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Shale 2023

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Shale 2023

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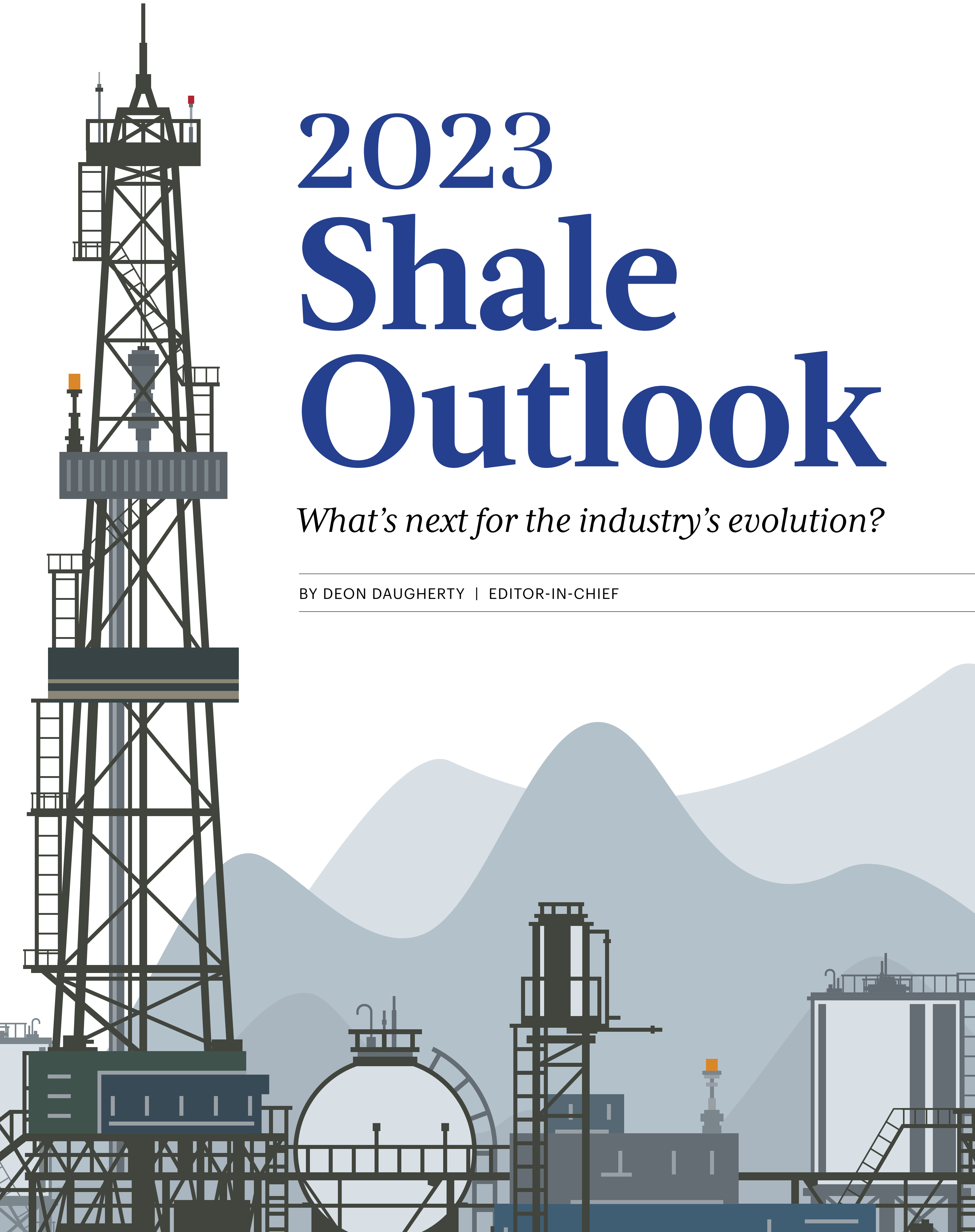
SHALE FORECAST



2023 Shale Outlook

What's next for the industry's evolution?

BY DEON DAUGHERTY | EDITOR-IN-CHIEF

The scene for U.S. shale in 2023 is setting up as a more dramatic iteration of the second half of 2022: more consolidation, higher inflation and more aggressive capital return programs.

Top analysts and market watchers anticipated growth in 2022 on the order of 1 MMbbl/d of oil. It didn't happen in 2022, and it's even less likely to occur in the year ahead. Most forecasts put growth around 500,000 bbl/d for both years.

There is no one issue that's slowed growth. Rather, it's a confluence of things: cost inflation; the corporate commitment to return cash to shareholders; a lower rate of reinvestment in operations; and the aging of even the most prolific plays, which is diminishing the production of some wells developed by some operators.

"We're 15 years into this, and we've learned a lot along the way, but there's not as much virgin rock out there as some people would like to think," said Andrew Gillick, managing director and energy sector strategist at Enverus.

During past periods of shale weakness or operational hiccups, producers have innovated their way out of a slowdown. In 2017, Permian Basin pure-play Pioneer Natural Resources Co. shocked the market with a revelation during the second-quarter earnings season that its gas-to-oil ratio (GOR) in the Midland Basin was increasing. In short, the more a well produces, the more its pressure drops. Gas rises into the oil reservoir and dilutes the resource. Not a marketable proposition at the time for companies that largely viewed oil as the profit and gas as its byproduct.

Certainly, rising GOR wasn't a Pioneer-specific problem. It was a shale drilling challenge that other players confronted too. A massive sell-off of Permian producers' stock ensued.

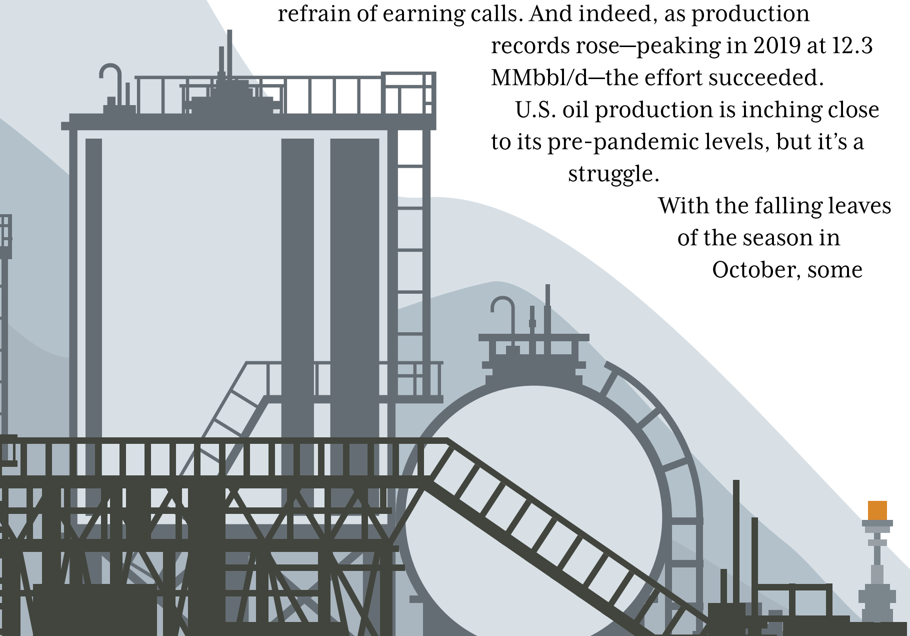
Undaunted, Pioneer's engineers went to work. The firm tested and retested spacing patterns and pad development. Field managers reworked the producer's aggressive flowback strategy. Operations teams tweaked other elements of the development strategy.

The GOR panic passed, and Permian producers' share prices popped back up.

Then came the angst of parent-child well interference. This is a phenomenon of secondary wells being placed so close to initial wells that they tap into the first flows, diminishing the returns of both. Operators went back to the drawing board and found ways to modify well spacing to their advantage. The endeavor was so successful that "manufacturing mode" became a common refrain of earning calls. And indeed, as production records rose—peaking in 2019 at 12.3 MMbbl/d—the effort succeeded.

U.S. oil production is inching close to its pre-pandemic levels, but it's a struggle.

With the falling leaves of the season in October, some



Top 50 US Shale Producers
(By average volume, 1H 2022)

Rank	Operator	Gross boe/d
1	HILCORP	2,113,488
2	CHESAPEAKE ENERGY	1,239,866
3	EXXON MOBIL	1,112,851
4	CONOCOPHILLIPS	1,110,972
5	OXY	1,053,035
6	EOG RESOURCES	1,004,558
7	EQT	939,139
8	CHEVRON	892,648
9	SOUTHWESTERN ENERGY	887,668
10	DEVON ENERGY	795,099
11	COTERRA ENERGY	758,568
12	PIONEER NATURAL RESOURCES	750,434
13	BP	602,330
14	CONTINENTAL RESOURCES	599,616
15	ANTERO RESOURCES	529,343
16	SHELL	485,473
17	DIAMONDBACK	434,858
18	ASCENT RESOURCES LLC	398,755
19	OVINTIV	356,185
20	RANGE RESOURCES	352,941
21	MARATHON OIL	351,563
22	AETHON ENERGY	330,601
23	COMSTOCK	326,778
24	MEWBOURNE OIL	321,727
25	CNX	290,085
26	PDC ENERGY	258,852
27	ENDEAVOR ENERGY	254,619
28	CHORD ENERGY	226,281
29	HESS	225,975
30	APA CORP	222,607
31	ROCKCLIFF ENERGY II LLC	220,779
32	CIVITAS RESOURCES	218,255
33	GULFPORT	195,403
34	SM ENERGY	192,448
35	NATIONAL FUEL GAS	189,450
36	ENCINO ENERGY	182,380
37	TRINITY OPERATING	156,079
38	PERMIAN RESOURCES	151,201
39	DIVERSIFIED ENERGY	149,332
40	LEWIS	148,658
41	CROWNQUEST OPERATING	147,624
42	CALLON	133,431
43	TUG HILL OPERATING, LLC	130,646
44	EARTHSTONE	124,958
45	REPSOL	124,741
46	FLYWHEEL ENERGY	122,798
47	MERIT ENERGY	122,409
48	MATADOR RESOURCES	122,235
49	LAREDO	120,048
50	CRESCENT ENERGY CO	118,229
		22,298,020

Source: Enverus

US Rig Count
(Average 1H 2022)

Rank	Operator	U.S. Rigs Running
1	EOG RESOURCES	28
2	CONOCOPHILLIPS	26
3	DEVON ENERGY	25
4	OXY	25
5	MEWBOURNE OIL	23
6	PIONEER NATURAL RESOURCES	21
7	CONTINENTAL RESOURCES	20
8	EXXON MOBIL	19
9	CHEVRON	15
10	DIAMONDBACK	15
11	ENDEAVOR ENERGY	15
12	AETHON ENERGY	14
13	CHESAPEAKE ENERGY	14
14	SOUTHWESTERN ENERGY	9
15	COTERRA ENERGY	9
16	BP	9
17	MARATHON	9
18	COMSTOCK	8
19	OVINTIV	7
20	PERMIAN RESOURCES	7
21	TRINITY OPERATING	6
22	CROWNQUEST OPERATING	6
23	CALLON	6
24	TUG HILL OPERATING, LLC	5
25	EARTHSTONE	5
26	REPSOL	5
27	MATADOR RESOURCES	5
28	PDC ENERGY	4
29	APA CORP.	4
30	ROCKCLIFF ENERGY II LLC	4
31	SM ENERGY	4
32	HILCORP	3
33	EQT	3
34	ANTERO RESOURCES	3
35	CHORD ENERGY	3
36	HESS	3
37	ENCINO ENERGY	3
38	ASCENT RESOURCES LLC	2
39	RANGE RESOURCES	2
40	CNX	2
41	CIVITAS RESOURCES	2
42	GULFPORT	2
43	NATIONAL FUEL GAS	2
44	LAREDO	2
45	DIVERSIFIED ENERGY	1
46	CRESCENT ENERGY COMPANY	1
47	SHELL	0
48	LEWIS	0
49	FLYWHEEL ENERGY	0
50	MERIT ENERGY	0

Source: Enverus

"We're 15 years into this, and we've learned a lot along the way, but there's not as much virgin rock out there as some people would like to think."

—ANDREW GILLICK, Enverus

of the largest U.S. oil producers signaled a slowdown productivity and volume gains in the top shale plays,

Pioneer leadership told investors the company will reshuffle its drilling portfolio in 2023 to target wells with potentially higher returns, a move to boost lagging productivity levels.

Chevron Corp. and Exxon Mobil Corp. also expressed caution against their Permian oil and gas volumes. Chevron's full-year volume will be near the low end of its 700,000-boe/d to 750,000-boe/d guidance. Exxon Mobil dropped its 2022 forecasted gain to 20% from an earlier expectation of 25%.

"Productivity came in a little less than we anticipated, and we wanted to rectify that," Pioneer president Richard Dealy said.

Nevertheless, the Pioneer team remains optimistic.

"We're really just reshuffling the portfolio and bringing forward higher-return wells and deferring some of the wells that were great wells, but … we got higher thresholds that we can hit. And so, we've just deferred those and reallocated the capital," Dealy said. "But the reality is we have high confidence that we're going to achieve the results that we have laid out here."

BOTTLING A LIGHTNING BOLT

The U.S. energy business is rich with some of the most creative and innovative minds of any industry, Gullick told Hart Energy. And so, it's conceivable that the next big thing could revive production.

"I'm not going to sell technology short. I'm not going to sell this industry short," he said. "But I don't think technology is going to find a new basin."

If commodity prices remain high, there is more opportunity to develop lesser quality rock. But that doesn't make the wells produce better, it only makes them somewhat profitable.

Indeed, operators may not have to invest as much in research as they might engage in strategy and planning to boost results, Gillick said.

"I think better planning might bail us out, but I'm looking at the industry now in this mature manufacturing mode where capital is being returned to shareholders. There's a focus on ESG or on holistically running the companies in a way maybe that was different than before," he said. "I'm not sure technology is going to save us."

Still, the U.S. Energy Information Administration (EIA) estimates the nation's oil production in 2023 will top 2019's record 12.29-MMbbl/d output.

Meanwhile, there are steps operators can take to stem declines. Better budgetary planning for asset pace and development and tighter guidance to Wall Street could help.

Moreover, a handful of companies missed meeting production guidance because offset wells degraded their production.

"It's either you're not looking out the window to see what your

Top US Shale Private Operators
(Average 1H 2022)

Operator	Gross boe/d (avg 1H22)	Gross bbl/d	Gross Mcf/d	U.S. Rigs Running
HILCORP	2,113,488	296,930	10,899,055	3
ASCENT RESOURCES LLC	398,755	15,559	2,299,166	2
AETHON ENERGY	330,601	402	1,981,184	14
MEWBOURNE OIL	321,727	195,193	759,166	23
ENDEAVOR ENERGY	254,619	177,708	461,461	15
ROCKCLIFF ENERGY II	220,779	347	1,322,573	4
ENCINO ENERGY	182,380	21,084	967,760	3
TRINITY OPERATING	156,079	14,761	847,891	6
LEWIS	148,658	3,084	873,409	0
CROWNQUEST OPERATING	147,624	95,328	313,771	6
TUG HILL OPERATING, LLC	130,646	7,621	738,150	5
FLYWHEEL ENERGY	122,798	---	736,725	0
MERIT ENERGY	122,409	19,987	614,378	0
	4,650,562	848,004	22,814,688	81
	[21% total]	[11% total]	[27% total]	[20% total]

Source: Enverus

neighbor is doing right next to you or you're not following the permits or you're not talking to your peers," Gillick said. "I think that just comes down to planning."

Some firms blamed supply chain issues for production disruptions. During the third-quarter earnings period, SM Energy Co. reset its second-half guidance downward by 10,000 bbl/d based on delays and offset activity.

Several companies advised investors of capital spending boosts mostly to manage growing inflation.

