Oil and Gas Investor

PERMIAN PLAYS

WILDCATTERS' LEGACY & EVOLUTION

M&A Attention Turns to Family Oil Companies

THE OGINTERVIEW

RISE OF A SHALE MAN

CEO Kyle Koontz Takes the Reins at BPX

SPECIAL OGI REPORT

TOP 100 PRIVATE COMPANIES

New E&Ps Make Rank Amid Consolidation Shuffle

AUSTRALIA'S BEETALOO BONANZA

US Shale Explores Down Under

HARTENERGY.COM

JULY 2024

BUILDING BLOCKS OF A STRONGER OIL & GAS INDUSTRY

As an active participant in the energy industry with a principal mentality for over 90 years, we understand that capital and ideas are indispensable to a thriving oil and gas industry. Our advisory assignments demonstrate how an independent investment bank, backed by extensive industry knowledge and innovative ideas, can help build stronger, more prosperous energy companies.

UNDISCLOSED	$190 MILLION	$120 MILLION	$41 MILLION	UNDISCLOSED
ASSET DIVESTITURE	INITIAL PUBLIC OFFERING	ABL REVOLVER & TERM LOAN	FOLLOW ON OFFERING	A PORTFOLIO COMPANY OF Dorilton. HAS BEEN ACQUIRED BY
Financial Advisor	Underwriter	Financial Advisor	Bookrunner	Financial Advisor
UNDISCLOSED	**$324 MILLION**	**$475 MILLION**	**UNDISCLOSED**	**$155 MILLION**
UNDISCLOSED SELLER HAS SOLD NON-OPERATED WORKING INTERESTS TO	INITIAL PUBLIC OFFERING	HAS AGREED TO BE ACQUIRED BY	ASSET DIVESTITURE	SENIOR SECURED TERM LOAN
Financial Advisor	Financial Advisor	Financial Advisor	Financial Advisor	Financial Advisor
$1.3 BILLION	**UNDISCLOSED**	**$55 MILLION**	**$126 MILLION**	**$307 MILLION**
ENPC BUSINESS COMBINATION WITH ROCK TO FORM GRANITE RIDGE	ASSET DIVESTITURE	HAS RECEIVED AN INVESTMENT FROM **MADISON VALLEY PARTNERS**	ASSET DIVESTITURE	SENIOR SECURED TERM LOAN & PREFERRED EQUITY
Financial Advisor	Financial Advisor	Financial Advisor	Financial Advisor	Financial Advisor

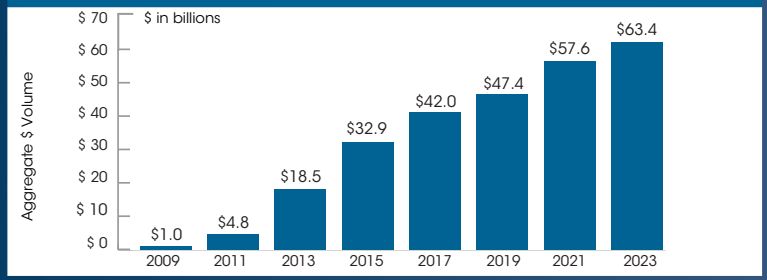
STEPHENS ENERGY GROUP KEY STATISTICS

$63+ Billion
Energy Investment Banking Transaction Volume Since 2009

~$300 Million
Average Transaction Size

222
Transactions Closed since 2009

ENERGY GROUP AGGREGATE TRANSACTION VOLUME



Keith Behrens, Managing Director, Head of the Energy Group • 214-258-2762 • keith.behrens@stephens.com
Paul Moorman, Managing Director • 214-258-2773 • paul.moorman@stephens.com
Brad Nelson, Managing Director • 214-258-2763 • brad.nelson@stephens.com
Evan Smith, Senior Vice President • 214-258-2758 • evan.smith@stephens.com
300 Crescent Court | Suite 600 | Dallas, TX 75201

For the most recent list of our transactions,
visit stephens.com/buildingblocks

Stephens

HARTENERGY.COM

Oil and Gas Investor

JULY 2024/VOLUME 44/NUMBER 7

SPECIAL OGI REPORT:

