companies covered by Cowen analysts, 2020 capex was down by 20%, or about $9 billion.

After oil prices tumbled in March, The Woodlands, Texas-based Earthstone Energy Inc. responded with a two-thirds cut to capex to a midpoint of $55 million, down from $165 million. The company plans to drop its single rig in the second quarter and limit completions to three wells already in progress. Assuming $30/bbl WTI and existing service costs, the company said it expected to generate free cash flow.

Robert Anderson, the newly appointed CEO of Earthstone, said survival—regardless of how low WTI sinks or rises—comes down to managing debt, revolver use and a hedging strategy.

Earthstone's hedging strategy utilizes swaps, hedging 18 to 24 months out at 65% or more of its production forecast. The company doesn't use debt to acquire acreage.

"With low debt, strong operations and low G&A, for a small-cap producer, we are well situated to handle prices even into the low teens," Anderson said. "We averaged about $13.50 per boe for all-in cash costs in 2019. This includes all cash costs to run our business. Without being forced into shutting wells in due to constraints we can't control, we would expect to continue to produce. We will have 11 wells drilled and waiting on completions so, when prices improve, we can quickly resume capital spending and bring on new production."

Oklahoma-headquartered WPX Energy Inc. cut $400 million, or about 25%, of its capital budget. At the time, the company planned to maintain oil production of about 150,000 barrels per day for the rest of the year.

"We're seeing capex budgets being revised down by 30% from original guidance," Linda Htein, senior research manager for Wood Mackenzie, said on a webcast in late March. Among these are shale player EOG Resources Inc., which cut its capex by 30% and shifted from guidance of double-digit production growth to roughly flat compared to last year. Others, such as Permian Basin operator Pioneer Natural Resources Co. cut its budget by 45% and its rig count by half.

"That sounds dramatic, but we've actually seen more dramatic cuts than this," Htein said. "Apache, for example, had eight rigs running in the Permian, and they have plans to drop all eight of them."

Mayor warned that the world that emerges from the coronavirus may be radically different. One senior executive told Mayor in late March that oil prices may eventually sink into the single digits before rallying.

Longer term, E&Ps will need to fundamentally reevaluate their entire operating structure, she said. "We're recommending folks start rethinking from the ground up, reprioritizing the entire portfolio," including which basins and projects are viable and whether regional offices still make sense, she said.

"I think they have to start literally from a clean sheet of paper because just trimming off the edges and even cutting into the muscle isn't going to be enough to deal with the fact that we went from a $60 price environment to the low $20s in the span of eight weeks," Mayor said.

Companies in the best condition to survive should reshape their operating structure, cost basis, their portfolio strategy and generally rebuild from the ground up.

"They don't have the luxury of doing that right now, but this is going to be with us for the next 12 to 18 months at the earliest before we even start to begin to come back."

### Cuts, vol. 2

A few companies, including Diamondback Energy Inc. and Occidental Petroleum Corp., announced a second round of operational changes—in the same month. More were expected to follow.

Others, such as WPX and EOG Resources, preached patience and flexibility.

Kenneth Boedeker, EOG Resources' senior vice president of exploration and production, told investors at the virtual Scotia Howard Weil Energy Conference that, if warranted, the operator can flex down its planned 2020 capital spending program below the 30% cut announced in March. The company already dropped its capex plans to between $4.3 billion and $4.7 billion and added that the revised budget still offered strong returns at $30 oil. However, with the price per barrel sinking further, the company may adjust the plan again.

"We have a midpoint of $4.5 billion at this point, and we have a significant amount of flexibility in our plan to get there," said Boedeker. "In terms of plan C, we continue to have a significant amount of flexibility in our plan and in our operations both in rig count and in frac crews. If these prices persist, we have the flexibility to go ahead and flex our capital plan even further down. We're watching prices day-to-day, but we're not knee-jerk reacting to any change in price."

The initial funding cut spared most development programs in the Permian and Eagle Ford. EOG also said it would move forward with other infrastructure projects that would help the company on the other side of the price slump, including possible gas gathering and water projects. However, all projects will be reviewed if further cuts are needed.

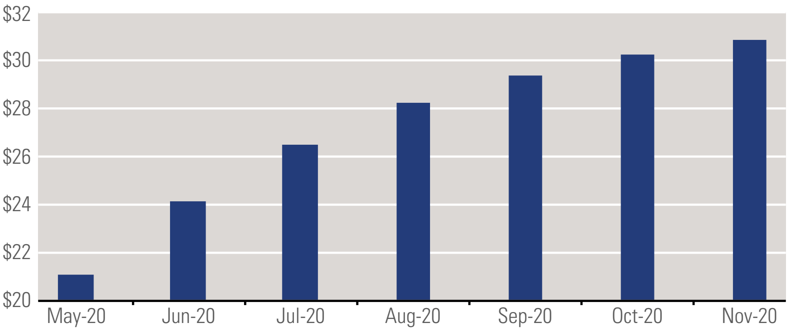
"If we continue to cut then what we'll see is we may reduce some of those plans in other areas as well as cut in the Eagle Ford and the Permian," said Boedeker. "Our sacred cow is returns. We're going to go wherever we can generate returns at those oil prices."

At year-end 2019, EOG had over $2 billion in cash on the balance sheet and around $1 billion in debt maturities due in 2020.

"We have a significant amount of flexibility both operationally and financially to meet whatever pricing environment we see in the future," Boedeker added. "We've learned from past downturns how to manage through these and how to structure our contracts to give us the maximum flexibility to react to substantial price reductions like we've seen over the past few weeks."

**WTI In Contango**

On April 1, the spread between the May and November futures prices was almost $10/bbl.




Source: Globex

Anderson said Earthstone can produce oil into the low teens and still be confident in covering its costs.

"A glut of oil and storage filling up sounds like it is happening in real time. This virus has created a drop in demand that we have never seen before," he said. "We are taking this one day at a time and, as a small producer, we don't have access to meaningful storage. If we get to the situation of having to reduce production or flat out shut-in wells, we will go through an orderly process to do so."

**Borrowed time**

Triple Crown Resources LLC CEO Ryan Keys said he expects to see the needs of company balance sheets driving M&A. He also suspects companies will suffer after borrowing base redeterminations, which have the potential to complicate E&Ps' debt positions.

"By the time we get to fall redetermination season, there will be a lot of assets from distressed and Chapter 11 companies being auctioned off," Keys said. "Some banks with big enough portfolios have decided they're going the 'smashco' route after they end up owning the assets."

Other E&Ps may survive one or two redetermination seasons, "but they're basically slowly melting ice cubes with no chance to recover. Those guys need to merge with someone in all-equity deals."

Bankruptcies are already brewing with Denver-based Whiting Petroleum Corp. declaring bankruptcy April 1. Reuters reported the same day that Callon Petroleum Co. hired advisers to restructure its more than $3 billion in debt. Callon declined to comment on the report.

The Baker Hughes Rig Count continued to a precipitous drop, with 64 rigs falling in the U.S. between March 27 and April 3.

Keys said much of the debt owed by companies will trade at distressed or junk levels that is still viable by proved developed producing assets at strip pricing. That will open the door to capital willing to risk a Chapter 11 bankruptcy to own good assets—or ride an oil recovery to high dividends.

"I would love to have a lot of capital to deploy right now," he said.

***"The pandemic will be behind us soon and combined with low commodity prices demand will snap back at a time when supply growth has stopped," said Robert Turnham, president and COO of Goodrich Petroleum Corp.***

Beyond cutting, the options get more painful or more profound. Companies are already grappling with whether to shut in producing wells, gauging a Texas proposal for oil quotas, and how much more to cut and how deeply.

Longer term, laying down rigs might be an option but isn't viable or realistic.

"Cutting to zero capex certainly will allow you to generate free cash flow, but the loss in EBITDA and borrowing base availability due to falling volumes becomes problematic after a period of time," said Robert Turnham, president and COO of Goodrich Petroleum Corp.

Coping with decline rates also becomes problematic.

However, there are some "interesting dynamics" on the gas side in the Lower 48—less associated gas from oil plays as producers slow down activity, according to Wood Mackenzie.

That could bode well for Goodrich, an independent with assets in the Haynesville, Tuscaloosa Marine and Eagle Ford shales. Nearly all of its production is natural gas.

"Lower volumes in Permian and elsewhere obviously take associated gas out of the supply mix, which will benefit natural gas prices," Turnham said. "We likely won't see the prompt months move to acceptable prices until COVID-19 is behind us, global growth in GDP resumes and LNG overhang is eliminated, but you are already seeing higher natural gas prices in the back of the curve reflecting this dynamic."

Higher gas prices could incentivize new drilling in dry gas plays, particularly in the northeast region and the Haynesville, Htein said, helping to balance the gas market in 2021.

In all, the U.S. shale industry could do more to remain competitive in uncertain times. Reducing fixed costs and continued consolidation to "reduce redundant costs" across companies come to mind for Anderson.

"As we have seen over the past couple of years, there are too many companies with too much G&A [general and administrative expenses]," Anderson said. "We need to create scale to be competitive and reduce the fixed costs across the industry and lower the costs of operations. Scale does drive down the overall cost of the business, and we plan to be a consolidator and continue our cost-efficient operations."

Generating competitive free-cash-flow yield to pay down debt and right-size balance sheets is essential, according to Turnham. Then, "companies will be paid again for growth and inventory."

"The pandemic will be behind us soon and combined with low commodity prices demand will snap back at a time when supply growth has stopped," Turnham said.

In the meantime, the industry must work through the supply overhang until prices recover. It'll be "tough sledding for a while but the decisive, fundamental moves that we are all making will right the ship," he said, recalling advice from a prominent Wall Street executive to "look over the valley to the other side; there are better days ahead." ☐

# FULL REVERSE

Market forces are at competing odds, with a silent virus killing global demand for oil and foreign antagonists pushing more volumes into the supply pipeline. How does it end, and who wins—or just remains standing?

ARTICLE BY
JOSEPH MARKMAN

PHOTOGRAPHY BY
STEVE TOON

On March 9, the U.S. Energy Information Administration (EIA) decided to delay release of its monthly Short-Term Energy Outlook. It had to—the world its data depicted had gone to hell.

A sharply different forecast appeared two days later. The price of WTI, which in January was expected to average $64/bbl for the year, would average $43/bbl in 2020, the EIA said. Others would chime in later in the month. Barclays Plc predicted $28/bbl for WTI; Dutch bank ING saw $20/bbl for global benchmark Brent.

The collapse of OPEC+ on March 6 aimed a battering ram at crude oil markets. On March 9, it struck fiercely, tearing away 24.6% of WTI's price. It struck again on March 16 (10.5%) and again on March 18 (24.4%).

The oil and gas industry has always embraced its roller coaster existence. Boom-and-bust is part of the lore, part of the drama and, for those who can outlast the bust to soar with the boom, part of the fun. But this downcycle is not akin to 2016, 2008, 1991 or 1973. It is fueled by fear of an invisible killer, stoked by a market conflict by foreign antagonists. This time is different, out of control, perhaps harsher, and many E&Ps will be unable to survive.

"I've seen a lot of stuff go on in the oil market in the past 35, 36 years that I've been following it, and I've seen a lot of things happen in the global economy, and I've never seen anything remotely like this, to the degree of uncertainty like this," Craig Pirrong, professor of finance at the University of Houston's Bauer College of Business, told *Investor*. "That's what really sets this episode apart from some of the grim episodes that we've experienced in the past."

### Volatile times

A truce between the Russians and Saudis might be conceivable, but negotiating with a pandemic is not an option. Until the spread of

***"Everybody in the industry is going to take a big big hit ... but the most vulnerable are the relatively leveraged E&P players, particularly in the U.S. shale. They just don't have the balance sheets to survive," said University of Houston professor Craig Pirrong.***

***"What you're going to see as soon as we get out of this: who are the winners, who are the losers?" Peter Fasullo said.***

COVID-19 has been arrested, efforts to move toward recovery are essentially futile.

"The old adage, 'low prices will cure low prices,' is just not working," Peter Fasullo, co-founder and principal at En*Vantage Inc., told *Investor*. "That adage relies on two things: Once low prices have occurred, you get a bounce back in demand because prices stimulate the economy. People start consuming more because prices are low, and it throttles back supply. But the problem is, until the virus is controlled, and we have a handle on it, demand's not going to bounce back. Gasoline may be selling at $1.50 at the pump; it doesn't mean I can buy it and travel while current lockdowns are in place."

By late March, both WTI and Brent were in steep contango, meaning that the November price was well above the May front-month price. For WTI, the spread was about $10/bbl. That provides incentive for traders to buy up crude and pump it into storage, Pirrong said. Typically, that volume would spark an upward price trend, but the stranglehold that COVID-19 has placed on the economy stymies any significant movement. He expects commodities markets to convulse over the next three to six months.

"The market is also signaling that there is just a huge amount of volatility, and we could see, given this uncertainty, a dramatic change in either direction," Pirrong said. "We could go back up into the $40s. The basic point is that there is so much uncertainty that we're talking about a historically wide range around current prices and current futures prices."

He does not really expect prices to sink to the teens, although he offers a 5% chance that they could. How about single digits? That's unlikely, Pirrong said, but if the Saudis and the Russians continue to pump and flood the market, and the demand collapse driven by the virus persists simply because the virus persists, and that ocean of oil fills up storage then, in theory, crude prices could descend into the single digits. But he doesn't consider it likely.

Driving the crisis is too much supply from U.S. unconventional fields, particularly the Permian Basin, and plunging global demand. En*Vantage expects U.S. producers to shed 1 MMbbl/d of their March average production of 13 million barrels per day (MMbbl/d) by the close of the second quarter. It won't be enough because domestic demand will decrease by 4 MMbbl/d, En*Vantage said.

Global demand averaged about 100 MMbbl/d in 2019. The IEA and IHS Markit predicted demand will decline a staggering 20 MMbbl/d during the second quarter. Goldman Sachs forecast an 18.7 MMbbl/d plunge.

### What's the damage?

But prices don't need to crater into the teens to elicit pain. In late March, the Dallas Federal Reserve determined that 35% of 107 E&Ps surveyed were conducting business in basins where the price had fallen below a level sufficient to cover operating expenses. The range in the Dallas Fed's first-quarter energy survey stretched from $23/bbl in the Eagle Ford Shale to $36/bbl in nonshale basins. The average across the basins was $30/bbl.

On average, E&Ps said they needed the price to be $49/bbl to profitably drill a well. That average across the regions ranged from $46/bbl to $52/bbl, so if oil prices top out in the $40s, as Pirrong suggests might be the top of the range, it is an early signal that drilling could, at best, be limited for the foreseeable future.

"It's a pretty bleak outlook," Pirrong said. "Essentially, everybody in the industry is going to take a big hit, and that's already reflected in stock prices, but the most vulnerable are the relatively leveraged E&P players, particularly in the U.S. shale. They just don't have the balance sheets to survive."

He anticipates a dramatic decline in U.S. drilling activity that will hit the oilfield service firms hard. High levels of unemployment can be expected as well, particularly among E&Ps.

### The coming shakeout

Demand was entirely inelastic to price in March, Fasullo said, which put tremendous pressure on E&Ps to constrain supply. Making a very bad situation worse, Saudi Arabia, Russia and UAE are making plans to ramp up production. They, along with traders, are scrambling to secure ships to transport crude or store it as the global surplus grows. U.S. exports—which had been the solution for booming U.S. crude production—are currently, for the most part, greatly compromised. That's because rapidly rising freight costs along with the global surplus have narrowed the price spread between Brent and WTI to under $4/bbl, strangling export economics. With U.S. oil demand contracting and exports sure to be threatened, storage becomes the only option to handle excess crude.

"As we put more crude in storage—which is limited—the challenge gets back to the E&P companies," he said. "How fast can they throttle back? In a free market environment, throttling back production can be very uneven. Some companies are financially stronger than others, so some companies continue to produce. Some companies are more hedged than others, so they can continue while other companies can't; some companies just have to produce to pay down debt."

The great U.S. oil-producing machine has had massive forward momentum through 2019, and although it was expected to slow in 2020, it cannot stop quickly or easily even in this awful environment. Fasullo likened it to the time it takes to stop a supertanker. So, any additional crude on the market will exacerbate the low-price dilemma. The inevitable result is a slew of the oil patch's weaker players forced into tough decisions about their future viability.

"What you're going to see as soon as we get out of this: who are the winners, who are the losers?" Fasullo said. "Who's going to get rationalized, whose properties may get bought. You may see the new world order of E&P companies after this is all over with." □

# OFS: LOWER-FOR-LONGER SCENARIO

As E&Ps jam the brakes on capex spend, the largest U.S. oilfield service providers respond in unison, cutting costs where they can and laying down equipment where they must.

ARTICLE BY
BLAKE WRIGHT

PHOTOGRAPHY BY
STEVE TOON

Large oilfield service companies are planning for the worst in 2020 as the industry faces the dual threat of a commodity price collapse and COVID-19. Executives from Schlumberger Ltd., Halliburton Co. and Baker Hughes Co. are all in agreement that the market situation is fluid and trending south and that activity levels across the U.S. and the world are being impacted.

As a result, many service providers are looking at decisive and hefty spending cuts with plans to concentrate remaining capital on operations that generate cash flow as the headwinds stiffen.

"These market conditions are prompting us to accelerate our position in product lines, accelerate our position in 'scale-to-fit' and accelerating laying down equipment and unfortunately separating some of our resources and employees," Schlumberger CEO Olivier Le Peuch told investors at the recent Scotia Howard Weil Conference. "We don't necessarily need to restructure. The restructure was already pending. It is not an easy ride, I must say, but I think we are doing everything we can."

Schlumberger can flex its capital spending plans lower, if warranted, down as much as 30% below last year's spend of around $1.6 billion. Le Peuch added that in case of an extreme scenario the company would be looking for a way to exceed that cut and keep operating.

"The industry is facing an unprecedented dual impact on the demand and supply side, which none of us have ever witnessed over the course of our professional lifetimes," said Halliburton CFO Lance Loeffler. "While the duration and magnitude of the downturn is still relatively unknown and continues to evolve, know that Halliburton will be swift with our actions. We don't have presumptions on a sharp recovery at this point and will take actions with that view in mind."

Halliburton is seeing a rapid reduction in activity across North America and a 60% to 65% overall decline assumption in rig count is being modeled for the last quarter of 2020. In mid-March, the company furloughed about 3,500 employees at its Houston headquarters for a two-month period in a move to help weather the storm. The company's capex will be significantly lower than the originally announced $1.2 billion. Loeffler cited the 2015 to 2016 capex level of $800 million not being out of the question for this year.

"We're going to be very thoughtful about pricing," added Loeffler. "It was already at a fairly challenging level for the industry to really justify any reinvestment. I think this will only put more stress on that. At the end of the day, it really doesn't make much sense for us to burn up our equipment for sub-scale returns. It will be a very different view of North America, and I believe it will be happening in the short term."

Baker Hughes also is preparing for a 'pretty meaningful' downturn as it looks to accelerate cost cutting initiatives and scaling the business as needed. The company's North American business is about 40% production related op-

prices," analysts said in a note. "Therefore, reducing cash burn is the goal. Eventually, necessary service activity will normalize; however, there is no clarity as to when this would occur. While this is a cyclical industry, at today's activity levels some companies may not get to the better times."

"While this is a cyclical industry, at today's activity levels some companies may not get to the better times."

—Raymond James & Associates

erations—artificial lift and production chemicals—and 60% drilling and completions.

"Well completions are going to be coming down," said Judson Bailey, vice president of investor relations for Baker Hughes. "E&Ps are going to be cash-constrained. Our lift business will come under some pressure. Our completions side doesn't have pressure pumping. It's rotary steerables, completion tools, etc. I would expect those to, at least initially, fall in line with the overall drilling and completion trends."

Like its competitors, the contractor can scale its planned 2020 capex based on activity. A 20% to 30% reduction in spending is something that is 'doable,' according to Bailey.

If it's any consolation, operators realize they need oilfield service companies to survive. If one player goes down, it becomes a bit harder for the industry to remain competitive.

"We need service companies to stay in business or else we cannot get our goals accomplished," Earthstone Energy Inc. CEO Robert Anderson said, adding the company tends to work with smaller oilfield service companies with cultures similar to its own. "We also don't try to squeeze the last dollar out of the service company. If we can't make money on a project, then we both go home. So, we try to get everyone focused on the economics."

Raymond James & Associates forecast U.S. upstream spending would fall by 50% year-over-year.

"There are some restrictions to how quickly activity can fall, but what is clear is that the U.S. oilfield needs to effectively come to a stop. It remains unlikely that noninvestment grade credit markets will open up to oilfield services without a significant rebound in oil

**Specialists under pressure**

Analysts with Wood Mackenzie have also signaled an acceleration to the downturn in the U.S. oil service sector, with increasing capital discipline by operators impacting demand for equipment and labor in 2020.

"In the U.S. Lower 48 market, we are already seeing major pricing concessions," said Mhairidh Evans, principal analyst in Wood Mackenzie's upstream supply chain research team. "Some pressure pumpers have reduced prices by as much as 20%, while rig rates have dropped by about 15%."

Pressure pumper BJ Services was already facing a soft market for services ahead of the oil price crash due to many operators transitioning to a 'living within cash flow' business model. The contractor has implemented executive and organizational salary adjustments, suspended certain stipends and discretionary benefits such as 401k and is continuing to reduce and adapt its workforce where required. BJ has enacted temporary furloughs on the portions of its workforce immediately impacted by client changes.

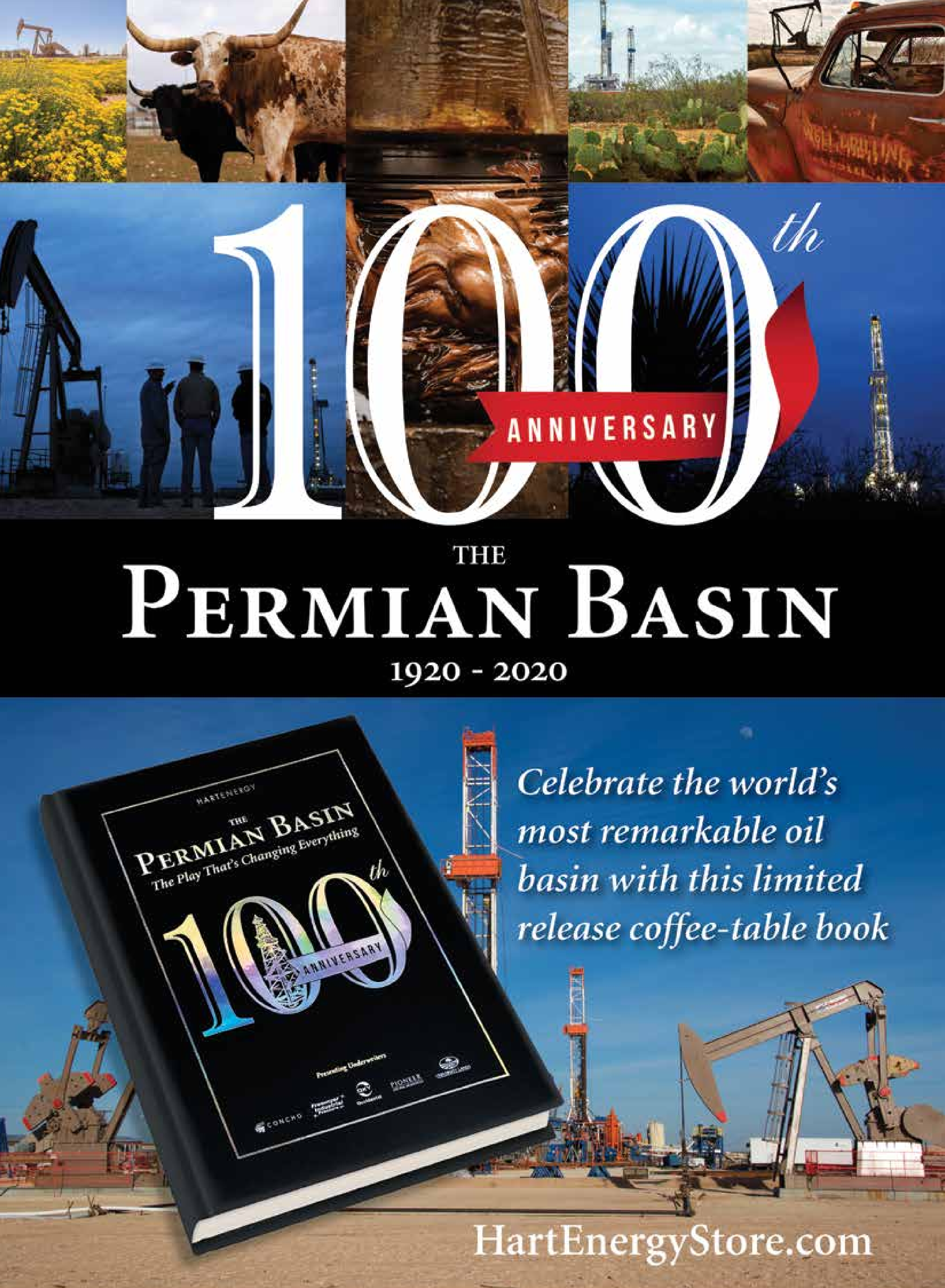
"Clients are certainly suspending projects," said BJ Services CEO Warren Zemlak. "That's probably been the more immediate and significant impact. This market continues to throw new challenges at us. Given the erosion of pricing over the past couple of years I think that, quite frankly, there isn't a whole lot to give."

Contract driller Nabors Industries has cut its planned 2020 spending plan from a midpoint of about $360 million to just under $300 million due to the rapidly deteriorating industry landscape. The contractor is planning for a prolonged impact of the coronavirus and has already been notified of operator's plans to lay down rigs in the immediate future.

"We are planning and assuming that it is going to be a fairly rugged downturn," said Nabors CFO William Restrepo. "For planning purposes we're assuming it is going to be fairly long with an impact on pricing and volume."

Nabors has also implemented broad salary reductions across the company (20% for certain management and 10% for certain other employees) as well as a suspension of its dividend. □

*Velda Addison contributed to this article.*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# THE MASKED OILMAN

We're taking a departure from the normal here. But what's 'normal' right now anyway? And what will be normal next quarter? So, we asked.

INTERVIEW BY
NISSA DARBONNE

ILLUSTRATION BY
ROBERT D. AVILA

*Finding an oil and gas producer with a corporate message to share with* Oil and Gas Investor's *readers at press time was like trying to find a thermometer during a global pandemic. The interview that had already been done was based on a world that was $60 WTI.*

*That had become the stuff of yore—so yore that millies could even finally play the meme game "I'm gonna tell my kids one day __." In this case, accurate would be "I'm gonna tell my kids one day about when hand sanitizer was a form of currency."*

*So find an industry executive who had something to say anonymously?*

*This longtime wildcatter—now solely a private oil and gas investor—has seen five decades of industry booms and busts. Here's his take on the business as it stood the first week of April.*

*While the remarks aren't controversial—unrestrained profanity was allowed, but he didn't even use any, which was disappointing because hearing some without being the one saying it would have been refreshing—he simply preferred to let his comments represent no particular person.*

*They likely represent the thoughts of any oil and gas investor.*

*Here's his take.*

**Investor** How do you *really* feel about things?

**Oilman** About the coronavirus? The destruction of demand? OPEC+ not cutting back?

**Investor** Yeah, all of it.

**Oilman** The reaction of Saudi Arabia to Russia's noncompliance obviously occurred prior to any demand destruction that is related to the coronavirus, so I think that situation is unrelated to everything that has happened.

It's been dwarfed by the demand destruction, and it's not the objective the Saudis were aiming for. So that's why I think there is hope there may be some OPEC++ [OPEC and Russia and the U.S.] reaction that may limit current supply.

Some estimates are of demand destruction of 25 million barrels per day. I would think anybody would agree 15 million barrels per day is almost a certainty of what's been destroyed.

OPEC++ is not going to change the dynamic of the commodity price, but I think it will certainly avoid the calamity we're looking at in May where the price of oil goes to zero.

**Investor** Yeah, snooping on ship traffic on VesselFinder.com, it's incredible the number of oil tankers parked—just sitting there—outside the Houston Ship Channel. To see it in person too from the shore, you know something is wrong.

**Oilman** Supply is probably 15 million barrels per day above demand. Where are you going to put the oil? There is no place to put it. The forecast of tanks being topped out and nowhere to pump the oil, particularly in the Permian, makes all the sense in the world.

That's what the anxiety I had was derived from. That was prior to the hopeful announcement by President Trump [of working too on cutting back on world supply].

Nominations have already been made for April—unless force majeure plays out. All bets are off when people start invoking force majeure and that will probably happen.

But there is a very near-term reality that oil cannot be transported to the Gulf Coast because there's just no room for it.

I think cooler heads will prevail between the Russia-Saudi pissing match. The unfortunate demand destruction of the coronavirus is so incredibly unprecedented in our industry. It is unprecedented under every banner you could put it.

The demand-versus-supply diversion is just mind-boggling.

**Investor** Speaking of oil having nowhere to go, the Texas Railroad Commission [RCC] is talking about pro rationing again, but what's the point if the oil can't go anywhere anyway?

**Oilman** My understanding is it's more to ensure an *equitable* decrease in production as opposed to the *haves* having the ability to produce and the *have nots* not. Those *haves* have contracts and relationships and whatever you want to call it—probably a strong-armed opportunity and that's probably overstated, but still.

The Exxon Mobils and the largest independents of the world will probably have a better opportunity to move their barrels than Mom and Pop and anyone in between Mom and Pop and the largest independents.

"OPEC++ is not going to change the dynamic of the commodity price, but I think it will certainly avoid the calamity we're looking at in May where the price of oil goes to zero."

That's my understanding of why we would consider enacting a proration schedule—to just make it an equitable reduction in volumes and not having some companies get to produce their full productive capabilities and some not getting to produce any of it.

**Investor** Not doing that would push the smaller ones out.

**Oilman** Right.

**Investor** And all markets are better when there is more competition and not less.

**Oilman** Right. And that's what the RRC was created upon. It was created to control the entire stage of production.

Now it certainly wasn't designed as a cartel in theory, but it does create a level playing field—for the entire industry in the state to be treated as a singular entity and there be no favoritism.

**Investor** What's your forecast for Chapter 11 filings? One for if OPEC+ does nothing; two, if they do something. Is it too late for some operators no matter what?

**Oilman** OPEC++ because we have to be involved in that as well. OPEC and Russia are not going to cut 15 million barrels per day so we can produce flat out. I think that is what has been put forth, and I don't blame them whatsoever.

Now, how we as an industry [in the U.S.] would cut back is a more challenging exercise; we aren't nationalized.

But assuming we could come to some ability—such as the prorationing approach by the RRC—to cut, hypothetically, 2.5 million barrels per day to be part of the overall 15-million-barrel-per-day cut, it would take a visible strain off the companies that are challenged with their debt.

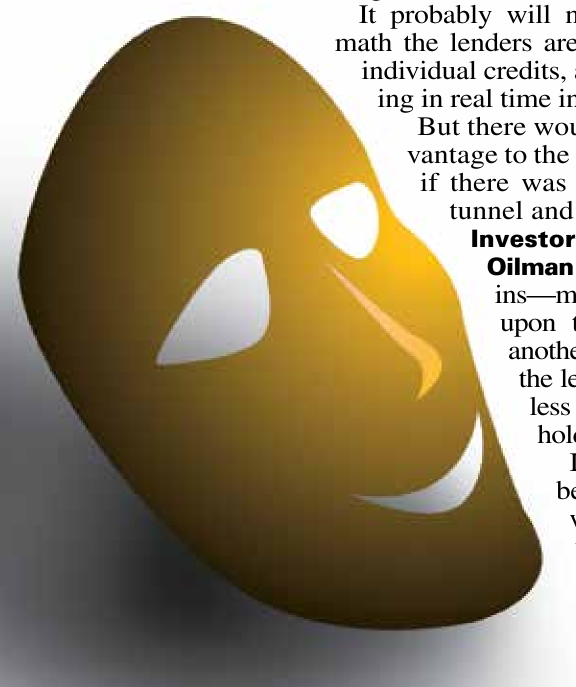
It probably will not physically change the math the lenders are embarking on with their individual credits, and a lot of that is happening in real time in spring redeterminations.

But there would be a psychological advantage to the lenders to be more lenient if there was a light at the end of the tunnel and it wasn't a train.

**Investor** And if it doesn't happen?

**Oilman** If we do see massive shut-ins—massive curtailments forced upon the industry—it just adds another element of uncertainty to the lender's calculus that creates less likelihood that they will hold their nose.

I know there is a hierarchy being construed as we speak within each bank as to which are the more putrid of credits. Those that are the most putrid are certainly going to be coming under more scrutiny.