Producers can no longer plan for several years of $40 breakeven rates, Gillick said.

"There's a couple of years, but that's changing too, as costs go higher," he said. "The rock is the same, but the well doesn't cost $6 million anymore, it costs $8 million. So that changes your return profile. That low-cost breakeven inventory is evaporating every quarter as prices go up."

In general, the 10% to 15% cost inflation rate producers reported in 2022 will likely carry forward into 2023, he said.

For small operators and private producers, the rate of inflation could climb as high as 20%.

"They don't have long-term contracts, so they get dinged now or even earlier, whereas the larger operators have longer-term contracts," Gillick said. "They're going to get dinged next year, and the average cost will be up 20%. But for some operators, it's already more than that. For others, it's not that much."

CONSOLIDATION CONTINUUM

Analysts anticipate the consolidation that began taking shape during the second half of 2022 will continue in 2023. After a lackluster first half, upstream oil and gas M&A jolted awake in the third quarter with $16 billion in announced transactions.

"Operators that are bigger, more liquid and with more inventory have seen much bigger capital inflows over the last six to 12 months than the smaller-cap operators with shorter inventory lives," Gillick said. "If you think about the 2021 mantra, [investors] didn't care about how much inventory you have; the idea was just return all the capital you can as fast as you can because nobody's going to need crude oil in 2030."

But then, he said, something happened during the past 12 months to shake the system.

"People, I guess, opened their eyes to realize, 'Oh, we may need this crude oil stuff a little longer'," he said. "And so that inventory question never came back."

Consequently, the sector's equities have outperformed the commodity almost 30%, he said.

"That means the long money that hasn't been here—like the Fidelity long-term mutual fund money—is coming back."

All of which points to continued consolidation, Gillick and other analysts have said. Companies must grow to continue returning capital to shareholders. Most will opt to do that through acquisitions that may rely on equity.

"If you're a mid-cap, you'll have to bite the bullet at some point and merge maybe with another small- or mid-cap operator," Gillick said.

SETTING THE SCENE FOR 2023

Despite some instances of faltering production, cost overruns and general volatility, the U.S. E&P space showed a robust market performance. At the end of November the sector was outperforming the S&P 500 by 77% and the front month Brent price by 47%, said analyst Neil Mehta at Goldman Sachs.

"As we position for 2023, while we still see attractive risk/

Top 10 US Shale Producers
(By oil production, average 1H 2022)

Rank	Operator	Gross bbl/d
1	CONOCOPHILLIPS	712,315
2	OXY	666,839
3	EOG RESOURCES	606,155
4	CHEVRON	599,412
5	PIONEER NATURAL RESOURCES	493,507
6	DEVON ENERGY	467,572
7	EXXON MOBIL	450,009
8	SHELL	411,376
9	BP	335,235
10	HILCORP	296,930

Source: Enverus

Top 10 US Shale Producers
(By gas production, average 1H 2022)

Rank	Operator	Gross bbl/d
1	HILCORP	10,899,055
2	CHESAPEAKE ENERGY	6,899,970
3	EQT	5,614,692
4	SOUTHWESTERN ENERGY	5,199,056
5	EXXON MOBIL	3,976,879
6	COTERRA ENERGY	3,769,324
7	ANTERO RESOURCES	3,100,350
8	CONOCOPHILLIPS	2,391,854
9	EOG RESOURCES	2,390,327
10	OXY	2,317,080

Source: Enverus

"As we position for 2023, while we still see attractive risk/reward in a firm oil macro environment, we believe that focus will shift to stock picking."

—NEIL MEHTA, Goldman Sachs

reward in a firm oil macro environment, we believe that focus will shift to stock picking," he said in a note to investors.

Companies such as EOG Resources Inc. and Hess Corp. surprised to upside on asset quality and execution, according to Mehta. Gas-weighted Antero Resources Corp. benefited from the return of capital thesis; on the large company side, ConocoPhillips Co.'s performance was a solid example of the market supporting those producers that elevated shareholder returns, he said.

Several executives lamented the undervalued state of their stocks, which traded at a valuation discount for much of the year. Among them, Chesapeake Energy Corp. and Ovintiv Inc. stood out. On the other side of the equation, Occidental Petroleum Corp. benefited from its balance sheet repair.

In its "Macro Forecaster," Enverus Intelligence Research, a subsidiary of Enverus, reported that near-term recession risks, fallout from Russia's war on Ukraine, COVID-19's lingering depression on demand in China and OPEC's oil supply mechanizations will impact oil supply.

The group estimated those factors may coalesce in $100/bbl oil in 2023; Nymex natural gas may dip near $3.50 by summer.

OIL EXPECTATIONS

Analysts at Goldman Sachs remain optimistic for oil prices in 2023, citing near-term potential for improving demand from China and lower U.S. shale growth based on capital discipline, tight services and inflation and the impact of the OPEC+ quota reduction.

"Longer term, we believe underinvestment will drive lower supply growth and keep oil prices higher," Mehta said. "However, we note that E&Ps are increasingly already pricing in an improvement in oil prices relative to the current oil futures."

Relative to consensus estimates and strip pricing, Goldman is slightly bullish. Goldman pegs strip prices for WTI oil at $105/bbl in 2023 before steadying at $85 for the next two years. Consensus estimates forecast 2023 oil in the lower $90s before finding equilibrium in the mid-$80s. Strip prices fall to $70/bbl in 2025 estimates.

ACCOUNTING FOR GAS

In December, the EIA forecasted U.S. production of dry natural gas to average about 100 Bcf/d from December through March. Weather-related declines from freeze-offs and the potential for extreme winter weather anticipated in December dragged the estimate down some 0.5 Bcf/d from November expectations.

The EIA raised its 2023 forecast for all U.S. natural gas production in a December "Short Term Energy Outlook" report by almost 1% from the November estimate.

The researchers said gas production in the Permian Basin is likely to be limited early in 2023 by insufficient pipeline capacity to bring associated natural gas production to market, but those constraints will be resolved in the spring.

Growth in LNG exports will likely increase in 2023, following a peak during the first half of 2022, the EIA said. Those exports are tracking for a new record close to 12.5 Bcf/d in March 2023 and reaching up to 12.7 Bcf/d by year-end.

Henry Hub spot price is expected to average more than $6/MMBtu in the first quarter, up from November's monthly average of about $5.50/MMBtu.

"We expect natural gas prices will begin declining after January as U.S. storage levels move closer to the previous five-year average, largely as a result of rising U.S. natural gas production," the agency said in its report. "However, the possibility of price volatility remains high." ■

The Mighty Permian Persists

BY DEON DAUGHERTY | EDITOR-IN-CHIEF

By almost any measure, the Permian Basin delivers. The 55 counties in Texas and New Mexico that make up the Permian account for almost half—upward of 43%—the U.S.' oil production. The basin's market share is up almost 20% since 2013.

But the winds, as always, are changing and the "it's cyclical" refrain is as evident now as ever.

At the end of 2019, the U.S.' daily output hit 12 MMbbl, once again sustained by the 4.3 MMbbl/d produced in the Permian.

Indeed, it took a worldwide virus and its decimation of demand to slow the Permian's trajectory.

But more than two years since COVID-19 upended commodity and global economies, demand is back.

Is the Permian back, too?

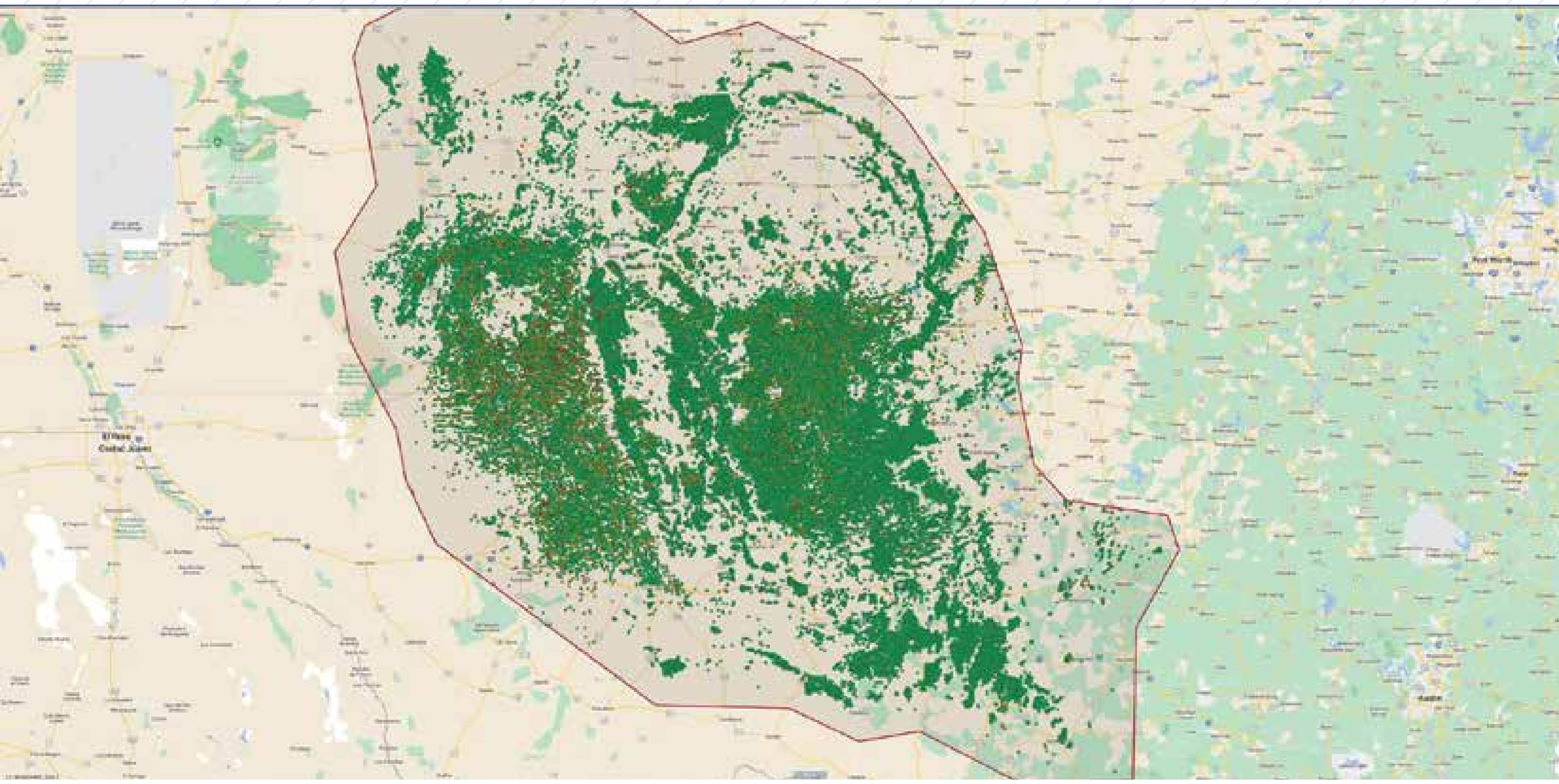
Producers that rolled back their growth—in part driven by positive demand signals, but also by shareholder demand—remain gun-shy about calling high-number production goals. Demand is heading upward, but the shareholder insistence for returns before growth is firmly in place. And as the mighty Permian nears its pre-pandemic production high, questions about its sustainability augment the conversation.

Supermajor ***Exxon Mobil Corp.*** is active in both the Delaware and Midland sides of the Permian, and production expectations were on target for 2022.

"Our production in the Permian Basin reached nearly 560,000 oil equivalent barrels per day, building on our strong growth from last year," said CEO Darren Woods in November.

"In the Permian, one of the challenges there is over the years, what we've been doing is working really hard to make sure we're maximizing the recovery of that resource," Woods said. "Obviously, as we go through that, we're optimizing and adjusting our development plans. That continues to be the case. So I expect this year, we'll probably come in at about 20% up on last year's growth, which was up 25% from the year before. So still very solid growth in the Permian."

ConocoPhillips Co. cemented its position in the Permian in 2021 with its acquisitions of Shell Enterprises' position in the Delaware Basin, which consisted of about 225,000 net acres, more than 600 miles of operated crude, natural gas and water pipelines and infrastructure, along with the purchase of Concho Resources, which owned assets in both the Delaware and Midland basins.



Source: Rextag

Nevertheless, the sentiment of slowing shale production prevails.

"Rapidly escalating costs combined with extremely tight supply are limiting the pace of industry-wide production growth," ConocoPhillips CEO Ryan Lance said in an earnings call.

ConocoPhillips, the largest independent U.S. oil producer, forecast overall production growth of about 900,000 bbl/d this year but warned that gains would slow in 2023 on unrelenting oilfield inflation.

DELAWARE INFLATION

On the storied west side of the Permian Basin is the Delaware Basin's 6.4-acre area, which reaches out from Eddy County in New Mexico to West Texas' Pecos County. It is the deepest of the Permian's sub-basins and holds the thickest rock, according to Enverus.

The top operator in the Delaware by production, the highly diversified EOG Resources, spoke frankly throughout 2022 about the impact of headwinds in the shale space, including mature wells and cost increases.

"Oilfield service capacity remains extremely tight and is further constrained by the limited availability of materials and experienced labor," EOG COO Billy Helms told investors mid-year. Those constraints fueled uncertainty in service costs, and he said the expectation is that they will continue to do so in 2023.

"These constraints are more concentrated in areas with the highest activities such as the Permian Basin," Helms said.

Conversely, the No. 2 producer in the Delaware, ***Devon Energy Corp.***, described "phenomenal" well performance in the play.

"This is an absolutely world-class asset," Clay Gaspar, Devon's operations chief, told investors in November. "We love the position we're in. We love the scale that we have. The team keeps delivering. We're still working on the efficiencies. We're still applying technology, always trying to get a little better, a little smarter each day. No doubt about it. We have some inflation coming our way. So, there is some squeeze on the margin, but I would take this world-class asset and love having it in our portfolio."

Devon's current focus is in the oil-rich Wolfcamp, Bone Spring, Avalon and Delaware formations, according to company data. The firm's operations in the Delaware provide both oil and natural gas production from a core acreage position of roughly 400,000 net acres across those formations.

Rounding out the top three Delaware producers is

Top Permian Producers

(1H 2022 Average)

DELAWARE

Rank	Company	boe/d	bbl/d	Mcf/d
1	EOG	581,410	350,353	1,386,310
2	DEVON	489,513	296,080	1,160,569
3	OXY	414,431	257,670	940,537
4	CONOCOPHILLIPS	385,673	234,733	905,614
5	EXXON MOBIL	309,774	179,276	782,971

MIDLAND

Rank	Company	boe/d	bbl/d	Mcf/d
1	PIONEER	750,168	493,270	1,541,353
2	DIAMONDBACK	308,285	206,561	610,332
3	ENDEAVOR ENERGY	253,505	177,156	458,086
4	EXXON MOBIL	219,674	127,999	550,044
5	CONOCOPHILLIPS	194,880	126,359	411,121

Source: Enverus

Occidental Petroleum Corp. (Oxy).

Oxy CEO Vicki Hollub said management remains "highly encouraged" by well performance in the Delaware.

"We delivered our best quarter to date for early well performance with the 46 wells online averaging peak 30-day rates of over 3,600 boe per day, demonstrating the superior quality of our inventory and subsurface expertise," she told investors during a third-quarter earnings call," she said. "And in the Texas Delaware, we recently brought online a new Silvertip well with the highest initial oil production of any horizontal well previously drilled in the Lower 48."

A key independent producer, Oxy is also testing the waters of carbon capture and sequestration in the Permian. In August, that company first announced a plan to begin detailed engineering and early site construction for its first large-scale direct air capture plant in Ector County, Texas, near Oxy's portfolio of acreage and infrastructure that are conducive to safe and secure storage of CO_2.