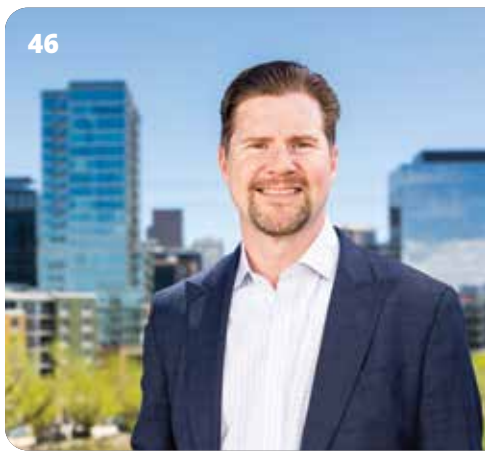
• PERMIAN PLAYS

• TOP PRIVATE COMPANIES

INTERNATIONAL EXPLORATION

The OGInterview

COMMENTARY



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

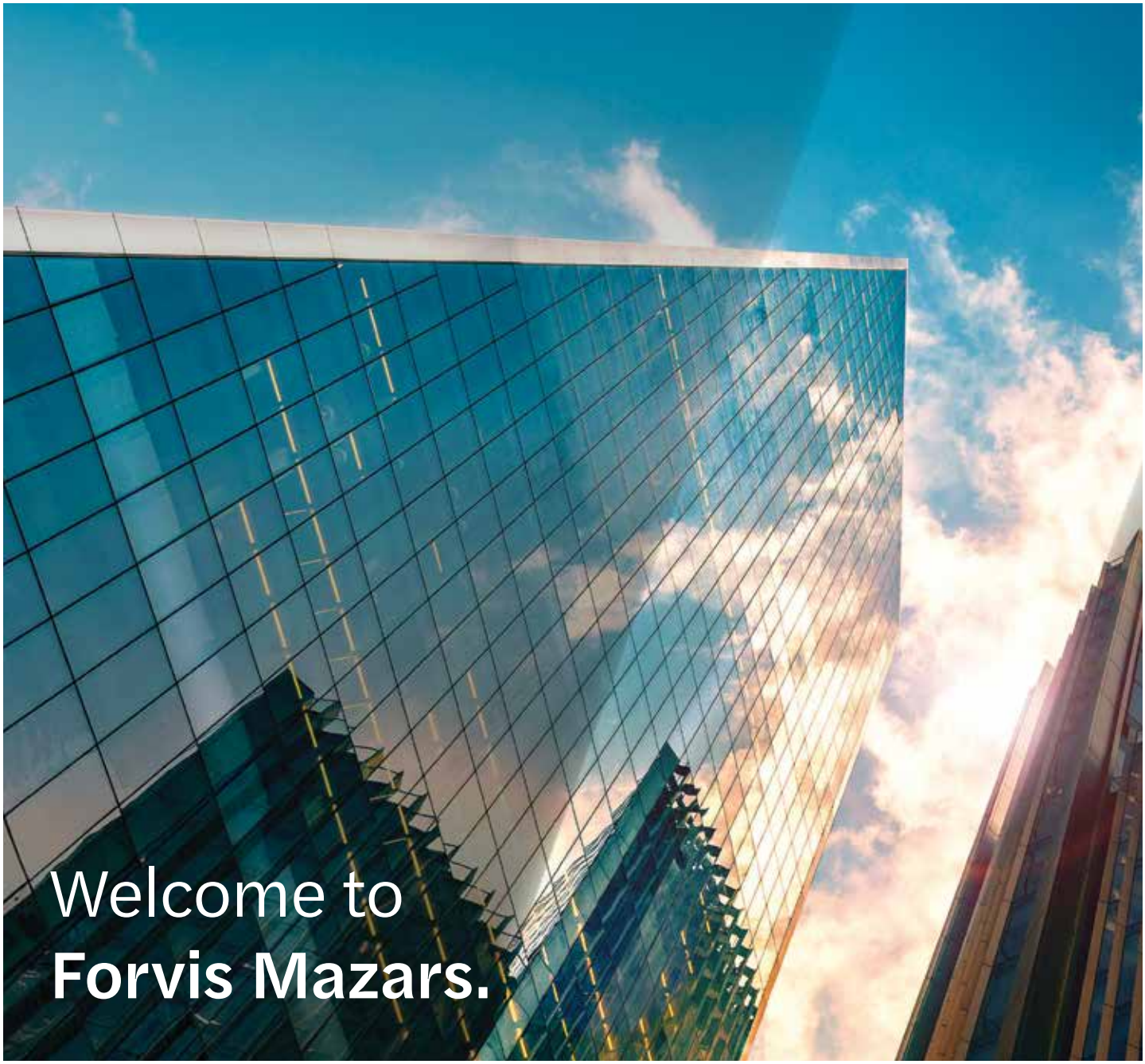
Subscription rates: United States and Canada: 1 year (12 issues) US$297; 2 years (24 issues) US$478; all other countries: 1 year (12 issues) US$387; 2 years (24 issues) US$649. Single copies: US$30 (prepaymentrequired). Denver residents add 7.3%; suburbs, 3.8%; other Colorado, 3%.