Among those, there's going to be a reasonable number that, upon discussion with the company and the bank group, will conclude with that "You are potentially in some element of default, but we certainly don't want your keys because this may be a short-term event. The oil price isn't going to come back up overnight. But there is a light at the end of the tunnel, and the [coronavirus] task force has given us some reason to believe there is a light at the end of the tunnel."

I think the banking community will hold its nose on those credits they deem slightly in default but don't deserve to be foreclosed upon or even considered in the bucket to be foreclosed upon.

**Investor** The FDIC messaged in the past week that it wants lenders to focus on customers "at this time of need" and not worry so much about the usual standards. It seems, though, that some operators had already gotten a few passes. Will some syndicates walk away from these?

**Oilman** Yes. You have those.

Then you have those that are in a bad situation but are taking action and have active relationships with lenders. Look at Callon [Petroleum Corp.], for example.

They're a public company. They're not in the bucket of hundreds or probably thousands of small private companies.

But I think the story is similar: They just knew "This isn't going to work. We are over-levered. And we are going to restructure."

There are those types of situations—self-imposed, but I'm sure the creditors were involved.

But, it's correct that, if all the covenants were strictly adhered to in the spring redetermination season, it would be so bloody and for no real solid reason to force these companies into default.

The last thing you want is the banks and trustees to take the keys to these companies. The system would just crater and all because of an event that was out of their control.

Now, yes, some companies have been in violation of covenants for many determinations and have gotten waivers. The banks have held their nose on these credits for maybe a year or more. Those are the ones they are going to say to "You were teetering in the past and now you're on your back. And there's nothing we can do about it."

But those who have been working with their banks and staying within compliance and not pushing their borrowing base, those guys are going to get the treatment you described—a "Wink-wink, I'm going to hold my nose" or "We're going to kick the can. We're not going to foreclose on everyone in violation of their covenants because that's just not a smart thing to do."

**Investor** OPEC++ wasn't possible in 2015 to 2016 when it would have been seen as antitrust. But now it seems it would be defended as a necessary wartime act.

**Oilman** Yeah, or force majeure. Here's an act of God, literally. I'm not blaming it on God. But it is an act of God that is out of everyone's control, and we don't have anywhere to put these barrels.

So we as a worldwide oil community are making the rational decision to keep these barrels in the ground until we have the demand restoration that will allow us to produce them.

I'd be hard pressed to think Congress will look at a shut-in situation for domestic production as a violation of antitrust. It's just a fact of life that we just don't have anywhere to put these barrels and we as a collective group—Saudi Arabia, Russia, everybody—need to act accordingly.

**Investor** Come to think of it, national-level proration could be effected with the old "new oil, old oil" technique? Albeit for a different reason than why it existed in the 1970s.

**Oilman** Yeah. And that's something that is just practical.

**Investor** What would go first?

**Oilman** There are two buckets. There are the wells that are commercial at $20 WTI less the differential. You would go well by well by well and lease by lease by lease and determine whether you're losing money and shut those wells in if you are. That's Bucket #1.

But that's not a very big bucket in a 13-million-barrel-per-day situation.

So you really have to go to the next bucket. It starts with the recently completed wells that you can choke back and that doesn't do any damage. You're curtailing near-term production that you probably want to curtail anyway because you're selling it at $10.

Then you start to get into the 2 or 3 or 6 year olds that are near-wellbore depleted. They, in a lot of cases, have high water cuts, and they're probably on gas lift and/or rod pump.

They are the most at risk for reservoir damage if they're shut-in. They would have problems that would cause bringing them back on to be both expensive and potentially have lower rates than when they were shut in.

Those are the ones that have the most risk.

I have no idea whether we as an industry could curtail, say, 2 million barrels per day and not put those riskier wellbores at risk. That would be an exercise that would be very interesting to do, and I'm sure operators are doing it in a one-off basis.

But, whether OPEC+ agrees or not, we probably have to do it.

**Investor** If between now and year-end nothing gets worse and things start to get better, when might the industry be robust again?

**Oilman** It's not a $64,000 question; it's a $64 zillion question because nobody knows. There are so many variables. It's not a $64,000 question; it's a $64-zillion question because nobody knows," and the entire world economy is dependent on some sense of normalcy in order to see meaningful recovery." There are so many variables.

How do you define "better?" Has the task force projection of deaths followed the curve and by early summer they are nominal? And new cases are nominal? And the government concludes we can "get back" to work and we work for three months and we haven't seen a resurgence in cases?

> "There is a hierarchy being construed as we speak within each bank as to which are the more putrid of credits. Those that are the most putrid are certainly going to be coming under more scrutiny."

That to me is the best-case scenario and in my view—and I'm an optimistic person—I think by the fourth quarter your demand is not fully restored but you're close.

Worldwide, we're not going to be flying as much, but I think we will be driving as much or maybe even more. So I think there is reason to believe that—with the scenario that most of the forecasts by the scientists are reasonably accurate—by the fourth quarter we are in a relatively normal demand situation for oil.

**Investor** If there is any glimpse of a pair in this hand, natural gas should have a better second-half 2020, with the decline in associated gas production?

**Oilman** Absolutely and don't discount the fact that the prompt month is $1.60. The Marcellus and Haynesville have basically gone to maintenance mode—if not decline mode. There is really very little drilling going on for dry gas—much less the total collapse of oil drilling.

So yeah, there's not an analyst out there today who isn't calling plus or minus $3-or-better gas for 2021. I think that's a fair statement.

And I don't know why it wouldn't be that way.

So, yes, there is a lining there in the industry—that those with gas-driven revenues are looking at a situation next year that should be very positive.

**Investor** What else should readers understand about the oil-price situation?

**Oilman** What I'm hopeful for is that the workforce isn't compromised. Not just our industry but the U.S. workforce in all industries. I want this statement to apply to all.

I mean compromised such that they're not going to come back to that industry for whatever reason. In the past, people have been laid off for reasons related to circumstances within the industry that were somewhat self-inflicted.

Those workers have a lot of times been reticent to return to the industry. It's a "fool me once, shame on you; fool me twice, shame on me."

So people at times have not come back to the industry because they don't want to put up with getting laid off again.

I hope we will be able to restore all of our industries and a workforce that is necessary to pick all the pieces right back up and move on.

Or it will be a much slower recovery for the overall economy.

People being able to get back to work at the same job they had is what I'm very hopeful for. □

# DWINDLING DEBT OPTIONS

Debt markets are bifurcated, with questions arising over E&Ps’ ability to pay upcoming maturities.

ARTICLE BY
CHRIS SHEEHAN, CFA

A double black swan event, combining the coronavirus crisis and a crude oil price war between Saudi Arabia and Russia, has put heavy pressure on balance sheets of much of the energy industry. Capex budgets have been slashed as crude prices have collapsed. Debt levels are under heightened scrutiny. As several observers have commented, the name of the game is “survival.”

Few claim a real handle on the price of crude, but prices have trended lower, with an expected oversupply pushing WTI prices down as far as $20/bbl as of mid-March. Any success from a return to the bargaining table by Saudi Arabia and Russia might help slow the pace of inventory builds, but the bigger factor for crude prices is COVID-19-related demand destruction.

Some analysts predict a path for crude prices to the teens or single digits, as crude and product storage levels approach maximum capacity and unused space is quickly filled as the market demand for oil declines.

Obviously, in the current environment, revised budgets have been predominately designed to avoid any outspend and increase in debt. But resetting a budget hinges on key variables. With revised capex cuts set mainly on a $30 to $35/bbl WTI, budgets would still spend 120% of organic cash flow at strip, which has a $22 prompt month and nearly $25 for the balance of 2020, according to a March 19 Morgan Stanley report.

The above illustrates the urgency of scaling back capex to hold down debt. This trend has seen some producers retreat from a goal of modest growth to one of maintenance mode, or holding production flat, and then a move to survival mode allowing for declines in output by year-end. In a late March survey, Barclays estimated a 37% drop in capex by large

SOURCE: LIGHTSPRING/SHUTTERSTOCK.COM

and small and mid-cap producers in 2020 versus 2019.

## Bifurcated debt markets

Capital markets can do little to shore up balance sheets. Equity markets have collapsed and, in any case, have been shut to upstream energy for months. Debt markets are bifurcated, with energy credits trading at deep discounts for all but the highest-quality issuers. For companies facing a need to refinance debt in the next few years, there is a "daunting debt wall" as maturities approach, according to an S&P Global report.

In addition, the outlook is for commercial banks to tighten significantly their reserve-based lending (RBL).

According to Tudor, Pickering, Holt & Co. (TPH), there could be a "brutal redetermination season" this spring, with the "best case scenario" being banks using oil and gas price decks based on the forward strip. Coupled with the high-yield debt market being closed, this means "many E&P names will trigger covenants on revolvers and will face high hurdles to tackle maturities as they come due."

For those companies carrying relatively high leverage or facing near term maturities, the outlook is dim.

Generally speaking, spreads in the high-yield energy sector have widened dramatically and now exceed by over 400 basis points the levels prevailing in February of 2016, when WTI fell to just over $26/bbl. In response to the widening of spreads in the corporate sector of the broader economy, Federal Reserve policy has been expanded so it can purchase corporate debt—but only if rated BBB- or higher, which excludes high-yield bonds.

Data from Bloomberg Barclays illustrate the sharp turn lower in the high-yield market. For example, Laredo Petroleum Inc. took advantage of a brief window in January to tap the high-yield market. It priced two bonds, with maturities in 2025 and 2028, at par to yield 9.5% and 10.125%, respectively. Prior to the OPEC meeting, the bond traded down markedly, to levels below 60, with yields well in excess of 20%.

In late March, in the wake of the OPEC meeting, the bonds were trading in the mid-30s to yield 35%.

"A name like Laredo could not come to market today, and that's the case with a lot of E&Ps and drillers," said one market observer.

Stronger names, such as Parsley Energy Inc., rated BB, and WPX Energy Inc., with a BB- rating, has not fared well but held up better. Parsley priced a senior note due in 2028 at par to yield 4.125%, while WPX priced a senior note due 2030 at par to yield 4.5%. Both bonds traded down to the low 90s prior to the OPEC meeting. After the meeting, the bonds traded at 57 to yield 13% and 51 to yield 13.75%, respectively.

The oilfield service sector has been hit even harder, where senior unsecured guaranteed notes had been issued by Nabors Industries Inc. and Transocean Ltd. These rank ahead of legacy unsecured notes without guarantees. Nabors' two tranches, yielding 7.25% and 7.5% at par, traded down into the 80s pre-OPEC. The Transocean issue, priced to yield 8% at par, fared worse and slid into the 70s.

Post-OPEC, the discounts have deepened, with the bonds trading in the 30s and 40s, respectively.

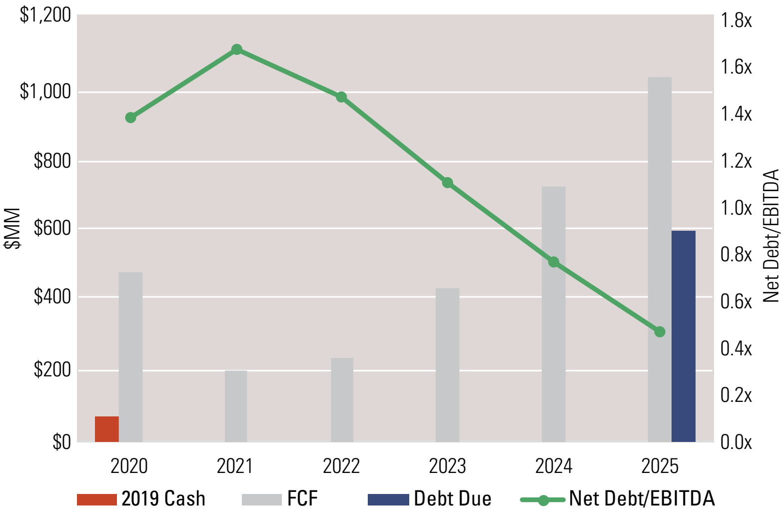
## Wave of bankruptcies

"I think it's inevitable that we're going to have another wave of bankruptcies," observed Gary Stromberg, a principal and head of high-yield energy research at PGIM Fixed Income, an investment arm of Prudential Financial. New issuance has come to a halt, with the energy sector of the high-yield market "effectively closed," and the market "really punishing" existing bonds in secondary trading.

Obviously, the breakup of the OPEC+ meeting without an agreement has only helped to hasten the slide in the energy high-yield market.

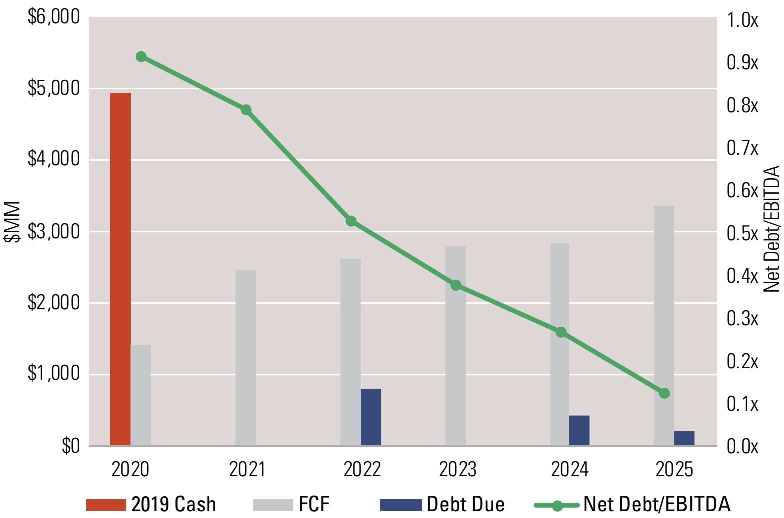
"I don't want to say OPEC is unraveling," said Stromberg. "But, clearly, not being able to continue the cuts they had in place is extremely

**Concho Resources (CXO)**




Source: Tudor, Pickering, Holt & Co.

**ConocoPhillips (COP)**




Source: Tudor, Pickering, Holt & Co.

“The market is really punishing these companies, given the oil price outlook and the cost outlook of these levered companies,” said Gary Stromberg, principal and head of high-yield energy research at PGIM Fixed Income.

bearish for the market.” And with Saudi Arabia putting over 2 million barrels per day (MMbbl/d) on the market, coupled with demand destruction of 3 to 4 MMbbl/d due to the coronavirus, “if you start adding it all up, the world becomes awash in crude very quickly.”

Compared with the severe market conditions in 2015 to 2016, the high-yield credits today “are actually in better shape,” according to Stromberg. “We weeded out a lot of the really weak credits during the last mini cycle.” However, the fact that credits had improved—even as spreads in the sector had surpassed levels last seen in early 2016—“tells you how weak the high-yield energy market really is.”

The Barclays High-Yield Energy Index indicated a spread over U.S. Treasuries of about 700 basis points in early 2016. Recently, the spread widened still further to as much as 2,200 basis points. “The market is really punishing these companies, given the oil price outlook and the cost outlook of these levered companies,” said Stromberg.

In evaluating high-yield bonds, more stringent metrics are often being used, noted Stromberg. On proved developing producing properties, some investors are no longer using PV-10 metrics, but rather PV-12 or PV-15 valuation. No longer is any value accorded to proved undeveloped properties or to acreage in an assessment of collateral.

“That’s a major change in the markets that’s happened over roughly the last year,” he said.

## Hefty cuts to borrowing bases

For E&Ps facing near-dated maturities, the option of using a bank borrowing base to pay down senior notes or to provide liquidity has likely dimmed, according to Stromberg. “We understand the banks are using much lower prices in this spring redetermination season, and our expectation is that you’ll see pretty hefty cuts to those borrowing bases,” he said.

In addition, a number of E&Ps risk failing to meet the covenants of their bank facilities, said Stromberg. If in breach of a covenant, “the banks have in the past provided relief if they think it’s a short-term issue. But in this type of market and what we’re seeing with the commodity markets, the banks are going to be much less willing to give relief on covenants.”

What other options are available to producers—at a cost?

One possible avenue is a first lien term loan, “but it’s going to be expensive,” cautioned Stromberg.

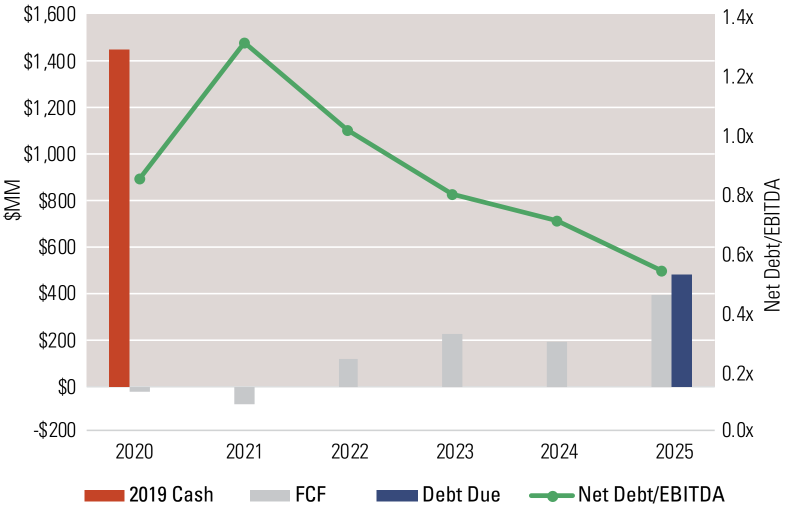
“The problem is that, if you are at Libor plus 250 basis points on your borrowing base—which is where a lot of these E&Ps are—first lien energy bonds may have a 10% coupon,” he said. So you’re taking a company that already has trouble potentially serving interest payments at recent low oil prices, and now you’re adding a much bigger interest burden on it.”

One potential area for optimism, said Stromberg, was the likelihood of a rebound in natural gas prices.

“I have a more bullish, medium-term view of natural gas,” he said. “We’re going to see the rig count for oil come down. That does two things: It brings the oil supply down in the U.S., and a lot of the associated gas produced from Permian wells will also fall off. So, in a market where natural gas supply is declining in the U.S., and assuming a normal winter next year, you could see prices snap back a little quicker with gas.”

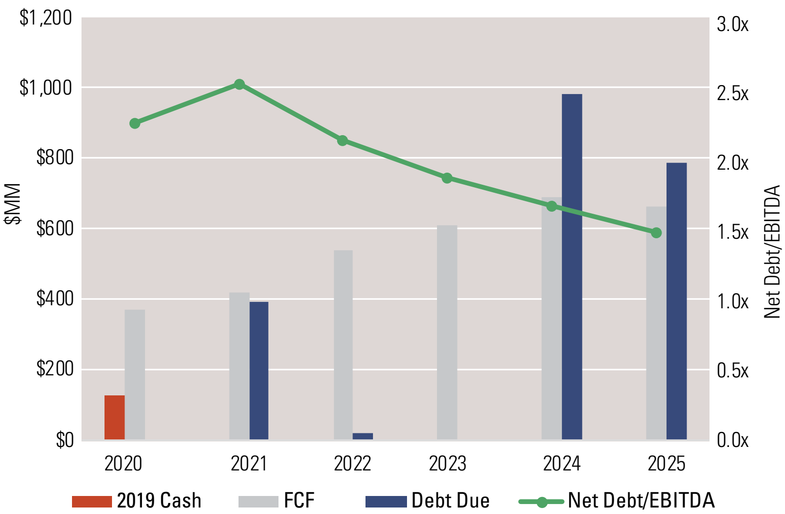
Over the longer term, however, market forces are “going to starve capital out of the system,” which will ultimately be good for the oil

**Devon Energy (DVN)**




Source: Tudor, Pickering, Holt & Co.

**Diamondback Energy (FANG)**




Source: Tudor, Pickering, Holt & Co.

and gas sector, according to Stromberg. But in the meantime, "companies are going to struggle to find capital," he warned.

"We've had a perfect storm of the coronavirus hitting the largest demand source for oil, transportation, at a time when OPEC has been holding 2 million barrels per day off the market and has effectively been losing market share to the U.S. And Saudi Arabia has made a very difficult decision to stop losing market share," he said.

**Coming surge of 'fallen angels'**

Rating agencies recently downgraded Occidental Petroleum Corp. to junk, burdened by $38 billion in debt following its acquisition of Anadarko Petroleum Corp. While defaults may shrink the high-yield market, "everyone is now focused on the coming surge of 'fallen angels,'" which by Stromberg's estimate could top $50 billion. "Investors have plenty to do," but at oil prices below $30/bbl, "not many companies can break even."

Funding issues for energy producers have reached a truly critical point—the point of survival—according to Matt Portillo, CFA, managing director of E&P research for TPH. "It's all about survival," he said. "The key is being able to survive and not destroy your balance sheet between now and the recovery. It's really about who lives and who doesn't in the current environment."

A narrower filter of names able to access debt markets has been long in the making, according to Portillo.

The energy sector was "constructed around the view you'd always have access to a liquid capital market and you could constantly roll your debt forward," he said. "But most upstream E&Ps were so focused on growth, coupled with assumed access to capital, that they never solved for trying to generate free cash flow. For years they didn't generate enough free cash flow to pay back the principal they owed on their debt."

As high-yield investors shifted their focus away from a net asset value model and toward a corporate free-cash-flow model, reticence grew in terms of continuing to fund some companies, especially among smaller cap names, according to Portillo. "That's why I think you started to see the high-yield market bifurcate in a big way in 2019. And that's caused a seizing up of access to capital last year," he said.

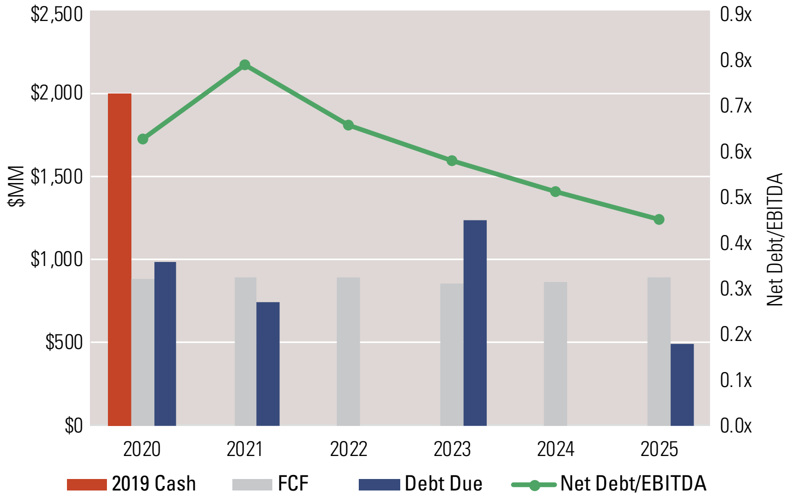
**From bad to worse**

An already bad situation has gone "from bad to worse" with the twin shocks on demand and supply from the coronavirus pandemic and the market share war between Riyadh and Moscow, said Portillo. "A lot of the upstream sector will go into a bit of a death spiral if we stay at recent prices, because as they cut to cash neutrality, output starts to decline, EBITDA starts to decline and E&Ps are still not generating free cash flow."

As capex is set closer to cash flow to avoid adding debt, TPH estimates U.S. oil production will decline by 10% to 11% from the fourth quarter of last year to the fourth quarter of 2020. This is based on an estimated 50% cut in capex for its coverage in 2020. For 2021, as industry hedges roll off for oil from 2020 levels, it expects a further 17% cut in capex, resulting in a 5% to 6% drop in year-over-year production.

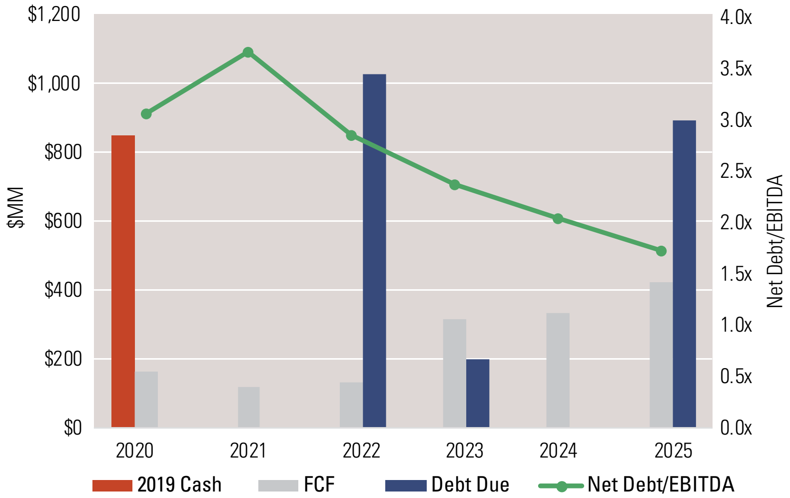
As production slides, prospects for generating free cash flow frequently diminish, especially for smaller companies.

**EOG Resources (EOG)**




Source: Tudor, Pickering, Holt & Co.

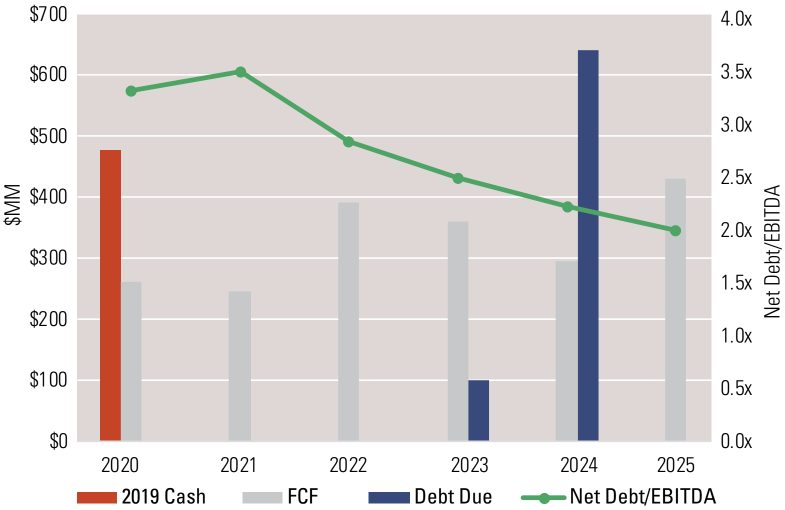
**Marathon Oil (MRO)**




Source: Tudor, Pickering, Holt & Co.

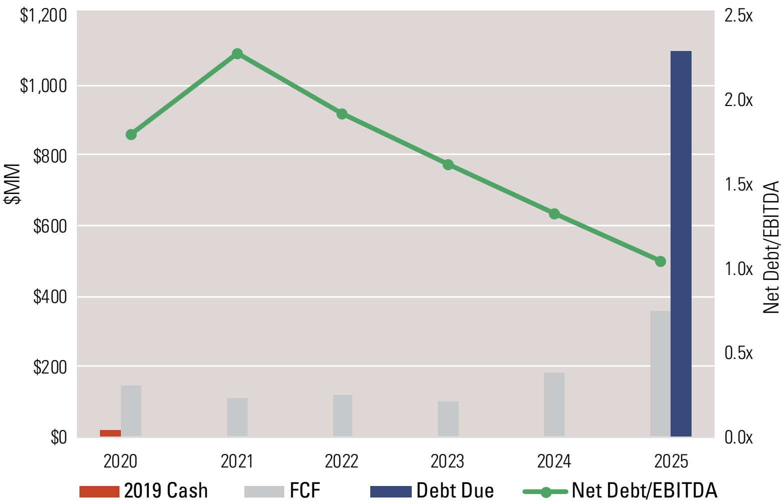
"The key is being able to survive and not destroy your balance sheet between now and the recovery. It's really about who lives and who doesn't," said Matt Portillo, CFA, managing director, E&P research, TPH.

**Noble Energy (NBL)**




Source: Tudor, Pickering, Holt & Co.

**Parsley Energy (PE)**




Source: Tudor, Pickering, Holt & Co.

"The punchline from investors is that real distress is likely to hit E&Ps that don't organically generate free cash flow to pay back their debt over the next three or four years," said Portillo, citing feedback from institutional investors. As a result, "anyone with a debt maturity wall coming due before 2024 is likely to find itself in real distress as it relates to both equity and debt investors."

Before the collapse in crude prices, a rule of thumb was that "the market really didn't have much appetite to finance extensions of debt maturities if leverage was over 1x to 1.5x net debt-to-EBITDA at $50/bbl WTI," said Portillo. Some greater latitude may be afforded to larger, financially stronger producers, but interest in rolling over debt would not extend beyond 2x by EBITDA Concho Resources Inc. for even core names, he added.

Names that are viewed by TPH as core holdings make up a relative small group: ConocoPhillips Co., Concho Resources, EOG Resources Inc. and Pioneer Natural Resources Co.

A second group of more "risk-on" producers—names to visit as the market looks close to bottoming—is made up of two parts: large-cap value stocks and well-positioned Permian mid-cap names. The former is comprised of Devon Energy Corp., Marathon Oil Corp. and Noble Energy Inc., and the latter of Diamondback Energy Inc., Parsley Energy Inc. and WPX Energy Inc.

"All those names have plenty of liquidity and will be able to make it through the cycle," said Portillo. As noted earlier, Parsley and WPX took advantage of a debt window being open earlier in the year. "Although they were at the upper bounds of the leverage metric, there was a clear line-of-sight to compression of that EBITDA multiple. And they got fantastic rates on the debt they issued."

For the large-cap value names, Devon and Marathon, Portillo pointed to both producers having substantial cash positions and, as a result, no real liquidity or maturity issues of concern. In Noble Energy's case, he pointed to the significant free cash flow under long-term contract from its Leviathan project in the Mediterranean Sea as one of several factors allowing the company to "navigate through the cycle."

On the other side of the coin are the many companies that face "major concerns in the near term on liquidity and leverage," according to TPH. The reality is that "the industry, for the most part, doesn't work below $50/bbl," observed Portillo.

"The distress is going to accelerate," he commented. "The banks have tried to be as lenient as they possibly can over the last few years in order to work with the industry. Unfortunately, the collapse in the asset market is starting to cause losses to accelerate on a number of the credit facilities and the high-yield and unsecured bonds in the market. And we don't see the asset market improving any time soon."

Are there any rays of light if you look out far enough beyond the clouds?

Assuming U.S. oil production declines during the next two years and demand reverts to a normalized level in 2021, "a lot of the spare capacity in the OPEC+ countries basically gets eaten up," said Portillo. "And we're starting to see major project deferrals in areas like the Gulf of Mexico and internationally. For 2022 and beyond, the market is facing a very tight amount of spare capacity globally."

## One-directional trade

In a debt market characterized by steep selloffs and heightened volatility, relative value is lost amid an almost one-way wave of selling, according to Ray Lemanski, managing director and head of credit strategy at KeyBanc Capital Markets Inc.

"Nobody is looking for relative value right now among the oil and gas names, whether it's the debt or the equity names," said Lemanski. "There isn't a lot of differentiation. Investors aren't saying, 'I like this over that.' People are selling what they can. And, right now, everything is pretty much one-directional."

Lemanski recently conducted a study in which he assigned high-yield E&P bonds to one of three categories. The largest category by far was one titled "stressed/distressed," which made up over 75% of the total and comprised issuers trading on a yield-to-worst of 13% or more. These are ones where the issuers face "much more significant credits issues and the market is losing confidence in them."

The first of the two other categories is termed "market rate" and comprises issuers that should be able to refinance in a more normalized type of market, typically on a yield-to-worst of around 8% or lower. The second was those whose refinancing depended on some improvement in the credit or commodity environment, typically associated with an upturn in oil and gas prices.

To see some stability in bonds issued by the E&P sector, "the first thing that has to happen is the bond prices in the secondary market need to bottom out—and that's not happening," he said. "Everybody's been hit, including the midstream and, to a lesser extent, the pipeline companies. And it's another tremendous body blow to the folks in the oilfield service sector," he added.

"The best indicator of market trends for E&P issuers is to look at the price of the bonds and the yields as we go forward," said Lemanski. "Look at them across the board, look at them by basin, look at them by rating category, and see if there are trends that you can discern, and then you can make a bit of a broader call. Looking at each individual name right now isn't really telling you very much."

For example, looking at a universe of over 15 names in the Permian Basin, only three were trading at stressed/distressed levels, according to Lemanski. By contrast, in Appalachia, bonds were trading at yields ranging from 15% up to over 20%. And in the Bakken, a number of E&Ps, both public and private, were trading at yields that were north of 30%, he said.

### Basins that 'lead you out'

In terms of trends, "the basins or sectors that were more favored before this happened will be the ones that will lead you out. And the ones that were less favored will remain so and will recover less quickly," he advised. "You'll see buyside analysts start to come out from under their desks and point to relative value between one name and another. That's not taking place right now."