"The Permian location of our first direct air capture will provide us [with] multiple options to maximize the value of captured CO_2. We have the ability to inject the CO_2 into a saline reservoir producing CDRs [carbon dioxide removal] or to utilize the captured CO_2 to produce net-zero oil from our enhanced oil recovery assets," Hollub said. "Our conversations with many corporate partners and potential clients have highlighted the significant demand for CDRs generated through CO_2 sequestration."

One of the nation's largest independents, ConocoPhillips, and supermajor Exxon Mobil round out the top five producers in the Delaware, respectively.

FAIR TO MIDLAND

It might have originated as a British expression of 'eh, I'm a bit better than okay,' the oil patch took on the phrase "fair to Midland" and made it part of the lexicon. And it stands up today for the eastern side of the Permian.

Stretching north to south from Lamb and Hale counties to the top of Crockett County, the Midland Basin has been a hotspot since the 1940s, Enverus notes. The play took off in the 1970s and has intermittently been a key performer every time oil pops.

And each of the top five producers are at the top of their respective games, too. ***Pioneer Natural Resources Co.*** has reached the goal of CEO Scott Sheffield to become a basin pure play, and it's paid off. Not only is the company the top producer in the basin, it is also a poster child for emission reduction ambitions across the industry.

Beyond the oil riches of the Permian, Pioneer intends to dig in for deep gas in 2023.The firm will test its deep Barnett and Woodford gas in the Midland to determine productivity, COO Rich Dealy said, during third-quarter earnings in October.

"We expect those wells obviously—they're deeper—to be gassier, and we know we'll find resource there," he said, during a call with analysts.

"We just want to understand what that resource is. So we think it's worthwhile to spend some capital next year to test those zones and then we'll see what the productivity looks like and go from there."

Mississippian-age Barnett and Woodford underlie the Permian's popular oil targets—the Permian-age Wolfcamp and Spraberry—and are at depths up to more than 12,000 feet.

Coming in as the second-largest producer by volume in the Midland is the voracious ***Diamondback Energy Inc.*** In 2022, Diamondback celebrated its first decade as a public company.

Diamondback Energy continued to add onto its position in the Midland portion of the Permian Basin with the acquisition of Lario Permian LLC in November in a cash-and-stock transaction valued at $1.55 billion.

In October, the company made its first acquisition since March 2021, reminding anyone watching that even one of the Permian Basin's largest independents—the company was Texas' second-largest oil producer in 2021—is constantly on the lookout for replacement inventory. Diamondback's $1.6 billion deal to buy Firebird Energy in October follows a torrid M&A stretch for Diamondback in which, over two and a half years beginning in 2018, the company paid more than $13.7 billion for rivals QEP Resources ($2.2 billion), Ajax Resources ($1.2 billion) and Energen Corp. ($9.2 billion) among others.

"The challenge for public E&Ps in the M&A market is adding inventory while keeping the valuation on deals in line or less than their own cash flow multiples and free cash flow yields," said Andrew Dittmar, director at Enverus Intelligence Research. "Diamondback appears to have just managed that."

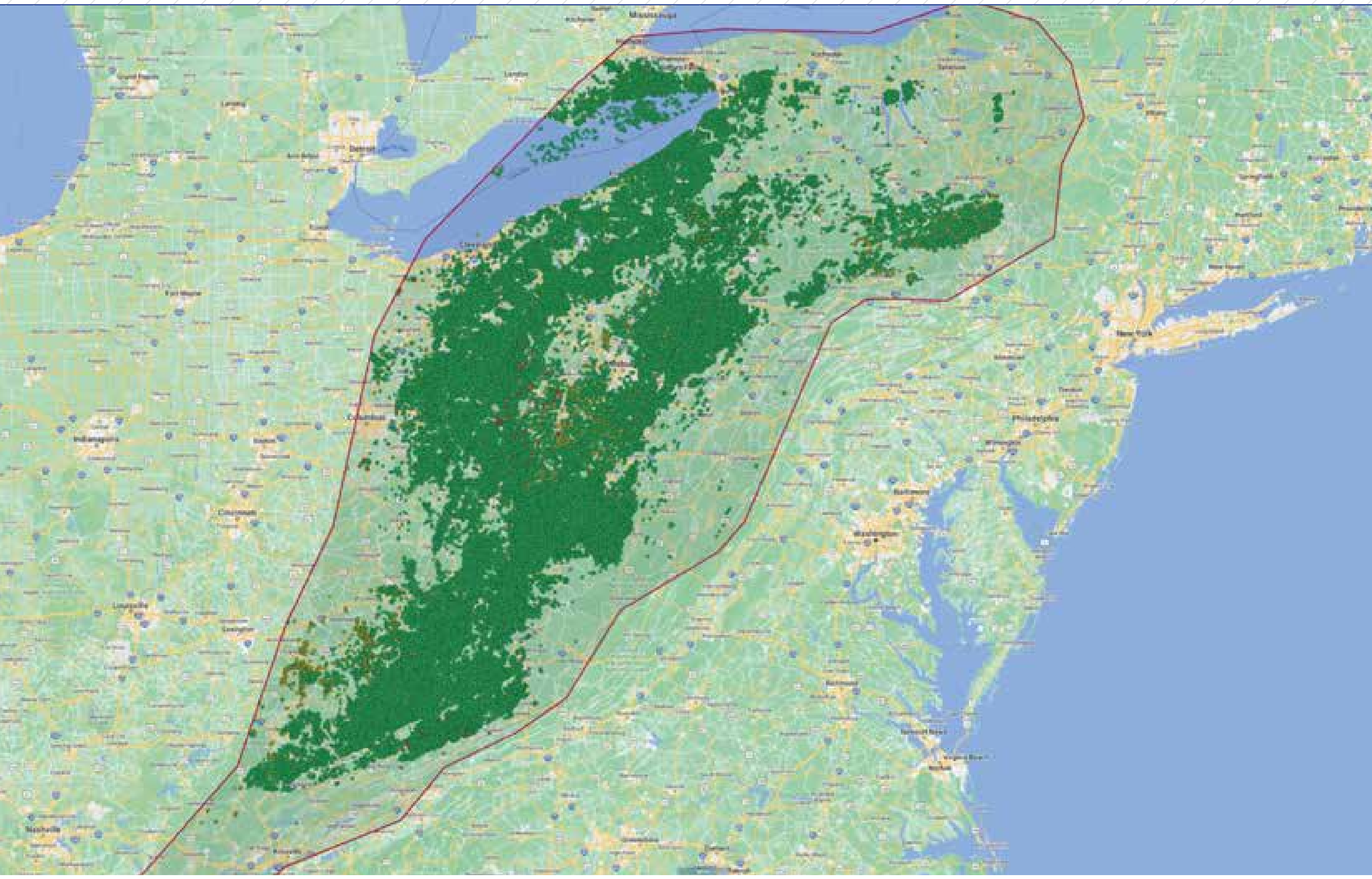
On the operations side, CFO Kaes Van't Hof addressed portions of the firm's growth strategy during a third-quarter call with investors.

"Our math tells us that we're finding a striking a good balance here between [internal rate of return] and [net present value]. We may not have the highest oil per foot but certainly spacing wells a little tighter, as well as codeveloping more economic zones together and I expect that trend to continue to head our way," he said. "I think we're set up now for a few years of very solid development, particularly in the Midland Basin side."

The third-largest producer in the Midland is privately held ***Endeavor Energy Resources***. With its headquarters located near the action in the city of Midland, Endeavor employs more than 1,200 locals and is one of the largest private producers in the U.S.

Endeavor holds roughly 370,000 net acres in the six core Midland Basin counties, where it focuses its activity. Since 2016, the company has completed more than 900 horizontal wells. Management has said the firm has developed less than 10% of its current inventory, suggesting the room for growth is substantial.

Taking the fourth and fifth slots for the largest-volume producers in the Midland is supermajor Exxon Mobil and mega independent ConocoPhillips, respectively. ■



Source: Rextag

Marcellus Shale Gains Ground

BY MADISON RATTCLIFF | ASSOCIATE EDITOR

First announced as the newest player in the shale scene by Range Resources Corp. in December 2007, the Marcellus Shale formation has now produced approximately 80 Tcf of natural gas to date.

Through development from natural gas-based producers such as EQT Corp., Southwestern Energy and Chesapeake Energy Corp., the shale play has rapidly expanded and continues to grow, with production anticipated to reach 38 Bcf/d in some areas by 2025, according to Randall Wright, president of Wright & Co. Inc.

"Production growth is on trend to meet that projection," Wright told attendees at Hart Energy's 2022 DUG East conference in June, sharing that earlier predictions of the play more than a decade prior were more skeptic: "If you could get 1 Bcf per 1,000 feet of lateral, it might be a viable play."

As geopolitical turmoil takes center stage in the winter of 2022-2023, many energy leaders believe that Marcellus Shale gas can be a turning point in aiding global economies on the road to energy stability and recovery.

"The energy macro landscape remains volatile as the world continues to grapple with a structural under supply of natural gas. Thanks to American source LNG, Europe has done a commendable job refilling its storage over the past few months," EQT CEO Toby Rice said in his company's third-quarter 2022 earnings call.

Top shale performers ***EQT, Chesapeake Energy, Antero Resources, Southwestern Energy*** and ***Coterra Energy*** produced a combined total of 2.9 MMboe/d, 30,065 bbl/d of oil and 17.3 Bcf/d of gas in the first half of 2022, according to data from advisory firm Enverus.

EQT produced a total of 859,302 boe/d from its Marcellus assets, comparable to the 939,139 boe/d it produced across all its assets in the first half of 2022. In addition, EQT reported 3,348 bbl/d in oil production, as well as 5.13 Bcf/d in natural gas production.

On Sept. 6, EQT announced the planned acquisition of THQ Appalachia I LLC (Tug Hill)'s upstream assets and THQ-XcL Holdings I LLC (XcL Midstream)'s gathering and processing assets for $5.2 billion.

"This deal checks all of the boxes of our guiding M&A principles, have significant industrial logics given direct offset to our existing lease sold in West Virginia and brings over 11 years of core inventory that immediately competes for capital inside and in EQT's portfolio," Rice said in the third-quarter earnings call.

'SUPER-RICH ACTIVITY'

Chesapeake produced 727,286 boe/d in the Marcellus in the first half of 2022, over half of its 1.23 MMboe/d produced across all the company's assets. Similarly, it produced 4.36 Bcf/d of natural gas from the basin, nearly two-thirds of its total 6.89 Bcf/d natural gas production.

Prior to the Russian invasion of Ukraine spurring an uneven dealmaking market, Chesapeake started the M&A year off strong with the acquisitions of Marcellus-based Chief Oil & Gas. On Jan. 25, 2022, the company agreed to acquire Chief E&D Holdings LP, along with Tug Hill Inc.'s associated, nonop interest for $2 billion in cash and approximately 9.44 million common shares.

Through the acquisition, the company was able to add leasehold to the lower part of the play, CEO Nick Dell'Osso said on the company's third-quarter 2022 earnings call.

"In the Marcellus, our synergies from the Chief acquisition continue to come to fruition," he said. "As we've discussed before, we're maximizing the capacity of the combined gathering systems.

"And we're looking forward to 2023, where our well design improvements of longer lateral length and enhanced completions should show up with improved productivity per well," he added.

Antero Resources is growing in the play. In the first half of 2022, the firm produced 455,453 boe/d, 8,286 bbl/d of oil and 2.68 Bcf/d of natural gas from the Marcellus. Combined with the company's Utica assets, it accounts for the majority of its total 529,343 boe/d, 12,615 bbl/d total oil production and 3.1 Bcf/d total natural gas production.

Through Antero's organic leasing program, the company added approximately 60 new drilling locations during the first nine months of the year, chairman, president and CEO Paul Rady said in the company's third-quarter 2022 earnings call.

"We have continued to maintain our focus on our core acreage footprint with a particular emphasis of spending capital on organic lease acquisitions," he said. "As opposed to larger transactions that can dilute our equity, create a large overhang on the stock and lever our balance sheet we have preferred to pick up smaller, more tailored acreage packages within our core liquids-rich position in West Virginia, where we continue to see tremendous well results."

Top Shale Cos/Marcellus
(1H 2022 Average)

Rank	Company	boe/d	bbl/d	Mcf/d
1	EQT	859,302	3,348	5,135,692
2	CHESAPEAKE	727,286	-	4,363,698
3	ANTERO RESOURCES	455,453	8,286	2,682,983
4	SOUTHWESTERN ENERGY	441,111	18,431	2,536,056
5	COTERRA ENERGY	436,933	-	2,621,581

Source: Enverus

CHESAPEAKE ENERGY CORP.

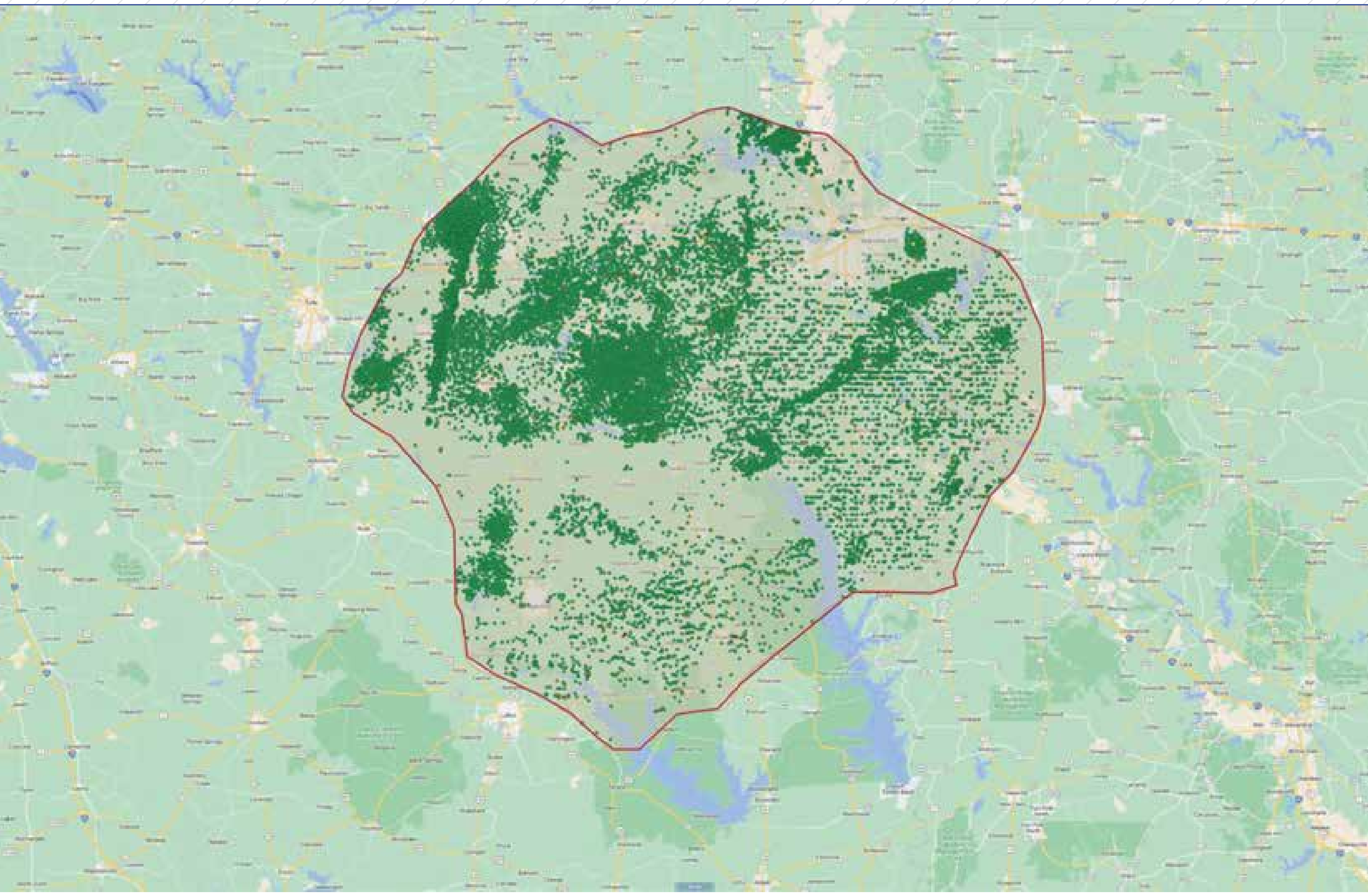
Approximately half of Southwestern Energy's production—887,668 boe/d—came from the Marcellus, which produced 441,111 boe/d in the first half of 2022. The company reported 18,431 bbl/d in oil production, as well as 2.53 Bcf/d in natural gas production, in the basin.