ACTIVITY HIGHLIGHTS

A&D

NEW ENERGIES

FINANCE & INVESTMENT



We are a new two-firm network with a 100-year legacy and a common commitment to our clients, people, and communities. Global to see the big picture and local to understand it. We provide advice that builds our clients' confidence and prepares them for what's next.

Providing clarity. Building confidence.

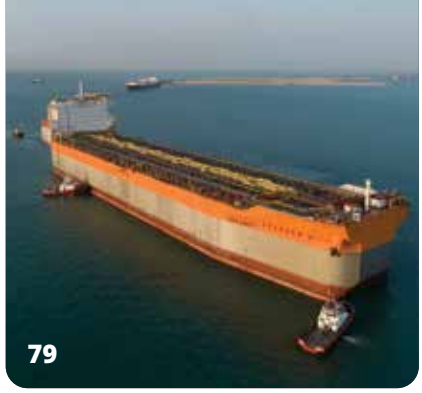
forvismazars.us

Assurance | Tax | Consulting

forvis mazars

Oil and Gas Investor
by HARTENERGY

1616 S. Voss Rd., Suite 1000
Houston, TX 77057
1-713-260-6400 Fax: 1-713-840-8585
HartEnergy.com



GLOBAL ENERGY

MIDSTREAM

TECHNOLOGY

ABOUT THE COVER:
The Santa Rita #1 well is emblematic of the early glory of Permian Basin wildcatters. Image courtesy Briscoe Center for American History, University of Texas at Austin.

PriorityPower

WE ARE THE ULTIMATE ADVANTAGE

REDUCING
Energy Spending

OPTIMIZING
Energy Efficiency

ENSURING
Energy Reliability

DECREASING
GHG Emissions

At Priority Power, we're your dedicated partner in navigating the energy landscape, offering comprehensive services to optimize operations and drive results. From infrastructure optimization to procurement and risk management, our tailored solutions prioritize efficiency, sustainability, and savings. With a proven track record and commitment to innovation, we empower your energy strategy for a brighter, sustainable future.

Seasonal Affective Disorder

A tempest of consolidation whips the order of E&Ps across the Lower 48.

DEON DAUGHERTY
EDITOR-IN-CHIEF
@Deon_Daugherty
ddaugherty@hartenergy.com

If you thought the first half of 2024 was hot, hold onto your hat during the next six months. You're going to need a nice, wide-brimmed one to keep cool this summer for certain. The winds of change are blowing through the U.S. E&P space with a mighty force never seen before. And forecasters are predicting one of the hottest years on record—whether gauging the mercury reading outdoors, commodity movement on the markets or the reshuffling of top domestic oil and gas producers.

And our team is chronicling the elemental shifts for you with award-winning expertise throughout this edition.

Public energy companies are swallowing their private peers whole, a trend that began during the second half of 2023 with the largest E&Ps and continues to gain steam with recent announcements by midstream operators and service companies. The net effect is dwindling numbers of standalone firms. But it arms private equity with loads of dry powder to reload. Expect a slew of new private companies managed by successful veterans to jump back in once they determine the water is, indeed, quite fine as non-core assets hit the market during the second half.