In the interim, the issues that are "front and center from a credit standpoint" for E&Ps are the outcome of redeterminations of RBL facilities from banks and the steepness of the underlying price decks, according to Lemanski. The near-term price assumption will be sub-\$30/bbl, and the question then relates to how steeply the commodity curve is assumed to move up in the out years, he said.

Compared to 2014 to 2016, when WTI finally hit a low of \$26/bbl, are funding sources more or less resilient?

"In general, the banking system is a lot better capitalized than at that time. And the banks have become somewhat more conservative in their RBL exposures than when they were

"The best indicator of market trends for E&P issuers is to look at the price of the bonds and the yields as we go forward," said Robert Lemanski, managing director, KeyBanc Capital Markets Inc.

caught in 2014 to 2016," said Lemanski. However, when the Saudis moved in late 2014, we weren't facing an external shock affecting the demand for oil as we are experiencing today. So I think it's potentially worse."

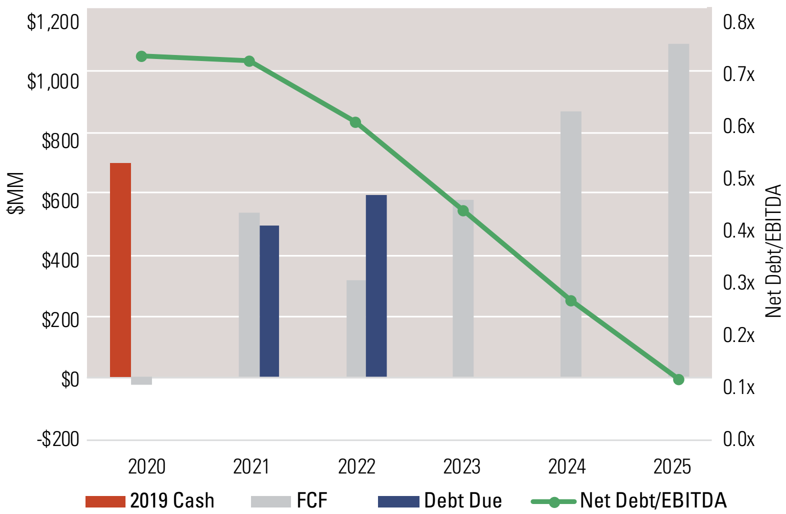
The problem is that "so much of the recovery in capital spending in the U.S. has come from the oil and gas industry," he observed. "And that is going to grind to a halt for a while. I'm not sure we'll see much more issuance for quite some time in 2020," said Lemanski

What would be the leading indicators of a functioning high-yield energy market?

"First, we need to get some general market stability, apart from oil and gas," said Lemanski. "In addition, there is an awful lot of oil that we need to work off. Even our lower-cost producers are struggling at current levels to survive and make money. You have to have some sort of resolution of the problem so you don't have this enormous amount of oil overhanging the system."

And at some point "you'll see the stronger or the more liquid credits, usually in the top tier, test the market successfully. Then others will follow on, perhaps from not as high a tier as the first to test the market. And full recovery of the sector is when first-time issuers are able to successfully tap the market at not an enormous spread to existing names trading in the market." ☐

**Pioneer Natural Resources (PXD)**




Source: Tudor, Pickering, Holt & Co.

# ROUGH RIDERS

Locked up in an MLP bankruptcy for nearly two years, Maverick Natural Resources has new management and a business model aimed at the relentless pursuit of free cash flow.

ARTICLE BY
DARREN BARBEE

*Sprint, Day 1, March 18. WTI spot price, $20.48. Total savings identified, $4.1 million—18% of goal.*

In mid-March, Maverick Natural Resources was like every other E&P in the Lower 48—boxed in by OPEC, a pandemic and buried under an avalanche of bad news that in roughly two weeks had drained the value of oil by 56%.

While other E&Ps rapidly slashed billions of dollars from their drilling programs, Maverick didn't have that option. The company lacks a robust capex program, forcing it to find savings elsewhere. But the Houston company is practiced at taking tight turns. This is, after all, a company of remnants, created by someone else's decisions and miscalculations during another bad time for the oil and gas industry.

By the time the company was ready to find places to cut, CEO Chris Heinson said the company's executives had been independently watching the news and taking actions he didn't direct. That's the way it was intended to work.

"I've told the organization their job, regardless of the environment, is to create free cash flow," Heinson said. Since the company began to adjust to the new commodity prices in March, it has identified millions in savings while preserving its sources of cash flow.

It's the way Heinson insisted on rebuilding Maverick from the remnants of Breitburn Energy Partners LP, a former MLP that entered bankruptcy protection with about $3 billion in debt. Nearly two years later, in 2018, Maverick emerged from the courthouse with about $105 million in debt and a sprawling set of odds-and-ends assets from one coast to the other as well as the Midwest and the Permian Basin.

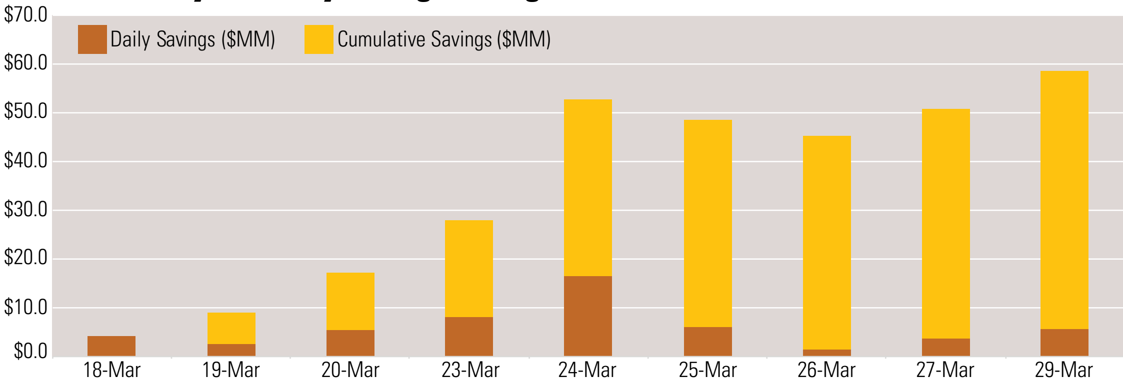
Breitburn, like other MLPs that rose up in the shale boom, was a giant aggregator, consuming complex assets in a seemingly unending cycle of acquisitions meant to increase cash flow. Following the 2014 downturn, MLPs fell apart in the low-price environment, leading to billions of dollars in bankruptcies and a diaspora of oil and gas assets.

Working with corporate improvement specialists at consultancy Alvarez & Marsal, Maverick's turnaround was swift and stunning. After four months of analysis and internal stress tests, Maverick emerged even leaner from bankruptcy—while generating more revenue.

SOURCE: MAVERICK NATURAL RESOURCES

***Maverick Natural Resource's Postle Field operations in the Midcontinent are among a variety of assets, including conventional wells and horizontal shale development, that the company had to knit together and make profitable following Breitburn Energy's bankruptcy.***

**Maverick's Day-Over-Day Savings During 2020 Crisis**




Source: Maverick Natural Resources

***"It is a perverse thing, but it is better to be hands off and to allow more trust, more decisions. The natural temptation you must resist is to direct the actions of the organization below you," said Maverick Natural Resources CEO Chris Heinson.***

Breitburn had used restructuring advisers to make "what you'd think of as the typical cost reductions," Heinson said. Maverick's target was a 20% reduction in lease operating expenses (LOE) per barrel of oil equivalent (boe).

But Heinson also wanted to create a new company with employees who weren't merely excellent operators but could also direct themselves. The resulting two-week long exercises were strenuous and anxiety-inducing.

"They are intense," Heinson said. "They're intense by design."

The company called them sprints.

**Running flat out**

*Sprint, Day 3: March 20. WTI spot price, $19.48. Total savings identified, $11.85 million—53% of goal.*

In one of the remote areas where Maverick operates, the company was faced with paying high rates for power, a part of oil and gas industry life when dealing with electricity co-ops or highly-regulated providers.

A group of Maverick employees self-organized and brainstormed on how they could pay less or renegotiate a lower rate or find a credible alternative to purchase power on the grid.

One plan would use microgenerators to power operations from Maverick produced fuel. Another idea would send power from another state into the area by building a major transmission line over a river.

After generating credible alternatives, Maverick's group was able to win concessions—a strategy the company has adopted elsewhere.

"It was real, credible actions that these teams are independently taking that no one in senior management ever thought of," Heinson said. "But they would not accept that the utility prices coming out of these restricted areas and co-ops could not be changed even though I will say in most of these areas that is actually the rule."

The breaking of bad habits is grueling, vigilant work. The command-and-control structure in place at Breitburn, like that at most E&Ps, became more deeply engrained after its May 2016 bankruptcy. The path workers took to reach decisions deepened into ruts as Breitburn's reorganization dragged on in a 21-month saga.

"The first [thing] we needed to change was the culture, which is a very difficult problem to tackle," Heinson said. "Decisions, particularly during the extended bankruptcy, were quite constrained. They had to be routed for special approval all the way up to the bankruptcy court, which is incredibly crippling. It gets professionals into this state where they're just frozen, and the effort it takes to get a decision made ends up becoming not worth the trouble."

With the sprints, the goal was to shake things up—creating a culture that dispensed with employees asking for permission to take action and freed up managers reluctant to make decisions before seeing every scrap of available data.

The model isn't new and is relied upon among Silicon Valley technology companies.

"What we do is not uncommon," Heinson said. "It is uncommon in oil and gas."

Heinson, an avid reader, said he took cues from the writings of the economist Peter Drucker, whose most influential works were written in the 1940s and 1950s.

"He has a whole school of thought associated with clarifying what leaderships' jobs are and what management's role is and what the workforce is all built around," Heinson said.

Heinson wanted to empower employees and tearing down impediments, particularly at lower levels of the organization, and create a workforce that was unafraid to make decisions on the fly, without seeking approval.

"It is a perverse thing, but it is better to be hands off and to allow more trust, more decisions. The natural temptation you must resist is to direct the actions of the organization below you."

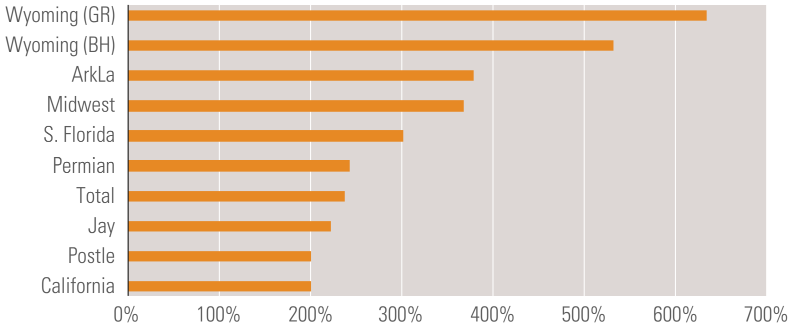
Maverick's sprints were designed to wring every dollar of savings out of the company but to also jolt the staff out of any sense of complacency.

The first of the company's three sprints was decidedly unproductive from a cost-savings standpoint, Heinson said.

"You have to do the most unpleasant things first. The first sprint, reducing field labor, had a much smaller impact than the next couple."

But the sprints were also a way to rewire the nervous system of the company so that executives would engage in taking calculated risks. The entire company, including the accounting staff, field operations, engineering and the receptionist, ran the sprints tighter in a large common area.

**Exceeding Cash-Flow Goals Amid 2020 Crisis**




Source: Maverick Natural Resources

To break habits, "you focus on intensity. You focus on creating stress. And you have to sustain that for a long enough period that it becomes their practice," he said. "And that's what you're left with."

"Every day, the metric that we were looking to hit was an LOE per boe target … which creates an incredible amount of focus and pressure on the results," he said.

As Maverick eyed its LOE targets, the new way of working began to take hold.

### Anchored to reality

*Sprint, Day 7: March 24. WTI spot price, $21.03. Total savings identified, $19.88 million—89% of goal.*

After a close look at some of Maverick's wells, some clearly didn't make sense—or, more importantly, oil.

In the 90 days after Maverick emerged from bankruptcy in February 2018, the company's new backer, EIG Global Energy Partners, tasked Alvarez & Marsal with rightsizing the company.

At the time, Maverick held roughly 600,000 net acres and 7,600 net wells spread out across the Permian, Oklahoma, Wyoming, Florida, Michigan and other several other states. The company now operates roughly 5,000 wells.

Then came the company's data, which, when analyzed, gave a sobering picture of a company that had been in stasis for far too long.

Jay Campbell, a managing director at Alvarez & Marsal, said the firm created economic models, mapping out costs for wells, based on a variety of factors such as water hauling costs.

"When we did that, we saw that there were wells that were producing large amounts of water and almost no oil," he said. "The well was basically under water, literally, from a financial standpoint and an actual standpoint. They were just water wells."

The company's historic mindset was that a well could not be shut in because every barrel of production mattered. However, shutting in the well would cause a relatively minor loss of production and realize an economic gain from reduced hauling costs.

Working with fellow managing director Lee Maginniss, Campbell began piecing together a picture of a company that turned out to be the worst performer in every basin in which it operated.

With its first 90 days complete, a new management team arrived, headed by Heinson, the former COO of Sanchez Energy Corp. Campbell said Maverick's team made it clear that only economic barrels mattered.

From the outset, Maginniss said Heinson was not only open to what the data showed but aggressive about understanding the company's top-quartile peers. Maverick's team were "relentlessly figuring out … what are

SOURCE: MAVERICK NATURAL RESOURCES

***Maverick Natural Resources emerged from bankruptcy in 2018, reorganized financially but still in disarray. A review into the company's holdings in the Permian Basin, Oklahoma, Wyoming, Florida and other states found a company replete with wasteful practices.***

other operators doing differently that we could think about adopting that to some degree," Maginniss said.

Maverick's team was also open to taking concepts from other industries and "how those examples could apply to us, even if it wasn't an E&P," he said.

After benchmarking showed how Maverick compared to other operators, Campbell recalled that the management team didn't argue with the data.

"They basically said, 'If those are the facts, what do we do about it?' And I think that mindset has served them well because … they move forward and figure out how to address it," he said.

Heinson said his reaction was to "anchor ourselves in reality." Heinson insisted on a level of granular data so his team could understand as much as possible about the company's operations.

"It was a sobering wakeup call," he said. "But you know, we did find interesting things."

In some cases, for instance, labor costs were out of step with peer operators.

"The average cost per employee in one particular area was something like $30,000 or $40,000 more than the average," he said.

Alvarez & Marsal's benchmarking showed that top quartile performance would require the company to reduce its LOE per boe by 20%.

After Maverick's first sprint was complete, Maverick continued to seek improvements in its LOE costs.

The autonomy that the company was building helped bridge regional differences in an organization that has conventional wells, horizontal shale development and nitrogen flood enhanced oil recovery. Further sprints identified actions that could be taken to create value and, finally, to start planning how to make changes.

"In the end, you are left with this menu of actions that your organization can take which allowed us to be strategic with our decisions."

The task seemed daunting considering the organization had already gone through bankruptcy, conducted layoffs, renegotiated vendor rates and cut other costs.

After four months, and three rounds of company sprints, the company had found initial savings of 23% LOE per boe. Maverick has made the changes while squeezing an additional $45 million in EBITDA from operations.

"You're going to ask me, 'Well how in the world did they do that?' But, well, I have no idea."

By fourth-quarter 2019, Heinson said the company had reduced LOE by 32% while improving EBITDA 33%.

"It gives you the idea of the magnitude of change that is actually possible if you identify where the value creation is appropriate and that you can really energize and empower the whole of the organization to work on these things," he said.

SOURCE: MAVERICK NATURAL RESOURCES

***Following a rapid drop in oil prices, Maverick Natural Resources ran what it calls "sprints" to reduce expenses and increase cash flow by $22 million. The company ultimately increased cash flow by nearly $53 million.***

**Stop the bleeding**

*Sprint, Day 12: March 29. WTI spot price, $15.48. Total savings identified, $52.93 million—238% of goal.*

Over the phone, Heinson hesitated, pondering whether to answer a question about Maverick's process for setting new cash flow targets for each of the company's nine business units.

In March, Heinson set new goals for Maverick's 200 employees as it responded to the coronavirus pandemic and the oil price war. Oil prices had been ravaged, and the company was again on the hunt for savings while improving its free cash flow by a target of $22 million.

From March 18 through March 29, the company ran what it called a "stop the bleeding" sprint. Maverick's plans included shutting in 785 wells. One division also found health, safety and environmental savings across the business. Other changes across the organization, like its sprints in 2018, are ones Heinson may never know about.

Heinson relented. His free cash flow targets? "I make them up. What I try and do is come up with a number that is sufficiently large enough that I make all my managers nauseous," he said.

He conceded he was being somewhat facetious. But in general he doesn't delve into data models, instead relying on what he calls "reasonableness checks" involving some analytics and an awareness of discrete actions he knows will eliminate larger costs.

"It is really important that you don't over-science your targets because as soon as you start doing that, you're putting an artificial constraint on the organization," he said. "And you've eliminated the organization's ability to positively surprise you."

At the end of the sprint, the company's nine business units each bested Heinson's free-cash-flow targets. Overall, the company estimated improving free cash flow by nearly $53 million. □

# THE WATER'S FINE

Historic service cost lows and fewer barriers to entry could trigger investment back into the U.S. Gulf of Mexico … even at $30 oil.

ARTICLE BY
BLAKE WRIGHT

The double whammy of excess oil supply and the coronavirus has done a number on crude oil prices, which in turn has prompted E&P companies to slash capital spending plans for 2020. Larger independents like Devon Energy Corp., Noble Energy Inc. and Pioneer Natural Resources Co. have chopped spending plans by a third to almost half so far, mainly around their unconventional resource plays and deferring exploration programs. This trio has something else in common. Over the past decade and a half, each exited a dark horse, long-lived asset play that has shown increasing signs of its resilience in these most recent trying times—the U.S. Gulf of Mexico.

As an oil province, the U.S. Gulf has been referred to as the 'Dead Sea' by many—and many times over. The region has been through many peaks and troughs since the first well was drilled there more than 80 years ago. Investment in the region has ebbed and flowed with the shifting tides—be it the splash of deepwater royalty relief which spurred a robust exploration phase in the region during the 1990s, or the Deepwater Horizon incident in 2010 that ground activity to a halt.

The place producers find themselves today are truly uncharted waters—a perfect storm of oil price destruction due to oversupply and oil demand destruction related to most of the world operating remotely due to the threat of COVID-19.

The situation is dire, but like all crises, it can be viewed as equal parts danger and opportunity. Cautious opportunity.

"Operators will have to be more selective with reduced budgets," said Justin Rostant, principal analyst with Wood Mackenzie. "I expect companies will cut 2020 budgets and

***LLOG Exploration Co.'s Who Dat facility in the Gulf of Mexico came on stream in December 2011.***

PHOTO COURTESY OF LLOG EXPLORATION CO.

even some 2021—wherever they can as they become more disciplined with their reduced investment capital.

"Breakeven prices for projects we expected to FID [final investment decision] in 2020 range from Brent $38 to $45/bbl, so they are still attractive in the long run, but I now expect some to be delayed as operators try to slow down their near-term spend. Where you will likely see a bigger impact is in exploration wells drilled. Companies with rig contracts in place will reduce exploration activity and focus on development wells or lower risk exploration wells near infrastructure that can be tied back and brought online quickly to generate revenue."

Today's crisis is yet another marker in the timeline, but one that could hold a silver lining for cash-rich, less risk averse operators at a time when service costs are depressed, even for the most elite equipment.

"Rig rates used to be in the $600,000 per day range at its peak for a deepwater rig," said Rostant. "In 2018, we saw day rates as low of $150,000, but current rates are closer to $220,000. These lower rates are a huge contributor to the overall costs coming down in the deepwater Gulf of Mexico.

"The other thing that you're seeing as well is the technology on the rigs; the high-spec rigs have always improved the efficiency and how fast they can drill wells. Back in 2014, we had an average five days per thousand feet from a drilling rate standpoint. By 2019, it was touching two and a half days per thousand feet. So again, part of that's due to the high-spec rigs coming into the Gulf of Mexico."

The current outlook may take rates even lower. Pundits see that the combination of E&P capex cuts and the impact of COVID-19 on the ability to get personnel and equipment and services to and from offshore rigs will soon put downward pressure on utilization. If the U.S. Gulf goes into lockdown due to increasing logistics complications, the fleet will go idle and warm stack the units in the region. According to a recent report from Westwood Global, the result will be likely an increase in force majeure declarations, which can lead to contract renegotiations or, in some cases, terminations.

The Trump administration is looking into a possible aid package for oil and gas producers, including those offshore. A group of lawmakers sent a letter to the White House asking the president to reduce or waive collections of production royalties from the federal waters of the U.S. Gulf. The move followed Trump's decision to purchase 30 million barrels of oil from producers for the U.S. Strategic Petroleum Reserve.

A mid-March U.S. Gulf lease sale attracted only half the bids of the previous fall auction. The sale took in $93 million in high bids, the lowest tally in four years. While the offerings did not attract much new investment, the legacy independents in the region, such as W&T Offshore Inc., Houston Energy LP and LLOG Exploration Co., participated scoring multiple lease blocks at bargain prices.

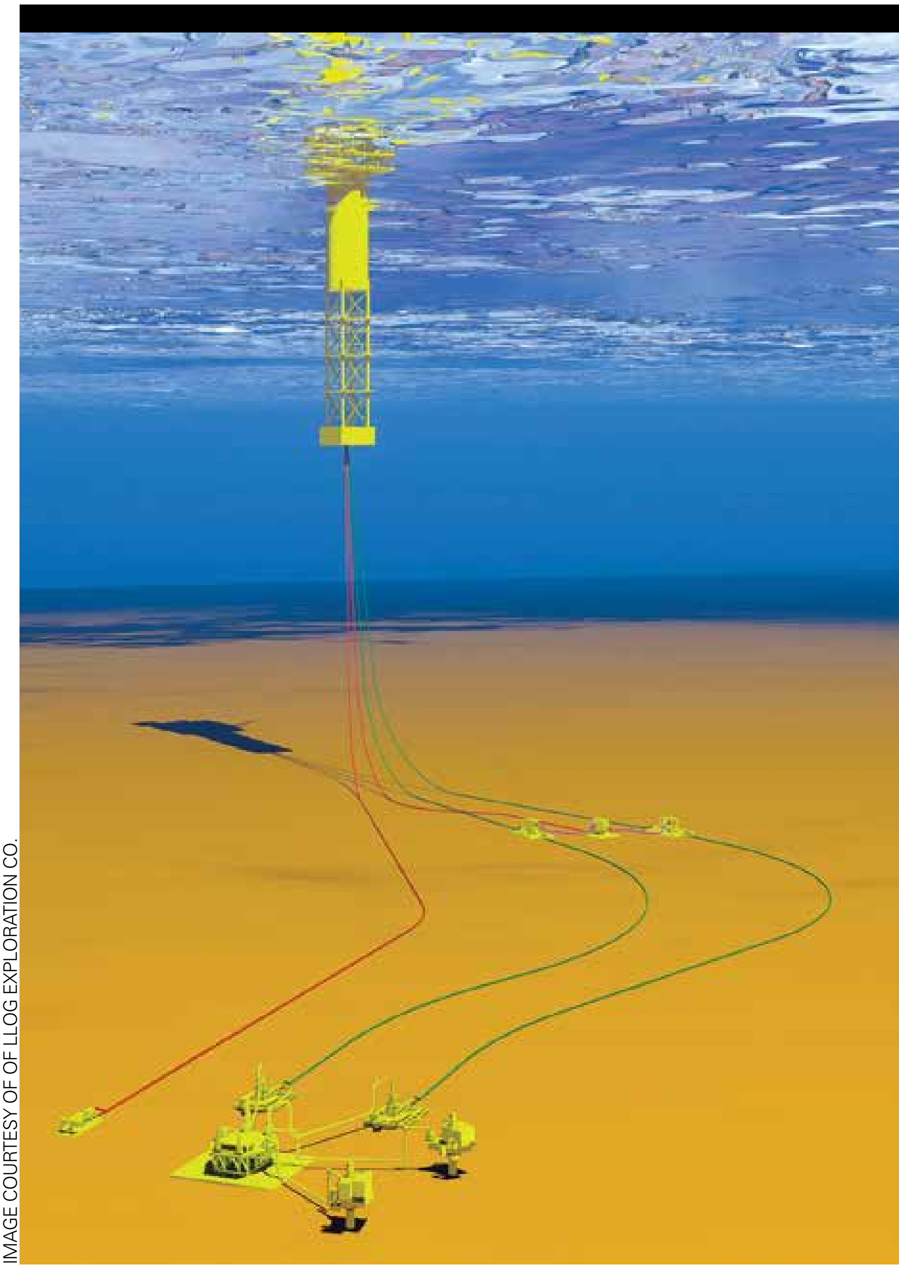


IMAGE COURTESY OF OF LLOG EXPLORATION CO.

***An artist rendering of the LLOG Exploration Co.-led deepwater Buckskin development in the U.S. Gulf.***

**Denizen of the deep**

LLOG took its first steps in the deepwater U.S. Gulf in 2002 with a series of wells in the region's flex trend area just beyond the shelf's edge. Since that time, almost 100% of the company's investment dollars have been pumped in the Gulf's deep waters. LLOG has drilled 296 wells in the U.S. Gulf since 2002 with 104 of those being in deep water. From 2010 forward, the operator has concentrated solely on the region's deepwater theater. Several of the private company's peers were leaving the region around the same time as it went all-in, taking their capital and putting it into the burgeoning shale plays around the U.S. Lower 48. So, why didn't LLOG join the exodus and come onshore with its peers?

"It can be difficult to acquire acreage in the unconventional play as a fast follower," explained Rick Fowler, COO of LLOG. "Also, to execute effectively in the unconventional play requires a different staff and culture. LLOG's breakeven costs in the deepwater

***LLOG Exploration Co. COO Rick Fowler said the company has not been tempted to look outside the deepwater U.S. Gulf for additional drilling opportunities.***

Gulf of Mexico compare favorably to the unconventional plays."

The operator has a number of deep Gulf discoveries that are in various stages of development including its Buckskin project, which achieved phase one production in June 2019 and where additional drilling is planned. LLOG also has redevelopment plans ongoing at its Who Dat Field originally brought online in 2011. The project includes drilling new wells in and near the field.

The company has sanctioned its Praline subsea development, which will tie into the Pompano fixed platform in Mississippi Canyon Block 29. Praline is a Pliocene-aged subsalt oil discovery located in Mississippi Canyon Block 74. Additional discoveries moving toward development include Leon (Keathley Canyon Block 642), Moccasin (Keathley Canyon Block 736), Shenandoah (Walker Ridge blocks 51 and 52), Spruance (Ewing Bank Block 877), Taggart (Mississippi Canyon Block 816) and Yucatan (Walker Ridge lock 95).

"LLOG has been somewhat contrarian throughout our history, and historically we've added the most value to our company during periods of low commodity prices," Fowler said. "We tend to keep our budgets flat, which allows us to drill more wells when commodity prices are low, which can drive down costs of services. At the moment, LLOG has one deepwater rig under contract, the Seadrill West Neptune, which we expect to continue working throughout 2020."

At press time, LLOG had the rig conducting completion operations following a sidetrack at its J Bellis Field in Green Canyon Block 157. J Bellis is a three-well subsea tieback to the EnVen Energy Corp.-operated Brutus tension-leg platform one block to the east.

LLOG has been offered opportunities in other offshore provinces, but according to Fowler, the company prefers to explore in the area where it is most familiar with the rocks and fluids. Additionally, U.S. Gulf infrastructure, access to services and regulatory environment offer key advantages.

"LLOG continues to see plenty of opportunities in the deepwater Gulf of Mexico so we've not been tempted to look elsewhere," he added.

### Competitive with the shales

Kosmos Energy Ltd. is an international player but sees much of its 2020 production growth coming from the strategic exploitation of its deepwater U.S. Gulf assets that reside in


***LLOG Exploration Co. performing development work at the Buckskin project in the deepwater Keathley Canyon area of the Gulf of Mexico.***

the play's more active regions. The company refers to the assets as its "advantaged portfolio" for several reasons—No. 1 being how it stacks up against other basins around the U.S. and globally for both quality and lower carbon emissions. The operator estimates its deepwater U.S. Gulf operations casts off about 7 kilograms of $CO_2$ per barrel of oil equivalent. Kosmos rates the Permian Basin at around 16 kilograms of $CO_2$ per equivalent barrel.

"I want to point out the competitiveness of the deepwater Gulf of Mexico versus the Permian," Andrew Inglis, chairman and CEO of Kosmos, told investors in late February. "Based on an expert third-party analysis of public data, carbon intensity is twice as high in the Permian compared to Gulf of Mexico. The advantage stems from the natural aquifer drive, which requires no gas or water injection, an abundance of existing and available infrastructure, no routine flaring and no fracking," he said.

Kosmos' infrastructure-led exploration (ILX) portfolio is designed to give it quick access to new reserves utilizing existing hardware and subsea technology. The company participated in an ILX venture at Gladden Deep in early 2019, which resulted in a discovery with recoverable resources expected to be around 7 million barrels of oil equivalent gross. That might not seem like a lot of oil, but when you can install a single subsea well and hook it into an existing pipeline that flows back to a nearby floating production platform, the economics are attractive.

A third-quarter 2019 ILX well at the Nearly Headless Nick prospect in Mississippi Canyon Block 387 was successfully drilled, encountering 85 feet of net pay in the Middle Miocene objective. That well was brought on stream via subsea tie-back to the LLOG-operated Delta House floating production unit.

"We see growth coming from the ILX opportunities," said Inglis. "We've seen growth actually in the Gulf of Mexico. When we took the asset on, it was doing slightly less than 25,000 barrels a day. We're forecasting a range up to 28,000 barrels a day for this year. That's come from the tieback of the initial successes that we have in Gladden and Nearly Headless Nick. So these things are relatively fast time to production. So in terms of the medium term, the growth is going to come from ILX success. We've got a three-well program in the second half of 2020 [planned] in the Gulf of Mexico."

The three-well program comes from five high-graded prospects and is slated to kick off around mid-year. Two of the prospects, Spencer and Tiberius are located in Keathley Canyon and are in tieback range of the Occidental Petroleum Corp.-operated Lucius spar platform in Block 875.

Spencer will test a Pliocene prospect while Tiberius will test a deeper Wilcox prospect. Additional prospects include Zora and Honey Ryder, which are Miocene amplitudes adjacent to the company's Odd Job Field in Mississippi Canyon Block 214. Highland Rim is located in Mississippi Canyon Block 864 and is another Miocene amplitude in tieback range of the Devil's Tower spar.

"All of these prospects share similar financial characteristics, tieback to existing infrastructure resulting in high return, fast payback projects," said Inglis.

Kosmos' U.S. Gulf portfolio depth boasts 23 prospects across 71 blocks or approximately 375 million barrels oil equivalent of net unrisked resource in total. According to the company, the opportunities amount to over five years of future drilling inventory at three to four wells a year.

***Werrus Energy founder Sergei Pokrovsky picked up a pair of shallow-water blocks in a 2019 U.S. Gulf lease sale and could be looking to add additional acreage soon.***

**The contrarian**

Where some folks see liability, others see opportunity. When Werrus Energy was formed in 2017, the private energy fund and investment management company sought to invest in low-cost energy products, mainly across North America.

The company dipped its toe in the Austin Chalk, Canada's Montney Shale and the saltwater disposal business in Appalachia with small but targeted investments. Then, under its subsidiary, Werrus AquaMarine, it did something few have done over the past decade—it entered the shallow-water U.S. Gulf of Mexico, snatching up 100% working interest in a pair of undeveloped blocks. The move was curious given the mass exodus out of the region over the past several years.

Many majors have shed their shallow-water portfolios in favor of bigger game further offshore or to invest in the shale gale of the past decade in places like the Permian Basin. Larger independents also fled the region. Companies like Devon Energy, Pioneer Natural Resources and Noble Energy, once mainstays in the U.S. Gulf, sold out of the space to tackle the shales and/or perceived greener pastures internationally.

"I want to be as diverse as possible," said Sergei Pokrovsky, founder and managing director of Werrus Energy. "I don't want to put all my eggs in the same basket whether it's purely upstream, shale or whatever. I'm in the business of managing risk first and foremost. The barriers to entry (in the Gulf) have come way down. Services prices are depressed to the point that I don't think they can get any lower."

Werrus AquaMarine spent less than $350,000 combined on Main Pass Block 295 and South Timbalier Block 267. Both blocks are situated in less than 250 feet of water, and neither block has any structures associated with them.