In addition, Southwestern placed 14 wells with an average lateral length of approximately 15,600 ft in the Marcellus during the third quarter of 2022, COO Clay Carrell said on the company's earnings call.

"Our superrich area in West Virginia accounted for eight of those wells, and our Marcellus and Utica dry gas acreage in Pennsylvania and Ohio accounted for the remaining Appalachia turn-in lines," he continued. "In the fourth quarter, based on our superrich activity and the timing of completions, we anticipate holding oil volumes flat."

Coterra Energy's diverse portfolio has operations sprawled across the U.S. from the combined assets of Cabot Oil & Gas and Cimarex Energy. In the Marcellus shale, it holds approximately 177,000 net acres, the company reported on its website.

In the first half of the year, Coterra reported 436,933 boe/d produced in the Marcellus, compared to the total of 758,568 boe/d produced across the Marcellus, Permian and Anadarko basins combined. Additionally, it produced 2.62 Bcf/d of natural gas in the shale, approximately two-thirds of the 3.76 Bcf/d of natural gas produced across all the company's assets. ■



Source: Rextag

The Haynesville Takes Shape

BY MADISON RATTCLIFF | ASSOCIATE EDITOR

Located in northwestern Louisiana and sprawling into eastern Texas, the Haynesville Shale play was thrust into the spotlight in March 2008. Petrohawk Energy Corp. and Chesapeake Energy Corp. both announced lease acreages in Louisiana, sparking a flood of interest to the region.

"The Barnett remains No. 1 in Chesapeake's portfolio, but the Haynesville Shale could be even bigger someday," then-CEO and chairman of Chesapeake, the late Aubrey McClendon, said at IPAA's 2008 Oil & Gas Investment Symposium in New York.

Although some remained skeptical of the shale's potential, the approximately 9,000-sq-mile formation has proven itself worthy of the praise it received at the play's inception.

Analysts from J.P. Morgan found in its September "JPM Natural Gas Reservoir" report a 54% increase in Haynesville rig activity from the 46 average count in 2021 to 71 in the first half of 2022. In addition, they reported the increase in Haynesville activity as "one of the key factors that is supporting the supply imbalance in our 2023 natural gas supply-demand work.

"Recent gas pipeline scrapes are running ahead of expectations, reaching record highs of ~99.3 Bcf/d in September, with MTD gas production estimated at 98.7 Bcf/d, which compares to the August average of 97.7 Bcf/d and the September 2021 average of 92.7 Bcf/d," the analysts stated.

Top basin performers ***Chesapeake Energy, Southwestern Energy, Comstock Resources, Aethon Energy*** and ***Rockcliff Energy II*** produced a combined total of 1.53 MMboe/d, 83 bbl/d of oil and 9.2 Bcf/d of gas in the first half of 2022, according to data from advisory firm Enverus.

One of the first operators to enter the basin, Chesapeake was the Haynesville's largest producer in the first half. Enverus data showed that of the company's 1.23 MMboe/d produced in the half, 365,766 boe/d came from its Haynesville operations, with 2.19 Bcf/d of the 6.98 Bcf/d total produced coming from the Haynesville as well.

Although it produced 89,862 bbl/d of oil in the first half of the year, none of Chesapeake's oil production came from the Haynesville, according to the data.

The latter half of the year was dedicated to focusing on Chesapeake's midstream capacity, the company shared on its third-quarter 2022 earnings call, which includes developing a new pipeline project with an associated carbon capture and sequestration program.

"In the Haynesville, we've made significant strides with midstream capacity," CEO Nick Dell'Osso said on the earnings call. "We've increased our gathering and treating capacity by 25% for this year and up to 60% in four years."

"We've also committed 700 MMcf/d to a new pipeline to be built by momentum from the heart of the Haynesville play down to [Gilles]," he continued.

HIGH RESULTS

At Southwestern, the company's "strategic intent is to generate resilient free cash flow from responsible natural gas development," has enabled it to establish a presence within the two largest natural gas basins in the U.S. and become the largest gas producer in the Haynesville Shale.

"Our well-timed Haynesville acquisition [Indigo Natural Resources, GEP Haynesville] positioned us as the largest Haynesville producer, giving us scaled production and reserves near the LNG corridor and other growing gas demand centers along the Gulf Coast," president and CEO Bill Way said in Southwestern's third-quarter 2022 earnings call.

The company reported 334,716 boe/d in first half 2022 production from the Haynesville, comparable to the total 887,668 boe/d produced by the company across all its assets, according to Enverus data. In the basin, it also produced 2 Bcf/d of its total reported 5.19 Bcf/d across the combined Haynesville and Appalachian assets.

Comstock has assets spanning throughout northern Louisiana and eastern Texas, making it the third most productive Haynesville operator with eight total rigs. The company produced a total of 314,483 boe/d, 28 bbl/d of oil and 1.88 Bcf/d of gas in the Haynesville in the first half of 2022.

Top Haynesville Producers
(1H 2022 Average)

Rank	Company	boe/d	bbl/d	Mcf/d
1	CHESAPEAKE	365,766	N/A	2,194,587
2	SOUTHWESTERN ENERGY	334,716	0	2,008,290
3	COMSTOCK	314,483	28	1,886,725
4	AETHON ENERGY	313,492	19	1,880,835
5	ROCKCLIFF ENERGY II	205,997	36	1,235,764

Source: Enverus

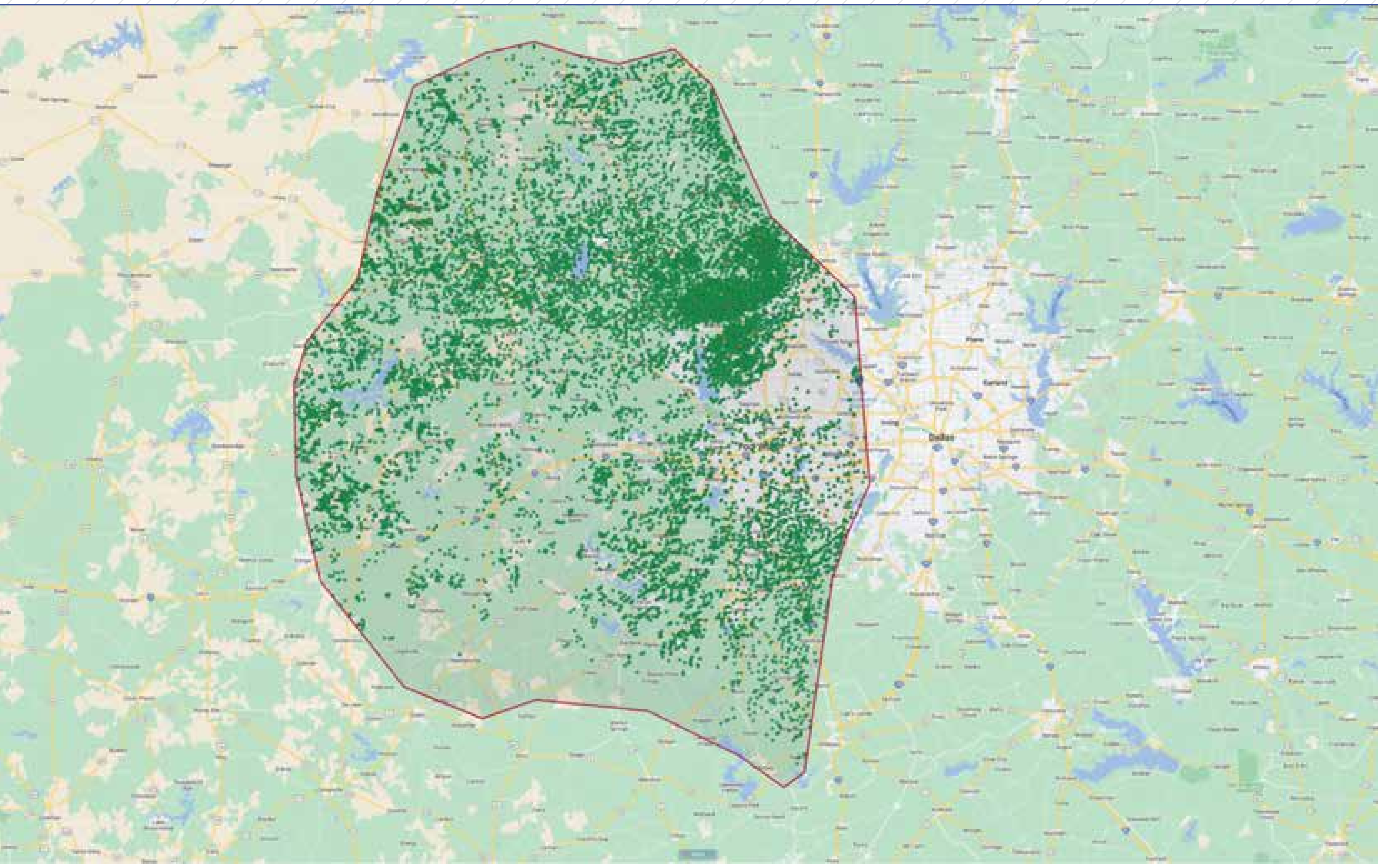

CHESAPEAKE ENERGY CORP.

During the company's third-quarter 2022 earnings call, chairman and CEO Jay Allison shared that Comstock had the highest quarterly results ever achieved in its history thanks to the increased sale of shale natural gas. He added that a new well in Robertson County in the western region contributed to the company's success and that the company also drilled a second well.

"We've also drilled our second well in this region, near the Circle M called the KC Block [ph], which was successfully drilled and completed, and is expected to be turned to sales this month," Allison said.

As the largest private producer in the Haynesville, Aethon produced 313,492 boe/d of its total 330,601 boe/d from the basin. Additionally, 19 bbl/d of its total 402 bbl/d of oil production and 1.88 Bcf/d of its total 1.98 Bcf/d of natural gas production came from the Haynesville.

The second private company to emerge as a Haynesville top player, Rockcliff production totaled 205,997 boe/d in the Haynesville in the first half of the year, according to Enverus. Thirty-six bbl/d of its 347 bbl/d total oil production in the half came from the East Texas basin, as did 1.24 Bcf/d of its 1. 32 Bcf/d total natural gas production. ■



Source: Rextag

The Barnett Revitalizes

BY DEON DAUGHERTY | EDITOR-IN-CHIEF

In North Texas' Barnett Shale play, older wells are being rejuvenating and recompleted with modern fracturing technology. The net effect is boosting E&P volumes and midstream opportunities.

The gas play's top producer, ***BKV Corp.***, a private operator based in Denver, has successfully implemented refracturing at more than 200 wells in the Barnett Shale.

Researchers at East Daley Analytics said that although the basin was previously one in decline, the Barnett's production could stabilize as a result of well refracs—provided natural gas prices remain at or above the economic threshold to maintain the programs.

A successful refrack can boost output from an old well near its original initial production (IP) rate, though production tends to fall off quickly, the analysts said.

And in the Barnett, home to at least 16,000 horizontal wells, the oldest of which is 40 years old, that technology is crucial.

BKV already stood as the top producer in the grandfatherly Barnett after its 2020 entry into Texas, following the purchase of assets from Devon Energy for up to $830 million, including contingency fees.

But the firm supersized in July with the purchase, led by CEO Chris Kalnin, of upstream and midstream infrastructure from subsidiaries of Exxon Mobil Corp. for $750 million. The transaction included Exxon Mobil subsidiary XTO Energy Inc.'s upstream assets in Tarrant, Johnson and Parker counties, Texas, as well as Barnett Gathering LLC's 750 miles of gathering pipelines, compression and midstream processing.

Kalnin told Hart Energy this summer that he intends to make BKV a Barnett consolidator.

"That's the strategy, right? You've got to be the biggest dog in the play and certainly that's where we're going on the upstream side," he said.

BKV is eyeing additional acquisitions among the

Barnett's "long in the tooth" upstream producers.

"I could see a billion dollars going into that business, upstream," he said.

BKV's Barnett thesis relies on four decades and 7,000 wells worth of data, jumpstarting first-generation wellbores with cost-efficient refracs.

BKV on Nov. 18 filed paperwork to conduct an initial public offering, following more than $2 billion in acquisitions in the past two years.The company averages daily production of 864 MMcfe/d, consisting of approximately 79% natural gas and approximately 21% NGL, according to a filing with the Securities and Exchange Commission.

NEW TECHNOLOGY

TotalEnergies has been exploring and producing the U.S. since 1957. Its onshore business in the Barnett, called TEEP Barnett, was founded in 2016. From its headquarters in Fort Worth, Texas, the firm is focused on developing natural gas wells in urban areas.

In 2009, TotalEnergies acquired a 25% stake in a Barnett partnership. Its transaction in 2016 provided the firm with more than 2,800 wells, 750 padsites and over 200,000 mineral leases.

The Paris-based supermajor has plans to deploy new technology that will eliminate about 7,000 tons of methane emissions each year in the play by 2024. During a successful pilot project at the Barnett site in March 2021, Qnergy's technology proved to be reliable, simple to install and easy to operate, allowing to eliminate up to 98% of the methane venting emissions related to instruments using natural gas.

Following successful additional tests, TotalEnergies has decided to install this new technology by deploying 100 units on the Barnett field in 2021 and 2022.

"To fully play its role in the energy transition, notably as a substitute for coal, the integrated natural gas chain must limit its methane emissions as much as possible," said Carole Le Gall, senior vice president of sustainability and climate at TotalEnergies.

"We have successfully demonstrated the effectiveness of Qnergy's technology on the Barnett field. By immediately deploying this technology on our U.S. onshore operations, we are actively demonstrating our commitment to reducing our own methane emissions by 20% between 2020 and 2025."

THE PRIVATES

The next highest grossing producers in the Barnett are private operators: ***Bedrock Energy Partners*** in Houston, ***United Production Partners*** (UPP) in Houston and ***Crescent Energy Co.***, also in Houston.

Bedrock is focused primarily on the acquisition and exploitation of mature onshore assets. It was founded by CEO Will Todd and COO Spencer Cox in 2018. The firm operates gas-weighted properties in seven North Texas counties.

"It's difficult to be a small operator with a large well count," Todd told Hart Energy, "but we overcame it by creating a fun culture where data and the accessibility to that data matters. … Every well matters and every person matters. If you set things up correctly, you give yourself a chance to make the right decision for both."

UPP was created in 2019 through the combination of long-life assets in Tarrant, Johnson and Sutton counties. Most of the firm's wells are connected to electronic measurement equipment to enable constant monitoring of wells and facilities. UPP currently operates about 1,095 wells across 99,000 net acres.

Crescent City is managed by private-equity group KKR's energy real estate team.

"We are excited about the potential for continued value creation as we expand Crescent Energy. Executing our strategy over the last decade, we've built a unique platform with financial strength, asset scale and flexibility that we believe is well-positioned to be a leader in a consolidating market," said CEO David Rockecharlie.

The firm joined the Oil & Gas Methane Partnership 2.1 Initiative in February.