The midstream space is going full-steam ahead with M&A. In his piece, Sandy Segrist, our midstream senior editor, weighs the mechanizations in the sector. He notes that while midstream consolidation is often enough a follow-on effect of E&P's M&A action, the market has a few surprises in store.

Our senior editor for all things shale and M&A, Chris Mathews, digs into the backstory on the families that set the groundwork for the industry itself, including the multi-generational powerhouse that remains independent and private, Dallas-based Hunt Oil, and Ira G. Yates' West Texas gamble turned diamond in the rough, Yates Oil Field. This piece concludes our four-month analysis of the Permian Basin, but there's more ahead as our team continues to explore basin antics and analytics.

Speaking of top private companies, *Oil and Gas Investor* has for the third time in as many years joined forces with Enverus to analyze the top 100 private E&Ps. Consolidation would have compressed the list if not for new entrants emerging in the industry and on the roster.

Meanwhile, Down Under, Nissa Darbonne, Hart Energy's executive editor-at-large, has studied the work of domestic industry veterans who are working with a longtime Australian wildcatter to explore the country's beatific Beetaloo Basin.

Coming full circle to recognize the finest vintages, a refashioning of established Eagle Ford wells in South Texas is gaining ground. Top independents ConocoPhillips and Devon Energy are launching a refrac campaign in the region to heighten its retro appeal.

And that's just a portion of what's in the July magazine.

Ahead for August, we'll explore emerging trends in E&P finance, the appeal of the Utica Basin and why producers are retreating from the pure-play stance that has dictated the last decade. OGI

DEON DAUGHERTY
EDITOR-IN-CHIEF

NOG CLOSES DEALS

More Than $3.5 Billion of Deals Signed Since 2018

PERMIAN

50+ Transactions
including:

VERITAS ENERGY, LLC
MIDLAND-PETRO
ALPHA PERMIAN
Forge energy II
LAREDO PETROLEUM
NOVO

$2.0 Billion+

2021-2023

WILLISTON

250+ Transactions
including:

W Energy Partners
PIVOTAL PETROLEUM PARTNERS
FLYWHEEL ENERGY
SALT CREEK OIL+GAS
COMSTOCK RESOURCES
INCLINE ENERGY PARTNERS

$1.1 Billion+

2018-2023

MARCELLUS

Northern Oil
purchased non-operated assets from:
Reliance Marcellus, LLC

$120.9 Million

2021

NOG

Northern Oil and Gas, Inc.

Creative capital solutions including drilling partnerships and non-operating structures