"When I entered the Gulf, part of my search criteria was that I only wanted to consider assets I could access with a jack-up," explained Pokrovsky. "A proved hydrocarbon system in that block was another. That means that there should've been some penetration there that showed oil. I wouldn't go purely into the greenfield. There's not too many of those left. Also, I needed to be more on the liquid side. Another thing was, I wanted to limit myself to

> "The shelf of the Gulf of Mexico lost its mojo and attractiveness. A lot of people just rushed away from it and left a lot of good things behind."
>
> —Sergei Pokrovsky, Werrus Energy

additional exposure that's kind of out of my control. So I wanted to find the blocks without additional liabilities. I wanted a clean slate."

Main Pass 295 will likely be the location of the first Werrus AquaMarine well. It has a known hydrocarbon system with deeper bonus potential.

In 2013, Apache Corp. (together with two other partners) drilled its Heron well on the block reaching a total depth of 19,555 feet. Partner Energy XXI reported up to 100 feet net oil pay, of which a substantial proportion is in three relatively shallow sands (between 8,405 feet and 9,110 feet), immediately underlying a salt overhang.

While Werrus is most interested in the much shallower oil pays, it is well aware of the additional bounty that lies below salt.

"There is an interesting subsalt play there, but that's not something that I'm going after right now," said Pokrovsky. "I know that it's there. I know what to do with it, but it's going to take more capital. I look at Main Pass 295 as a good launching point because there's plenty of low-hanging fruit that could be economical."

The company is fully funded to drill the initial well; however, it is in discussions with a potential co-investor to take a 25% stake in the project. Werrus is in negotiations with a rig contractor to move a jack-up onto Block 295. The goal is the get the well down prior to this year's hurricane season, which kicks off on June 1. However, there is no pressure to get it done prior to then. If a deal cannot be struck in time, the company will likely wait until late fall to drill.

"I don't have any pressure, either from investors or from the overall market right now, to go and do something, to go and spend money," said Pokrovsky. "But I do need to spend this money to take us to the next level."

If the well is successful and a commercial development is green-lit, Werrus would move forward with a newbuild production platform—a rarity in the shallow-water Gulf these days—which could kick-start a slow, deliberate move to increase its foothold in the region.

"I would consider expanding and maybe getting a couple more blocks at that point," said Pokrovsky. "There have been cycles in the past several years of clear underinvestment in finding new projects. The shelf of the Gulf of Mexico lost its mojo and attractiveness. A lot of people just rushed away from it and left a lot of good things behind."

**There and back again**

For over three and half decades, W&T Offshore has been a fleet of foot operator in the U.S. Gulf, adding reserves both by acquisition and the drill bit. However, in 2011, the company took a position in the then burgeoning Permian Basin of West Texas. The 21,900 gross acres entry cost the company $366 million. At the time of the deal, W&T founder and CEO Tracy Krohn called it a "new focus area that offers the potential for substantial long-term growth and attractive full-cycle economic returns." After four years of drilling, pumping and trying to generate positive cash flow out of the properties, the oil price dropped. The project was stuck in neutral, and W&T sold the assets for $376.1 million.

"We didn't do any one thing to bring the company down by going out to West Texas, but it wasn't optimal for us," recalled Krohn. "Things could have gone differently, but the truth is, we just spent a lot of money. When you think of the money we spent and what we got in return, West Texas just doesn't cash flow."

After that, the company returned to the U.S. Gulf exclusively, an area Krohn knew could be cash-flow positive by continuing to work and rework the company's substantial shallow and deepwater footprint.

"Reserves are generally bigger," Krohn said of his attraction to the U.S. Gulf. "Cash flow is usually better. It takes a while if you're doing a greenfield project, it takes a while to get things on production, but the good news is we have a pretty good footprint across the Gulf of Mexico. So there is a lot of infrastructure already in place. Having that is very helpful. Having a large vault of intellectual property is quite valuable as well. A lot of the guys that are with us have been out in this basin for a very long time. We've got a lot of data. Those are the ties that bind us to the Gulf of Mexico. I think it is an excellent place for us to be."

The company has remained active in the acquisition arena. Last December, it struck a deal with ConocoPhillips Co. to purchase the oil-weighted Magnolia Field in the Garden Banks area of the deepwater Gulf for $20 million and assumption of property liabilities. In October 2019, the field was producing 2,300 net barrels of oil equivalent per day (82% oil) to the acquired stake.

Today's commodity price challenges has prompted the operator to slash its 2020 spending plans by more than 70% from a range of $15 million to $25 million from its prior level of $50 million to $100 million. At the midpoint of the revised budget, the company expects to remain cash flow positive at or above $25/bbl of oil and $1.50 per thousand cubic feet of natural gas.

W&T's drilling plans in 2020 for the region will be slowed but not halted entirely. □

# THE BAKKEN TAKES A HIT

Between a historic oil price crash and resource maturity, some say the Bakken may have only five or six good drilling years left. What's the opportunity now?

ARTICLE BY
LESLIE HAINES

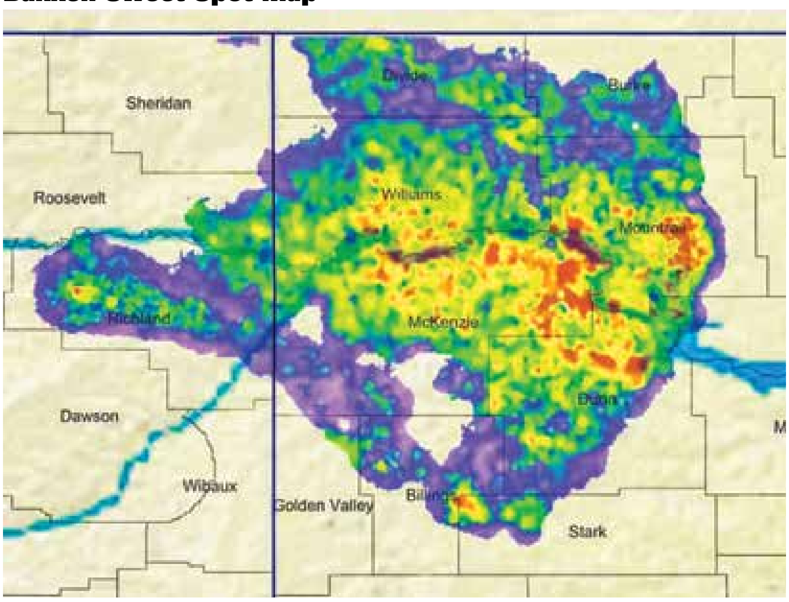
This year we can celebrate the remarkable contributions that the Bakken Shale has made to the U.S. energy picture since the first horizontal wells were drilled to the prolific formation. But at the same time, it is now one of the most mature of the shale plays: More than 14,300 horizontal wells have been completed in the Bakken-Three Forks formations.

Even before the price of WTI sunk to an unnerving 20-year low in March, people were already wondering how and where the play can evolve in the near term. For the past two or three years, the rig count has remained steady at about 50 to 55 rigs—and each modern rig can do the work of three previously. Permits to drill were averaging 55 to 60 per month before the oil price crash but are trending down now.

Officials recently presented data on estimated revenue from oil and gas to North Dakota lawmakers who are preparing the state's next budget. They estimated about 95 well completions a month, or 1,140 completions, although they are revising those projections now.

In late 2014 before the so-called OPEC Thanksgiving Surprise, production was 1.32 million barrels per day (MMbbl/d). It fell to about 920,000 bbl/d during the price crash that endured in 2015. It had recovered to 1.54 MMbbl/d in November 2019—setting an all-time record.

**Bakken Sweet Spot Map**




Source: HPDI, 1Derrick, Bernstein estimates

"The Bakken play was getting old, but we did that [record] simply with technology. We had to make the Bakken a $50 oil play and not a $70 oil play," said Ron Ness, North Dakota Petroleum Council president. The group represents companies operating about 95% of the production in the state. One example of the way better technology keeps this play going: At its Foreman Butte area, Whiting Petroleum Corp. put on production 17 wells last year, and it said "they have consistently outperformed offset wells by over 2.5 times over the first 90 days."

"Operators have proven they can make the Bakken work at an average market price of $52.98 in December 2019," Ness told *Investor*. The $64,000 question now is: Can they make it work if prices remain below $30?

Lynn Helms, director of the Department of Minerals Resources, told North Dakota legislators that oil production could max out within five years as companies run out of core drilling inventory. He said roughly 20% of drilling activity already is taking place outside of core Bakken locations.

"The end of (core area-drilling) is on the horizon; we can see it from here," Helms told the Legislature's interim Government Finance Committee.

Bakken production has always been ultrasensitive to oil price, especially given its long distance from markets and the pipeline bottlenecks seen in recent years. At press time, the 12-month strip for WTI was about $20/bbl, but the price of Bakken sweet crude at the hub in Clearbrook, Minn., was around $13/bbl. From Clearbrook the crude flows south to Cushing, Okla.

A Dallas Fed survey conducted in mid-March of 107 E&Ps (not just for the Bakken but in all plays) indicated that 65% of respondents said they need WTI to be at or above $23 to cover operating expense for existing wells, never mind for drilling. To drill a new well that is profitable, the average response was $49/bbl.

### Dropping rigs

Now, low oil prices will again hasten a production decline, because much of the production is in the hands of financially distressed companies that won't drill as much to replace output, such as Whiting and Oasis Petroleum Co., or in the hands of smaller private operators that mostly own Tier 2 acreage with well results that will not be as good as in Tier 1.

In March, the largest public Bakken operators announced reduced completion activity for 2020. Continental Resources Inc., one of the largest acreage holders and producers in North Dakota, said it will cut its Bakken rig count from nine to three for the rest of 2020. Hess Corp. is cutting from six down to one. Beleaguered Whiting (which filed for Chapter 11 bankruptcy protection in April) has three, but it cut its 2020 capex by 30%. It also just drew an additional $650 million from its credit facility to weather the storm, but at the same time it is still moving ahead to expand capacity at its Robinson Lake oil gathering facility by 2021, to take an additional 20,000 bbl/d. Oasis Petroleum has guided to two rigs.

Helms and Ness told the legislative committee that the state's oil production will peak at around 1.8 MMbbl/d in five years, up from the current 1.5 MMbbl/d, some 250,000 bbl/d higher than its previous, late-2014, peak.

But as operators, investors and government officials look to the Bakken's future, these estimates could be thrown out the window due to two factors: technology advances we can't predict today and the price of the commodity itself.

"Great resources can always withstand great challenges," said Ness, the day after oil fell off a cliff in mid-March, hitting $20/bbl. "Every producer is always strategizing; they've been through this before. They do have challenges and difficult decisions to make."

In mid-March when he spoke, Platts reported that Bakken crude for May delivery traded about $6/bbl below the price of WTI, for a net value of about $16/bbl—the lowest price on record for the front-month crude, Platts said. Year-to-date Williston Bakken crude was averaging about $45.60/bbl, down some 70% since New Year's Day.

Free cash flow in most every oil play will be zero if oil remains at $30/bbl or below, according to Rystad Energy on March 18. And troubling, respondents to the Fed survey said if oil is at $40, only 25% of the companies could remain solvent one or two years.

### Remaining locations

Near-term problems will endure throughout 2020, possibly through at first-half 2021, but setting aside any considerations about damaging oil prices, what does the future opportunity set look like? The 2013 assessment by the USGS estimated 7.3 billion bbl of undiscovered yet technically recoverable oil in the Bakken.

Bernstein Research looked at data and maps from Enverus Drillinginfo that show where most wells have been drilled to date and where the most prolific wells have been located—the so-called Tier 1 acreage. Bernstein E&P analyst Bob Brackett concluded in a report, "Only 1,100 remaining drilling locations are economical at or below $50/bbl WTI.

SOURCE: HESS CORP.

"That figure increases to 6,600 locations for WTI at or below $60. And, 6,600 wells would cover only the next six years of production under our supply model and assumes optimistically that no other hiccups occur. We ultimately need higher oil prices for the remaining locations to be 'in the money.'

"Our findings are consistent with our expectation regarding a mature play like the Bakken. Most locations with low breakeven prices (i.e. most productive ones) have already been drilled. For instance, while about 60% of all the locations with breakeven below $40 have been exploited, 8% of all wells with breakeven greater than $70/bbl have been brought online."

### Tier 1 vs. Tier 2

Experts contend that transferring technical advances and drilling longer laterals to fringe areas outside the core has worked well to increase well results since 2014. We spoke with

**Companies Owning Tier 2 Acres***

| | |
|---|---|
| Kraken Oil & Gas LLC | 44,000 |
| White Rock Oil & gas LLC | 32,800 |
| Cobra Oil & Gas Corp. | 18,500 |
| Salt Creek Oil & Gas LLC | 8,500 |
| MAP Energy | 2,000 |
| Bakken Resources Inc. | 1,000 |

*None have acreage in Tier 1 areas. All are privately held.
Source: Enverus Drillinginfo

Enverus to find out more about what defines the core: Tier 1 locations with a low breakeven price and good oil recovery per well, or EUR. The company has built different type curves for specific areas within the Bakken, all normalized to certain well lengths and completion techniques, according to Hakan Corapcioglu, senior energy market analyst, strategy and analytics, in Denver.

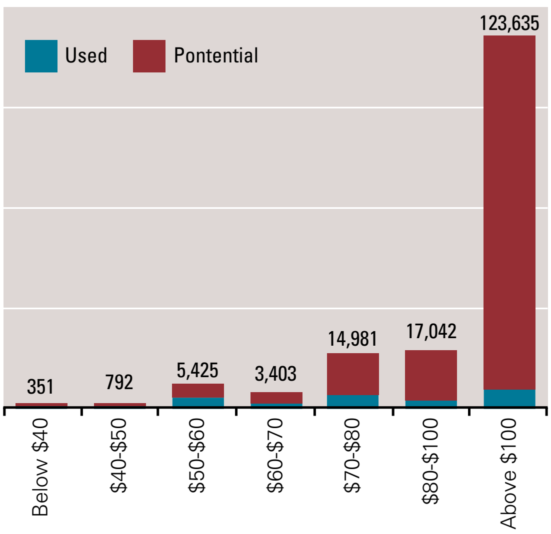
"So some wells' EURs may be down-normalized, and some may be up-normalized. And these are not company specific, but rather we're trying to look at the basin and these type curve areas more holistically.

"The average Tier 1 oil EUR is around 620,000 barrels (bbl) and Tier 2 oil EUR is around 445,000 bbl," Corapcioglu told *Investor*. "But as I mentioned before, there will be individual wells that are way above these numbers.

"For the IRR piece, if I were to run an average IRR for Tier 1 and 2 at $50 oil and a $3 gas price, it comes out to about 36% IRR and 17% IRR, respectively. These numbers, of course, can and will vary from operator to operator and on an individual well basis. And IRR numbers are tied to commodity prices, so the returns will be much less under the conditions we are in today."

If the play is quite mature, with most of the Tier 1 locations already drilled, then how are EUR statistics trending? "They actually have been trending upwards since 2014," Corapcioglu said. "This is due to operators getting more efficient with their drilling and completion programs: drilling longer laterals, optimizing their completion techniques, the use of proppant and fluids for their fracture designs, etc."

**Remaining Locations In The Money At Oil Price Points**




Source: Enverus, Bernstein estimates

### Midstream progress

The Bakken was among the first plays "to benefit big-time from the shale revolution, experiencing a 400%-plus increase in crude oil production in the first half of the 2010s," RBN Energy said. "The play has had more than its share of challenges, however, including a serious lack of takeaway capacity that spurred the first rapid deployment of modern-day crude-by-rail, followed by a rig-count collapse and major production decline after the mid-decade crash in oil prices.

"Producers have been planning for continued production growth in 2020, though many may be reassessing those plans in light of [the recent] coronavirus-related price slide. In any case, production growth is only possible if there's sufficient gathering infrastructure in place," said the RBN report.

Consulting firm East Daley Capital said in a February report that the Bakken will be affected by expansions on the Dakota Access Pipeline and the Bridger Pipeline set to come online in 2021.

Bridger Pipeline vice president Tad True told *Investor* that he's been "amazed at the ingenuity" of his customers to make the Bakken work at different oil price levels.

"I would say a lot of them have a lot more room to grow in the core by going back to their pads and drilling more on some spacing units. The core is an enormous geographic area of some 70 miles, and we have gathering systems in that area. On any given day we run 200,000 bbl/d, and we'll be expanding to 400. This is the largest expansion we've done on Bridger.

"I'm confident the Bakken is still going to grow."

Flaring of natural gas continues in North Dakota, but producers and midstream companies have been working overtime to build additional gas processing infrastructure, said an RBN report. "About 670 million cubic feet a day [MMcf/d] of new processing capacity was added in the second half of 2019, another 400 MMcf/d is coming online in the first quarter of 2020 and still more will follow later this year and in 2021."

The Petroleum Council's Ness said he'd be a fool to predict oil prices now, but he was confident markets and operators will adjust as they always have in the past. "The best thing to cure low oil prices is low oil prices," he said. "We've just got to roll with the punches, but we're going to see a contraction, no question. We will recover, but it's a function of how long and how big is the fight to get us there.

"At the end of the day we're still producing about 1.5 MMbbl/d. Dollar for dollar, it's still the best play. We need demand—producing more oil at $25 is not the answer." ☐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# BORN IN THE BAKKEN

U.S. tight rock oil production exceeded 9 million barrels per day in March, according to the U.S. Energy Information Administration. The story began 20 years ago in Richland County, Mont., with a prospector, two wildcatters, Halliburton and a bold venture: land a lateral in the middle Bakken—and frac it.

ADAPTED FROM "THE AMERICAN SHALES" BY NISSA DARBONNE

Until 2000, the Williston Basin's Bakken Formation had been a bailout zone. When a well targeting another formation wasn't going to pay, the Bakken was tapped for what little the super-tight rock would give up. The investors might recoup some of what they spent.

Burlington Resources Inc. had tried tapping the formation with horizontals in the late 1980s and into the early 1990s. It had some initial indication of success in a sweet spot in western North Dakota.

But it had been landing the laterals in the upper Bakken—a shale member—and hadn't been fracking them. The wells dried up fast while trying to move oil out of nearly solid rock. The play was declared dead in a 1996 report by the North Dakota Geological Survey.

"Without a change in current circumstances," it reported, "such as a new way to stimulate Bakken Formation reservoirs or the discovery of a new area with rock and/or reservoir properties similar to the (productive) fairway, completions in the Bakken Formation will be made only for salvage ....

"There will always be a few completions in the Bakken Formation but, in those wells, the Bakken will be completed as bail-out zones."

That same spring, over in Montana, prospector Dick Findley and operator Bob Robinson did just that: They bailed out in the Bakken—in the middle member—in Montana in

SOURCE: KELLY OIL & GAS LLC

***Dick Findley named the prospect Sleeping Giant. "It turned out to be correct," he said. At right, the Burning Tree State 36-2H, now owned by Enerplus Corp., is on pump.***

Mustang Field when an underlying Nisku, aka Birdbear, target didn't work out.

The dolomitic middle Bakken is tight, but not as tight as the shale members above and below. The rock in that vertical well, in particular, had behaved unusually, though, even while it was being drilled.

"About 40 minutes after we penetrated it," Findley said, "we got bottoms up and had a 400-unit gas increase. And we encountered about a 10-foot drilling break, which indicated porosity.

"I didn't think there was any porosity to speak of in the middle member. That seemed pretty unusual."

He put it aside, though. Dawn was coming. "I was going to blame it on the early morning. I hoped that my mind was just fuzzy."

Back at the hotel in Sidney about a dozen miles from the well, "I don't know how long I was asleep, but my eyes popped open," he said.

"I was thinking, 'Wait a minute. Oil isn't in the shale' like most people thought, including myself. 'It looks like, in this area, the oil is in the middle member.'"

The pair bailed out in it. They made their money back.

But the well, Albin FLB 2-33, kept flowing. Robinson phoned Findley, telling him, "You know, this just isn't declining. Do you think we have someplace to develop this?"

Findley wasn't optimistic. It was an anomaly, he thought. But he looked. Where else might an Albin FLB 2-33 work?

North of Albin, logs of old wells that went through the Bakken didn't show much porosity and wasn't as high in resistivity. Looking south, however, old logs were showing the middle Bakken to have very persistent porosity—between 8% and 12% in a long trend.

"It took me a couple of days; there were maybe 20 to 25 wells I could look at. Every one of them had porosity and high resistivity for oil."

After Findley plugged each well into his map, it began to show a consistent northwest/southeast trend—an ancient shoreline. "It looked like it was 40 miles long and 4.5 miles wide."

He called Robinson. "I think we found a giant oil field," Findley told him. Robinson was skeptical. "He said, 'I kind of doubt that.'"

But the pair began leasing. They would need a lot more money. "It was going to take a couple million dollars to buy all the leases available on this trend, and Bob didn't have that kind of money nor did I."

Findley had given the prospect a name: Sleeping Giant. He said, "You get pretty desperate when you start naming prospects after so many years.

"It really did look like a giant oil field that was just waiting to be developed. So I called it Sleeping Giant."

**Partners, money**

In the 1980s, Findley had met Cameron Smith, a New York-based oil and gas investor who matched operators with private capital via his Cosco Capital Management LLC firm. He and Robinson gave Smith a call.

Smith had been in touch over the years with Bobby Lyle, the founder of Dallas-based Lyco Energy Corp.

Findley, Robinson and Lyle met. They leased 50,000 acres and reentered 10 verticals in the trend to check the log data. Lyco had 75% working interest and carried Findley and Robinson, as Sleeping Giant LLC, for their 25%.

Lyle said, "It was a fair deal, and we liked the people and the concept. We thought it was worth the risk and that, if it worked, there was potentially a lot of oil there."

Nine reentries were attempted in 1997 and a tenth in early 1998. In general, they proved Findley's theory that the middle Bakken would produce from one end of the northwest/southeast trend to the other.

Lyle believed that the sweet spot—just 10 to 15 feet thick—of the roughly 30-foot zone would have to be produced horizontally, though, and these laterals would have to be fracked.

That would be costly—at least $1.75 million each. "We didn't have any money to really test this idea," Lyle said.

"So I called Dick Cheney."

He and Cheney, chairman of Dallas-based Halliburton Co. at the time, were both on the Southern Methodist University board of trustees.

Lyle said, "I told Dick what we wanted to do and asked if Halliburton was interested in participating."

At the time, Halliburton was developing a unit to invest in E&P projects in which it could deploy new technology. It was a business development proposition that was hoped to jumpstart more oilfield activity—thus, more oilfield contracts.

Some weeks later, Lyle received a call: "They said, 'We think this will work.'"

But oil prices were falling. A barrel had pushed past $25, but estimates of Pacific Rim demand growth had been inflated, prompting the "Asian contagion" market fallout. Meanwhile, OPEC was slow to cut back on its output.

A barrel fell to as little as $11 in December 1998. Regional spot prices were even less.

The Halliburton group asked Lyle, "What do you want to do?" He replied, "I'm not drilling a well up there with oil at $8.75 a barrel."

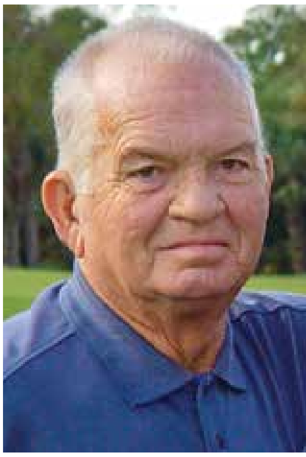
Halliburton agreed. Meanwhile, it and Lyco engineers continued to draft the fracked-lateral plans. The initial ideas involved making select perforations along the wellbore and pushing a massive amount of water and sand into the rock.

"You would just pump into those perforations along the entire lateral length all at once and try to control the placement of the sand by the placement of the perforations," Findley said.

While they waited, oil improved, exceeding $26 in December 1999 and heading to $30. The price was the best since 1985. Lyle said, "Finally, we started drilling the test well."

**The lateral**

Burning Tree State 36-2H was placed about 17 miles northwest of the now four-year-old



*The late Bob Robinson, owner at the time of the Sleeping Giant prospect of Kelly Oil & Gas LLC, asked Findley to look into how far this porosity trend might be, resulting in Sleeping Giant LLC.*

***Bobby Lyle joined as operator of the prospect and enlisted Halliburton Co. as a partner. To frac horizontals in tight rock "seems pretty simple" today, he said. "However, at the time, what we were doing had never been attempted."***

Albin FLB 2-33. The middle Bakken there was at about 10,000 feet below the surface.

The decision was made that the lateral should be driven along the top half of the roughly 30-foot section, just below the upper Bakken Shale. The drilling crew would need to keep the bit in that small window.

Lyle said, "Today … the task seems pretty simple. However, at the time, what we were doing had never been attempted. We were all a little nervous."

Findley recalled one of the engineers saying, "This permeability is so low there's no way this play is ever going to work. Let's walk away. It's just not worth doing."

But, "Bobby Lyle said, 'No. We've come this far. Let's go ahead and drill it horizontal.'"

The lateral reached about 1,700 feet; the original plan was to take it to about 3,000 feet.

Lyle said, "The well started to torque up on us. I was concerned we were going to lose it. I told the Halliburton group, 'We have enough exposure. Let's stop and test the idea. If we twist off now, we may never get back here again.'

"People might have gotten cold feet. 'If we lose the well, we're going to leave a lot of money in the hole. And we may not convince ourselves that we ought to try this again.' They said, 'We think that's a good idea.'

"So we stopped drilling."

## The frac

It was time to complete the well. Perforations had been made in preparation for the frac job. From just open holes along the horizontal wellbore, "we were surprised by the (natural) flowback we were getting," Lyle said. "It was better than we anticipated."

Findley and Robinson had decided to go out and watch the frac. Upon arriving, though, "there was nobody out there. Nothing," Findley said. "We didn't know what was going on."

They wandered around the site. "There was this dust-covered gauge on the ground, and it had 400 pounds on it. Bob looked over to the storage tank and saw this flap going up and down on the top. We put two and two together and said, 'My goodness. This well is flowing!'

"About that time, a tanker pulled up onto the location. The driver got out and said, 'Well, this is my second load of oil today. I've already taken 400 barrels (bbl) out of this thing.'

"Bob and I were pretty happy. It was flowing naturally—without a frac."

Still, it would be fracked; the flow, then, was even more impressive. Also, it turned out that the upper Bakken was a worthy barrier. Adding isotopes to the frac fluid, the completions engineers were able to log where the cracks went.

Findley said, "Invariably, that frac would come right up to the shale and just stop; it just wouldn't go up into the shale."

They didn't lose their frac.

And, then, they waited. Would the well, like the old horizontals in the upper Bakken in North Dakota and the verticals in the middle Bakken dolomite outside of Findley's porosity-trend fairway, just fizzle out?

Lyle said, "We didn't want to run out and get all excited about something that, overnight, was going to (begin producing) water.

"We were cautiously optimistic."

On May 26, 2000, Burning Tree State 36-2H came on with an official IP of 196 bbl on a quarter-inch choke from three sets of perforations in the roughly 1,700-foot lateral at about 10,000 feet below the surface. The IP was about three times that of the vertical Albin 2-33 and up to seven times the average of the vertical reentries.

## More wells

Based on just the initial results, however, Halliburton was disappointed: It had signed on for only one well. Lyle had wanted Halliburton in for at least three; Halliburton would sign for only one.

Halliburton wanted now to participate in testing further. Could it yet further improve results from this generous rock?

After a couple months online, the rate just wasn't declining.

Lyle said, "From our standpoint, we were tickled: We had what appeared to be a successful prototype, and there were no real encumbrances in terms of a commitment (with Halliburton) on a go-forward basis.

"It gave us a little bit better negotiation position."

For Halliburton, should the play work out, the technology and expertise it could develop could translate across its business worldwide. Particularly, it would give it a position and edge in the Williston Basin to serve other producers wanting to do a Lyco-type completion.

Most frac jobs in the region were just small ones and on vertical wells. Burning Tree State 36-2H was the first fracked horizontal in the Williston Basin.

Halliburton signed a new, 10-well deal under which it became the preferred service provider.

Findley said of the middle Bakken, "Nobody would ever think you could produce oil out of such a low-permeability rock in (what became named) Elm Coulee Field."

He recalled that, after making the brochure about his Sleeping Giant idea to take to the Lyco group to review in the summer of 1996, "I was kind of embarrassed for naming it that. It sounded a little hokey.

"Thinking back on it now, you know, it turned out to be correct."

## The neighbors

In 2000, only six wells were drilled in Richland County—Lyco's in the Bakken and five by others in Ratcliffe, Nisku, Red River or Stonewall. Lyco had managed to remain alone in the play, but other leaseholders were all around it. Some were exploring other formations; some simply owned acreage HBPed by existing verticals.

"They said, 'You're not going to make any money in Montana. You cannot make any money in the Bakken. That's absurd.' A few years later, they were buying acreage all around us."

—Bobby Lyle,
Lyco Energy Corp.

The neighbors were watching, though. What kind of decline curve would Lyco get from its middle Bakken wells? Would the wells just sputter out? Or would they be economic?

Privately held Dallas-based Headington Oil Co. had been curious. It made a vertical, Albin 31X-28, for 130 bbl in late 1997. The hole had been bored to Red River; it was completed uphole in Bakken about a 15-minute, northerly stroll through a field from Findley and Robinson's Albin of 18 months earlier.

In 2001, Lyco gave everyone more to talk about. It went nine-for-nine in its follow-up Bakken attempts, all horizontals, bringing them online with between 190 and 368 bbl.

Headington then went in with a horizontal—Dynneson 11X-5. The well flowed 181 bbl a day its first 12 days online; upon being fracked a couple months later, it came back on with 242 bbl.

In 2002, already 10-for-10, Lyco went another 10-for-10. Among them, it took its Peabody-Bahls 2-16H lateral about 8,500 feet for 576 bbl on Nov. 22, 2002—its biggest well yet and the longest-reach well yet in the state's history.

Lyle said, "That gave us momentary bragging rights. It's always fun to be part of something that is done for the first time."

In 2002, Headington's WCA Foundation 21X-1 came on with 445 bbl from dual laterals. One turned at 9,943 feet and went southeast for about 2,500 feet; a second went out about 4,000 feet.

By year-end 2002, Lyco had advanced to No. 5 oil producer in Montana, making 686,766 bbl that year—even advancing past several Cedar Hills anticline operators south of Richland County, Mont.

The state named the new Bakken play: Elm Coulee Field. Its first appearance on the Montana list of oil fields was at No. 5 among the all-time top 100.

In 2004, it made 7.5 million barrels (MMbbl); Lyco's share was 4.7 MMbbl. Oil reached about $50 in 2005. Lyco went 35-for-35 that year.

Continental Resources Inc. had joined the play; it went 32-for-32. All Elm Coulee Field operators combined were 143-for-143.

By year-end 2005, cumulative field production was 27.1 MMbbl—roughly half of all the oil made in the state that year.

Lyco advanced to No. 2 oil producer, making 4.1 MMbbl that year, second only to Encore Acquisition Co. (6.4 million) and its enormous Cedar Creek anticline fields.

**'Common sense'**

Fellow oil and gas explorers had dismissed Lyco's early work, Lyle said. "They said, 'You're not going to make any money in Montana. You cannot make any money in the Bakken. That's absurd.'

"A few years later, they were buying acreage all around us."

By July 2005, Lyco and Sleeping Giant LLC had run their race—and won. The property was sold to Enerplus Corp. for $421 million.

The idea in 1996 had made 8.8 MMbbl for the partnership. Every one of their horizontal attempts was a commercial success—100%. Lyco had gone 83-for-83.

Besides the 27 MMbbl the five-year-old field had made, it had also given up some 26 billion cubic feet of associated gas. It was making 30 million cubic feet a day.

Lyle had recognized early in the Sleeping Giant program that gas gathering infrastructure would be needed in addition to more oil pipeline infrastructure. Gas flaring is allowed in the state but not in perpetuity.

Also, the gas that the wells were making was full of valuable NGL.

Lyle had gone to the gas-pipeline operator in the area and explained he would be needing gas takeaway service. Lyle was sent away. "They said, 'Well, we don't really think that's likely to happen. We think that's folly.'"

Lyle returned twice; the company refused to believe him.

Eventually, he went to Harold Hamm, Continental's founder and who also owned oil pipeliner Hiland Partners LLC. Hamm was the only pipeline operator who would listen to Lyle.

Hamm said, "We put in the oil gathering pipe, and we brought in the gas gathering. There was just one company gathering gas up there, and they, basically, had no competition.

"The result had been that, whatever they offered you, you had to take it. That's not very attractive."

Lyle and Hamm agreed to dedicate their middle Bakken gas to a new pipe; Burlington joined as well.

Meanwhile, Hamm took the Bakken idea to North Dakota, took Continental Resources public and has grown it into one of the largest U.S. oil producers.

"Bobby—well, he just has very good common sense," Hamm said. "He had a good plan for what he thought he could do with Elm Coulee Field, and he had Halliburton in there with him, willing to spend money on the technology and apply it.