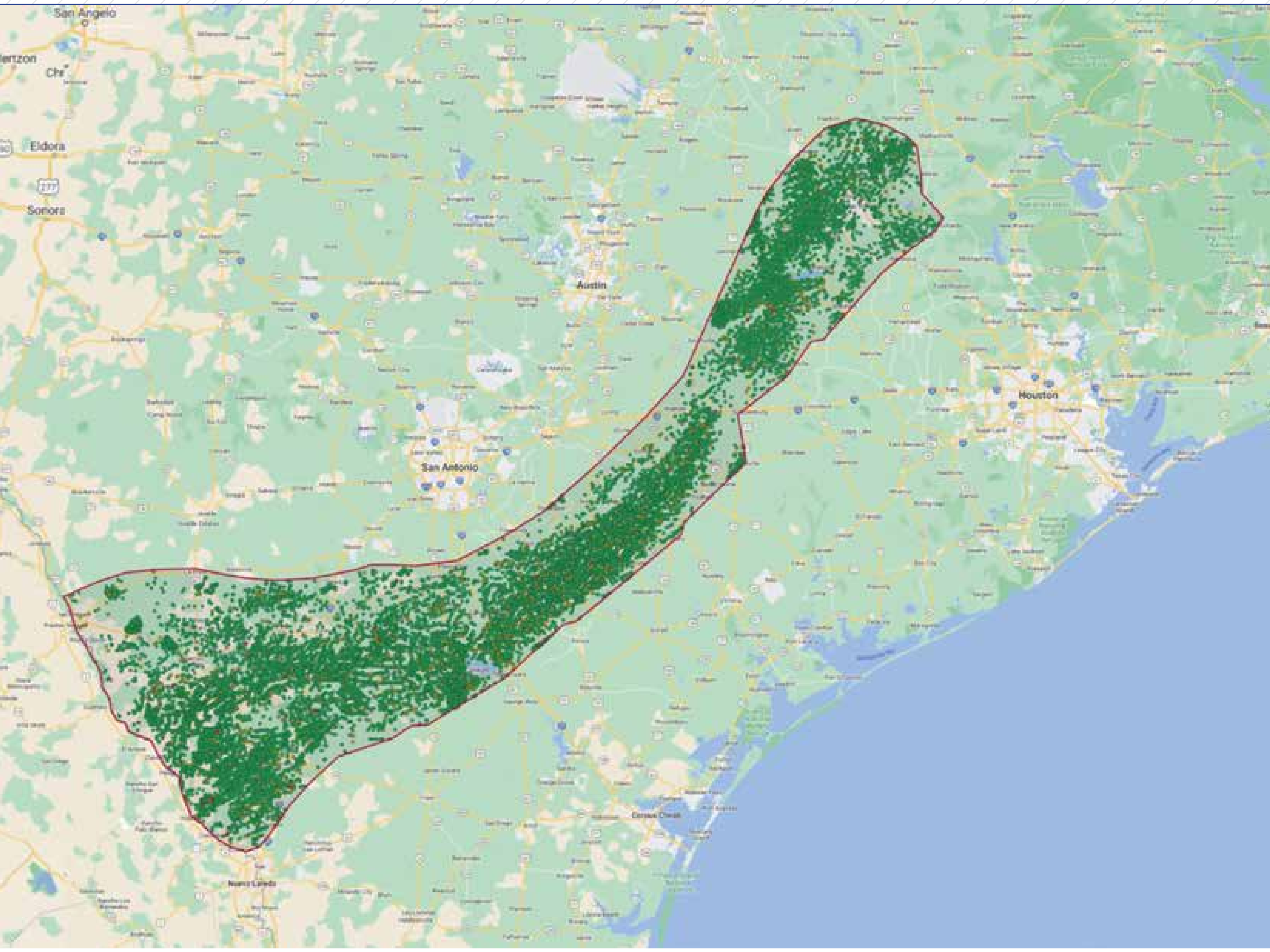
"Crescent Energy is meeting today's energy needs while focusing on a cleaner tomorrow," he said. ■

Top Barnett Producers
(1H 2022 Average)

Rank	Company	boe/d	bbl/d	Mcf/d
1	BKV CORP.	110,170	392	658,615
2	TOTALENERGIES	64,719	6	388,258
3	BEDROCK ENERGY PARTNERS	24,903	289	147,673
4	UPP OPERATING	19,238	21	115,283
5	CRESCENT ENERGY CO.	18,059	45	108,074

Source: Enverus

BKV CORP.



Source: Rextag

The Eagle Ford Soars

BY DEON DAUGHERTY | EDITOR-IN-CHIEF

Often cast in the shadow of the mighty Permian Basin, the South Texas Eagle Ford Shale began showing signs of a resurgence in 2022.

By proximity alone, the Eagle Ford offers several advantages for potential investors, researchers at East Daley Analytics said.

"Producers in South Texas are closer to Gulf Coast industrial demand centers and export terminals, resulting in higher realized prices for crude oil, natural gas and NGL. And unlike the Permian, producers in the Eagle Ford aren't plagued by significant takeaway constraints for natural gas," analysts said in late November.

Indeed, the Eagle Ford was adding rigs in November, peaking at 97 by Dec. 1, with a gain of five rigs added across four weeks. That figure represents the highest count since March 2019.

By contrast, the Permian in West Texas and eastern New Mexico shed 23 rigs during the same period.

But it's more than players in the basin getting busier that suggests a revitalization is in play.

The third largest player by volume in the Eagle Ford, ***Marathon Oil Corp.***, acquired basin pure-play Ensign Natural Resources in a $3 billion cash deal in November. The transaction included assets comprising 130,000 net acres, more than 600 undrilled locations and 67,000 net boe/d of production spanning Live Oak, Bee, Karnes and Dewitt counties.

Marathon is hardly the only large independent taking notice of what's happening in South Texas.

Its announcement followed the September closing of Devon Energy Corp.'s purchase of Validus Energy for $1.8 billion. Meanwhile, Chesapeake Energy Corp. is shopping its Eagle Ford assets in a deal that Enverus said in July could fetch between $4.6 billion and $5.9 billion, based on strip prices at the time.

EAGLE FORD ACTIVITY

Dealmakers appear to be excited at the potential sale of several private companies in the Eagle Ford. Possible targets include BlackBrush Oil & Gas LLC, GulfTex Energy LLC and 1776 Energy Operators LLC among others.

Marathon's is the second deal in the Eagle Ford to potentially set the stage for buyers' willingness to pay more for potential upside.

During Marathon Oil's Nov. 3 earnings call, CEO Lee Tillman said the Ensign deal found a "sweet spot" between immediate cash flow accretion and inventory that competes for capital within the company's portfolio.

"On the value component, when we think about the valuation, I would say in general we would kind of put it almost 50:50 between PDP and future undrilled development opportunities," he said. "That was one of the unique opportunities about the deal."

The largest producer in the Eagle Ford, ***ConocoPhillips Co.***, was one of the first companies to invest intensively in the liquids-rich play. In 2009, ConocoPhillips began exploring its development potential and by the end of 2021, it held about 200,000 net leasehold and mineral acres, mostly in DeWitt, Karnes and Live Oak counties. ConocoPhillips has drilled more than 1,600 wells in the field through the years, representing 40% of its potential drilling inventory, and built infrastructure capacity with central facilities and pipelines, with an emphasis on liquids value optimization through the operation of two condensate processing facilities, according to company data. Its current focus is on full-field development in the Eagle Ford, its second-most prolific unconventional resource holding.

At ***EOG Resources Inc.***, the second-most prodigious producer in the play, executives have pointed out the financial benefits and efficiencies that come from steady work in a basin.

"We started drilling Eagle Ford wells, 8,500-foot laterals at $12 million a well. We're down to $4 million or $5 million a well at this point in time," Ken Boedeker, EOG's executive vice president for E&P, said in November during the BofA Securities Global Energy Conference in November. "That's that continual improvement."

Boedeker also said the location of EOG's assets in the Eagle Ford present new opportunities in the wake of global desire for LNG.

"We have a significant amount of flexibility on what we can take with LNG," he said. "The majority of our gas out of the Eagle Ford ... obviously goes into [Corpus Christi]. We do have an increased exposure to LNG. We have 140 million a day now exposed to international pricing with LNG. And that goes up to 420 million a day in 2025 with Cheniere Stage 3 coming on. There's an additional 300 that's linked to Houston Ship Channel, just to make sure there aren't any differentials at that point in time."

But it's not just the large public indies playing in the Eagle Ford. Rounding out the top five operators is ***Verdun Oil Co.*** and ***SilverBow Resources***, two private producers.

Verdun owns more than 177,000 net mineral acres in the trend across Dimmit, La Salle, Frio, McMullen, Live Oak, Atascosa, Karnes, Gonzales and DeWitt counties. As of April 2022, the company was operating more than 1,200 wells in the region.

SilverBow upped the ante in the Eagle Ford during the spring of 2022. The Houston-based firm closed its cash-and-stock acquisition valued at roughly $71 million of SandPoint Operating LLC, marking the company's latest purchase in the Eagle Ford Shale. It was the fourth expansion deal for SilverBow's footprint in less than a year. ■

Top Eagle Ford Producers
(1H 2022 Average)

Rank	Company	boe/d	bbl/d	Mcf/d
1	CONOCOPHILLIPS	77,387	48,918	170,813
2	EOG RESOURCES	25,014	13,989	66,150
3	MARATHON	19,077	12,608	38,811
4	VERDUN OIL CO.	17,916	11,734	37,091
5	SILVERBOW RESOURCES	14,064	340	82,343

Source: Enverus

TOM FOX

Bakken EOR Trial Increased Output by 25%

Pilot project shows alternating produced gas with water/surfactant EOR mix boosts production and cuts costs in the Bakken Shale.

BY PAUL WISEMAN | CONTRIBUTING EDITOR

Much as the development of hydraulic fracturing enabled the shale revolution, new EOR techniques are poised to revitalize those quickly-depleting wells.

Shale's tightness renders useless traditional EOR methods like waterflood and CO_2 flood, so each well must be treated separately. According to Gordon Pospisil, development adviser for Denver-based Liberty Resources II LLC, implementing EOR for these wells is vital because producers can only reach about 6% of a field's capacity with the approach he called "drill, frac and drain."

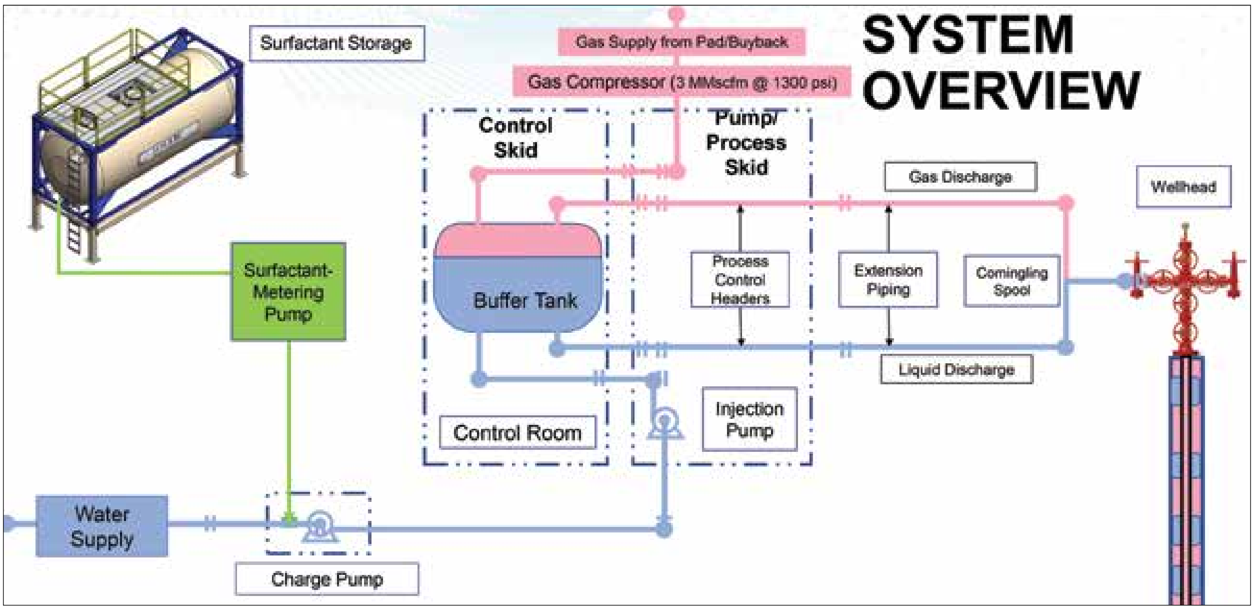
Liberty Resources II produces about 10,000 boe/d from wells in the Bakken and Three Forks basins of North Dakota.

The best shale wells have already been drilled, so to continue to increase—or even maintain—oil production, new development must be accompanied by enhancing existing wells. EOR is also much more cost-effective.

About 10 years ago, producers began developing a well-by-well EOR system known as Huff n' Puff (HnP). With HnP, the operator injects a gas, typically site-produced natural gas, into an existing well at high pressure, then lets the well "soak" for a few days before returning it to production.

While this has proven beneficial, it requires extremely high pressures involving large and expensive compressors, and the actual production boosts are small. Looking to reduce both the cost and safety issues associated with high pressures while further enhancing production, Pospisil and others teamed up for a Bakken test in Mountrail County, N.D., in 2021. Their method involved alternating the gas injection with water, or water alternating gas (WAG).

The pilot was designed, permitted and conducted by Liberty in partnership with the Energy & Environmental Research Center (EERC) and EOR ETC. According to the abstract of a paper authored by Pospisil and a team of experts, "The objectives were to 1. repressure the reservoir above the minimum miscibility pressure



Source: Liberty Resources II LLC

Instead of using high-pressure pumps to inject just natural gas into the Huff n' Puff EOR method for tight Bakken shales, this system alternated gas with surfactant-laden water, known as water alternating gas, or WAG.

CONOCOPHILLIPS CO.

(MMP); 2. prove the concept of using water co-injection to build hydrostatic pressure to inject gas at low surface pressures and to improve gas conformance; and 3. use a surfactant to enhance oil recovery through rock wettability alteration and interfacial tension reduction."

Because the Bakken formation has more interwell communication than some shale plays, maintaining each well's pressure required finding a way to contain the gas near the treated well. "We were focusing on using water injection as well as gas injection to build pressure, and include the conformance along the wellbore," he said.

Water's low compressibility allowed pressure to build quickly compared to injecting just gas. This was designed to reduce the surface horsepower required, mitigate costs and improve safety. The water also provided a vehicle for inserting surfactant.

The test was on a single well. Full commercialization involves an ongoing cycle starting with one well in the shutdown/injection/restart process, then moving across the field one well at a time.

THE PROCESS

"We essentially met all our objectives," Pospisil said. "We were able to inject gas and water to target volumes and build pressure in the reservoir, adding energy. Then we saw an oil response when we returned the well to production."

They also contained the gas and water in the drill spacing unit, eliminating concerns about migrating off-lease or interacting with nearby wells.

"We were able to inject gas and water to target volumes and build pressure in the reservoir, adding energy. Then we saw an oil response when we returned the well to production."