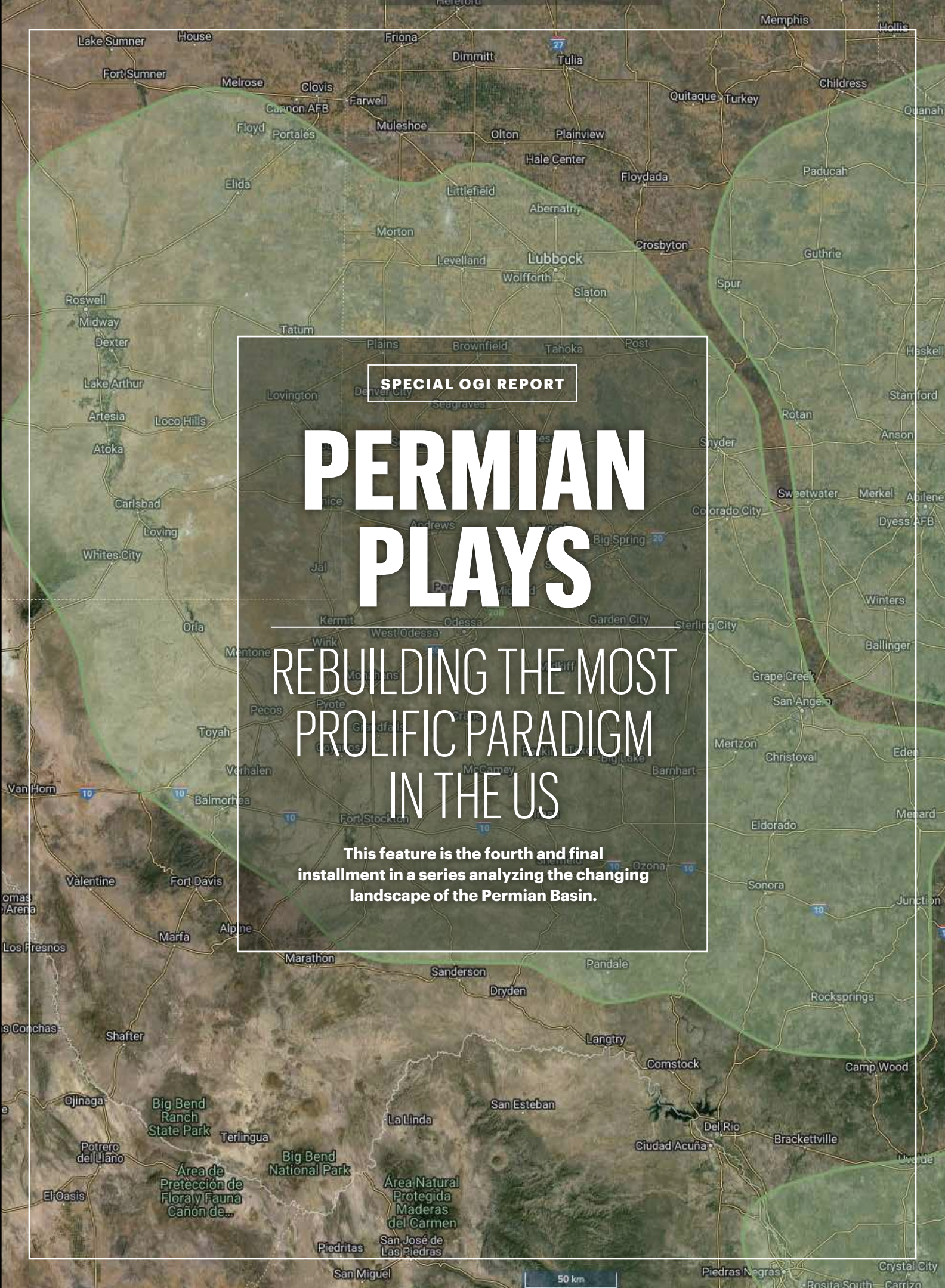
Adam Dirlam, *President*
Nicholas O' Grady, *Chief Executive Officer*

952.476.9800
bizdev@northernoil.com

PETRO - HUNT

L.L.C.

www.petrohunt.com



SPECIAL OGI REPORT

PERMIAN PLAYS

REBUILDING THE MOST PROLIFIC PARADIGM IN THE US

This feature is the fourth and final installment in a series analyzing the changing landscape of the Permian Basin.

IT'S ALL RELATIVE

FAMILY OIL COMPANIES ATTRACT HUGE M&A ATTENTION

What role do firms controlled by descendants of the original Permian wildcatters play in a sector increasingly dominated by scale?

After more than a century of exploration and development, the Permian Basin is the gift that keeps on giving.

And as operators jockey for scale and runway in America's biggest resource basin, they're knocking on the doors of wildcatting families that have been in the Permian since the beginning.

Today, family-owned oil and gas companies stand out among the most coveted M&A opportunities in the basin after a historic consolidation trend.

But oil was nary a thought on the mind of David Fasken when the Toronto attorney purchased a 220,000-acre ranch in West Texas in 1913.

Fasken, who acquired the "C Ranch" sight unseen for $6.50 per acre, planned to carve out farming homesteads from the property and sell them off individually for a healthy profit.

Unfortunately, he failed to account for the lack of water in barren West Texas to support farming ventures. Left with a massive, contiguous block of land and no conceivable exit strategy, his family resigned themselves to managing cattle on the ranch.

CHRIS MATHEWS
SENIOR EDITOR, SHALE/A&D
@chrismathews52
cmathews@hartenergy.com

David Fasken died in 1929, unaware of the vast fortune hiding in the rock beneath his feet, waiting to be unearthed.