"I have a great deal of respect for him. A lot of people just didn't give him a lot of credit.

"They should have." □

***Continental Resources Inc. founder Harold Hamm joined in the Montana play and took it to North Dakota. He said of Lyle, "He had a good plan for what he thought he could do with Elm Coulee Field ... A lot of people just didn't give him a lot of credit. They should have."***

# HEDGING IN TOUGH TIMES

In oil and gas, the decision to not hedge has always been at producers' own peril. Fewer E&Ps have hedges in place than in prior years, according to a survey, which suggests a difficult path through the recent price collapse.

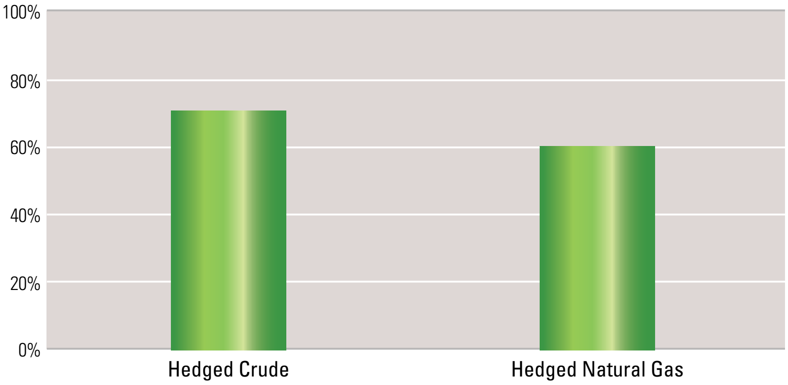
ARTICLE BY
SHANE RANDOLPH
AND
JOSH SCHULTE

While energy markets continue to be volatile, fewer oil and gas producers have hedges in place than in prior years. In addition, a number of producers hedged with strategies containing sold puts on large portions of their production. This essentially creates a trapdoor where a company doesn't have price protection below the strike price of the sold put, which for some is anything less than $45/bbl on crude.

The following is a survey of 30 of the largest public oil and gas E&P companies and their hedging activities as disclosed in their Dec. 31, 2019, 10-K filings. It also includes comparisons to the same survey done in the prior year.

The first trading day of 2019 was the lowest daily closing price achieved by the prompt WTI futures contract in 2019 at $46.54/bbl. From there, it was a rocky ride between closing prices from around $50/bbl to $65/bbl for the remainder of the year. The crude price crash in early March 2020 that took prices down to nearly $30/bbl surprised many. Natural gas prices followed an unusual path in 2019. Early in 2019, the prompt natural gas futures price reached just above $3.50/MMBtu, similar to price levels in early 2018. However, the average closing price for the prompt natural gas contract during the final two months of 2019 was about $1.55/MMBtu lower than the average closing price for the final two months of 2018. Natural gas prices have dipped well below $2/MMBtu in early 2020.

**% Of 2019 Surveyed Companies Hedged By Commodity**




Source: Opportune LLP

The following survey provides as much information as possible based on information disclosed in regulatory filings. U.S. GAAP accounting rules form the minimum disclosures companies must provide in their filings to provide users these understandings:

- An entity's use of hedges;
- How the hedges and the hedged production are accounted for in the filing; and
- How the hedges affect the financial statements.

While the accounting rules require entities to disclose the level of an entity's derivative activity, there can be variance in practice as to how much information a company discloses about the instrument types, volume of production hedged and the average hedge price.

### Why hedge?

Upstream companies have relatively straightforward objectives, which are to search for, develop and extract hydrocarbons. These activities are very capital intensive and require large amounts of cash. Companies need enough cash flow, not only to support a level of capex and exploration activity to ensure that oil and gas continues to flow but also to make debt payments, comply with debt covenants and support general and administrative costs. Hedging programs at upstream companies are developed with the primary purpose of providing a level of cash flow to increase the likelihood of meeting those needs.

Without the protection of an effective hedging program, an upstream company's cash flows are subject to the volatility of the market. An upstream company without hedges will benefit from higher market prices, but they have a very short amount of time to react when market prices decline. This is a predicament many upstream companies experienced during the 2014 price downturn and what many experienced in early March 2020.

The following outlines the percentage of companies in the survey that maintained hedges as of Dec. 31, 2019, for crude, natural gas or NGL. Consistent with prior years, it's clear that the majority of public oil and gas producers maintain hedging programs. However, fewer companies had hedges than in prior years. Twenty-five of the 30 upstream energy companies surveyed, or 83%, had hedges on the books as of Dec. 31, 2019. This was down from 93% as of Dec. 31, 2018. As of Dec. 31, 2019, 70% of the surveyed companies had crude hedges in place, and 60% had gas hedges in place.

## Types of instruments

While some companies will state that they have a hedging program and have executed hedges, investors should carefully consider the types of instruments utilized. The downside protection provided by some instruments may not be that significant. The following notes the number of companies holding various instrument types in their hedging portfolio.

Of the companies reviewed, swaps continue to be the preferred instrument for both natural gas and crude. For a producer, swaps provide the highest amount of downside protection. However, swaps limit upside price participation. This leads producers to utilize purchased puts, which can be costly, or costless collars, which allow the producer to participate within a range of price movements.

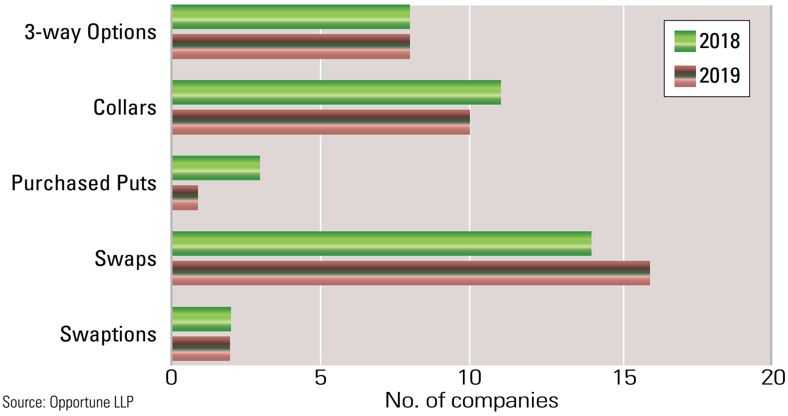
Other instruments noted in the survey were swaptions, three-way options and put spreads. Swaptions, often used to raise a strike price by allowing a counterparty to increase the volume or lengthen the tenor of the contract at its discretion, continue to represent a minority of the instrument types utilized by the public companies.

Three-way collars and, to a lesser extent, put spreads (purchased put and sold put) continue to exist. Many producers were hurt by strategies containing sold puts during the 2014 price collapse as they contain what some consider a trap door. For example, a producer that entered into a three-way option with a $45/bbl sold put, $50/bbl purchased put and $60/bbl sold call would participate in price movements between $50/bbl and $60/bbl.

However, once the price goes below $45/bbl, the company would have no downside protection. This was particularly painful for many producers in 2014 that had sold puts in the $65/bbl to $75/bbl range under the belief that prices wouldn't go below those levels. Opportune is seeing this pattern again in early 2020 where current oil and gas market prices are below sold put strikes. There's no downside protection beyond the strike price of the sold puts. Producers hedging chunks of the production with these instruments were definitely not prepared.

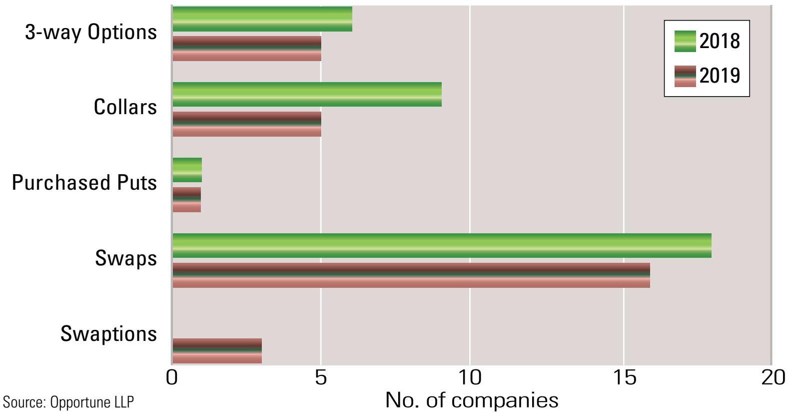
A strategy utilizing both swaps and collars was common for both crude and natural gas. The types of instruments used for gas remained generally consistent with the prior year, with over 80% of hedging companies utilizing either

**Crude Hedge Instrument Types Comparison**



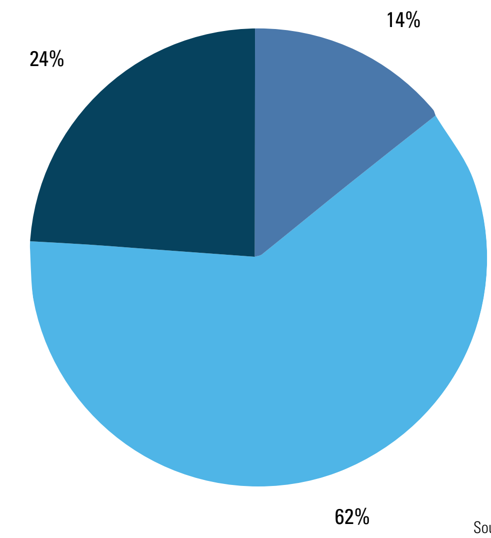

Source: Opportune LLP

**Natural Gas Hedge Instrument Types Comparison**

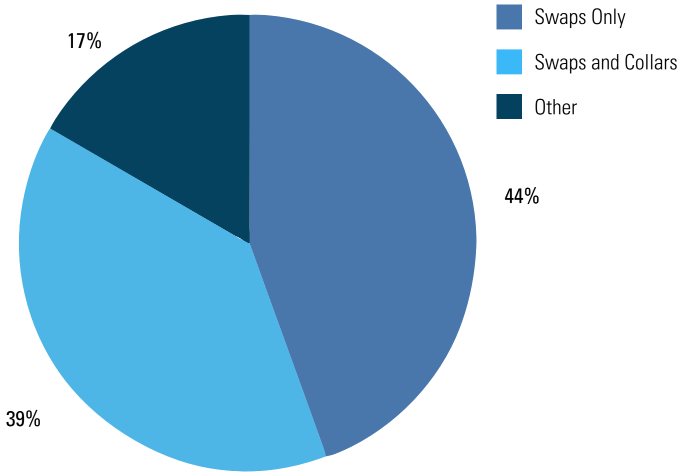



Source: Opportune LLP

**Crude Hedge Strategy (2019 Survey)**

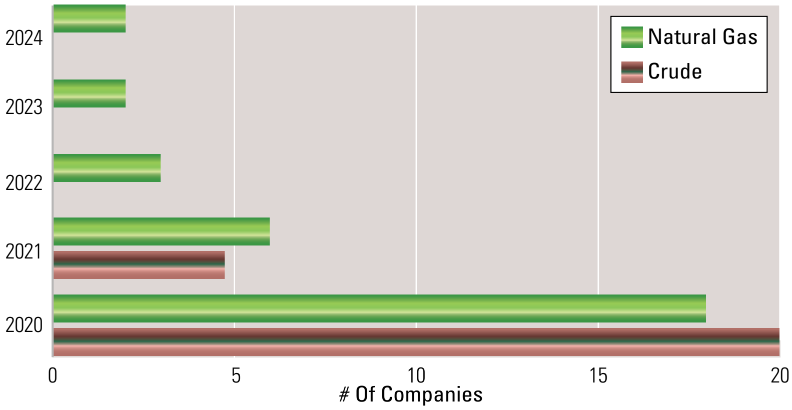



**Natural Gas Hedge Strategy (2019 Survey)**



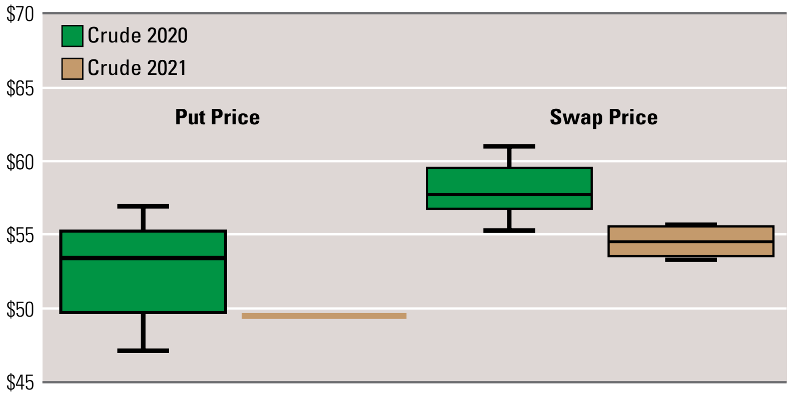

Source: Opportune LLC

**Crude And Natural Gas Hedge Tenors (2019 Survey)**



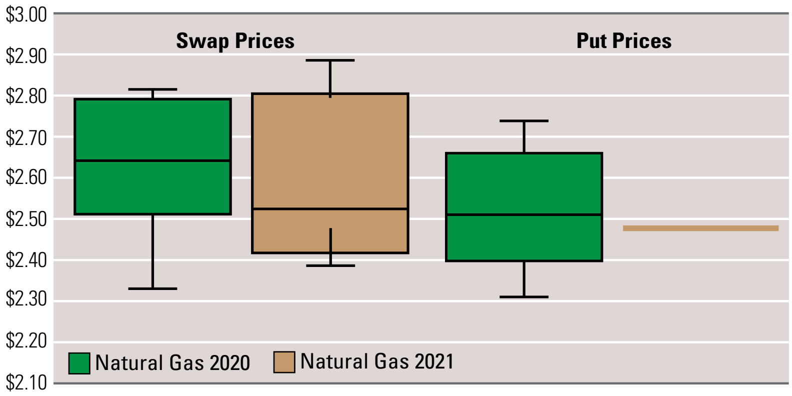

Source: Opportune LLP

**Crude Swap and Put Prices**




Source: Opportune LLP

**Natural Gas Swap And Put Prices**




Source: Opportune LLP

exclusively swaps or both swaps and collars. The use of crude collars and three-way collars remained consistent in 2019 compared to 2018.

### Length of hedging

When executing a hedging program, many companies are challenged with how far out to hedge their production. If prices increase over time, they largely give up upside. However, if prices drop, it allows a company to weather the storm for a longer period. Based on the survey results, it's common for companies to hedge some level of the prompt 12-month period representing calendar 2020. None of the companies hedged crude beyond 2021, while a handful of companies hedged natural gas in 2022 to 2024.

### Price levels

The ability to only hedge at the top of the market is impossible. The decision of when to hedge and at what price level is rooted more in the risk management policy of providing predictable cash flows than in an ability to predict prices. As a hedging program is intended to increase cash-flow predictability, the price level at which companies execute hedges is often heavily influenced by operating budgets and debt compliance.

Of the 25 companies that disclosed that they had hedges on their books at the end of 2019, 20 gave their average prices for WTI Cushing crude, Henry Hub natural gas or both. The average swap price for crude was $58.41/bbl for 2020 and $54.52/bbl for 2021. The average swap price for natural gas was $2.58/MMBtu for 2020 and $2.54/MMBtu for 2021. The average collar put price (non-three way) for crude was $53.48/bbl for 2020 and $49.68/bbl for 2021. The average collar put price (non-three way) for natural gas was $2.45/MMBtu for 2020 and $2.38/MMBtu for 2021. The average sold put prices in 2020 were $45.70/bbl for crude and $2.15/MMBtu for gas.

### Hedge coverage

Consistent with prior years, few companies disclosed the amount of their forecasted production that was hedged as of Dec. 31, 2019. Only four companies disclosed a percentage of forecasted production hedged. For companies that did disclose this information, the average hedge level for crude was 61% of forecasted 2020 production and, for natural gas, was 42% of forecasted 2020 production. Note that these hedge levels include coverage provided by three-way options.

In summary, fewer E&Ps had hedges in place at Dec. 31, 2019, than in prior years, and sold puts continue to exist in many hedge portfolios. Companies with strong hedge books have a better ability to try to weather the storm. Those companies that were not appropriately hedged are struggling.

The implementation of a hedging program can be an important tool that helps a company ensure certainty of cash flow and perhaps avoid filing bankruptcy. Management teams are encouraged to consider the various alternatives and strategies that a hedging program can provide in meeting their ever-changing business plans. ☐

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*Shane Randolph is a managing director at Opportune LLP and assists companies and financial institutions throughout North America, South America, Europe and Asia-Pacific in their understanding of what is possible as they deal with the challenges of implementing risk management programs and highly technical accounting pronouncements. Josh Schulte is a manager in Opportune LLP's commodity risk management advisory group and assists companies with developing and executing complex risk management programs.*

# A&D Watch

EDITED BY
DARREN BARBEE

## Sky Falls In On First-Quarter M&A

**THE INEVITABLE** collapse of M&A in first-quarter 2020 grinded out a mere $770 million in deals—about one-tenth of typical values—as oil and gas companies drowned in oversupply, **Enverus** said in an April 2 report.

As oil prices plunged to 18-year lows, the quarter's deal value fell far below the $8 billion averaged in the past decade. Enverus said that nearly all deals were transacted before the COVID-19 pandemic and the over pumping of crude oil by Saudi Arabia as OPEC's production détente with Russia fell apart.

Featured deals of the first quarter included bankruptcy sales and a royalty deal.

"Even before oil prices collapsed on COVID-19-related demand issues and the surge in global production led by Saudi Arabia, M&A markets were highly challenged," said Andrew Dittmar, senior M&A analyst for Enverus. "Responding to Wall Street pressures, E&Ps had slashed spending and refocused from growth to cash flow, dampening the appetite for acquisitions."

Enverus said the largest first-quarter deal was the successful stalking horse bid by **Alpine Energy Capital** for the assets of bankrupt Midland Basin operator **Approach Resources Inc**. The assets were sold as part of a Chapter 11 proceeding for $193 million.

Enverus speculated that bankruptcy sales might drive future deal flow or be a new clearinghouse for dealmakers if creditors are "perhaps leery of taking equity in a reorganization."

However, the analytics firm also noted that **Sanchez Energy Corp.** creditors are apparently taking equity stakes in a reorganized company that could emerge from bankruptcy. Sanchez entered bankruptcy in August with about $2.3 billion in debt.

**Rystad Energy** reported on April 3 that dozens and perhaps hundreds of upstream companies could seek bankruptcy protection depending on the depths and duration of WTI prices. Producers are heavily indebted, and current prices are "likely to create the largest number of such filings in modern history" this year, according to Rystad's analysis.

By 2021, bankruptcy filings could climb to 150 or more cases should oil prices remain at $30/bbl Rystad said. In a worst-case scenario, at sustained $20 WTI prices, E&Ps carrying nearly $250 billion in debt would be at risk.

Legal firm **Haynes and Boone LLP** recorded seven E&P bankruptcies since January totaling $7.7 billion. The largest, **Whiting Petroleum Co.**, entered bankruptcy protection April 1 with a restructuring agreement for its $5.9 billion in debt.

Through the sudden shift in oil prices and surges in supply, mineral and royalty asset deals had been a continuing bright spot for the industry. In January, **Kimbell Royalty Partners**, one of six publicly traded royalty companies, bought a diversified package from private-equity-sponsored **Springbok Energy I & II** for $175 million, Enverus said.

"Mineral and royalty interests are playing an increasing role in deal markets," said John Spears, Enverus market research director. "We expect additional capital will be interested in deploying here, even in a down market. The challenge will be navigating a wide bid-ask spread between buyers and sellers with rig numbers and development plans for acreage in flux."

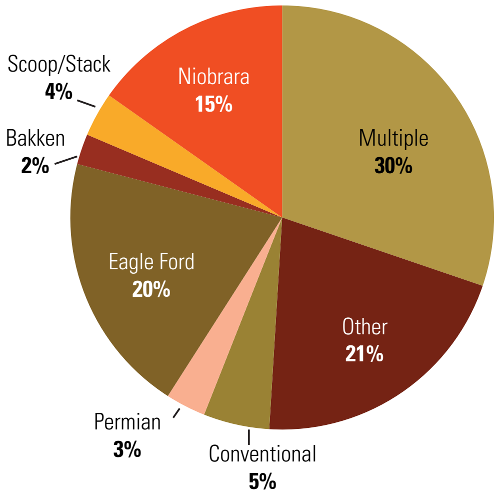
The M&A market is likely to rebalance as rigs are idled and operators cut capex, which may reduce the need to add further inventory. Buyers with capital and the appetite for deals should see opportunities materialize once some stability is added to the market, Enverus said.

Buyer groups with potential to capitalize on opportunities are likely to include majors, private and institutional capital, and foreign buyers.

"As painful as the downturn is, this may finally push the industry into healthy consolidation that leaves us with larger, more efficient, and better capitalized operators when the recovery starts," added Dittmar. "These buyers will likely have opportunities to acquire high-quality assets that might have been viewed as too expensive before the downturn."

*—Darren Barbee*

**US Upstream Active Deals For Sale**




Source: Enverus

**First-Quarter 2020 Deals**

| Date | Buyer | Seller | Deal | $MM |
|---|---|---|---|---|
| Feb. 4 | *Alpine Energy Capital | Approach Resources Inc. | Midland Basin assets | $193 |
| Jan. 31 | Undisclosed | ConocoPhillips Co. | Conventional assets | $186 |
| Jan. 9 | Kimbell Royalty | Springbok Energy | Royalty interests | $175 |
| Jan. 24 | KeyBank | EdgeMarc Energy Asset | Marcellus assets | $90 |
| Feb. 26 | Undisclosed | HighPoint Resources | Diversified assets | $27 |

Source: Enverus

# Basic Energy Acquires NexTier's Well Services Business

**BASIC ENERGY SERVICES INC.** acquired production operations from **NexTier Oilfield Solutions Inc.** as Basic develops its U.S. well services capabilities.

In a news release, Basic said it paid about $94 million for the NexTier production operations, which the company plans to fund through a combination of cash and notes that includes proceeds from the previously announced sale of its pumping service assets.

The NexTier production operations, known as **C&J Well Services**, is the third-largest rig servicing provider in the U.S. Combined, Basic expects to achieve $17 million in annual run-rate cost synergies.

"This transaction solidifies Basic's foundation to become the leading and most trusted production services provider in the country," Keith L. Schilling, president and CEO of Basic, said in a statement.

Similar to other oilfield service providers, Basic has been impacted by declining U.S. shale activity over the past year. As a result, Basic announced a plan in mid-December to divest its pumping services assets in multiple transactions. Expected proceeds of between $30 million and $45 million were earmarked for redeployment into the Fort Worth, Texas-based company's well servicing and water logistics businesses.


SOURCE: NEXTIER OILFIELD SOLUTIONS

"Starting with the near-complete sale of our pumping services assets, we have taken important steps to bolster our core production-focused businesses, enhance our credit profile and ultimately position the company for future growth and leadership," Schilling added.

C&J Well Services was originally established in San Angelo, Texas, in 1948 by Frank Pool, founder of **Pool Well Servicing**. Last year, **C&J Energy** combined with rival pressure pumper **Keane Group Inc.** in an all-stock merger forming NexTier.

Together, Basic's workover fleet will grow to 411 high spec rigs with nearly 5,000 employees across 11 states including expanded footprints in the Permian Basin, California and other key oil basins, which Schilling said positions Basic to increase stockholder value.

"Importantly, we expect our increased operating scale, enhanced credit metrics and strong cash flow generation will enable the company to continue to de-lever while remaining a disciplined but active participant in the ongoing consolidation occurring in our industry," he said.

**Morgan Stanley & Co. LLC** served as Basic's financial adviser for the transaction. **Weil, Gotshal & Manges LLP** was the company's legal adviser. Additionally, **Lazard** is serving as financial adviser to the special committee of the board of Basic.

# Market Meltdown Cools BLM Auction

**OIL AND GAS LEASE** sales offered by the Trump administration in three Western states on March 24 drew few bids as a crash in energy prices tamped down interest among drillers.

The Bureau of Land Management (BLM) received bids on just 40% of the 193,584 acres offered for leasing via online auctions in Wyoming, Nevada and Montana, bringing in total high bids of about $3.3 million, according to results from online marketplace **EnergyNet**.

Wyoming, which held the largest sale of 105 parcels covering 118,292 acres, accounted for 99% of the bid total. Wyoming is the top U.S. state for gas production on federal lands and the second biggest for oil production, according to the U.S. Energy Information Administration.

Yet even there, bidding was sparse. Parcels covering just 72,000 acres received bids, and 40% of that acreage sold for the minimum price of $2 an acre. The average price of $46 an acre was less than half the average price last year, which exceeded $100 per acre in a federal lease sales held in Wyoming.

In Nevada, BLM received bids on less than 2% of the 70,110 acres offered, in a sale that brought in less than $2,500 total. In Montana, eight parcels covering 5,180 acres received an average price per acre of about $5.

Drilling on federal lands is a crucial part of President Donald Trump's "energy dominance" agenda to maximize domestic production of fossil fuels.

But the industry is in crisis as countries including the U.S. take unprecedented steps to contain the coronavirus pandemic, which has curbed demand for products such as gasoline and jet fuel.

U.S. oil prices have dropped roughly half since the middle of February to about $24/bbl.

Taxpayer advocacy groups had urged the Trump administration to delay the sales to ensure better return to federal coffers.

"In this environment, it is impossible for the American taxpayer to expect anywhere near a fair return on oil and gas leases," Taxpayers for Common Sense and Conservatives for Responsible Stewardship said in a joint statement last week.

In a statement, BLM spokesman Derrick Henry said the agency was not postponing lease sales.

"Using an all-of-the-above approach to energy development, we are helping to meet our nation's growing energy needs by facilitating development and letting free market forces work," he said. "Oil and gas lease sales and royalties continue to propel America's economy and support good-paying energy sector jobs," he added.

BLM will offer another 20 parcels on 18,960 acres in Colorado on March 26.

In March, the U.S. held an auction for oil and gas leases in the Gulf of Mexico that generated the lowest total of high bids for any domestic offshore auction since 2016. Also in March, BLM held a lease sale in Utah that received mostly minimum bids of $2 an acre.

# Enbridge Sells Ozark System to Black Bear

**ENBRIDGE INC. SOLD** natural gas pipeline transportation and gathering systems in the southeastern U.S., according to **Black Bear Transmission LLC**, which said it had acquired the assets for an undisclosed amount.

In an April 1 news release, Black Bear said it completed the acquisition of **Ozark Gas Transmission LLC** and **Ozark Gas Gathering LLC** from a subsidiary of Calgary, Alberta-based Enbridge.

Based in Houston, Black Bear is a portfolio company of **Basalt Infrastructure Partner LLP**'s second fund. The investment firm formed Black Bear through the acquisition of **Third Coast Midstream LLC**'s natural gas transmission business, which closed December.

Rebranded as **Black Bear Transmission**, the natural gas

SOURCE: G B HART/SHUTTERSTOCK.COM

transmission business included seven regulated natural gas pipelines, stretching approximately 550 miles. The pipelines were connected to eight major long-haul pipelines across Louisiana, Alabama, Mississippi, Tennessee and Arkansas.

The Ozark acquisition adds a 367-mile, FERC-regulated interstate natural gas pipeline transportation system. The system extends from southeastern Oklahoma through Arkansas to southeastern Missouri and has significant interconnectivity to major long-haul natural gas pipelines.

The deal also includes a fee-based, 330-mile natural gas gathering system that connects regional production into the Ozark Gas Transmission Pipeline.

Black Bear CEO Rene Casadaban said in a statement, "This investment expands our asset base of high-quality, demand-driven natural gas pipelines serving utilities and other key end-user customers across the southeastern United States."

**Barclays** was exclusive financial adviser to Basalt, and **Morgan, Lewis & Bockius LLP** served as the firm's legal adviser. **TD Securities** was exclusive financial adviser to Enbridge and **Norton Rose Fulbright US LLP** provided the company legal advice.

# Shell Exits, Energy Transfer Takes Over Lakes Charles LNG

**ENERGY TRANSFER LP** announced March 30 that it will take over development of the Lake Charles, La., LNG export project following Shell's announcement that it has decided not to proceed with an equity investment in the project, citing current market conditions.

Energy Transfer will take over the role of lead project developer and will continue the project's development. The company will evaluate various alternatives to advance the project, including the possibility of bringing in one or more equity partners and reducing the size of the project from three trains (16.45 mtpa of LNG capacity) to two trains (11 mtpa).

"We continue to believe that Lake Charles is the most competitive and credible LNG project on the Gulf Coast," said Tom Mason, executive vice president and president, LNG. "Having the ability to capitalize on our existing regasification infrastructure at Lake Charles provides a cost advantage over other proposed LNG projects on the Gulf Coast. The Lake Charles project also benefits from its unparalleled connectivity to Energy Transfer's existing nationwide interstate and intrastate pipeline system that provides direct access to multiple natural gas basins in the U.S."

Energy Transfer and Shell signed a project framework agreement in March

SOURCE: FELIX MIZIOZNIKOV/SHUTTERSTOCK.COM

2019, under which the two companies agreed to share the cost of developing the project. Since that time the two companies have jointly undertaken the engineering, procurement and construction (EPC) bidding process.

Shell has committed to support Energy Transfer with this process through the receipt of commercial EPC bids in the second quarter of 2020. Additionally, Shell will continue to support Energy Transfer during a transition period to facilitate the latter's plans to continue the development of the project.

"We remain in discussions with several significant LNG buyers from Europe and Asia regarding LNG offtake arrangements as well as, in some cases, a potential equity investment in the project," Mason said. "In light of the advanced state of the development of the project, we remain focused on pursuing this project on a disciplined, cost-efficient basis and, ultimately, the decision to make a final investment decision will be dependent on market conditions and capital expenditure considerations."

# GoM High Lease Bids Fall To $93 Million


SOURCE: DONVICTORIO/SHUTTERSTOCK.COM

**FOCUSED ON THE** long-term potential of offshore oil and gas development as today's market faces unprecedented headwinds, offshore players placed a combined $93 million in high bids on blocks in the U.S. Gulf of Mexico (GoM).

The March 18 lease sale, which was scheduled in late 2019, came amid a market collapse that has seen a growing list of oil and gas companies chop capital budgets for the year. Facing uncertainty brought by the coronavirus pandemic and oil price war sparked by OPEC+ alliance breakup, companies participating in the sale had until 10 a.m. March 17—the day before the sale—to withdraw bids previously placed.

But none had, Mike Celata, director of the U.S. Bureau of Ocean Energy Management (BOEM), said during a media call following the sale. Preliminary sale statistics provided by BOEM showed 22 companies participated in the sale, placing 84 bids on just 71 of the nearly 14,600 blocks available across the GoM region.

The number of participants is down from the 30 companies that participated in the March 2019 lease sale, which brought in more than $244 million in high bids on 227 blocks. Back then, oil prices were hovering around $60 per barrel, compared to less than half that today.

"While bidding did take a tough hit, it could have been substantially worse due to the unprecedented near-term financial constraints created by COVID-19 and the oil price war between Saudi Arabia and Russia," National Ocean Industries Association President Erik Milito said in statement. "Long-term projections for energy demand, including oil and natural gas, show strong growth for the foreseeable future. Offshore projects are undertaken with the long-term outlook in mind."

Celata admitted he didn't know what to expect going into the sale, given what had happened in the markets in the prior two weeks.

"But I'm pleased with the dollars bid per acre. I think that's a fair assessment of the sale, and I think that bodes well for this sale and then future sales," he said, which he said averaged around $234 but was $251 per acre for deep water—"the driving force of all these lease sales." It was the highest since August 2017. "So, from that aspect, dollars per acre, we did fairly well."

The $93 million in high bids for the sale, the first of two federal offshore oil and gas lease sales scheduled for 2020, was the lowest since 2016, Reuters reported.

Before the latest market crash, the August 2019 lease sale results added to renewed optimism offshore. That sale garnered $159.4 million in high bids.

Despite the market ups and downs, interest remains in the GoM with several multimillion-dollar bids placed by offshore players as evidence. Topping the list of high bids on a single block was **BHP Billiton Petroleum Deepwater Inc.**, which bid about $11 million for Green Canyon Block 80.

Another block in the area received a $5 million bid.

"Those were both newly available blocks, and they were offset to Green Canyon 124, which was the high bid in the last sale," Celata added, pointing out the possible pursuit of Miocene-aged reservoirs in fairly large structures in the area. "All this bidding was by BHP. So, there's still prospects out there that operators are interested in acquiring."

Commenting on the sale in a statement, Mfon Usoro, senior research analyst with **Wood Mackenzie**'s GoM upstream team, said, "BHP also bid on a cluster of blocks in Alaminos Canyon to bolt onto its existing acreage in the region where it is currently evaluating results of the Ocean Bottom Node seismic."