—GORDON POSPISIL, Liberty Resources II LLC

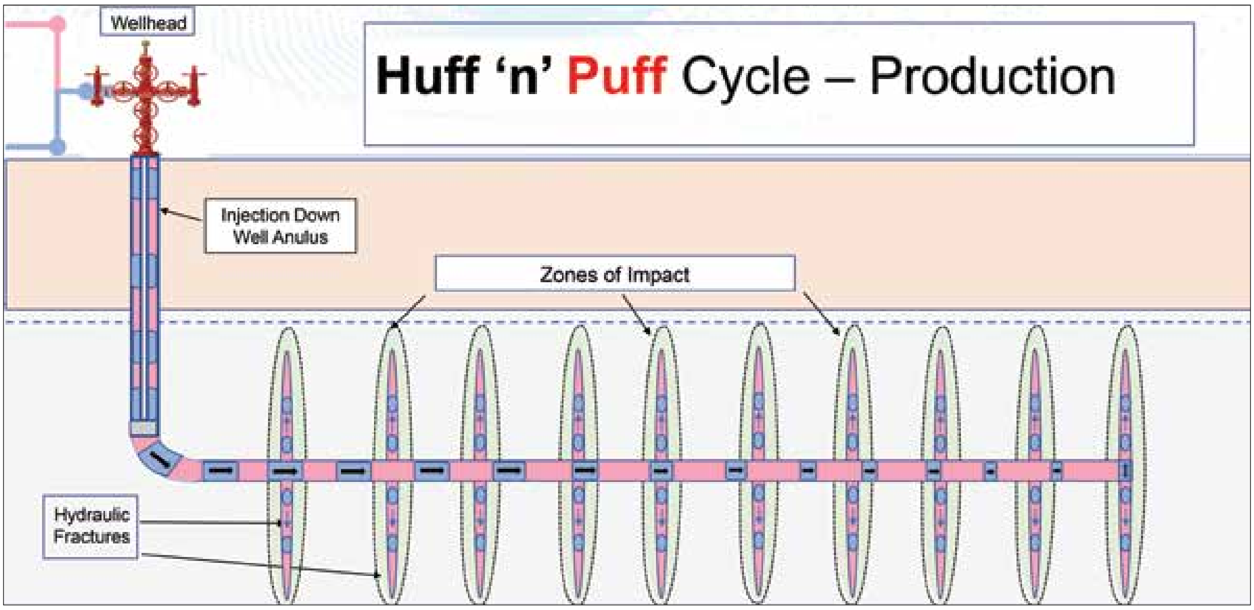
In addition, they observed "much higher efficiencies in regards to oil response we saw versus the amount of gas we injected." Those increases were compared to previous field research, by other producers, which used very high gas injection rates instead of WAG.

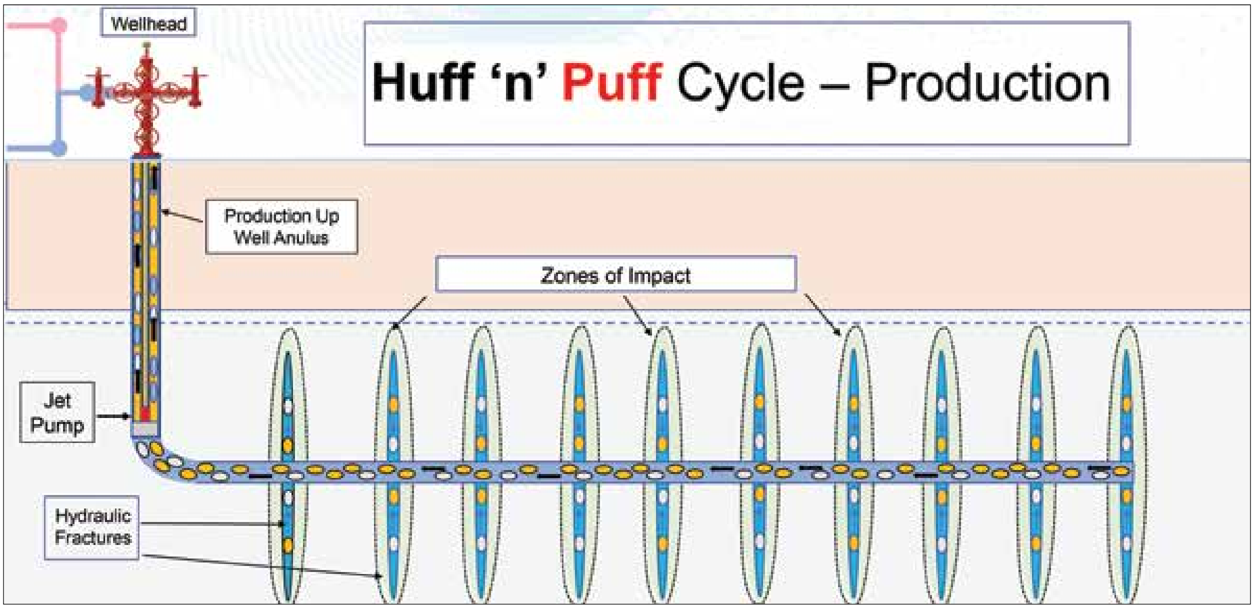
RESULTS: MORE OIL, LESS COST

"We were able to generate about 8,000 barrels of incremental oil after the injection of this single slug. We were able to do that with about 4 to 5 Mcf per incremental barrel," he said, and that this was an increase of about 25% over the previous production rate.

Eagle Ford projects by other entities required two to five times as much gas, Pospisil noted.

The key to the test was EOR ETC's unit that provided for





Source: Liberty Resources II LLC

These graphics compare injection with production cycles in the WAG Huff n' Puff system.

continuous injection of water alternating with gas.

"This allowed us to rapidly switch between water and gas injection," removing delays involved in disconnecting and reconnecting gas and water sources, he said. WAG allowed them to use a much smaller and less costly compressor.

IMPLEMENTATION

Pospisil and the team are pleased with the results, but some improvements are needed before it is scalable. One would be making it viable using produced water instead of fresh water, which they used in the tests. That change would make the solution more cost effective.

Once the procedure is commercially available, the producer would do the WAG injection for seven days, then produce the well for 30 days. The injection equipment would continuously rotate from one well to the next.

"You might repeat five to 10 cycles on one pad before moving to the next," stopping once the returns began to diminish, he said.

That could effectively raise the well's total production by 80% to 100%, he noted. And it delivers ESG benefits, he added.

"It's a great ESG benefit," Pospisil said, "from the standpoint of less surface impact, better utilization of the gas, water and all the infrastructure. We see that as part of the future." ■

Where Carbon Capture and Storage Fits Into the Fuel Future

Companies from Chevron Corp. to Oxy dive head-first into the carbon capture market and the potentially profitable CO_2 industry.

BY RYAN RAY | CONTRIBUTING EDITOR

Billionaire Bill Gates' recent book, "How to Avoid a Climate Disaster," suggests that the world should aim for a "zero" carbon policy. Gates understands it is impossible to prevent the industrialized world from producing CO_2, as even the act of capturing the gas creates more of it. Still, according to Gates, the world should strive to reach a preindustrial level when "the earth's carbon cycle was probably roughly in balance." If the world is to get to a "near net zero," as Gates suggests we should, there is little doubt that companies will have to do more.

He's not alone in his quest to reach a near net zero. Fellow billionaire Elon Musk is also in the carbon capture industry. In 2021, Musk announced a $100 million prize called XPRIZE, aimed at "fighting climate change and rebalancing Earth's carbon cycle."

So far, Musk's group has awarded $15 million and will award the rest in 2025.

Both Gates and Musk's rhetoric are in line with the Paris Agreement, which calls "to reach global peaking of greenhouse-gas emissions as soon as possible to achieve a climate neutral world by mid-century."

It's not just billionaires and governments backing the near net-zero initiative. Oil and gas companies are rolling out new carbon capture and storage (CCS) operations worldwide.

Earlier this year, Exxon Mobil Corp. along with CNOOC and Shell Plc announced they had signed a memorandum of understanding to "evaluate the potential for a world-scale carbon capture and storage project to reduce greenhouse-gas emissions at the Dayawan Petrochemical Industrial Park in Huizhou, Guangdong Province, China."

Per the announcement, the project could capture up to 10 million metric tons (MMmt) of CO_2 annually. The progress is only a small percentage of the estimated 36.4 Bmt emitted yearly. Even if Exxon Mobil's effort in China will not move the needle, it is one step in the global plan to reduce emissions. With a similar strategy deployed in the U.S., Exxon Mobil and other oil and gas companies could play a key role in eliminating U.S. energy-related emissions, which, per the Energy Information Administration, average about 5.13 MMmt.

"This new low-carbon energy project will help us leverage those strengths for the next chapter of the energy transition."

—DAVE LAWLER, bp America Inc.

Like any daunting task, one company cannot do it all. According to the Global CCS Institute (GCCSI), only 30 commercial facilities are capturing and injecting CO_2 globally, with 153 in development. Although that number may seem low, during the past 12 months alone new facilities brought online represent a 44% increase in carbon catching capacity.

THE ENERGY CAPITAL

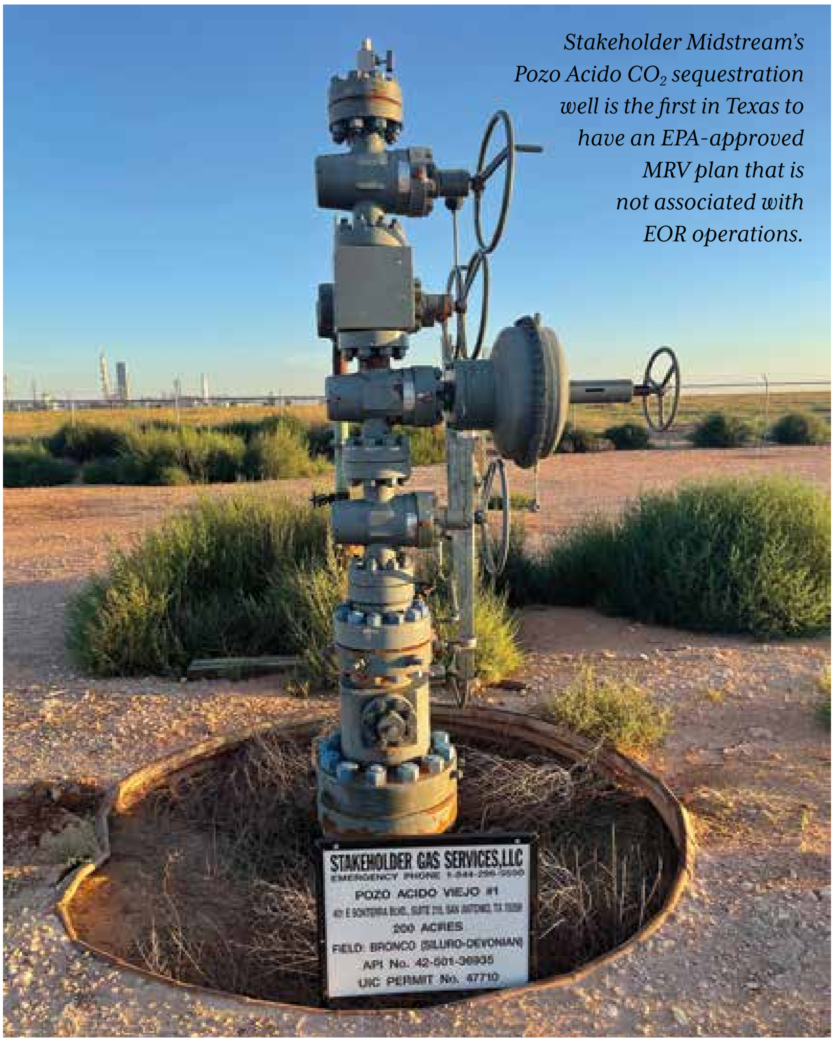
It should be no surprise that Houston, the energy capital of the world, is the home of a significant CCS initiative. Some 14 companies, including Exxon Mobil, Chevron Corp., Marathon Oil Corp., Phillips 66 Co. and others, are evaluating how to best implement proven CCS technologies near Houston.

If successful, these efforts could safely store up to 50 mt of CO_2 by 2030 and 100 mt by 2040, according to Exxon Mobil.

Additionally, bp Plc and Linde plan to store 15 mt of CO_2 annually by 2026 in the greater Houston area. Under this partnership, Linde will provide the proprietary technology to capture and compress, and bp will leverage its trading and shipping unit to gain the permits required for permanent sequestration.

Speaking on the partnership, Dave Lawler, chairman and president of bp America Inc., said, "The energy expertise in Texas and strong supply chains have been generations in the making. This new low-carbon energy project will help us leverage those strengths for the next chapter of the energy transition. In particular, it can help decarbonize hard-to-abate industries for the greatest potential impact on emissions while protecting jobs. bp is proud to support this project as we continue delivering on our own strategy and net-zero ambition."

If this project is successful, both companies have indicated that similar projects could be done elsewhere in the U.S.



Stakeholder Midstream's Pozo Acido CO_2 sequestration well is the first in Texas to have an EPA-approved MRV plan that is not associated with EOR operations.

STAKEHOLDER MIDSTREAM

MONTEREY SHALE

Chevron announced a new project at its San Joaquin Valley, Calif., facility in May 2022 through its Chevron New Energies Division.

Chevron sees this as beneficial to the community in multiple ways.

"As Chevron advances to a lower-carbon future, we're identifying ways to advance our operations as well, so we can continue to provide local jobs, support the local economy, and generate local government revenue that supports critical community services," said Molly Laegeler, vice president, San Joaquin Valley, Chevron. "We are excited about this Chevron New Energies project and fostering continued collaboration with local regulators throughout this process, not only to position the region to benefit from these lower carbon solutions, but that we continue to protect people and the environment. We believe this project has the potential to benefit the region on many levels and that Kern County is an ideal location for carbon capture and storage."

The project in Kern County has received local support from Kern Economic Development Corp. president and CEO Richard Chapman.

"We have a long history of working with Chevron and have appreciated their significant involvement in our community and the role they have played in Kern County," Chapman said. "We are excited to see their commitment to lowering the carbon footprint of their local operations and look forward to seeing the innovation and technology they plan to deploy. These efforts aim to ensure job security and workforce development opportunities and maintain the quality of life we enjoy here."

California Sen. Anna Caballero also openly backed the project. "As we enter our hottest time of the year, we need to be sure we have enough energy to prevent brownouts and blackouts," she said. "This project is designed to serve a dual purpose: ensure we have electricity when we need it and help provide climate action for our Central Valley and California."

PROGRESS IN THE PERMIAN

In August 2022, Occidental Petroleum Corp. (Oxy) and its subsidiary, 1PointFive, announced plans to create their first large-scale direct air capture (DAC) plant, which will be built in Ector County, Texas.

Per the announcement, the plant should be operational in late 2024 and would be the largest DAC plan in the world. Oxy plans to capture 550,000 mt of CO_2 annually. The plant can also expand up to 1 mt annually. 1PointFive has plans to deploy 70 DAC facilities worldwide by 2035, based on current compliance and market conditions.

This aligns with what Oxy executives told analysts on a March 23 conference call. CEO Vikki Hollub said President Joe Biden's 2021 trillion infrastructure bill and the state of the voluntary and involuntary carbon market allowed the company to pursue this path.

Oxy's strategy has expansion beyond the Permian Basin in mind. CFO Robert Peterson said, "Sequestration hubs, which will be located in the U.S., support our direct air capture and point source capture development by serving as an accessible location for the safe and economical storage of CO_2 in saline formations."

DAC is just one of the methods companies are exploring. In September 2022, Stakeholder Midstream announced it received approval from the Environmental Protection Agency (EPA) for its plan to sequester CO_2 by injecting it into the company's Pozo Acido well located near the Texas-New Mexico border.

This plan would allow Stakeholder Midstream and companies that contract with Stakeholder to sequester the CO_2 in the aforementioned Pozo Acido well permanently. The business here is not reselling but taking advantage of the 45Q tax credit.

Like Oxy, Stakeholder Midstream believes the market is expanding.

"Carbon and emissions management is an integral focus and business segment for our company," said Stakeholder Midstream chief commercial officer Brett Baker. "We believe that by offering these services to third parties, including other gas processing plants in the Permian region and beyond, we can provide an environmentally responsible solution for CO_2 emitters to reduce the carbon intensity of their oil and gas operations and to meet their ESG goals. Our vision is to become one of the leading carbon solutions providers in the United States by helping producers and like-minded midstream companies across multiple basins decarbonize their operations."