Most of the ranch has been kept in the family. Fasken Oil & Ranch remains one of the largest private landowners in Texas with the C Ranch, along with a handful of other properties in South Texas.

The C Ranch is on the outskirts of the budding suburbia northwest of Midland, Texas. Fasken Oil & Ranch has drilled vertical wells on the C Ranch for years. But compared to its neighbors, the C Ranch is relatively undeveloped from a horizontal standpoint.

It's core Midland Basin inventory, the kind of land that commands massive premiums from the world's largest oil producers.

Fasken Oil & Ranch has an inventory of over 900 gross operated locations, with most breaking even with oil prices below $50/bbl, according to figures from Enverus Intelligence Research.

Given the relative lack of horizontal development, the Fasken property also has "extremely low" exposure to child-well locations, at less than 10%, said Andrew

PETRO-HUNT: THROUGH THE YEARS

1920s
H.L. Hunt starts his oil and gas career in El Dorado, Ark.

1920s
H.L. Hunt pioneers the East Texas Oil Field from the drill test of the Daisy Bradford #3 near Kilgore, Texas.

The discovery of oil at the Daisy Bradford No. 3 well in 1930 heralded the start of the East Texas Oil Boom. (Petro-Hunt)

1930s-40s
H.L. Hunt discovers the Olla and Nebo-Hemphill fields in LaSalle Parish, La.

1944
H.L. Hunt drills the first well in Alabama, the #1 Jackson.

MATT B. MERRITT/FASKEN OIL & RANCH

Located just northwest of Midland, Texas, David Fasken's original purchase is mostly intact, relatively undeveloped horizontally–and still in the family.

Dittmar, principal analyst at Enverus.

"Were the Faskens to be interested in selling, the Midland inventory alone would likely be worth [$3 billion to $4 billion] before accounting for the value of production or holdings in other plays like the Eagle Ford," Dittmar said.

Surface rights, mineral interests and other infrastructure would make the Fasken asset even more valuable. Not a bad outcome for a disappointingly arid tract of West Texas land purchased for $6.50 per acre.

But a key question remains: Will the Faskens ever sell?

It's top-of-mind for inventory holders left standing in the Permian after a historic land grab.

In an industry increasingly dominated by scale and efficiency, the majors are growing bigger–hoarding vast swathes of land in portfolios for future development.

According to a Rystad Energy analysis, only six firms–Exxon Mobil, Chevron, Diamondback Energy, ConocoPhillips, Occidental Petroleum and EOG

FASKEN OIL & RANCH

A century ago, David Fasken acquired what would become his family legacy sight unseen. What he thought was a failed gamble turned into one of the few remaining family oil companies in the Permian.