The top five companies in terms of sum of high bids were:

- **Chevron USA Inc.**, 15 bids totaling about $24.7 million;
- BHP Billiton, six bids totaling about $20 million;
- **Shell Offshore Inc.**, seven bids totaling about $18.4 million;
- **BP Exploration & Production Inc.**, 16 bids totaling about $10.4 million; and
- **EnVen Energy Ventures LLC**, two bids totaling about $4 million.

Usoro pointed out that majors accounted for more than 60% of the high bid amount with competition seen between Shell, Chevron, BP and **Total SA** for recently-expired blocks in Green Canyon and Garden Banks.

"A notable block was [Garden Banks] 963, a stone's throw from Total's North Platte project, which expired in October 2019," Wood Mackenzie said in a statement. "Total and Shell went toe to toe on that block, with Total winning it with a $1 million bid, a fraction of the $22 million that was paid to pick up the block in 2012."

Blocks near existing infrastructure also continued to attract bidders as tiebacks and infrastructure-led exploration continue to make offshore more economic for oil and gas companies.

Of areas receiving bids, interest appeared the greatest in the Green Canyon blocks, and deep water continued to reign. Of the 71 blocks with bids, 53 had water depths of at least 800 meters, according to the preliminary statistics.

In all, participating companies placed about $108.6 million in bids.

"We should also remember that lease sales are just the start of the offshore investment window," Milito said. "Companies will spend millions of dollars exploring, evaluating and, hopefully, producing from many of today's lease blocks. NOIA member companies remain committed to providing energy security, economic growth and a high standard of living through American offshore energy production."

The next GoM lease sale is proposed for the summer. If held, it will mark the seventh sale of the 2017 to 2022 Outer Continental Shelf oil and gas leasing program.

"We think more lease sales are still in the cards, but higher oil prices will be required for bid amounts to climb back to historical norms," Usoro added. "Otherwise this sale result will continue with even lower bidding activity."

BOEM estimates the GoM Outer Continental Shelf contains about 48 billion barrels and 141 trillion cubic feet of undiscovered technically recoverable oil and gas resources.

*—Velda Addison*

# Water Midstream Consolidation To Continue

**OPERATORS INCREASINGLY** find that their water midstream assets don't fit into their efforts to win back investor and analyst confidence. 2019 and into 2020, the likes of **PDC Energy Inc.** (which eventually merged with **SRC Energy Inc.**), **Continental Resource Development Inc.**, **Noble Energy Inc.** and **Concho Resources Inc.**, among others, all shed water management assets from supply lines to disposal wells.

The trend continued almost immediately when the calendar flipped to 2020. In January **EOG Resources Inc.** sold 23 saltwater disposal wells and 300 miles of gathering pipelines to **Oilfield Water Logistics**, according to a report in the Houston Chronicle.

Most agree that in the current oil and gas industry economic environment consolidation is both imminent and necessary. And as shale wells start to age and produce more water, water management will continue to play a key role in operations.

However, as Shawn Maxson, principal and oilfield service practice lead at **Deloitte**, explained, for companies looking to maximize operational costs efficiencies, water midstream operations don't come with the same margins as production growth.

"You don't get the same level of return on investments in water management infrastructure that you do growing a new producing well," he said. "There are better uses of capital, and there are companies out there that are more capable at optimizing their water management infrastructure and managing it on an ongoing basis."

Maxson believes that more consolidation in the water midstream market will benefit the industry in the long term.

"Ultimately, it's about scale," he said. "Consolidation is a good thing from that perspective, as long as you have some alternatives that provide the capability to ensure the market is balanced."

One such alternative could be joint ventures (JVs) between operators and water midstream companies. In July 2019, Concho Resources formed a JV with **Solaris Water Midstream LLC** for produced water management in the northern Delaware Basin. In a case of two service providers joining forces, **$H_2O$ Midstream LLC** and **Layne Midstream** signed a long-term contract in January 2019 to serve as the preferred water services provider for **University Lands**, covering water operations across 167,000 acres in the Delaware Basin. Those two deals are likely indicative of what the industry will see, particularly in the Permian Basin. It's a dynamic that also could lead to new innovators entering the market and testing the waters.

"The majority of activity will be focused in the Permian," Maxson said. "I think we're going to continue to see small startups investing in innovative ways to deal with water recycling and reuse. Hopefully, we'll start seeing some trends that move us more toward more efficient water management models."

*—Brian Walzel*

# TRANSACTION HIGHLIGHTS

**DELAWARE BASIN**

■ **WPX Energy Inc.** on March 6 completed its $2.5 billion acquisition of **Felix Energy II**, growing its position in the Permian's Delaware Basin, which CEO Rick Muncrief believes will help the U.S. shale producer generate shareholder returns.

Backed by **EnCap Investments LP**, Felix Energy has a 58,500 net acre position in an overpressured, oily portion of the Delaware Basin in West Texas. Tulsa, Okla.-based WPX had entered an agreement to acquire the company in mid-December.

WPX expected the transaction—the largest E&P deal announced in the U.S. during the fourth quarter—to significantly boost its free cash flow in 2020 at $50 oil, allowing the company to implement a dividend.

"We remain absolutely convinced about the accretive nature of the transaction and the outstanding quality of these assets," Muncrief said in a March 6 news release. "They overlie a tremendous resource that clearly gives us the means for accelerating our ability to achieve our five-year targets for shareholders."

The company has core positions in the Permian and Williston basins, where it now expects to produce more than 150,000 bbl/d of oil.

**SOUTHEAST TEXAS**

■ **Denbury Resources Inc.** said it has entered into a definitive agreement with a subsidiary of **Navitas Petroleum** to sell half of its nearly 100% working interest position in four southeast Texas oil fields (consisting of Webster, Thompson, Manvel and East Hastings), for $50 million cash and a carried interest in 10 wells to be drilled by Navitas.

The sale is expected to close by early March 2020 and is subject to customary closing conditions. The company anticipates using the sale proceeds to fund operations, enhance liquidity and/or reduce debt.

Denbury will remain operator of the fields, but Navitas will drill and complete each of the 10 wells.

Under the agreement, Navitas is committed to funding 100% of the capital required to drill and complete an initial 10 horizontal wells across the fields, with the first of the 10 wells to be spudded within six months of closing and with all 10 wells to be completed within 18 months after closing. For these initial 10 wells, Denbury will receive only a 6.25% overriding royalty interest prior to the combined payout of the wells drilled in a specific field. Subsequent to payout, Denbury will hold and bear the cost of its 50% working interest in each well. Navitas is required to drill at least one well in each of the four fields.

After the initial 10-well program is completed and if certain performance hurdles are achieved, Navitas will have the opportunity to continue the development of the fields for up to six separate extension periods. During each extension period, Navitas can propose and drill up to 10 additional wells, totaling up to 60 additional wells on a pro-rata working interest basis

Denbury will retain 100% ownership of the future Webster Unit $CO_2$ enhanced oil recovery project. Navitas may elect to participate in the future $CO_2$ EOR project through reimbursement to Denbury of Navitas' working interest share of project costs incurred to date; or if Navitas declines to participate in the $CO_2$ EOR project, Denbury has the right to repurchase Navitas' working interest in Webster under a contractually agreed valuation mechanism.

**BARENTS SEA**

■ Norway proposed offering oil firms 36 offshore exploration blocks in an annual licensing round in mature areas, but for the first time in a decade it didn't include any acreage in the Arctic Barents Sea.

The energy ministry, announcing the plan on March 30, said it was still important to plan for the future despite the challenging environment, which has oil prices slumped. However, the proposed number of blocks on offer was down from 90 blocks proposed in the previous round a year ago, of which the government eventually awarded 69 blocks.

All the blocks are offered in the western part of the Norwegian Sea, with interested parties asked to submit comments in a public hearing by May 11, the oil and energy ministry said.

"In demanding times, it is important to plan for the future," Norway's Oil and Energy Minister, Tina Bru, said in a statement.

"Regular access to new exploration is crucial to further develop our largest industry and maintain activity on the Norwegian Continental Shelf."

The ministry did not say why it was not offering any blocks in the Barents Sea, the first time it has not done so since 2010.

Greenpeace, which has previously called on Norway to stop exploring for new petroleum resources, said there would be little demand given the recent slump in oil prices.

"It clearly shows that there is little appetite from the industry for drilling in the Barents Sea, up in the sensitive Arctic," Frode Pleym, head of Greenpeace in Norway, told *Reuters*.

The oil and energy ministry was not immediately available for further comment.

Norway introduced annual rounds for mature areas in 2003 to expand areas that have been already explored or had an existing oil and gas infrastructure.

Greenpeace said the country should use the oil market crash to speed up its transition to renewable energy.

Oil prices fell sharply again on March 30, with North Sea oil hitting its lowest level in 18 years at below $23/bbl, on heightened fears that the shutdown of much of the global economy due to the coronavirus could last months and demand for fuel could decline further.

**GOM**

■ Mexico's oil regulator approved on March 20 a request by French oil company **Total SA** to give up its E&P rights to a deepwater block in the southern Gulf of Mexico that the firm had won at auction in 2016.

The regulator said Total decided to return the block due to the results it had obtained to date and must pay a fine of $21.2 million for failing to comply with its contract's minimum exploration work requirements.

Total, the project's operator, had won rights to the area in a consortium that also included U.S. oil major **Exxon Mobil Corp**.

Mexico's **Hokchi Energy** and U.S. **Talos Energy Inc**. have also relinquished some of their rights for exploring oil and gas areas in Mexico after winning offshore blocks as part of Mexico's flagship 2013 energy reform.

# DÉJÀ VU ALL OVER AGAIN

RICHARD MASON,
CHIEF TECHNICAL
DIRECTOR

Discussion in Texas among a handful of Permian producers and at least one commissioner with the Texas Railroad Commission is calling for reinstitution of proration as an administrative tactic to adjust to the crippling global oversupply in oil.

Proration is an administrative policy that adjusts hydrocarbon production to market demand.

Proration is an obtuse, nebulous term to anyone born after 1960. However, Texas oil production operated exclusively under proration from 1928 unofficially and officially in the 1930s until the U.S. imported its first barrel of oil four decades later in the 1970s. At that point, the railroad commission lifted production restrictions other than for conservation.

The Texas model incorporated allowables—production quotas—tied to acreage. At the core, and reflecting free market oil patch politics, all producers regardless of size are guaranteed market access. However, their share of access depends on the productive potential of an arbitrary acreage parcel and its relation to the whole.

A century ago, proration was a conservation measure. Production controls were developed to conserve hydrocarbons by preventing waste, either through reservoir damaging production methods that cut short a field's potential and stranded hydrocarbons, or for producing oil that went to economic waste in an oversupplied market.

Proration prevents an economic collapse in the market as occurred in the U.S. after the East Texas oil field was discovered. Here, production was so large it overwhelmed the national market. Independents ran "hot oil" to sell for whatever they could get, which was below 10 cents/bbl, or about $1.50/bbl today. It took the Texas National Guard and judicial rulings in favor of the Texas Railroad Commission at the state and federal level to bring proration and rational business practices to the oil patch in East Texas and, by extension, the U.S.

The Texas model operated successfully even though, by the early 1970s, producers were restricted to one day of restricted pumping per month. Texas, as the world's largest oil producer, set national market conditions under direction of the Texas Railroad Commission, which administered proration and made the agency a factor in the global oil market.

The proration concept originated as a response to a 19th century legal decision in Appalachia, birthplace of oil and gas. Faced with legal wrangling on how to apportion ownership of ground related minerals (and groundwater), courts adapted English hunting law to fit U.S. minerals. This law—the Rule of Capture—held that if a wild and migratory animal crossed property lines and was successfully hunted by the adjacent property owner, the kill was rightfully his, and he owed no compensation to the owner of the land where the migratory animal originated.

When applied to oil, the ruling encouraged wildcatters to drill as many wells along property lines as quickly as possible to capture as much oil as possible, including oil originating underneath adjacent land where a competing producer was pursuing the same strategy. This resulted in dissipation of reservoir pressure, stranded resource and led to the perennial boom/bust nature of hydrocarbon development.

Oil plays lasted three to five years at most, then collapsed, creating economic disarray. Producers moved boom to boom from Appalachia to Oklahoma, to the Texas Gulf Coast and North Texas by the 1920s. Then came discovery in the Permian Basin of two giant San Andres fields, Yates in Pecos County and Hendricks in Kermit County, one week apart in 1926.

Yates was the U.S. equivalent of Saudi Arabia's Ghawar Field with a potential 5.5 million barrels per day. Excess production from both fields led to a price collapse by 1928 and threatened early depletion in both reservoirs. Producers at Yates opted for voluntary proration based on newly developed reservoir pressure measurement techniques that provided all producers market access, prevented water encroachment and was tied to the productive potential in 100-acre parcels. Separately, Hendricks producers opted for 40-acre spacing until one producer balked, which brought a court fight that resulted in mandatory prorationing in the field by the Texas Railroad Commission.

Fast forward three decades. When OPEC organized global producers in the early 1960s, the organization based its quota system on the Texas model, which created the OPEC cartel. What goes around apparently has come around again today.

# EASTERN US

**1** A Smackover test planned by Shreveport, La.-based ***Sklar Exploration*** could reestablish production in Castleberry Field, a one-well Alabama reservoir last online in 2018. The Conecuh County venture, #1 Myrtice Ellis 35-9, will be directionally drilled to 12,876 ft in Section 35-4n-10e. According to IHS Markit, ***Midroc Operating*** opened Castleberry Field in 2009 with the completion of #35-8 McMillan. It was tested flowing 134 bbl of 43-degree-gravity crude and 107 Mcf of gas daily from Smackover at 12,272-76 ft. Within 4 miles to the south-southeast is Kirkland Field, a Smackover oil pool opened by Sklar in 2014. Through 2019, the Escambia County reservoir has recovered 511.874 Mbbl of crude and 1.3 Bcf of gas from perforations at 12,924-13,108 ft.

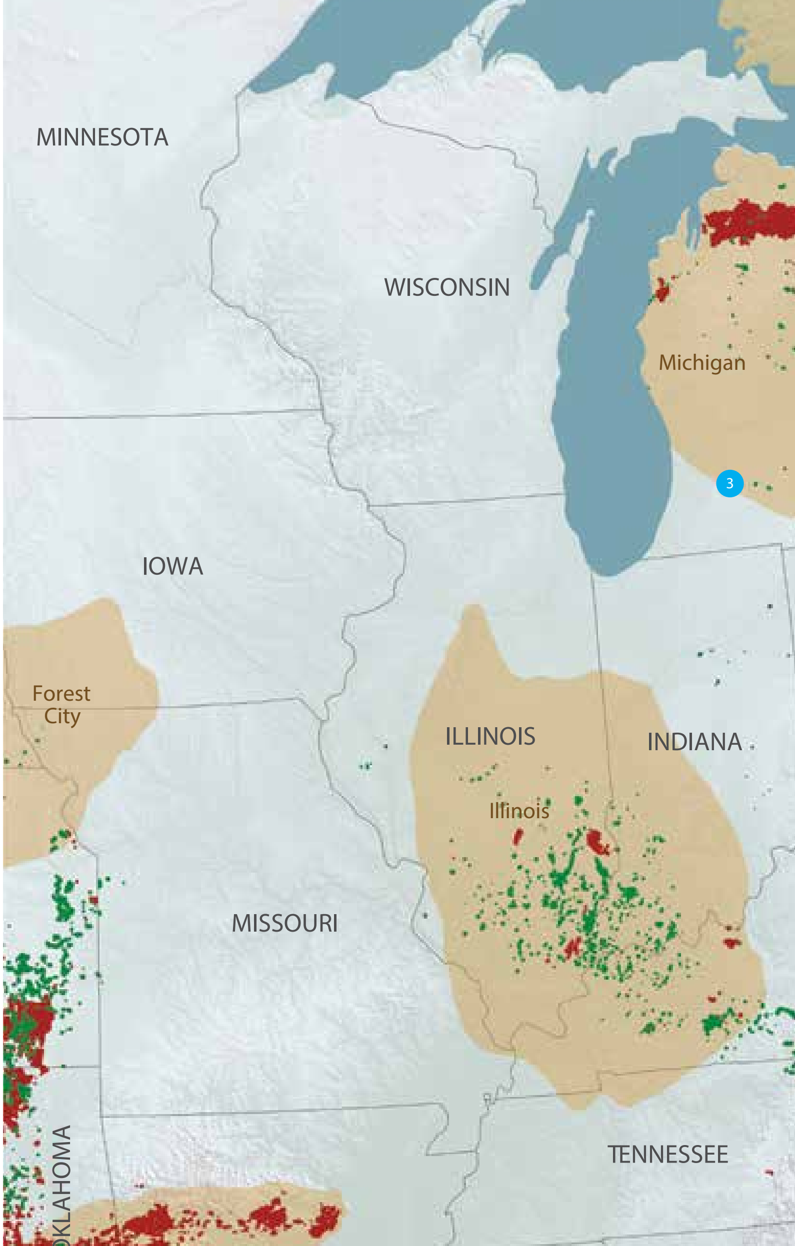
**2** ***Ventex Operating*** is nearing total depth at a Smackover test in Conecuh County, Ala., along the southeastern edge of Brooklyn Field. The #1 Pate 13-15 is being directionally drilled to a total depth of 12,500 ft, and it is in Section 13-3n-13e. One Brooklyn Field well has been completed in Section 13 at Ventex's #1 Cedar Creek Land & Timber 13-5. It was tested in 2019 flowing 743 bbl of crude from Smackover at 11,915-20 ft. The Adsison, Texas-based company's only other Brooklyn Field well, #1 Pate 11-3 in Section 11, was completed in 2018. Through November 2019, the well produced 137.47 Mbbl of crude and 109 MMcf of gas from Smackover at 11,740-80 ft.

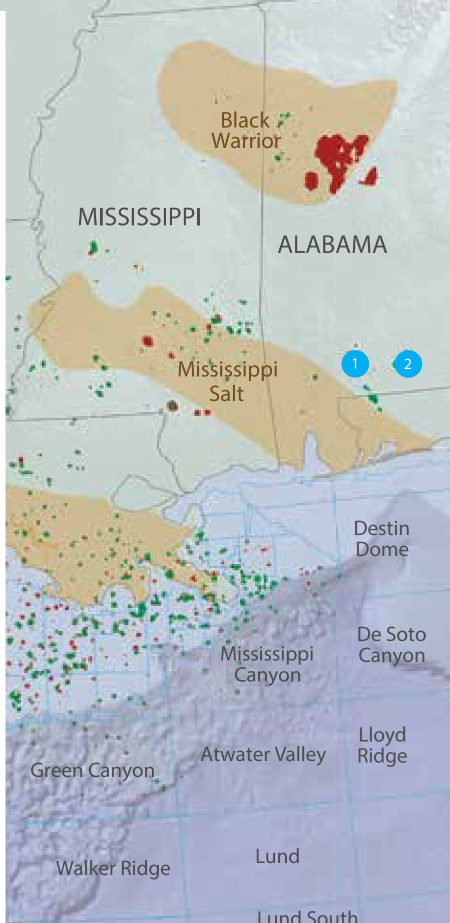
**3** ***Savoy Energy LP*** has scheduled a 4,000-ft exploratory test in Calhoun County, Mich., about 3 miles west of a Trenton/Black River project operated by the company. IHS Markit reported that #1-6 Fuller will be vertically drilled in Section 6-4s-8w. The Traverse City-based company has been active in the area since 2018. The company's discovery well, #1-34 Seymour in Section 34-3s-8w, was tested in 2018 pumping 48 bbl of crude daily from an undisclosed zone in Trenton. The Leroy East Field opener has recovered 72.686 Mbbl of crude through late 2019. The well was drilled to 4,035 ft. A 2019 completion by Savoy, #1-19 Motz in Section 19-4s-7w, was tested pumping 192 bbl of crude per day from Trenton at 3,482-98 ft. The discovery is 7 miles west of Trenton/Black River oil production in Tekonsha Field. To the west is Kalamazoo County's Climax Field, a Trenton/Black River reservoir opened in 2014.

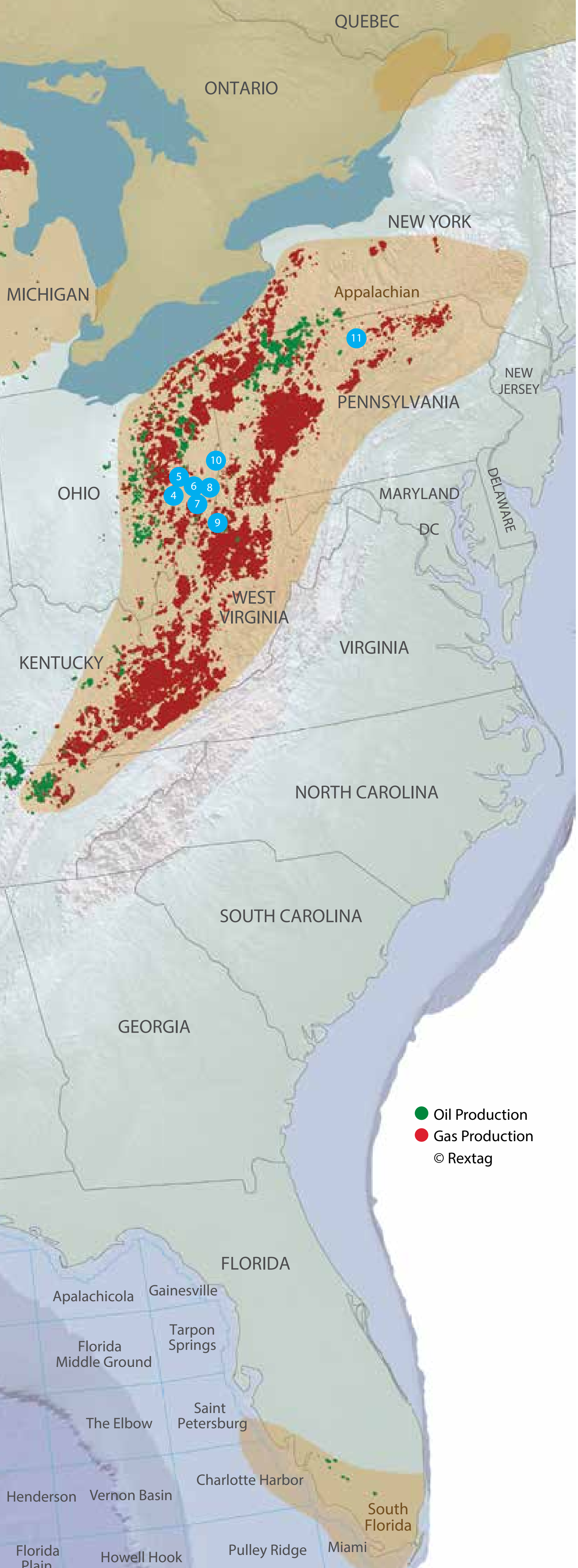
**4** Denver-based ***Antero Resources Corp.*** announced results from a Utica Shale completion in Monroe County, Ohio. The #1H McChesney Unit was drilled in Section 30-6n-6w. It initially flowed 24.387 MMcf of gas and 854 bbl of water per day, and production is from perforations between 8,900 and 18,426 ft. The venture was drilled to 18,564 ft, 8,611 ft true vertical, and bottomed in Section 7.

**5** A Harrison County, Ohio, Utica Shale well was tested flowing 1.314 Mbbl of oil, 14.209 MMcf of gas and 342 bbl of water per day. The ***Ascent Resources*** completion, #1H RH Sparger W NTG HR, is in Section 9-11n-6w. The McFadden Run Field venture was drilled to 22,587 ft with a true vertical depth of 7,884 ft and was tested after acidizing and fracturing. Production is from perforations between 8,246 and 22,394 ft. Ascent is based in Oklahoma City.

**6** Two Utica discoveries were reported in Harrison County, Ohio, by ***Ascent Resources***. The Uniontown Field wells were drilled from a pad in Section 5-9n-5w. The #2H Bravo SW ATH HR was drilled to 23,773 ft with a true vertical depth of 9,038 ft. It initially flowed 115 bbl of oil, 33.446 MMcf of gas and 226 bbl of water per day from perforations at 9,128-23,658 ft. The #4H Bravo S ATH HR was drilled to 24,175 ft (9,085 ft true vertical). The well flowed 116 bbl of oil, 32.948 MMcf of gas and 161 bbl of water per day from perforations at 9,278-24,019 ft.

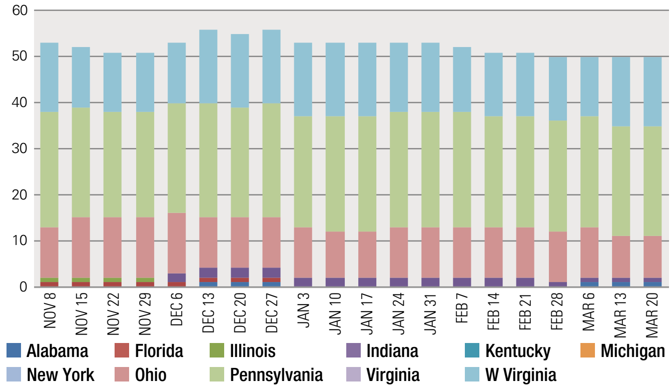





**Eastern US Rig Count**

Nov. 8, 2019-Mar. 20, 2020




Source: Baker Hughes Co.

**7** A Monroe County, Ohio, Utica Shale completion was reported by State College, Pa.-based ***Eclipse Resources I LP***. The Cameron Field well, #6H Craig Miller B, was drilled in Section 15-4n-4w to 25,195 ft, 10,431 ft true vertical. It initially flowed 17.418 MMcf of gas and 790 bbl of water per day, and it bottomed in Section 12. Production is from perforations between 10,629 and 25,404 ft.

**8** Two Utica Shale wells were completed in Belmont County, Ohio, by ***Ascent Resources***. The wells were drilled from a Harrisville Consolidated Field pad in Section 17-7n-4w. The #3H Crowie E RCH BL was drilled to 18,375 ft, 9,204 ft true vertical, and bottomed in Section 19. It flowed 24.252 MMcf of gas and 114 bbl of water per day from perforations at 10,084-21,395 ft after acidizing and fracturing. About 50 ft to the north, #1H Crowie RCH BL was also drilled to 18,375 ft, and the true vertical depth is 9,204 ft. It flowed 15.773 MMcf of gas and 120 bbl of water per day from perforations at 9,883-18,249 ft after acidizing and fracturing. The well bottomed in Section 19.

**9** In Tyler County, W. Va., ***CNX Gas*** completed a Marcellus Shale well. The #38SHRGHSM James E Ash ET AL is in Wilber Field. It was tested flowing 28 bbl of oil, 3.453 MMcf of gas and 459 bbl of water per day. The well was drilled to 16,952 ft with a true vertical depth of 6,540 ft. Production is from an acidized and fractured zone at 6,882-16,870 ft. CNX is based in Pittsburgh.

**10** ***Ascent Resources*** announced results from a Jefferson County, Ohio, Utica Shale discovery. The company's #5H Roxy NE was drilled in irregular Section 33-6n-2w in Bloomingdale Field. The completion was drilled to 21,612 ft (9,310 ft true vertical) and flowed 24.057 MMcf of gas with 252 bbl of water per day. Production is from a perforated zone at 9,909-21,461 ft.

**11** A ***Southwestern Production Co.*** Marcellus Shale discovery, #7H Bliss, initially flowed 31.074 MMcf of gas with no reported water per day. The McNett Field well is in Tioga County, Pa., and was drilled to the north in Section 4, Liberty 7.5 Quad, Liberty Township, to 14,838 ft with a true vertical depth of 7,026 ft. Gauged on an unreported choke size, the shut-in casing pressure was 3,153 psi, and production is from perforations between 7,020 and 14,736 ft. Southwestern's headquarters are in Spring, Texas.

## GULF COAST

**1** Two Eagleville Field wells were completed at a pad in De Witt County (RRC Dist. 2), Texas, by Oklahoma City-based ***Devon Energy Corp.*** in William Lyette Survey, A-303. The #13H E Butler was drilled to 19,617 ft, 13,320 ft true vertical, and produced 1.314 Mbbl of condensate, 3.475 MMcf of gas and 1.205 Mbbl of water per day from Eagle Ford at 13,723-19,408 ft. It was tested on a 20/64-in. choke, and the flowing tubing pressure was 4,435 psi. The #14H E Butler A was drilled to 19,614 ft, 13,302 ft true vertical. It was tested flowing 1.518 Mbbl of condensate, 3.118 MMcf of gas and 1.178 Mbbl of water per day from perforations at 13,722-19,415 ft. Gauged on a 20/64-in. choke, the flowing casing pressure was 5,438 psi, and the shut-in casing pressure was 5,468 psi.

**2** Two Tarrant County (RRC Dist. 5), Texas, Barnett Shale wells were reported by Fort Worth, Texas-based ***TEP Barnett USA***. The Newark East Field wells were drilled from a drillpad in Lewis G Tinsley Survey, A-1523. The #2H Carden-Heidi-Little was drilled to 17,458 ft, 7,192 ft true vertical. It was tested flowing 5.099 MMcf of gas and 1.35 Mbbl of water per day from perforations at 7,681-17,304 ft. It was tested on a 36/64-in. choke with a flowing tubing pressure of 1,214 psi and a shut-in tubing pressure of 1,716 psi. The #3H Carden-Heidi-Little was drilled to 17,025 ft with a true vertical depth of 7,192 ft and produced 6.171 MMcf of gas and 1.191 Mbbl of water per day from perforations at 7,651-16,936 ft. Gauged on a 46/64-in. choke, the flowing tubing pressure was 1,121 psi, and the shut-in tubing pressure was 1,818 psi.

**3** ***Verdun Oil & Gas***, based in Houston, has completed an Austin Chalk producer in a lightly drilled part of Austin County (RRC Dist. 3), Texas. The #1H Belleau Wood is in William Sutherland Survey, A-96, and was drilled to 22,025 ft, 14,384 ft true vertical. It initially flowed 10.339 MMcf of gas and 648 bbl of water per day from perforations at 14,230-22,001 ft. The Giddings Field venture bottomed about 1.5 miles to the southeast.

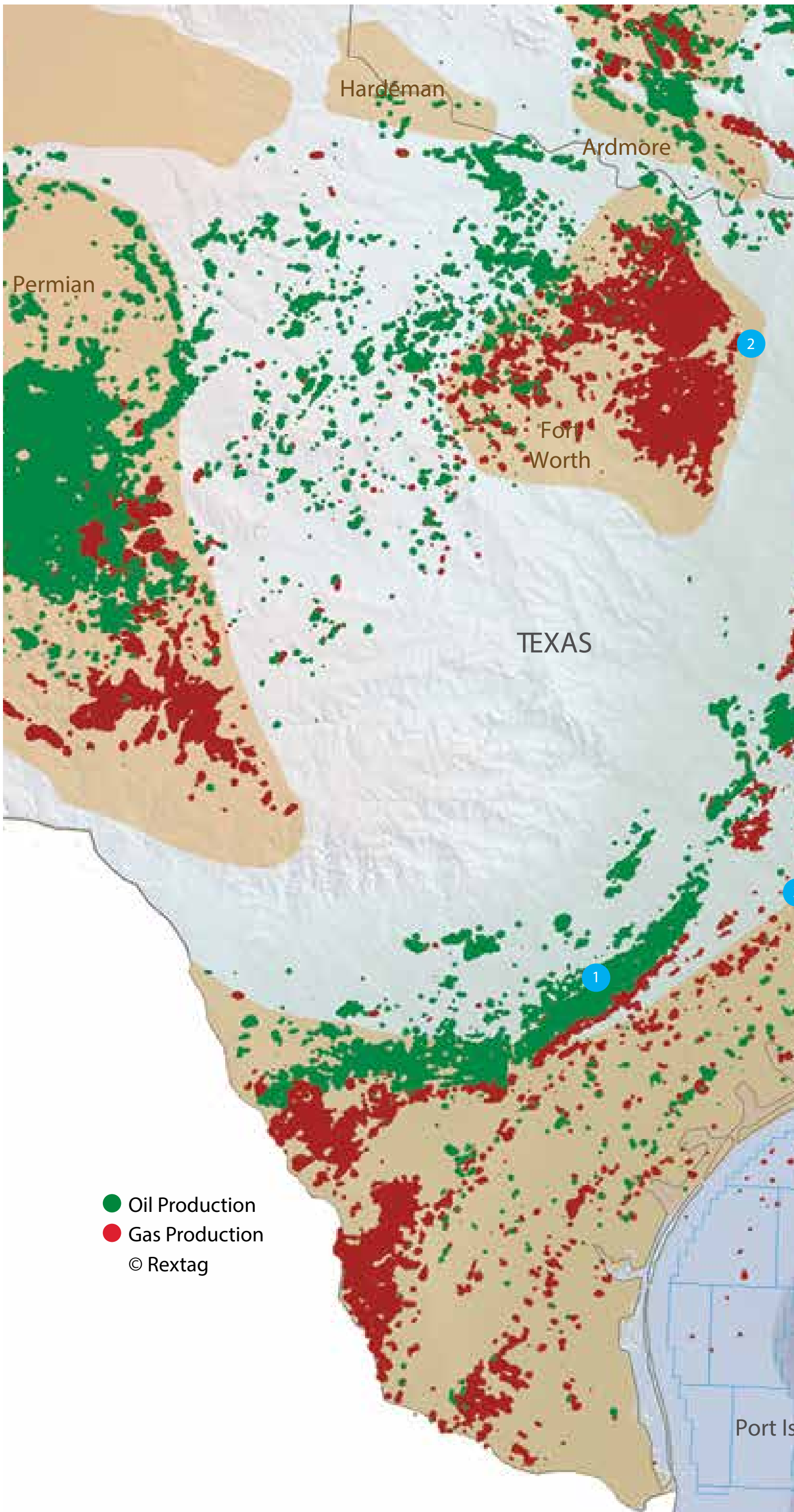
**4** ***Comstock Oil & Gas*** announced results from a Haynesville completion in Bethany Longstreet Field. The DeSoto Parish, La., venture, #3-ALT Bagley 4 HZ, produced 17.697 MMcf of gas and 1.093 Mbbl of water per day. It was drilled to 16,690 ft with a true vertical depth of 11,575 ft and is in Section 33-14n-16w. Production is from perforations between 11,963 and 16,475 ft. Gauged on a 28/64-in. choke, the flowing casing pressure was 5,451 psi. Comstock is based in Frisco, Texas.