Stakeholder has been strategic in selecting its primary location. According to the company, the well is adjacent to the Kinder Morgan Cortez Pipeline, which can transport 1.5 Bcf/d of CO_2. The nearby Oxy Bravo and Sheep Mountain, Kinder Morgan Central Basin and Trinity CO_2 pipelines could also prove valuable to the company's strategy.

As partnerships are formed and tax credits are issued, companies in the Permian will look to follow Oxy's model or possibly ship their CO_2 to Stakeholder to be sequestered. As long as the market stays competitive, other Permian companies will look for ways to monetize CO_2, whether its own or its competitors.

SEQUESTERING IN THE BAKKEN

In the Bakken Shale play, Summit Carbon Solutions is getting support from Continental Resources Inc. to the tune of $250 million during the next two years.

Summit's plans expand beyond just the Bakken, though. As it is currently planned, Summit would gather CO_2 from ethanol plants and other industrial sources from Iowa, Nebraska, Minnesota, North Dakota and South Dakota. After being collected by a pipeline system, the CO_2 would be stored in the Bakken permanently.

According to North Dakota Gov. Doug Burgum, the geology in the Bakken has considerable potential "because of the incredible geology that we have that would allow us to store all the nation's CO_2 for the next 50 years."

"Carbon and emissions management is an integral focus and business segment for our company."

—**BRETT BAKER,** Stakeholder Midstream

It's not just money that Continental is bringing to the table. As one of the leading companies in the Bakken formation, Continental will be able to provide valuable expertise in directing where best to inject and sequester the CO_2.

There is another player in the Bakken, namely Red Trail Energy. In June 2022, the company announced that it officially began the process of CCS at its facility near Richardton, N.D.

Red Trail Energy CEO Gerald Bacmeier, who spoke on the launch, said, "After six years of research, development and investment Red Trail Energy is celebrating this historic moment in North Dakota and United States history of becoming the first facility permitted under state primacy to capture and store CO_2. Our success establishes a trail for other industries in the state to follow."

According to the GCCSI, Indiana, West Virginia and Wyoming have enacted legislation or policies covering CO_2 storage. It also noted that Wyoming and North Dakota "have primacy for issuing permits under the Underground Injection Control Program, which covers injection wells for geologic storage of CO_2."

In regards to permitting and the Red Trail CCS project, Department of Mineral Resources director Lynn Helms said, "North Dakota regulators and policymakers have long seen the importance of creating a regulatory framework that complies with the federal rules while managing the pore space resource for the benefit of North Dakota property owners. Receiving primacy from the EPA paved the way for projects like this one to become operational in the state, and this is a large step toward making North Dakota a leader in carbon neutrality and a showcase for the rest of the world on how to treat carbon."

SHALE AND CCS

The Shale Revolution changed the oil and gas industry forever. Now, as the world looks for the best way to capture carbon, there is little doubt whether it is permanent sequestering or capturing to be repurposed. The future of carbon capturing technology will be developed and implemented across the shale plays. Companies utilizing prime market conditions, favorable permitting and tax credits will no doubt find new and creative ways to monetize the CO_2 industry. ■

Argentina's Vaca Muerta Aspires to Permian 2.0

The Vaca Muerta Shale is actively engaged in large-scale hydraulic fracking projects and the most likely to replicate the West Texas success story.

BY PIETRO D. PITTS | INTERNATIONAL MANAGING EDITOR

The North American fracking boom seemingly converted a number of U.S. shale plays, especially the Permian Basin, into household names across the global energy patch due to the use of a controversial, but effective, drilling technique.

The U.S. shale boom has the energy sector and world leaders talking about hydraulic fracturing as some miracle life-saving drug due to its ability to boost non-conventional production while contributing to energy security and LNG exports. That discussion is front and center in numerous countries across the Americas from Argentina to Colombia and Mexico. However, in Argentina, the discussion radiates the most from oil and gas C-suite executives and petroleum engineers to the presidency of the South American country.

While the question at the moment in the U.K. and other nations is to frac or not to frac, that's not the case in Argentina where the question government officials are asking companies is how to frac more to boost oil and gas production.

Argentina has estimated technically recoverable shale gas resources of 802 Tcf, according to the U.S. Energy Information Administration (EIA), ranking the country only second to China with its massive 1,115 Tcf. The Vaca Muerta is the main drilling target for companies and home to 308 Tcf, thus putting it on par with the Permian, which holds roughly 297 Tcf, according to Rystad Energy.

Situated in Argentina's Neuquen Basin, the Vaca Muerta is located far from the country's principal consumption centers, such as Buenos Aires. This is good socially and bad logistically as the Vaca Muerta holds 53% of the basin's resources and 38% of Argentina's resources.

REVIVING THE 'DEAD COW'

Headwinds from political uncertainties, infrastructure bottlenecks and a slow development pace continue to hamper the hopes of companies such as Pan American Energy, Tecpetrol, TotalEnergies and state-owned YPF, as well as government efforts, to attract interest to revive the "dead cow" shale play.

The major headwind remains above ground and relates to political uncertainties that seem to never vanish. This has impacted financing and investments in production, infrastructure and pipeline takeaway capacity. Smaller headwinds relate to an unstable regulatory framework, frac fleet availability and the need for incremental rigs, energy sector pundits argue.

From financial and economic perspectives, mass development of the Vaca Muerta has the potential to significantly boost oil and gas production and produce major improvements in the country's trade balance, according to YPF, the country's largest oil and gas producer and the largest shale producer outside North America.

Beyond the revenue boost to companies and government, ongoing development of the Vaca Muerta can reduce the need to import energy, especially LNG and piped gas from Bolivia. Further development could open

Vaca Muerta and U.S. Formations Comparison

	Total Organic Content (%)	Thickness (m)	Depth (m)	Area (km2)	Reservoir pressure (psi)
Vaca Muerta	3.0-10.0	50-450	1,700-3,500	30,000	6,500-9,500
Delaware (Permian)	1.0-8.0	30-1,200	60-30,000	26,000	7,500-9,000
Midland (Permian)	1.0-9.0	45-450	700-2,300	36,300	2,000-5,500
Eagle Ford (oil window)	3.0-5.0	30-100	1,200-4,270	5,200	4,500-8,500
Bakken	4.0-20.0	30-40	1,300-3,000	51,800	2,200-4,600
Barnett	4.0-5.0	60-90	1,700-3,000	18,000	3,000-4,000
Haynesville	0.5-4.0	60-90	3,200-4,200	23,300	7,000-12,000

Source: McKinsey & Co.

Key geological data

Least desirable — Most desirable

The Vaca Muerta's geology is comparable to the main formations in the U.S., particularly the Permian Basin.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SHUTTERSTOCK/SOBREVOLANDO PATAGONIA

the door for Argentina to become a sustainable year-long exporter of LNG, an idea the country has flirted with for some time now.

Amid the country-specific uncertainties and Russia's war in Ukraine, which has peaked interest again in LNG, the Argentine government is eyeing small LNG projects of roughly 1 million tons per annum over the short to near term. The government does not expect a serious sizable LNG project of scale to emerge until around 2030, Neuquen Province energy minister Alejandro Monteiro told Hart Energy in early October in Houston.

SLOW DEVELOPMENT PACE

The slow development pace in the Vaca Muerta is a telltale sign of just how far Argentina needs to go to achieve sustained double-digit production growth over the near to medium term or to aspire to something that could be dubbed "Permian 2.0."

Argentina's unconventional oil and gas resources are the fourth-most and second-most abundant in the world, respectively, and overwhelmingly found in the Vaca Muerta, according to the EIA. The geology is comparable to key U.S. formations, in particular, the Permian and its sub-basins, the Delaware and Midland.

However, a look at the horizontal wells completed in the Permian compared to the Vaca Muerta in the early development years reveals a large contrast between the two shale plays.

The numbers of horizontal wells completed in the first six years of development in the Midland and Delaware were a whopping 3,275 and 4,211, respectively, with exponential year-over-year growth, according to Rystad's 2018 Vaca Muerta study. In contrast, the number of horizontal wells completed in the Vaca Muerta during the same six-year period numbered just 402.

While horizontal well data are one focal point, on a number of other fronts, the Vaca Muerta goes head-to-head with the best of the best U.S. shale formations. The shale play offers comparatively high productivity rates and technical breakeven prices of $36/bbl for oil and $1.60/MMBtu for gas—both in line with U.S. formations—while higher drilling costs are seemingly offset by higher well productivity, which translates into higher initial production peaks and longer, sustained production levels, McKinsey & Co. revealed in an October 2022 study.

Impressively, the Vaca Muerta is within the desired lighter range of crude oils and has low sulfur content (less than 0.5% compared to a typical 1% to 3%), while the formation's production processes have an oil carbon intensity of 15.8 kilograms (kg) of CO_2/boe, which is among the lowest carbon intensities for oil and gas operations worldwide and well below the global average of 23 kg CO_2/boe, according to McKinsey.

Argentina's oil and gas production is expected to grow in coming years as the country moves the number of rigs from about 30 to 70 during the next four to five years, according to the consultancy.

Argentina's oil and gas production between January and October averaged 577,000 bbl/d and 4.59 Bcf/d, according to Argentina's energy secretariat. By 2026, these figures could rise to between 1 MMbbl/d and 1.1 MMbbl/d and 5.65 Bcf/d to 6 Bcf/d, respectively, according to estimates from YPF. By 2032, these figures could climb further to 1.73 MMbbl/d and 6.36 Bcf/d, respectively, according to McKinsey's long-term forecasts.

The Vaca Muerta's charm is hard to overlook despite the country-specific uncertainties because it offers short-cycle opportunities to boost both oil and gas supply over the near-to-medium term, which would be good for companies, the Argentine government and global energy markets scrambling to cover the lost of gas molecules and oil barrels due to Vladimir Putin's aggressions in Ukraine.

For now, it appears the "dead cow" is far from dead, but it is not completely revived either. ■

Improving Completions Through Better Near-Wellbore Conditions Knowledge

Drill2Frac's FlowFX solution helps finetune completion designs by modeling parameters such as the number of perf clusters and length of stages.

JENNIFER PALLANICH | SENIOR EDITOR, TECHNOLOGY

A solid understanding of near-wellbore conditions is a key component for successful completions.

Operators could use trial and error to test completions effectiveness, but without understanding near-wellbore conditions,that is a costly and time-consuming approach. So, obtaining wellbore conditions using pre-existing data and simulating different completion designs is a better, noninvasive option, according to Drill2Frac.

The company developed its FlowFX near-wellbore fluid distribution solution over a period of years.

Kevin Wutherich, Drill2Frac CTO, started his career as a completions engineer and understands the importance of getting flows right.

"I realized early on that the near wellbore is where everything happens," he said. "If you can get what happens in the near wellbore right, then you can have a good effect on the rest of the job. You can't control what happens after the fluid leaves the wellbore, but you can change what's happening in the near wellbore."

Rock properties in the near wellbore can change foot-by-foot, he noted, meaning clusters can be placed in different types of rocks.

"If you can get what happens in the near wellbore right, then you can have a good effect on the rest of the job."

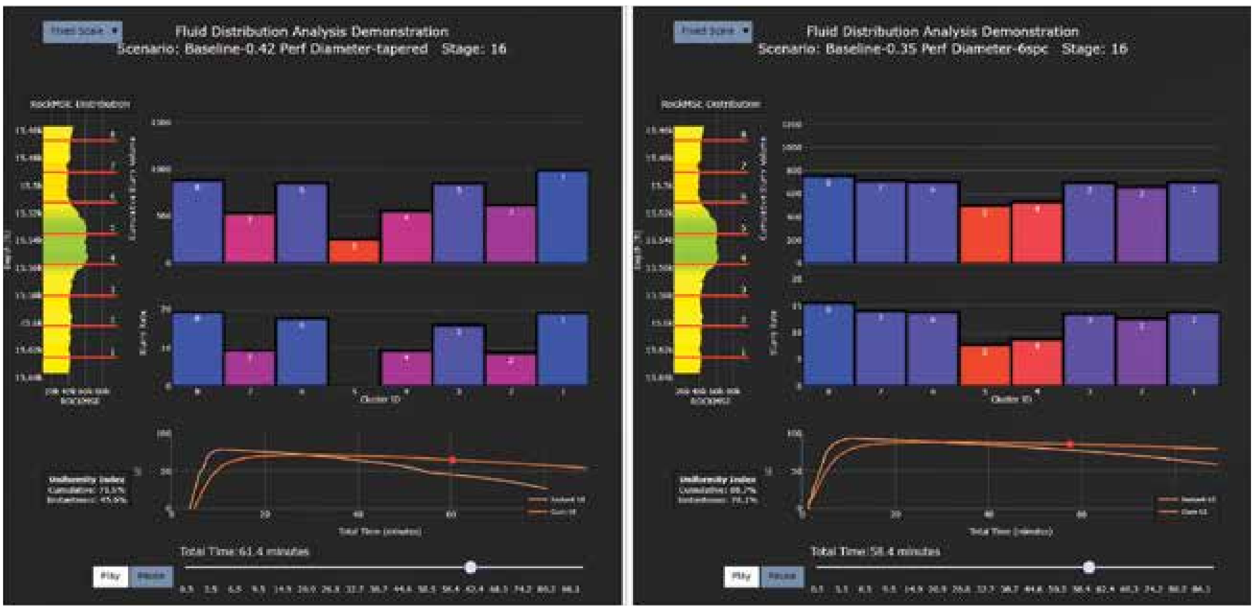
—KEVIN WUTHERICH, Drill2Frac

To adapt to the near wellbore, it is important to understand what the initial conditions are, he said.

"There have been models built to understand fracture efficiency, but they haven't been able to effectively take into account near-wellbore rock properties," Wutherich said.

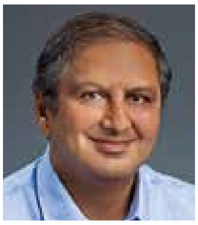
Between 2016 and 2019, Drill2Frac president Dharmesh Mehta said the company focused on improving the process it uses to characterize rock properties in the near wellbore, leveraging drilling data and other information operators had obtained, such as via downhole cameras or fiber optics.

The entire focus is to use data the customer already has instead of requiring them to collect new data, he said.



Source: Drill2Frac

The FlowFX simulation demonstration on the left shows how insufficient perforation friction allows intra-stage stress shadowing to dominate. However, when sufficient pressure drop is used, as shown on the right, a much better distribution occurs.



"Our entire focus is to use data the customer already has."

—DHARMESH MEHTA, Drill2Frac

But data alone is not enough, Mehta added.

"That left the last frontier, understanding things like erosion and stress-shadow models," he said.

Integrating those models with customer data was the next step.

With digital solutions for fluid distribution in place and the ability to detect depletion using data and processes, Drill2Frac's data and analytics help operators fine tune completion designs by modeling parameters such as number of perf clusters and length of stages, he said.

The result is a cloud-based solution designed as noninvasive in nature to help operators achieve more consistent and productive wells.

PLAYING WHAT-IF

FlowFX allows completion engineers to visualize frac plans and quickly simulate the effects of different designs, Mehta said.

It may seem reasonable to think that 1,000 lb of proppant pumped into eight clusters in a stage will distribute equally, he said. "The reality is that is not the case. You never get equal distribution."

As Mehta puts it, FlowFX provides a visualization of how the proppant is going into each cluster for each stage.

From there, it is possible to play what-if and learn what might happen if an element of the completion is tweaked, he said. All the physics and modeling happen behind the scenes, he said.

Customers can "turn the knobs" on the completion design to see how variables like number of stages, stage length, number of clusters per stage, shots per cluster, perf diameter, orientation of perfs, pump rates and the volume of proppants may affect the completion's effectiveness.

Mehta said it makes it easy for customers to understand the effects of the near-wellbore conditions.

"[It makes] that process simpler, easier and leverages the data you already have instead of collecting new data," he said.