1961
W. Herbert Hunt and Nelson Bunker Hunt discover the Sarir Field in Libya, one of the largest oilfields in Africa.

W. Herbert Hunt (left) and Nelson Bunker Hunt (right). (Marshall Hunt)

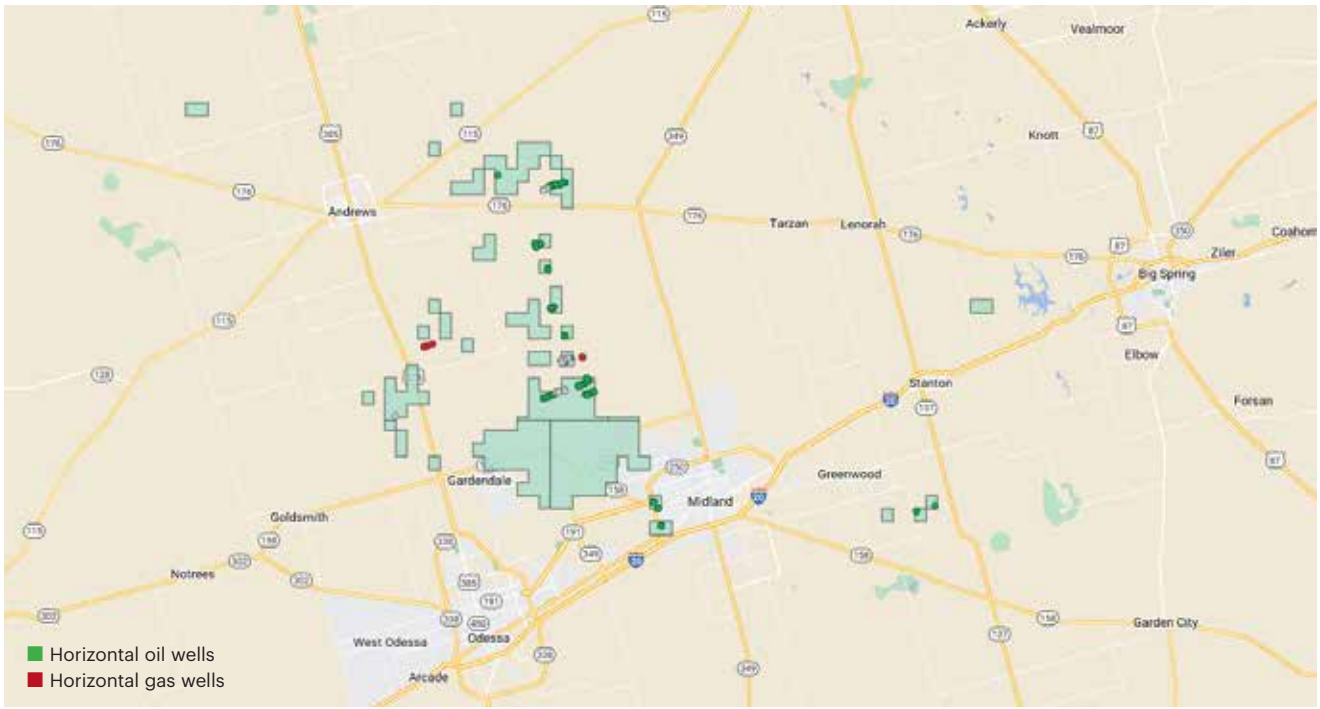
1970
Placid International opens the Dutch North Sea with the discovery on Block L 10/11.

1974
H.L. Hunt dies, leaving a legacy that was already in place for the next generation.

1975
Placid Refining purchases the Port Allen refinery in Louisiana.

1990s
The W. Herbert Hunt family starts Petro-Hunt, one of the nation's largest private oil and gas producers to this day.

Fasken Oil & Ranch



SOURCE: REXTAG

Fasken Oil & Ranch has an inventory of over 900 gross operated locations, with most breaking even with oil prices below $50/bbl, according to figures from Enverus Intelligence Research.

Resources–control about 62% of the remaining tight oil resource in the Permian Basin.

That's after a handful of eye-popping acquisitions that have closed or been inked over the past year:

- Exxon Mobil closed an acquisition of Pioneer Natural Resources for nearly $60 billion;
- Diamondback Energy is acquiring private Permian giant Endeavor Energy Resources for $26 billion;
- Occidental is acquiring private E&P CrownRock LP for $12 billion; and
- ConocoPhillips is acquiring public rival Marathon Oil for over $17 billion.

There's a smattering of smaller private equity-backed E&Ps left in the Permian, but a fraction as many compared to the basin's booming run last decade.

As acquisitive E&Ps scour the basin for M&A options, family-owned oil companies like Fasken Oil & Ranch and Mewbourne Oil stand out from the crowd as two of the basin's top private inventory holders.

Generally, family oil companies are more hesitant to sell than a private equity-backed E&P, which was built with the ultimate goal of selling.

Mewbourne Oil and Fasken Oil & Ranch have drilled wells and produced oil and gas for several generations. They've weathered decades of the ups-and-downs of the commodity cycle. These companies are built to last.

But as the years pass and wildcatting executives age, more and more family oil companies are selling.

Endeavor is the most prominent example. Autry

PETRO-HUNT: THROUGH THE YEARS (CONTINUED)

1990s

Petro-Hunt expands in the Williston Basin, South Texas, East Texas, Louisiana and Mississippi through six acquisitions.

Hunt family portrait, from left to right: Bunker, Herbert, Margaret, Hassie, Caroline and Lamar. (Marshall Hunt)

2006

Petro-Hunt drills the USA No. 2D-3-1H; the well has produced just over 2 MMbbl of oil, the highest producing well in the state of North Dakota in the Bakken/Three Forks formation.