**5** Shreveport, La.-based ***Caddo Parish Holdings LLC*** has completed a horizontal oil well in Caddo Parish, La. The Caddo-Pine Island Field well, #1 HLD Brown H, was tested pumping 110 bbl of oil, 125 Mcf of gas and 2.15 Mbbl of water per day from Annona at 1,867-6,948 ft. The new producer is in Section 17-21n-14w. It was drilled to 7,080 ft, and the true vertical depth is 1,673 ft. The lateral bottomed about 1 mile to the north in Section 8.

**6** ***GEP Haynesville*** has completed four strong Haynesville Shale wells from two separate pads in northern Sabine Parish, La. The Bayou San Miguel Field discoveries are in Section 26-9n-12w. The highest producing well, #2-Alt Olympia Minerals 26-23HC, flowed 40.29 MMcf of gas and 763 bbl of water daily from acid- and fracture-treated perforations at 13,005-21,293 ft. It was drilled to 21,507 ft (12,761 ft true vertical) and tested on a 33/64-in. choke with a flowing casing pressure of 8,481 psi. The horizontal lateral bottomed within 2 miles to the north in Section 23. The offsetting #1-Alt Minerals 26-23HC produced 39.845 MMcf of gas daily from perforations at 12,894-20,875 ft. It was drilled to 21,088 ft (12,763 ft true vertical) with a lateral extending about 1.5 miles to the north. Within 2 miles to the north-northwest in Section 23-9n-12w, #1-Alt Olympia Minerals 23-26HC flowed 31.182 MMcf of gas per day from perforations at 12,910-22,482 ft and was drilled to the south to 22,450 ft (12,766 ft true vertical) and bottomed in Section 26. It was tested on a 32/64-in. choke, and the flowing casing pressure was 8,566 psi. The #2-Alt Olympia Minerals 23-26HC flowed 37.599 MMcf of gas per day from perforations at 12,961-22,252 ft. It was drilled to the south to 22,450 ft (12,766 true vertical) and bottomed in Section 26. Tested on a 32/64-in. choke, the flowing casing pressure was 8,566 psi. GEP is based in The Woodlands, Texas.

**7** Lafayette, La.-based ***Byron Energy*** has completed the fourth well in the company's South Marsh Island Block 71 development program. The #4-F OCS G34266 encountered 91 ft of net pay in the primary target Pleistocene Sand. The well was drilled to 8,130 ft with a true vertical depth of 7,570 ft. The rig is preparing to drill #5-F OCS G34266, and it is also targeting Pleistocene, with a planned total depth of 8,788 ft (7,768 ft true vertical).

**8** ***Castex Energy*** recompleted a King Lake Field well in western Terrebonne Parish, La. According to IHS Markit, the Miocene workover, #1 Louisiana Land & Exploration, was tested



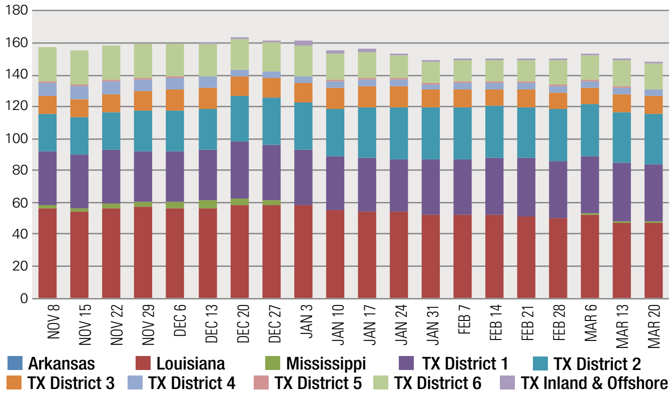
flowing 7.322 MMcf of gas and 351 bbl of 51.6-degree-gravity condensate per day from Textularia L (Miocene) at 17,066-17,114 ft. Gauged on an 11/64-in. choke, the flowing tubing pressure was 6,060 psi, and the shut-in tubing pressure was 6,426 psi. The 18,071-ft directional well was plugged back to 17,135 ft. The venture was initially completed by the Houston-based company in 2018, and it flowed 6.608 MMcf of gas daily from Textularia L at 17,164-17,229 ft. The discovery is in irregular Section 35-20s-14e.

**9** In South Timbalier Block 122, ***Hilcorp Energy Co.*** completed a Caillou Island Field well. The #14 SL 02856 was tested flowing 564 bbl of 48-degree-gravity oil, 5.968 MMcf of gas and 6 bbl of water per day. Production is from Miocene perforations at 18,436-18,866 ft. It was tested on a 26/64-in. choke, and the flowing tubing pressure was 3,022 psi. Hilcorp is based in Refugio, Texas.

**10** ***Beacon Offshore Energy***, based in Houston, announced that it has drilled a third well in the company's producing Claiborne Field. The #3SS OCS G34909 is in Mississippi Canyon Block 794. It hit 284 ft of pay across five different sands. The total depth was not disclosed. Area water depth is 1,500 ft. First production from Claiborne (Mississippi Canyon Block 794) Field was reported in 2017.

**Gulf Coast Rig Count**

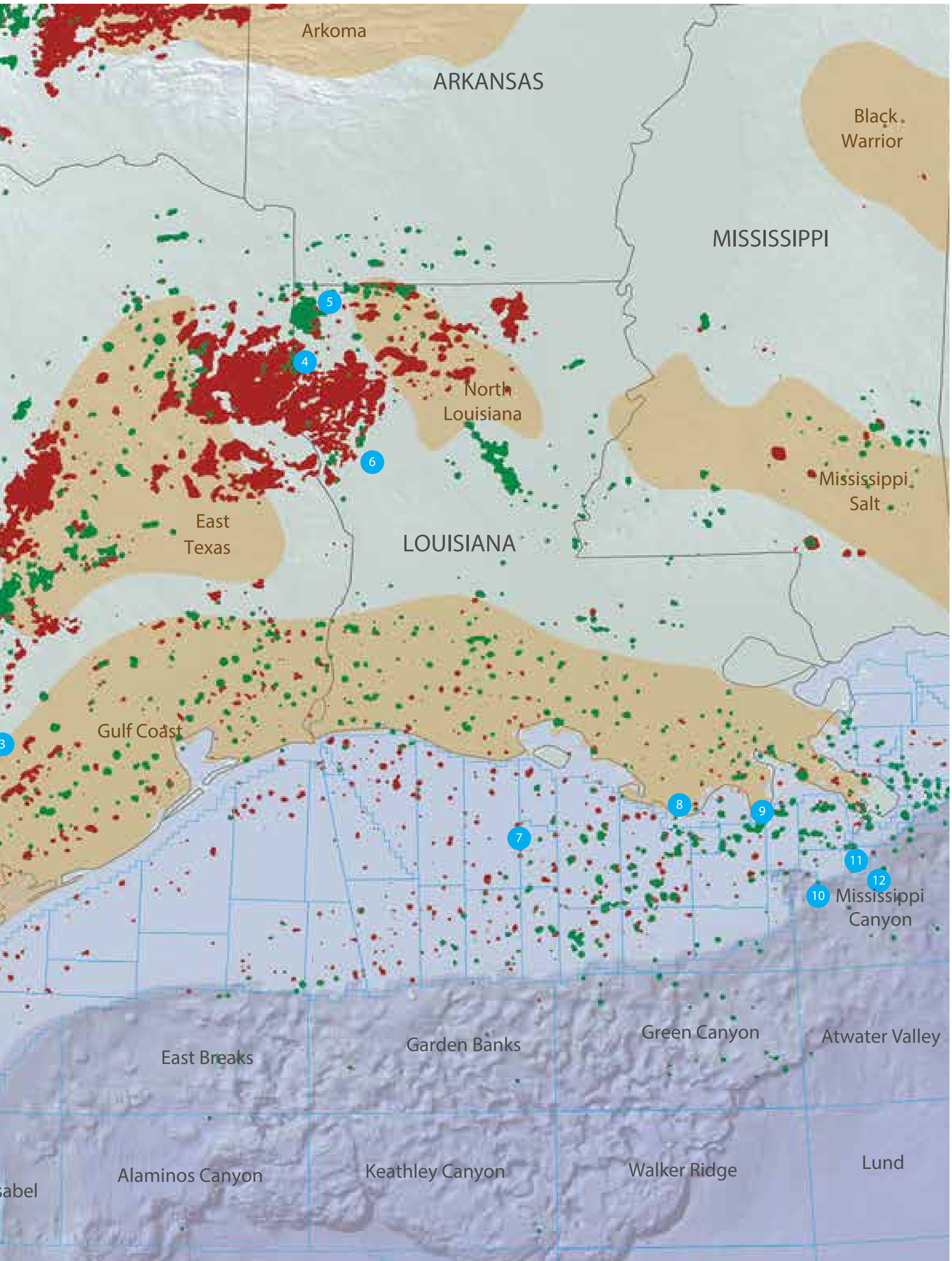
Nov. 8, 2019-Mar. 20, 2020




Source: Baker Hughes Co.

**11** ***LLOG Exploration*** announced results from a Mississippi Canyon Block 546 discovery. The #0SS004S0B OCS G25098 ST00BP00 was tested flowing 1.099 Mbbl of condensate, 32.634 MMcf of gas and 19 bbl of water per day from an interpreted Middle Miocene zone at 14,502-84 ft. It was drilled to 21,232 ft, 17,454 ft true vertical. Gauged on a 37/64-n. choke, the flowing tubing pressure was 7,083 psi. LLOG is based in Covington, La.

**12** A Lower Miocene oil well was competed by Houston-based ***Shell Oil Co.*** in the company's Kaikias Field. The Mississippi Canyon Block 812 discovery #6-K OCS G34461, was drilled to 27,386 ft (25,967 ft true vertical). It was completed in a zone at 26,525-26,662 ft. Water depth in the area is 4,500 ft. The Kaikias prospect was opened in 2018, and through 2019 four Miocene wells have combined to recover 16 MMbbl of crude and 37 Bcf of gas. The Kaikias discovery (#1 (BP) OCS G34458) was drilled in 2014 on Mississippi Canyon Block 812, bottoming to the north on Block 768. Total depth is 28,929 ft. The discovery well and the first appraisal test hit more than 300 ft of net oil pay.



## MIDCONTINENT & PERMIAN BASIN

**1** ***OXY USA Inc.*** completed a Bone Spring discovery in the Ingle Fields portion of Eddy County, N.M. The #001H Pure Gold MDP1 29-17 Federal Com was tested flowing 7.15 Mbbl of oil, with 8.214 MMcf of gas and 11.42 Mbbl of water per day. The 23,106-ft well has a true vertical depth of 10,038 ft and is in Section 29-23s-31e. It was tested on a 128/64-in. choke, and the flowing casing pressure was 823 psi. OXY is a subsidiary of Houston-based ***Occidental Petroleum Corp***.

**2** Two Lea County, N.M. Wolfcamp discoveries were completed from a drillpad in Section 24-25s-32e by Houston-based ***EOG Resources Inc***. The #728H Valiant 24 Federal Com produced 2.642 Mbbl of oil, 6.585 MMcf of gas and 6.703 Mbbl of water per day from perforations at 12,719-20,088 ft. It was drilled to 20,114 ft, and the true vertical depth is 12,553 ft. The #723H Valiant 24 Fed Com was tested flowing 2.762 Mbbl of oil with 7.549 MMcf of gas and 6.093 Mbbl of water per day from perforations at 12,644-20,003 ft. Gauged on a 64/64-in. choke, the shut-in casing pressure was 1,691 psi. The total depth is 20,059 ft, and the true vertical depth is 12,555 ft.

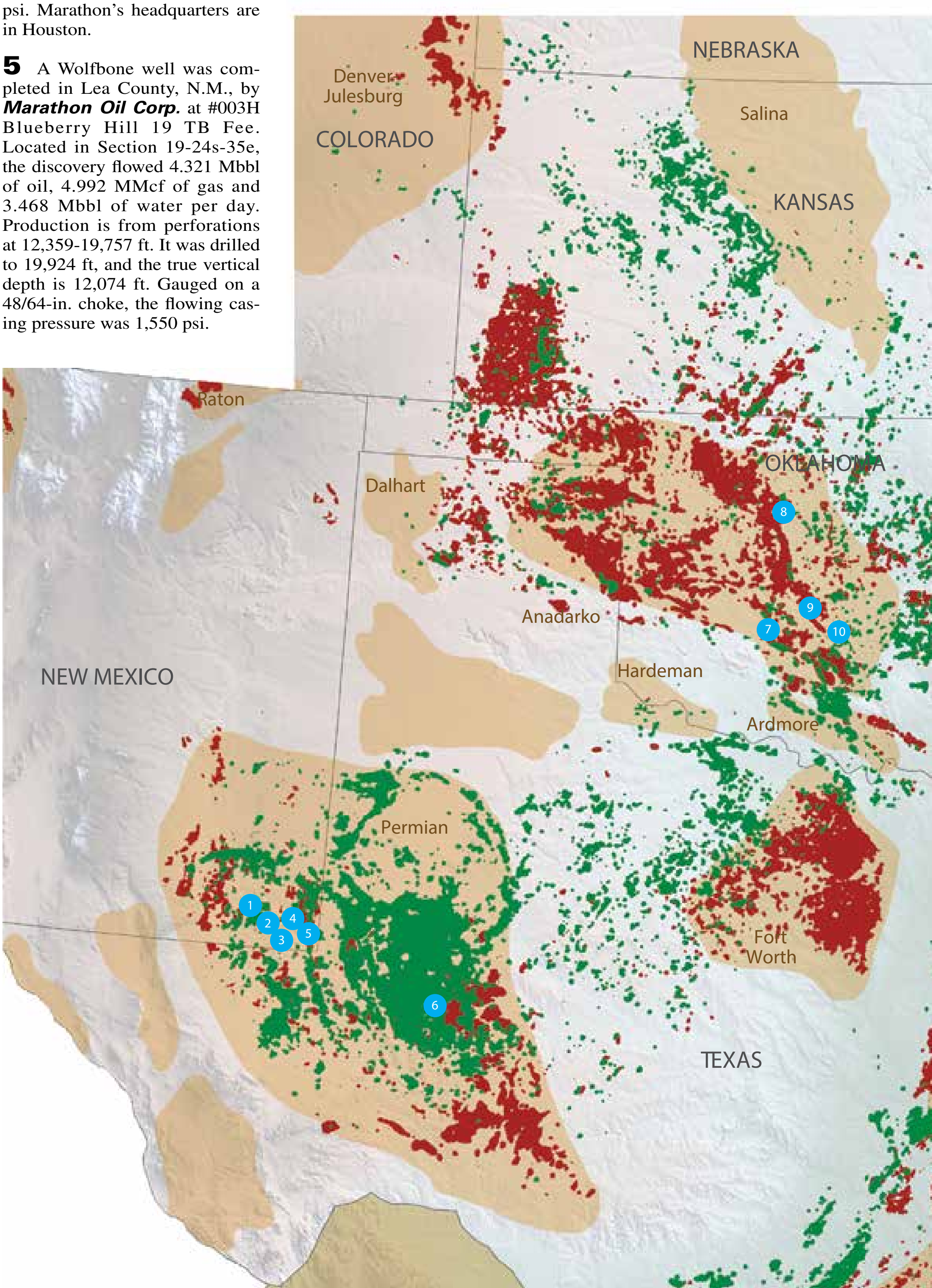
**3** ***EOG Resources Inc.*** reported that a Wolfcamp completion in Lea County, N.M., was tested flowing 3.199 Mbbl of oil, 5.829 MMcf of gas and 12.06 Mbbl of water per day. The #710H Peachtree 24 Federal Com is in Section 24-26s-33e. The Sanders Tank Field well was drilled to 22,831 with a true vertical depth of 12,582 ft, and production is from perforations at 12,695-22,830 ft. It was tested on a 92/64-in. choke, and the shut-in casing pressure was 1,310 psi.

**4** In Lea County, N.M., a Bone Spring well was completed by ***Marathon Oil Corp***. The #003H Ender Wiggins 14 TB FC is in Section 14-25s-34e in Red Hills Field. It initially flowed 2.272 Mbbl of oil, 2.176 MMcf of gas and 2.173 Mbbl of water per day from Bone Spring. Drilled to 19,840 ft, the true vertical depth is 12.337 ft, and the well is producing from perforations at 12,474-19,754 ft. Tested on a 64/64-in. choke, the shut-in casing pressure was 875 psi. Marathon's headquarters are in Houston.

**5** A Wolfbone well was completed in Lea County, N.M., by ***Marathon Oil Corp.*** at #003H Blueberry Hill 19 TB Fee. Located in Section 19-24s-35e, the discovery flowed 4.321 Mbbl of oil, 4.992 MMcf of gas and 3.468 Mbbl of water per day. Production is from perforations at 12,359-19,757 ft. It was drilled to 19,924 ft, and the true vertical depth is 12,074 ft. Gauged on a 48/64-in. choke, the flowing casing pressure was 1,550 psi.

**6** IHS Markit reported that ***Earthstone Energy*** has completed two Wolfcamp-Spraberry Trend wells from offsetting West Texas locations in Reagan County (RRC Dist. 7C), Texas. The Midland Basin wells were drilled in Section 8, GC&SF RR Co Survey, A-676. The #1BU Julie Hughes Unit 8-3 produced 852 bbl of 42.8-degree-gravity crude, 929 Mcf of gas and 1.668 Mbbl of water per day from acid- and fracture-stimulated perforations at 8,033-17,980 ft. It was drilled to 18,080 ft, and the lateral bottomed about 2 miles to the south-southeast in Section 3 with a true vertical depth of 7,650 ft. The parallel #2BU Julie Hughes Unit 8-3 had an initial potential of 980 bbl of 42.6-degree-gravity oil, 738 Mcf of gas and 1.186 Mbbl of water daily from treated perforations at 8,035-17,982 ft. It bottomed to the south-southwest at 18,090 ft, 7,675 ft true vertical. Earthstone's headquarters are in Denver.

**7** Results were announced by Stillwater, Okla.-based ***Territory Resources LLC*** from a Cement Field-Anadarko Basin workover. Located in Section 36-6n-10w of Caddo County, Okla., #2-36 Colonel initially flowed 5.65 MMcf of gas, 30 bbl



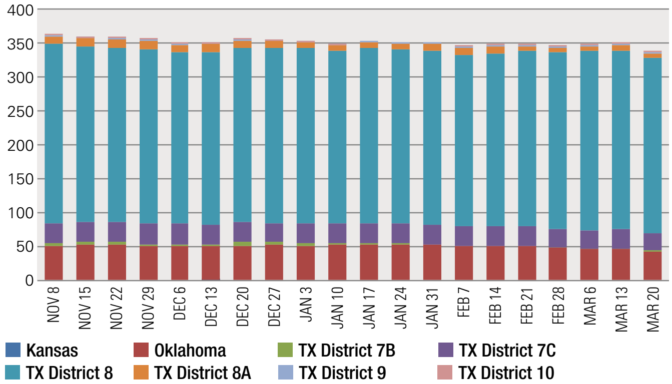
of 50-degree-gravity condensate and 8 bbl of water per day from Springer. It was tested on a 14/64-in. choke producing through untreated perforations at 11,798-11,818 ft with a shut-in tubing pressure of 8,381 psi and a flowing tubing pressure of 5,937 psi. ***Chesapeake Operating Inc.*** originally completed the well in five fracture-stimulated Springer intervals (79 net perforated ft) between 12,370 and 13,693 ft flowing 3.91 MMcf of gas, 1 bbl of condensate and 2 bbl of water per day; it was drilled to 13,950 ft.

**8** A Meramec completion by ***Ovintiv Inc.*** (formerly Encana Corp.) was tested flowing 79 bbl of oil, 2.22 MMcf of gas and 623 bbl of water per day. The horizontal discovery, #4H-30X Channel, is in Section 30-17n-9w of Kingfisher County, Okla. Gauged on a 44/64-in. choke, the shut-in casing pressure was 1,000 psi, and the flowing tubing pressure was 587 psi. The Altona Field well was drilled to the south to 19,695 ft with a true vertical depth of 9,199 ft. It bottomed in Section 31-17n-9w. Ovintiv Inc. is based in Calgary, Alberta.

**9** ***Camino Natural Resources LLC*** announced the completion of two Anadarko Basin horizontal producers drilled from a multiwell pad in Section 8-7n-7w in Grady County, Okla. According to IHS Markit, #16-21-1WH Holden 0707 was tested on a 34/64-in. choke flowing 13.6 MMcf of gas, 25 bbl of 55-degree-gravity condensate and 5.424 Mbbl of water per day after acidizing and fracturing in Woodford between 15,725 and 24,420 ft. It was drilled to the southeast and bottomed in Section 16, then south to 24,493 ft (16,129 ft true vertical) and bottomed in Section 21-7n-7w. About 30 ft north on the pad, #17-20-1MHR Kimber 0707 has a parallel lateral that was drilled across Section 17 to a bottomhole location in Section 20. The total depth is 24,800 ft, and the true vertical depth is 15,914 ft. It initially flowed 14.6 MMcf of gas, 6 bbl of oil and 5.808 Mbbl of water per day from Mississippian. It was perforated, acidized and fractured at 15,812-24,681 ft and tested on a 32/64-in. choke. Camino Natural Resources is based in Denver.

**Midcontinent & Permian Basin Rig Count**

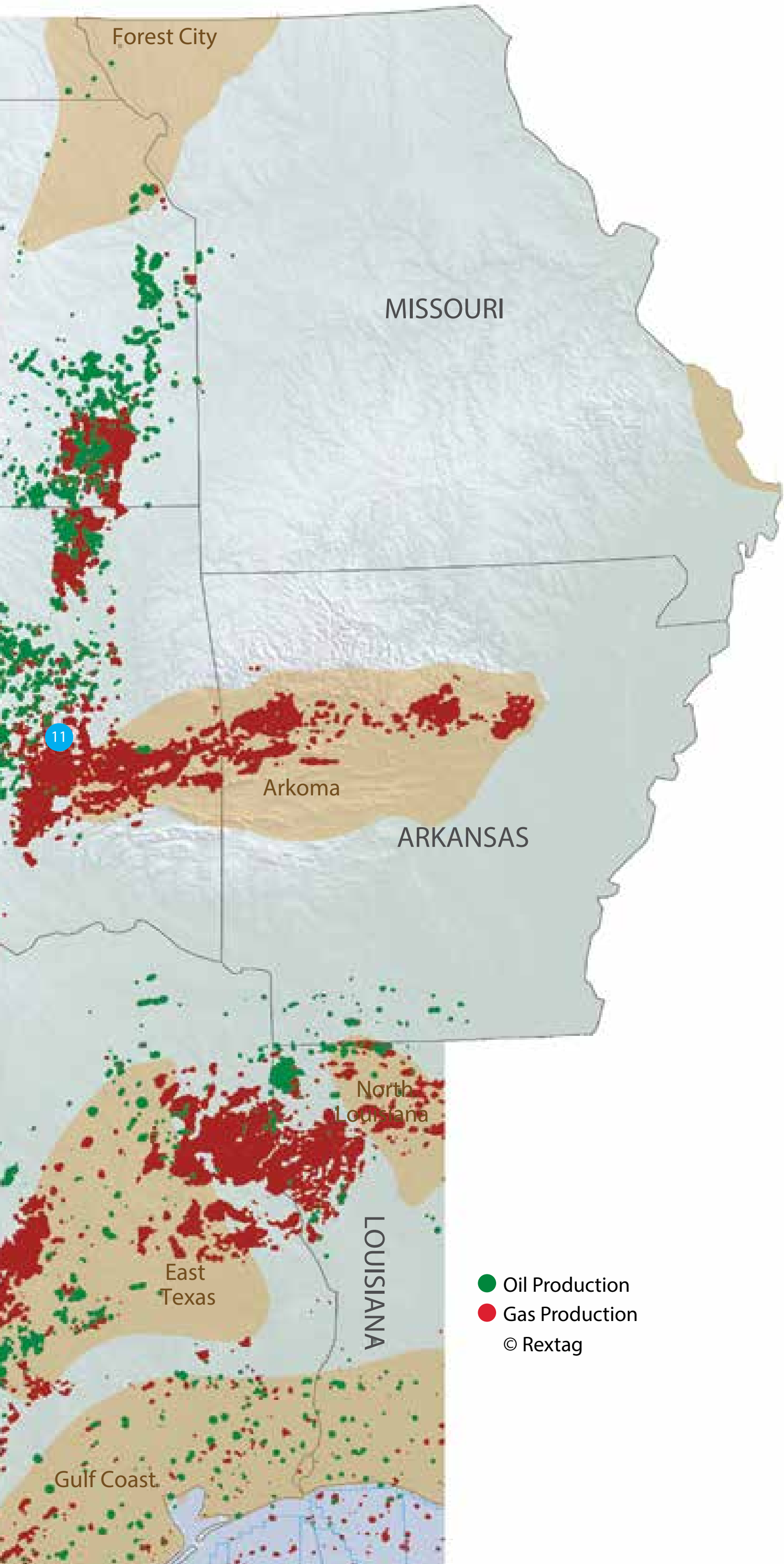
Nov. 8, 2019-Mar. 20, 2020




Source: Baker Hughes Co.

**10** Two horizontal Sycamore producers were completed from drillpads in the Anadarko Basin by Tulsa, Okla.-based ***Casillas Operating LLC***. The pads are in Section 6-5n-4w in McClain County, Okla. The #1-6MH Kilkenny flowed 640 bbl of 46-degree-gravity oil, 954 Mcf of gas and 763 bbl of water per day. It was drilled south across the section to 16,947 ft (11,382 ft true vertical). It was tested on a 92/64-in. choke after fracturing and acidizing. Production is from perforations at 12,014-16,806 ft. Within 1 mile to the east, #2-6MH Kilkenny flowed 648 bbl of oil with 1.07 MMcf of gas and 940 bbl of water per day. It was drilled to 16,767 ft, but no true vertical depth was reported. Production is from a treated interval at 11,911-16,672 ft and was tested on a 92/64-in. choke with a flowing tubing pressure of 1,861 psi.

**11** ***Calyx Energy III LLC*** announced results from an extended-reach producer in McIntosh County, Okla. The #3-18-19WH Edison is in Section 7-8n-13e, and it produced 8.85 MMcf of gas and 3.02 Mbbl of water per day. Production is from perforated and treated intervals in Woodford at 5,645-9,420 ft; Mayes, 9,822-10,045 ft; Woodford, 10,105-12,783; Mayes, 12,955-13,495 ft; and Woodford at 13,760-15,582 ft. It was tested on a 64/64-in. choke with a flowing tubing pressure of 480 psi. The discovery was drilled to 15,749 ft, and the true vertical depth is 5,163 ft with a bottomhole location to 2 miles to the south in Section 19-8n-13e. Calyx is based in Tulsa, Okla.



## WESTERN US

**1** Calgary-based ***Crescent Point Energy*** announced results from a horizontal Ute-land Butte delineation well in the Uinta Basin. The #13.5-21-16-3-1W-H1 Ute Tribal is in Section 21-3s-1w, Duchesne County, Utah. According to IHS Markit, the venture initially flowed 239 bbl of 40-degreee-gravity oil, 67 Mcf of gas and 390 bbl of water per day. Production is from a lateral (Lower Green River) that was drilled to the north to 8,588 ft to 18,431 ft with a bottom-hole location in Section 16-3s-1w. The true vertical depth is 8,571 ft. It was tested on a 14/64-in. choke following 42-stage fracturing between 8,618 and 18,151 ft, and the flowing casing pressure was 3,600 psi.

**2** A multizone producer in Sublette County, Wyo., was completed by Denver-based ***Jonah Energy LLC***. The #31-12 Stud Horse Butte is in Section 12-29n-108w. It was drilled to 12,796 ft, and the true vertical depth is 12,783 ft. It was fractured in eight stages and produced 52 bbl of oil, 7.053 MMcf of gas and 445 bbl of water per day from Fort Union (9,189-9,436 ft), Lance (9,681-12,305 ft) and Mesaverde (12,389-12,705 ft). It was tested on a 48/64-in. choke, and the shut-in casing pressure was 1,000 psi.

**3** IHS Markit reported that Denver-based ***DJR Operating LLC*** has completed a horizontal Gallup producer in the San Juan Basin. Located in Section 11-23n-8w in San Juan County, N.M. The #108H Betonnie Tsosie Wash Unit initially produced via gas lift 520 bbl of 40-degree-gravity oil, 1.89 MMcf of gas and 436 bbl of water per day. Production is from a lateral in Gallup drilled to the southeast to 13,675 ft, 5,200 ft true vertical. The venture bottomed in Section 13-23n-8w. The Betonnie Tsosie Wash was tested after 38-stage fracturing between 6,021 and 13,593 ft.

**4** In Sandoval County, N.M., ***DJR Operating LLC*** completed two Gallup producers from a San Juan Basin pad in Section 11-22n-6w. The #206H Venado Canyon Unit was tested flowing 265 bbl of 41-degree-gravity oil, 607 Mcf of gas and 169 bbl of water per day. The Gallup lateral was drilled to the southeast to 15,110 ft (5,247 ft true vertical) and bottomed in Section 13-22n-6w. It was tested after 45-stage fracturing between 6,058 and 15,027 ft. The #207H Venado Canyon Unit produced 315 bbl of oil, 1.303 MMcf of gas and 717 bbl of water daily. It was drilled southeastward to 13,478 ft (5,278 ft true vertical) and bottomed in Section 13-22n-6w. It was tested following 38-stage fracturing between 5,826 and 13,397 ft.

**5** Greenwood Village, Colo.-based ***Impact Exploration & Production LLC*** reported results from a horizontal Frontier well. The Converse County, Wyo., test, #447-5-32H Bacchus, produced 1.024 Mbbl of oil, 1.221 MMcf of gas and 2.453 Mbbl of water daily. Located in Section 8-37n-75w, production is from a lateral that was drilled to the north to 23,173 ft and bottomed in Section 32-37n-75w. The true vertical depth is 12,868 ft. It was tested on a 30/64-in. choke after 42-stage fracturing between 13,113 and 23,076 ft.

**6** A Niobrara well completed by ***EOG Resources Inc.*** produced 1.528 Mbbl of oil, 3.023 MMcf of gas and 2.247 Mbbl of water per day. The #1018-1918H Katara is in Section 19-40n-73w in Converse County, Wyo. It is producing from a lateral drilled to the north to 21,464 ft, 11,293 ft true vertical, and bottomed in Section 18-40n-73w. It was tested on a 28/64-in. choke after 43-stage fracturing between 11,807 and 21,317 ft. EOG is based in Houston.

**7** ***Anadarko Petroleum Corp.*** completed a horizontal Turner exploratory test that flowed 1.402 Mbbl of 46.8-degree-gravity oil, 3.214 MMcf of gas and 935 bbl of water. The #3569-31-T3XH EH Fed Galaxy E is in Section 30-35-69w of Converse County, Wyo. Production is from a lateral drilled to the south-southwest to 21,697 ft with a bottomhole location in Section 35. The true vertical depth is 10,873 ft. It was tested following 50-stage fracturing between 11,529 and 21,587 ft. Anadarko's headquarters are in The Woodlands, Texas.