Wutherich said the process makes it possible to model many different scenarios to show what they can expect to happen during fracturing with any modification, which is more cost-effective than trial and error.

"It's a model. It's not going to be perfect, but it's based on solid physics and data." So, it makes it possible to predict how changes in completion designs will affect fluid distribution along the wellbore, he said.

Instead of running operational trials on 50 completion designs, FlowFX can shortlist those designs to the five most likely to succeed, he said.

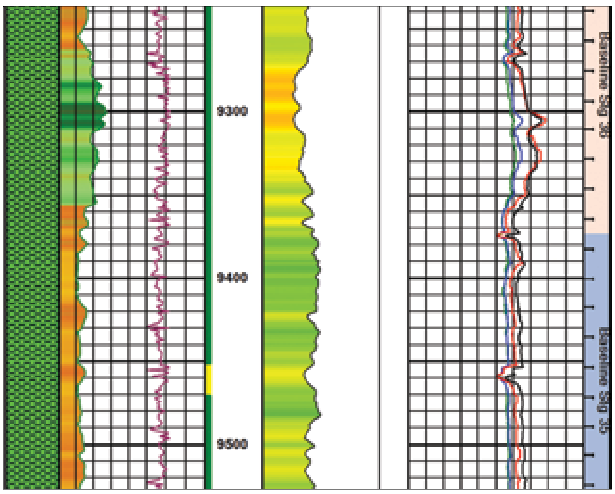
According to Wutherich, the model cannot take everything into account. Poor cement, for example, makes it hard to model what is going to happen because the cement is not fully controlling where the fluid will go.

Wutherich said Gordy Oil, a customer, made completion design decisions based on FlowFX for wells in the Delaware Basin. The ability to model different designs led to an optimized design that resulted in a significantly improved completion and production increase, he said.

Drill2Frac announced the availability of FlowFX during URTeC 2021 and has been using it internally for customers. The FlowFX 2023 update, which will be launched in the first quarter of 2023, incorporates feedback from customers.

One of the biggest changes is that it will be cloud-based, which will allow Drill2Frac customers to work directly with the digital solution and run simulations themselves. ■

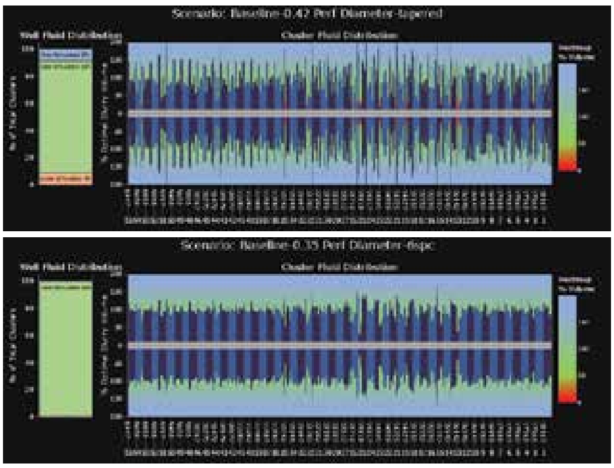
Drill2Frac OmniLog Example



Source: Drill2Frac

Some rock properties can be ascertained from drilling data as shown in this log. From left to right, mud log lithology, gamma ray, rate of penetration, OmniLog RockMSE, gas composition, stage and cluster design.

FlowFX Near-Wellbore Fluid Distribution Model Comparison



Source: Drill2Frac

FlowFX models how fluid will be distributed among perforation clusters for differing completion designs.

Autoblend, Top Fill Support Completions Operations

New electrical blender has higher up time than its traditional counterparts, while a mobile bucket elevator speeds up the sand delivery process.

BY JENNIFER PALLANICH | SENIOR EDITOR, TECHNOLOGY

Cutting the time to complete wells has driven innovation throughout the process, and Solaris Oilfield Infrastructure has turned its inventive engineering focus toward moving, storing and blending sand.

"What we're trying to do is help our customers be more efficient," said Scott Lambert, vice president of engineering at Solaris.

But a host of factors can contribute to nonproductive time (NPT), including blender repair and inefficiencies in transferring sand from trucks into storage silos.

Solaris wanted to find more ways to reduce NPT from equipment and a lack of stand, Lambert said.

So, Solaris developed the "AutoBlend," which is an integrated electric blender with a solid uptime record and the "Top Fill" bucket elevator for transferring sand into each company's vertical silos.

"There's been a push in the industry for electric blenders," Lambert said.

That is because conventional blenders powered by diesel engines are prone to issues that cause NPT, he said. Problems include engine failure, motor failure and hydraulic failure.

Lambert said the AutoBlend's electrical design means the mechanical parts are simpler because drive lines, gear boxes and other components are not required.

"It really simplifies things on the blender itself," he said.

The blender can be powered by a diesel generator, natural gas or field gas.

The AutoBlend design places an electronics room outside the blender that houses the controls, the high-power switchgear and drives for the motor.

"We stripped down the blender to what a blender does. Blend water and sand," Lambert said.

And because the AutoBlend was designed to operate in conjunction with Solaris' vertical sand silos, the blender does not require sand screws or a hopper. The blender has three tubs, which are supported by the company's six-pack silo design.

"You don't have to keep the hopper full. Our 2.5-million-pound storage system, that is our hopper," Lambert said.

And without the presence of sand screws, there is no worry about bearings going bad, he said.

In fact, sand screws are one of the leading causes of NPT for blenders, he said.

Because of how common blender problems are, it is not uncommon for operators to have multiple blenders on standby while one blender is pumping.

These blenders are working harder than ever, he said, because the total volumes previously pumped in a year

SOLARIS

"There's been a push in the industry for electric blenders."

—**SCOTT LAMBERT,** Solaris

may now be pumped in just a month with wells drilled horizontally rather than vertically, he said.

"It's much harder on frac equipment now than it was in the '90s or even the early 2000s," Lambert said.

AutoBlend has been available for about 18 months, and down time related to the AutoBlend has been in single-digit hours per month, Lambert said.

"We've faced some headwinds in adoption, much like we did when the sand storage happened," he said.

The pushback comes from the fact that pressure pumping customers already own blenders. And, if a customer has three to four blenders supporting every frac fleet, "a lot of capital is invested in those blenders," Lambert said.

He said Solaris understands the pushback, but also sees the value of the AutoBlend. It is available on a lease basis.

"For every four blenders working, we want one spare in the field but that's on us. The customer is not having to pay for that," he said.

LOADING UP

The six-pack silo system can now be filled using Solaris' Top Fill mobile bucket elevator, and the method saves time and money, Lambert said.

The challenge is how to get sand from bottom-drop trailers up to the top of a 50-foot silo without using long conveyor belts.

"If the silo is 50 feet tall, you've got a 100-foot-long conveyor belt feeding it from the ground. It takes up a lot of space," Lambert said.

Bottom-drop trailers can offload 55,000-pound payloads using the Top Fill elevator in just over four minutes.

"If you have the trucks lined up, we can deliver sand into the sand silo faster than the sand is being delivered to the blender," Lambert said. "It's a real space-saving piece of equipment. It's really compact."

Solaris' first Top Fill unit came out in January 2022. More than 20 have been manufactured, working in South Texas, the Permian Basin, Wyoming and the Rockies, and Solaris has more Top Fill units planned in its 2023 build program.

Development of the Top Fill started when Solaris considered the possibility of top-loading wet sand as the last mile of sand delivery became increasingly critical.

Top Fill is moving normal dry frac sand every day, "but we're performing tests with wet sand now," Lambert said. ■

Researchers are placing a sample in the chamber to prepare for the elemental analysis of the composition of the oilfield water sample.

TWEI

Produced Water Research Advances

The University of Texas Permian Basin's Texas Water and Energy Institute is analyzing data to potentially make predictions about the behavior of produced water.

BY JENNIFER PALLANICH | SENIOR EDITOR, TECHNOLOGY

When a barrel of oil comes out of the ground, it may be accompanied by 5 bbl of water or more. All that produced water needs a productive destination.

The University of Texas Permian Basin's Texas Water and Energy Institute (TWEI) is researching ways to treat produced water to be reused at construction sites, irrigate crops, support power generation and potentially recharge aquifers or add to surface water. The TWEI has two promising research projects underway and has already developed a database that companies can consult with to determine if their technology is capable of treating produced water from certain locations.

TWEI director and dean of the College of Engineering George Nnanna said the institute aims to find ways to use renewable energy-based sources to treat produced water and to increase water intelligence through data analytics.

The oil and gas industry produces so much water, but it must first be treated before it can be reused if it's not reinjected into the original reservoir. Different uses of the water have different treatment requirements.

In the Permian Basin, total dissolved solids can reach 200,000 mg/l, which makes treatment challenging.

"Eventually, if it's well-treated, I think it might not be far off to recharge the aquifer," Nnanna said. "In the California area, where the produced water has low dissolved salt, they are discharging it into the surface water."

FLOATING SYSTEM

One of the efforts underway at TWEI is a floating membrane system. The porous membrane design features nano-sized particles, and it floats on the surface of the produced water tank.

When the water permeates through the membrane, it evaporates. The clean water vapor is then collected and condensed into purified water.

Nnanna said the membrane enhances evaporation, which "we have been perfecting that."

The process, which Nnanna calls Enhanced Evaporation using Solar Umbrella, has "worked perfectly" at lab scale and has tested well at the pilot scale. It has drawn industry interest, and TWEI has been working toward an additional pilot at life scale for the past six months.

During that pilot, TWEI would seek to gather and analyze data that will help determine the parameters that affect the membrane's performance.

The lab test, which lasted a few weeks, generated a 17% to 20% enhancement in the evaporation rate, Nnanna said.

"We have ongoing experiments," he said. "We are still getting temperature, humidity and other data."

The material for the membrane is inexpensive, so the economics should not make treatment cost-prohibitive, he said. The membrane has been continuously used over six weeks without performance degradation issues.

DISSOLVED AIR FLOATATION

TWEI is also researching the viability of a pre-treatment system that injects tiny air bubbles into the bottom of produced water tanks. As the bubbles rise through the water, they can pull particulates to the surface of the water for skimming.

Following the initial pre-treatment, chemicals could be added to the water to help particulates coagulate before running the produced water through a series of filters to "produce a much cleaner water," Nnanna said.

TWEI has a 1,900-sq-ft facility to house the dissolved air floatation system. The next step for the research is to have the industry test produced water for effectiveness.

WATER INTELLIGENCE

TWEI has built a produced water database using more than 23 million data points collected from the U.S. Geological Survey and 45 different industries.

Nnanna said the data is being analyzed to see if it is possible to make projections about the behavior of produced water in the future. The database is available from TWEI and is accessible via subscription. A group within TWEI maintains the database.

"With our database, you can look at the water chemistry in a certain location and make a judgment if your technology is capable of treating the produced water from that place," he said. "Instead of going to the field to test it, you can look at this database, and it will give you an indication of the range of total dissolved solids."

The database has also made it possible to establish an empirical correlation between total dissolved salts and sodium and chloride.

"Instead of doing a laboratory characterization of produced water to get information on the total dissolved solids, if you know the concentration of sodium and chloride, you can use this equation to establish what the total dissolved solids will be," Nnanna said. ■

An aerial view of a ProPetro frac job in the Permian Basin.

PROPETRO

ProPetro's Low-Carbon Future

The oilfield service company is shifting its mindset from aggressive growth to sustainability.

BY JENNIFER PALLANICH | SENIOR EDITOR, TECHNOLOGY

Hot on the heels of a divestiture and an acquisition, ProPetro CEO Sam Sledge's high convictions for the company focus on resiliency and sustainability.

Founded in 2005, ProPetro grew from a frac fleet and a half in 2010 to 27 frac fleets in 2019.

"It was massive, aggressive growth," said Sledge, who joined the company in 2011 and was named its CEO a decade later. "We were built to do that very well."

But, the company has shifted focus to ensuring it's equipped with the right resources to be very successful in the long run, he said.

"As a public company, you get pushed to manage on a quarter-by-quarter basis by investors," he said. "But our highest priority is evolving and building a company that can sustain whatever future cycles are to come and take advantage of the tighter times like we're seeing right now."

That means optimizing the current business, transitioning the company's assets for a lower carbon future and making strategic and opportunistic investments and partnerships.

"We are internally shifting our mindsets and our processes toward being more sophisticated, more efficient internally than we were in the past when it was just more focused on adding the next crew, the next piece of equipment [or] the next team," Sledge said.

Part of optimizing the business included selling the company's noncore coiled tubing assets to STEP Energy Services in an equity transaction with a small cash component deal ProPetro announced in September 2022.

Another part is the twofold Regen and Defend program.

PROPETRO

ProPetro performs on location for a customer in the Permian Basin.

"We are internally shifting our mindsets and our processes toward being more sophisticated, more efficient internally than we were in the past when it was just more focused on adding the next crew, the next piece of equipment [or] the next team."

—SAM SLEDGE, ProPetro

Regen focuses on efficiently moving equipment out of the shop, while Defend focuses on preserving and lengthening the life of equipment on location through consistent maintenance practices in the field.

"It's fixing it faster at the shop, and it's breaking it slower in the field," Sledge said.

At the same time, ProPetro is winding down its investment into equipment that burns only diesel in favor of a "pretty aggressive" increasing investment into dual-fuel that also burns natural gas, as well as electric equipment.

At the end of 2021, ProPetro had 12 fleets running diesel only and one dual-fuel fleet. By the end of 2022, the composition was 10 diesel-only fleets and five dual-fuel fleets. Sledge said by the third quarter of this year there will be eight that are diesel only, two electric and seven dual-fuel. The goal is that over time, 80% or more of the fleet on offer will be electric or dual-fuel, he said.

SILVERTIP PURCHASE

In November, ProPetro announced the $150 million acquisition of Silvertip Completion Services Operating LLC, which has 23 wireline units that provide wireline perforating and pump down services. Like ProPetro, the cased hole wireline business works solely in the Permian Basin.

Sledge said ProPetro has avoided, to a certain extent, moving into the wireline side of the services sector, partly due to wanting to avoid downtime on location.

"Wireline downtime has been more or less engineered out of the system," he said.

Advances in wireline technology coupled with the maturation of completions programs with larger pad sizes have "helped us warm up to having a complementary service line," he said.

The purchase will help ProPetro produce more sustainable, consistent profits. And because ProPetro has not been involved in cased hole wireline work in the past, the integration will be straightforward, he said.

"When you're talking about integration and service businesses, you're talking about people," Sledge said.

Silvertip's management team has been encouraged to come aboard and bring along the team they have built, he said. There will be some back office integration on the administrative front, he said.

"We continue to ask ourselves with this very positive backdrop for oil and gas in general, what other opportunities are there like Silvertip to add complimentary service lines or businesses, and what other opportunities are there to continue to add scale to our business," he said.

Sledge said the question comes down to what a pressure pumping services completion-oriented service company should look like in five to 10 years. "Is it more diversified and more integrated or less? It's likely the prior. It's likely more diversified, more integrated and probably bigger as well."

With that in mind, ProPetro is "analyzing everything that's complimentary to us from a horizontal and vertical integration standpoint."

GEOGRAPHICAL SPOTLIGHT

From the outset, ProPetro is focused on operations in the Permian Basin, and according to Sledge, the company is open to expanding in other basins.

He said ProPetro has considered other locales, but the Permian has provided so much business that the company hasn't felt compelled to expand its footprint. The Permian "remains the lowest cost place to produce a hydrocarbon molecule on this side of the world, and it's become the most productive oil field in the world," he said. "We haven't had to go anywhere else."

The fact that the company focuses on its own backyard, so to speak, also helps make for happier personnel, Sledge said.

"We're not asking a team of people to go to the Bakken or to South Texas or East Texas on a whim to go help us with another project. So our employees are working basically within a hundred miles of where we're sitting every day," he said. "One of our competitors might need to fly a crew on a whim across the country to help with a certain project. That's not even an option from us." ■