**8** Denver-based ***Extraction Oil & Gas Inc.*** completed two Wattenberg Field wells from a drillpad in in Section 9-5n-65w of Weld County, Colo. The #8W-20-24 MT Fed Glenmere was drilled to 18,055 ft (6,886 ft true vertical) and was tested flowing 650 bbl of condensate, 3.539 MMcf of gas and 5.455 Mbbl of water per day from Niobrara. Production is from perforations at 8,514-18,028 ft. Gauged on a 20/64-in. choke, the flowing tubing pressure was 2,561 psi. The #8W-20-14 MT Fed Heath was drilled to 17,447 ft, 7,043 ft true vertical. It produced 683

bbl of condensate, 4.272 MMcf of gas and 148 bbl of water per day. Comingled production is from perforations in Codell (7,902-17,418 ft), Fort Hays (8,795-15,452 ft), Niobrara (11,700-11,865 ft) and Carlile (13,046-13,402 ft). Tested on a 20/64-in. choke, the flowing tubing pressure was 2,779 psi.

**9** ***EOG Resources Inc.*** completed a horizontal Codell discovery in Laramie County, Wyo. The #523-0428H Carpenter is in Section 4-12n-63w, and it initially produced via gas lift 597 bbl of 36.7-degree-gravity oil, 287 Mcf of gas and 1.825 Mbbl of water per day. Production is from a lateral in Codell that was drilled to the north to 18,002 ft (7,680 ft true vertical). It bottomed in Section 28 and was tested after 36-stage fracturing between 8,132 and 17,936 ft.

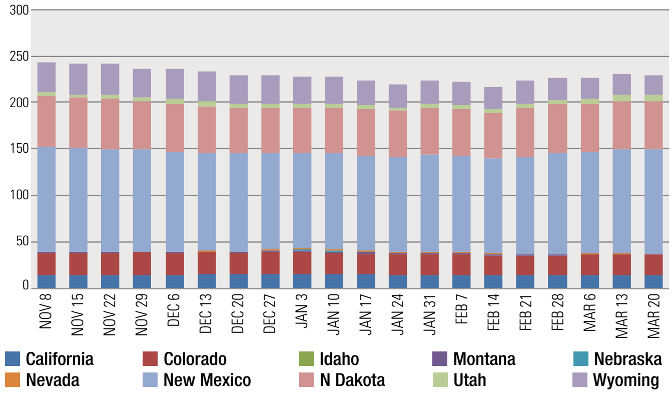
**10** Two Dunn County, N.D., Bailey Field wells were completed from a single pad in Section 14-145n-94w by Houston-based ***Marathon Oil Corp***. The #41-14TFH Maher was tested flowing 4.967 Mbbl of oil, 1.54 MMcf of gas and 7.98 Mbbl of water per day from Upper Three Forks. Production is from perforations at 10,980-20,902 ft. It was drilled to the south to 21,037 ft, 10,565 ft true vertical, and tested after 45-stage fracturing. Gauged on a 64/64-in. choke, the flowing casing pressure was 1,200 psi. Within 200 ft to the east, #11-13H Bryden produced 4.081 Mbbl of oil, 1.606 MMcf of gas and 5.889 Mbbl of water per day from Middle Bakken. Production is from perforations at 10,966-20,789 ft. It was drilled to the southeast to 21,013 ft, 10,496 ft true vertical, and was tested after 45-stage fracturing. Gauged on a 64/64-in. choke, the flowing casing pressure was 775 psi.

**11** In North Dakota's Reunion Bay Field, ***Marathon Oil Corp.*** completed a Middle Bakken discovery. The #11-17H Miriam USA was drilled in Section 8-150n-93w in Mountrail County. It initially flowed 4.866 Mbbl of oil, with 3.726 MMcf of gas and 2.561 Mbbl of water daily. Drilled to 22,740 ft, 10,832 ft true vertical, production is from perforations at 12,903-22,606 ft and tested on a 64/64-in. choke with a flowing casing pressure of 775 psi.

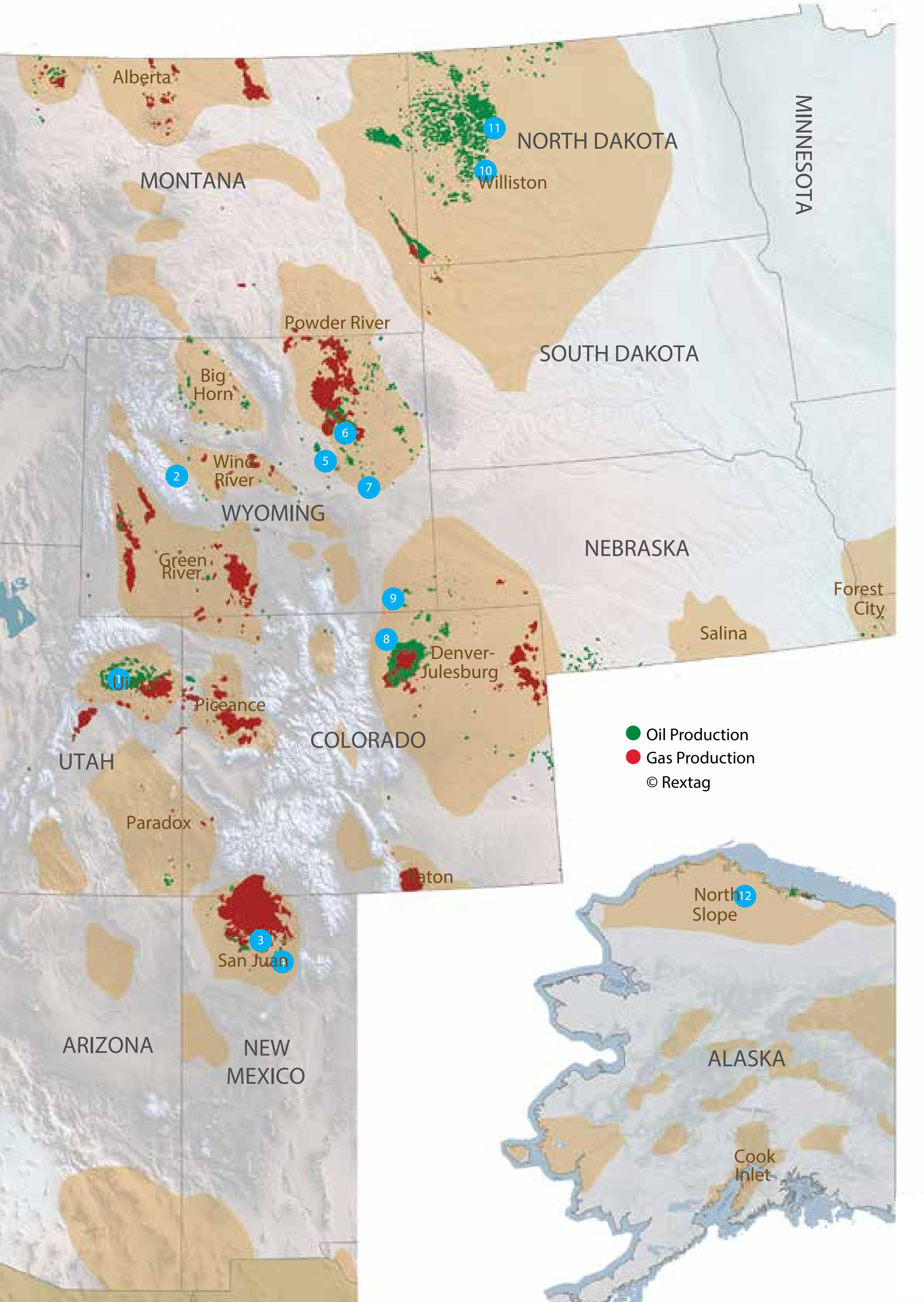
**12** Houston-based ***ConocoPhillips Co.*** is drilling at the first wildcat on its Harpoon prospect in the National Petroleum Reserve-Alaska. The #2 Harpoon is in Section 30-7n-3e, Umiat Meridian. The proposed total depth was not disclosed, and it reportedly will evaluate Nanushuk oil zones. The Willow Field discovery, #2 Tinmiaq in Section 34-10n-1w, is about 22 miles to the southeast. During testing it had a sustained 24-hour test rate of 1.6 Mbbl of oil, 631.5 MMcf of gas and 221 bbl of water per day from Nanushuk at 3,688-3,708 ft.

**Western US Rig Count**

Nov. 8, 2019-Mar. 20, 2020




Source: Baker Hughes Co.



# INTERNATIONAL HIGHLIGHTS

Numerous oil and gas companies have already restricted or stopped employee travel due to the coronavirus pandemic.

Petronas evacuated all 80 of its Malaysian employees from its operations in Iraq's Garraf Contract Area, and production is temporarily suspended until further notice.

The British government's Oil & Gas UK offices have banned people traveling to offshore installations if they have traveled recently to certain countries, including Italy, Iran, China and South Korea.

Royal Dutch Shell Plc was one of the first companies to suspend employee travel, and others did the same, including Equinor ASA. Chevron Corp. had sent home employees at its London offices in late February after an employee displayed flu-like symptoms—the company is also screening workers and visitors.

Chrysaor reported that a member of the crew on its North Everest platform in North Sea, Block 22/10a-A, had been quarantined onboard the platform. Equinor reported that one person at the Martin Linge Field platform in the Norwegian sector of the North Sea had tested positive for the coronavirus.

Bristow adapted helicopters for offshore U.K. workers showing signs of sickness with modifications to quarantine flight crews and medics and passenger-monitoring support for suspected workers.

*—Larry Prado*


**1 *Trinidad***

***Touchstone Exploration*** announced production test results from #1-ST1 Cascadura-1ST1 on the Ortoire exploration block. The testing was performed in two stages—the first stage included the lower-most 162 ft of pay in Herrera, and the second stage included 345 ft of pay in the upper part of the same horizon. The first stage flow test indicated an initial production range between 7.75-9.7 Mbbl of oil equivalent per day (approximately 40-50 MMcf of gas per day and an estimated 1.1-1.4 Mbbl per day of gas liquids). The second stage had a peak flowback rate of 5.76 MMboe per day including 29.4 MMcf of gas and 865 bbl per day of NGL. Wireline logs and drilling samples indicated approximately 1,037 ft of prospective hydrocarbon pay in the Cruse and Herrera formations at depths between 1,030 and 6,350 ft. Calgary, Alberta-based operator Touchstone holds an 80% working interest, and partner ***Heritage Petroleum Company Ltd.*** holds a 20% working interest.

**2 *Morocco***

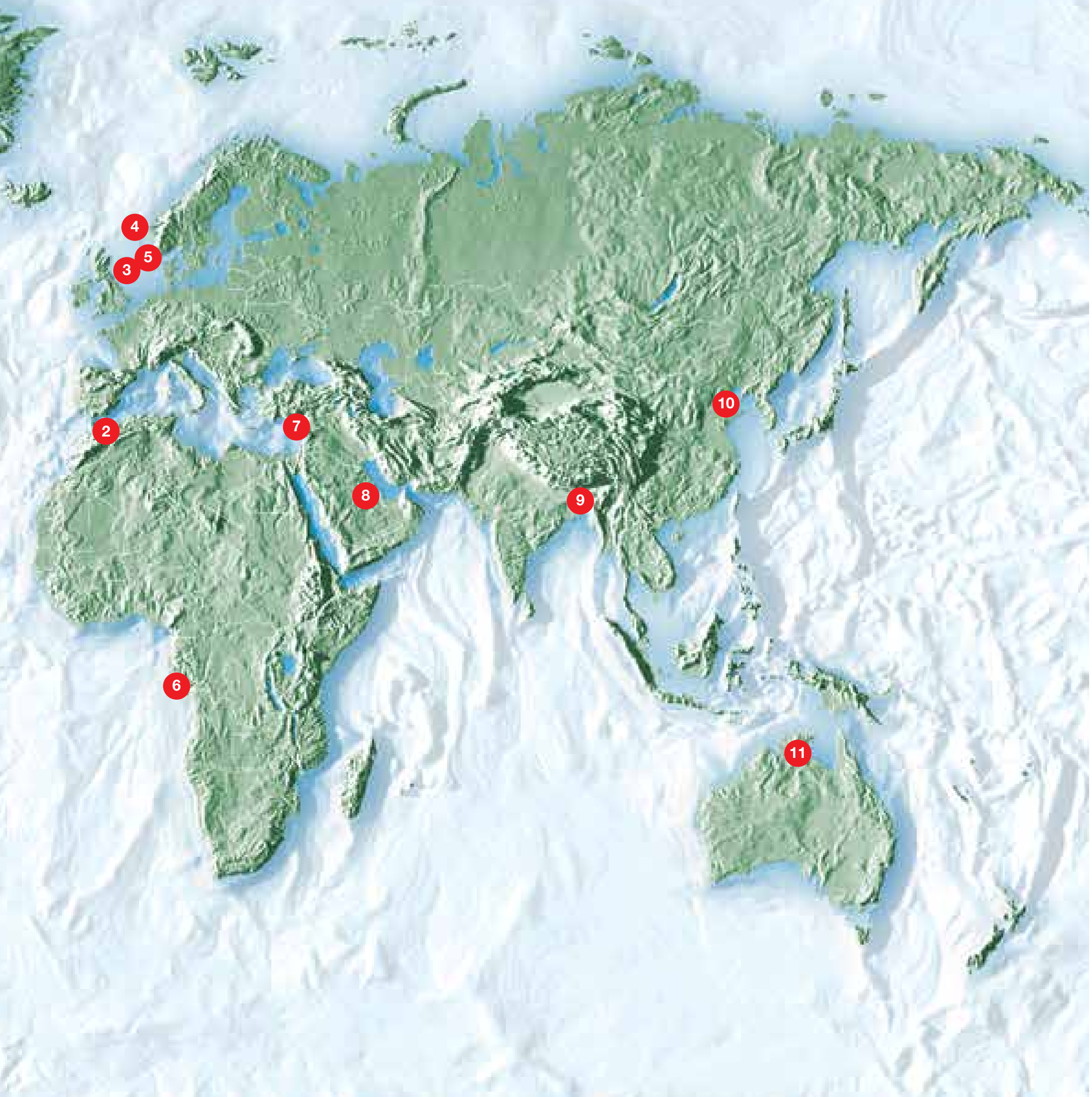
***SDX Energy*** announced a gas discovery at an exploration well in the Gharb Basin. The #1-Beni Malek was drilled to 1,551 m and encountered commercial quantities of gas in both target horizons (Upper and Lower Guebbas). According to the company, the discovery at #1-Beni Malek and the previously completed #2-OYF confirm that the prospectivity in its existing core production and development area extends to the north. Based upon results from both wells, the London-based company has de-risked up to 20 Bcf of P50 prospective resources for future drilling of which approximately 10 Bcf is located in and around #1-Beni Malek. SDX estimates that #1-Beni Malek produced approximately 900 MMcf of gas in Upper and Lower Guebbas, and it is estimated that Upper Guebbas flowed approximately 400 MMcf of recoverable gas.

**3 *UK***

Paris-based ***Total SA*** announced results from discovery at #30/12d-11 Isabella well in offshore U.K. license P1820. The well was drilled in a water depth of about 80 m. It encountered 64 m net pay of lean gas and condensate and high-quality light oil in Upper Jurassic and Triassic sandstone reservoirs. Additional testing and data analysis are planned to assess the resources and to determine the appraisal program required to confirm commerciality. The P1820 license is operated by Total with a 30% working interest, and ***Neptune Energy*** (50%), ***Ithaca Energy*** (10%) and ***Euroil Exploration*** (10%).

**4 *Norway***

Stavanger-based ***Equinor*** completed wildcat wells, #15/3-12 S and #15/3-12 A in offshore Norway production license PL 025 in the North Sea. The wells were drilled about 11 km southeast of the Gudrun prospect and about 4 km southeast of the Sigrun prospect. The primary and secondary exploration targets for #15/3-12 S were to prove petroleum in Middle and Upper Jurassic reservoir rocks (Hugin and Draupne). The 3,352-m well encountered three separate oil-filled reservoir zones of 9 m, 4 m and 9 m in Hugin, which are about 100 m thick. The exploration target for 3,796-m #15/3-12 A was to prove petroleum in Upper and Middle Jurassic reservoir rocks (Draupne and Hugin). The well hit Draupne and Hugin with respective thicknesses of about 85 m and 120 m. There are indications of oil in a thin, 3-m sandstone layer in Sleipner in the Middle Jurassic. No formation tests were performed. Preliminary estimates indicate 1-2.7 MMcm of recoverable oil.






## 5 *UK*

***Rockrose Energy*** is planning to drill the first of two infill development wells on the West Brae Field in the U.K. sector of the North Sea P108 Block 16/07a. The wells, #1-WPGZ and #1-WPOZ, are designed to access 2-P reserves of more than 8 MMbbl and could increase the Brae complex output by up to 6 Mbbl of oil per day. A four-well drilling campaign is scheduled at the ***Shell Oil***-operated Arran gas/condensate field development. London-based operator RockRose has a 30.4% working interest in Arran and the West Brae Field with 40% interest in partnership with ***Taqa Britani*** (45.7%), ***Spirit Energy*** (8%) and ***Nippon Exploration & Production*** (6.3%).

## 6 *Angola*

***Eni*** drilled and tested #3-Agogo, the second appraisal well of the Agogo discovery in offshore Angola Block 15/06. Results from the test increased the estimated size of it by approximately 40% to 1 Bbbl of oil with further upside to be tested in the northern sector of the field. The test also indicated a production capacity of more than 15 Mbbl of oil per day. The appraisal well was drilled to 4,321 m, and it is about 4.5 km northwest of #1-Agogo. Water depth in the area is 1.7 km. The #3-Agogo encountered 120 m of net pay in Miocene and Oligocene sandstones. Testing also showed that #3-Agogo is in communication with #2-Agogo reservoirs and the further extension of the Agogo discovery to the north. Block 15/06 partners are Rome-based operator Eni (36.8421%), ***Sonangol*** (36.8421%) and ***SSI Fifteen Ltd.*** (26.3158%).

## 7 *Lebanon*

***Total SA*** will begin exploration drilling in offshore Lebanon's Block 4. It will be the first exploration well on the block. The drilling in Block 4 will test the northward extension of Oligocene and Miocene sandstones (Tamar Sands) found in offshore Israel's Leviathan and Tamar fields. Nearby Block 9 also has a possible reserve in its carbonate limestone formations, similar in geology to offshore Egypt's Zohr Field and Cyprus's Calypso prospect. Operator Total holds 40% interest and operatorship of Block 4 in partnership with ***Eni*** (40%) and ***Novatek*** (20%).

## 8 *Saudi Arabia*

***Saudi Aramco*** received regulatory approval to develop the Al-Jafurah unconventional gas field in the Eastern Province. Al-Jafurah lies between Ghawar Field and Qatar in the ad Dahna desert. There are three conventional source rock intervals, Tuwaiq Mountain, Hanifa and Jubaila within the basin's Jurassic petroleum system. The volume of gas resources in the field is estimated at 200 Tcf of rich raw gas, which will provide the petrochemical and metallic industries. The Dhahran-based company expects field production to start in 2024. By 2036, it is estimated that approximately 2.2 Bcf of gas per day could be produced, with approximately 425 MMcf of associated ethane per day, which is about 40% of the company's current production. Aramco also expects the field to produce approximately 550 Mbbl of liquids and condensate per day.

## 9 *Bangladesh*

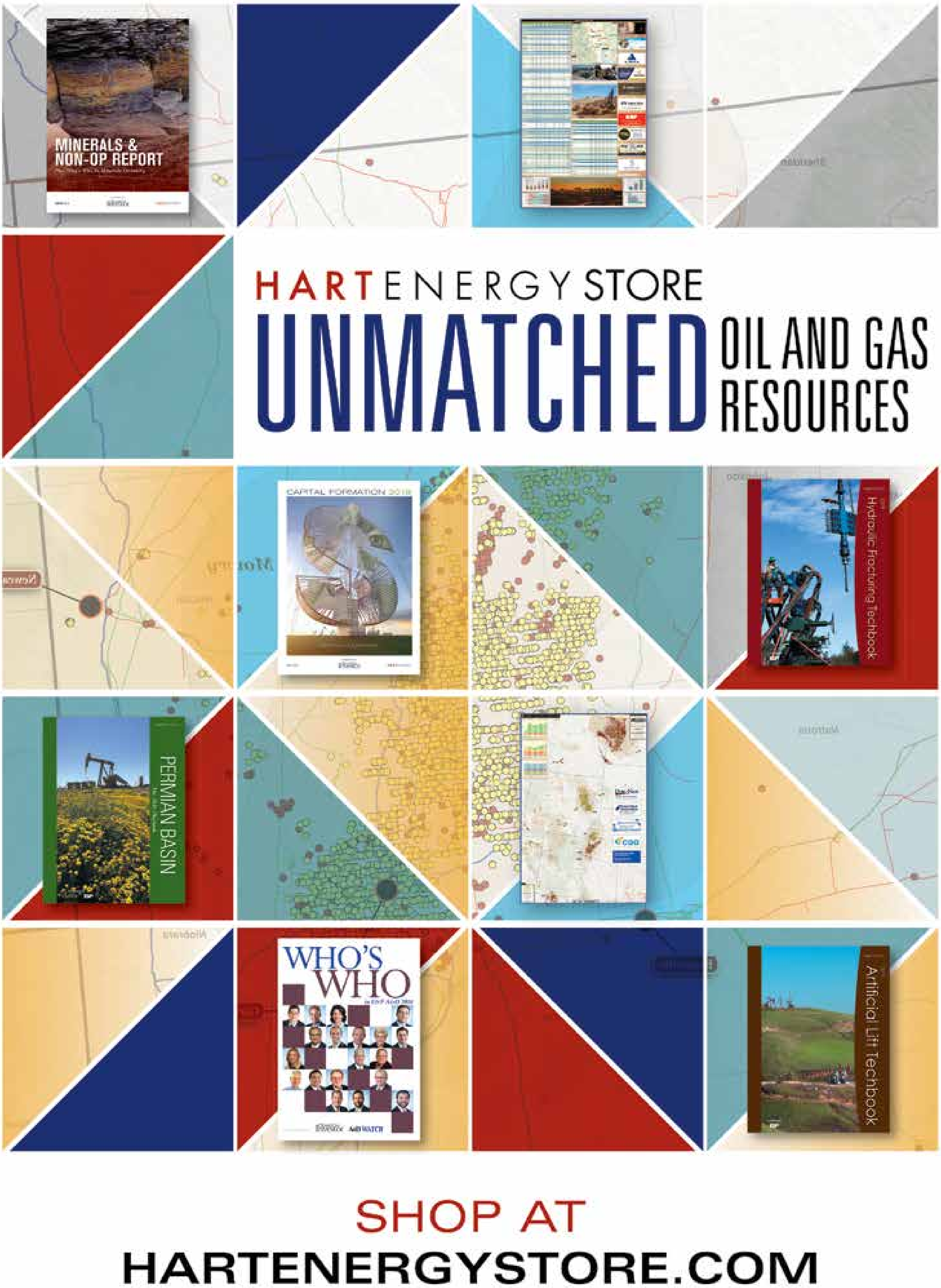
***Bangladesh Petroleum Exploration & Production***, based in Dhaka, Bangladesh, has discovered a new gas field in the Nabinagar upazila of Brahmanbaria. According to the company, the primary drilling was at #1-Srikail East in the Srikail East gas field. New production from the discovery will add 13 MMcf of gas per day from the field. The well is producing from an interval between 3,054 m and 3,082 m.

## 10 *China*

***China National Oil Corp.*** reported a discovery in the Bohai Bay, which is expected to be the first large-sized oil field in the Laibei lower uplift. The discovery well #3-KL6-1 was drilled to 1,596 m and encountered oil pay zones with a total thickness of approximately 20 m. During testing, it produced approximately 1.178 Mbbl of oil per day. The Kenli 6-1 structure is located in Laibei lower uplift in southern part of the basin. Area water depth is about 19 m. Additional surveying is planned for the Neogene lithological reservoir in the Laizhou Bay region of Bohai Bay. China Nation Oil is based in Beijing.

## 11 *Australia*

Sydney-based ***Empire Energy*** has received a permit to drill exploration well #1-Carpentaria in Northern Territory, Australia, in Block EP187. The 2,900-ft vertical venture will test Velkerri and Kyalla shales and will test Velkerri at approximately 2,200 m and Kyalla at about 1,200 m. Empire may perform a vertical fracture stimulation of Velkerri similar to the fracture stimulation a nearby exploratory, #1-Tanumbirini in adjoining Block EP161, followed by drilling and fracture stimulation of a horizontal well section for an extended production test.



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# FUNDS FLOW FOR MIDSTREAM

Private-equity sponsor Tailwater Capital LLC tied up a fourth fund in what otherwise has been a largely barren landscape for capital raising. Its Tailwater Energy Fund IV LP, focused on midstream infrastructure investments, raised $1.1 billion in capital commitments, including a co-investment in one of its portfolio companies.

Based in Dallas, Tailwater said it would target opportunities "across the midstream value chain from the wellhead to the refinery gates." Jason Downie, co-founder of Tailwater with Edward Herring, said that as it puts capital to work in a "strategic and patient way," it expects to see "some of the most compelling buying opportunities we have come across in many years."

Tailwater said it had a total of over $1.3 billion of dry powder. The company noted it had backed management teams operating in all the core onshore basins in the U.S. Since its founding in 2013, it has raised over $3.7 billion and executed more than 100 transactions representing over $20 billion in value. Its prior Tailwater Energy Fund III raised $1 billion and has committed capital to six portfolio companies.

"Having invested through multiple cycles, we are confident private equity will play a critical role in solving the prevailing capital constraints of the energy industry," said Downie.

A midstream funding was also announced by EnCap Flatrock Midstream, which made a $500 million commitment to Tatanka Midstream LLC. Headquartered in San Antonio, Tatanka is focused on creating value by improving operations, maintenance and overall efficiency of acquired businesses and building highly competitive assets that serve changing energy needs.

Tatanka is led by three industry veterans: CEO Keith Casey, president Nate Weeks and CFO Carlos Mata. Collectively, they have more than 75 years of experience in the midstream and downstream sectors.

Earlier, EnCap Flatrock Midstream made a capital commitment of $400 million to Edgewater Midstream LLC. Edgewater was formed to provide independent midstream logistics solutions to refiners, producers and marketers of crude oil, refined products and other bulk liquids.

Edgewater's three founders are CEO Stephen Smith, COO Mike Truby and chief commercial officer Brian Thomason.

*—Chris Sheehan, CFA*

## EQUITY

| Company | Exchange/ Symbol | Headquarters | Amount | Comments |
|---|---|---|---|---|
| Tailwater Capital LLC | N/A | Dallas | $1.1 billion | Announced that it has closed **Tailwater Energy Fund IV LP** with $1.1 billion in capital commitments, including a co-investment for one of Fund IV's platform companies. Having sourced capital from leading institutional investors, Fund IV will continue to employ a disciplined and nimble approach to investing, targeting opportunities across the midstream value chain from the wellhead to the refinery gates. |
| Tatanka Midstream LLC | N/A | San Antonio | $500 million | Secured initial capital commitment of $500 million from **EnCap Flatrock Midstream**. Tatanka's goal is to create value by improving the operations, maintenance and overall efficiency of acquired businesses and building highly competitive new assets that serve the continually growing and changing needs of the North American energy market. |
| Edgewater Midstream LLC | N/A | Houston | $400 million | Secured initial capital commitment of $400 million from **EnCap Flatrock Midstream** and the Edgewater management team. The company will focus on the acquisition, development and operation of pipeline and terminal solutions between and in proximity to major North American petroleum trading hubs and demand centers. |

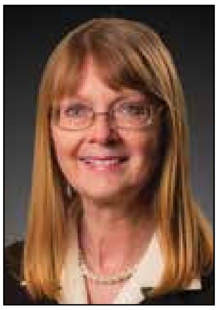
## DEBT

| Company | Exchange/ Symbol | Headquarters | Amount | Comments |
|---|---|---|---|---|
| Exxon Mobil Corp. | NYSE: XOM | Irving, Texas | $8.5 billion | Priced $8.5B worth of senior notes in five tranches as follows: $1.5 billion of 2.992% senior notes due 2025 at par to yield 2.992%; $1 billion of 3.294% senior notes due 2027 at par to yield 3.294%; $2 billion of 3.482% senior notes due 2030 at par to yield 3.482%; $1.25 billion of 4.227% senior notes due 2040 at par to yield 4.227%; and $2.75 billion of 4.327% senior notes due 2050 at par to yield 4.327%. Proceeds are to be used for general corporate purposes. |

# 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.

# SEIZE THE DAY



LESLIE HAINES, EXECUTIVE EDITOR-AT-LARGE

Stretch a rubber band too far, and it breaks. Snap! The pieces ricochet right back to sting your face. So here we are. Lower for longer eventually will lead to stronger for longer—but only for the survivors. For these, this slump of rare proportions could be the opportunity of a lifetime.

Everyone is looking for the silver linings. Would that be vastly lower service and supply costs? Rystad Energy said recently that in the last downturn (2014 to 2016), oilfield costs fell about 37% overall, 45% in shale plays and up to 40% offshore. That silver lining is not apt to be as easily found this time around because most cost reductions along the supply chain have been exhausted.

What about a recovery time frame? For industry and the wider economy, it will take several quarters, probably years. Oil demand will follow—or, will it? We took heart seeing the vast flow of cars, trains and celebrations in Wuhan, a city of 11 million people where the virus started its deadly sweep across the globe. We hope it's not going to have been a false start by the time you read this.

But there could be another consequence. On the environmental front of World War C, vehicular and factory activity has dropped precipitously—but water and air pollution from carbon emissions has too. The canals in Venice are so clear that we can now see the fish swimming in them. Who knew? The sky in Beijing turned blue. Pollution haze above Los Angeles highways is gone for now. Consumers see in the most dramatic way possible how reduced oil use makes such a big difference. This is going to turn a lot of assumptions on their head and further encourage the already widespread moves by governments to wean their economies off fossil fuels in the coming decades.

In the near term, as Jim Wicklund, managing director at Stephens Inc., said: "The business is not going away, but it is going to have a difficult 2020 and 2021."

It's hard to figure which sector is hurting the most, E&Ps or service companies—or which has become a screaming Buy. But on April 6, one brave soul said it is time to jump into oilfield services. Nicholas Green, senior research analyst for Bernstein, issued this call: "We started covering the space in 2014. We've never been bullish, even in the depths of '16. Yet expectations have dropped far too low—for the first time in seven years, it is time to buy!

"As committed bears, we do not upgrade lightly."

The market has priced in annihilation, which is misguided, and thus we see a major opportunity, he said. Green said he duplicated his models seven times to be sure, involving over 200 separate sector and company models. That research indicates to him that numerous top-tier service companies will survive and some have "material upside even in a $30 flat world." He also ran the models at $40.

His scenarios indicate this: Yes, EBITDA will be crushed by as much as 50%. But the majority of names will be able to show free cash flow; balance sheet distress is limited to an unlucky few.

Bottom line, he finds average upside of 60% to his Buys at $30 flat.

He named seven outright winners: Baker Hughes Co., National Oilwell Varco Inc., Tenaris SA, SBM Offshore, Subsea 7 SA, Saipem S.p.A. and Hunting. He also advised that investors take a position in the "dividend-cut crew" that are admittedly risky, but with the dividend cut being the signal to jump in. These names include Schlumberger Ltd., TechnipFMC Plc, Helmerich & Payne Inc., Wood Plc. and Petrofac Ltd.

On his watch list, ranked as Market perform, are Halliburton Co., Core Lab, Oceaneering International Inc. and Patterson-UTI Energy Inc. Each faces risks but upside is possible.

What about E&P ideas? Morgan Stanley likes Chevron Corp., ConocoPhillips Co., Noble Energy Inc., Hess Corp., Pioneer Natural Resources Co. and Cimarex Energy Co. Bernstein cited ConocoPhillips, Hess and EOG Resources. Non-Texas-oriented midstream companies might be worth a look, it added. Roth Capital Partners rated all E&Ps neutral. Analyst John White suspended price targets and earnings estimates for the names under coverage until they revise their guidance.

All analysts emphasize companies with good assets, a strong balance sheet and hedge position, and credit strength, or companies that can afford to keep paying at least some of their dividend without borrowing—or cut them altogether in order to pay debt instead.

Silver linings may be further in the future. WTI could reach $55/bbl again in 2022 once demand stabilizes, the economy revives and oil inventories are drawn down. Meanwhile, analysts see U.S. production shut-ins ahead.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