Petro-Hunt drilled and completed the world's first medium-radius, double lateral horizontal well in South Texas. (Petro-Hunt)

Stephens launched the company that would become Endeavor Energy Resources in the Permian Basin in 1979.

This year, the 85-year-old billionaire wildcatter sold Endeavor in the largest buyout of a private oil producer in the history of the sector, according to Enverus' calculations.

Tim Dunn sold his family's company, CrownQuest, a joint venture between CrownRock and Lime Rock Partners.

James "Jim" Henry, a longtime Permian Basin wildcatter who began his career with wells in conventional rock before moving into unconventional drilling, sold much of his company to Vital Energy last year. He sold his previous firm, Henry Petroleum, for $565 million to Concho Resources—now a part of ConocoPhillips.

Henry died last October at the age of 89.

EOG acquired a foundational position in the New Mexico Delaware Basin from Yates Petroleum in 2016. Nearly a century earlier, it was Martin Yates Jr. who drilled the first commercial oil well on New Mexico state lands in 1924. In 2015, different members of the Yates family sold Harvey E. Yates Co. (HEYCO) to Matador Resources.

Exxon Mobil and shale subsidiary XTO Energy dug deeper into New Mexico through a $6.6 billion acquisition in 2017 from the Bass family of Fort Worth.

With Permian M&A activity coming off a record high year, will more of these storied E&Ps finally sell?

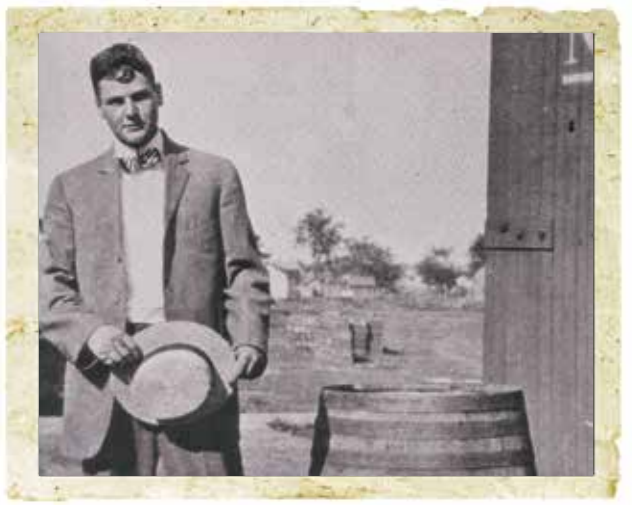
"I think we're on the edge of extinction of the family oil business," said Stephen Trauber, chairman and global head of energy and clean technology at Moelis & Co.

"The oil business now requires so much capital, and scale is so important," he said, "that it's hard to be a family office and compete."

Still Hunting

Family oil companies face unique challenges, but Marshall T. Hunt thinks the reports of their demise could be greatly overexaggerated.

He knows well the unique challenges of family oil companies. He's the great-grandson of H.L. Hunt, Hunt Oil founder and East Texas Oil Field wildcatter who during his time amassed one of the world's largest fortunes.



PETRO-HUNT

H.L. Hunt founded his first oil and gas business in the 1920s in El Dorado, Ark., during the height of the Arkansas oil boom.

"I think we're on the edge of extinction of the family oil business. The oil business now requires so much capital, and scale is so important, that it's hard to be a family office and compete."

STEPHEN TRAUBER, chairman and global head of energy and clean technology, Moelis & Co.

H.L. Hunt founded his first oil and gas business in the 1920s in El Dorado, Ark., during the height of the Arkansas oil boom. He would go on to acquire the drill test of the Daisy Bradford #3 near Kilgore, Texas, the discovery well for the massive East Texas Oil Field.

Hunt Oil was incorporated in Tyler, Texas, in 1934 before moving its headquarters to Dallas in 1937. It would grow into one of the world's largest private oil and gas producers.

2011
Petro-Hunt operates up to 16 rigs in the Williston Basin, ranking as one of the top liquids producers in North Dakota.

2012
Petro-Hunt divests certain Williston Basin assets to Halcón Resources.

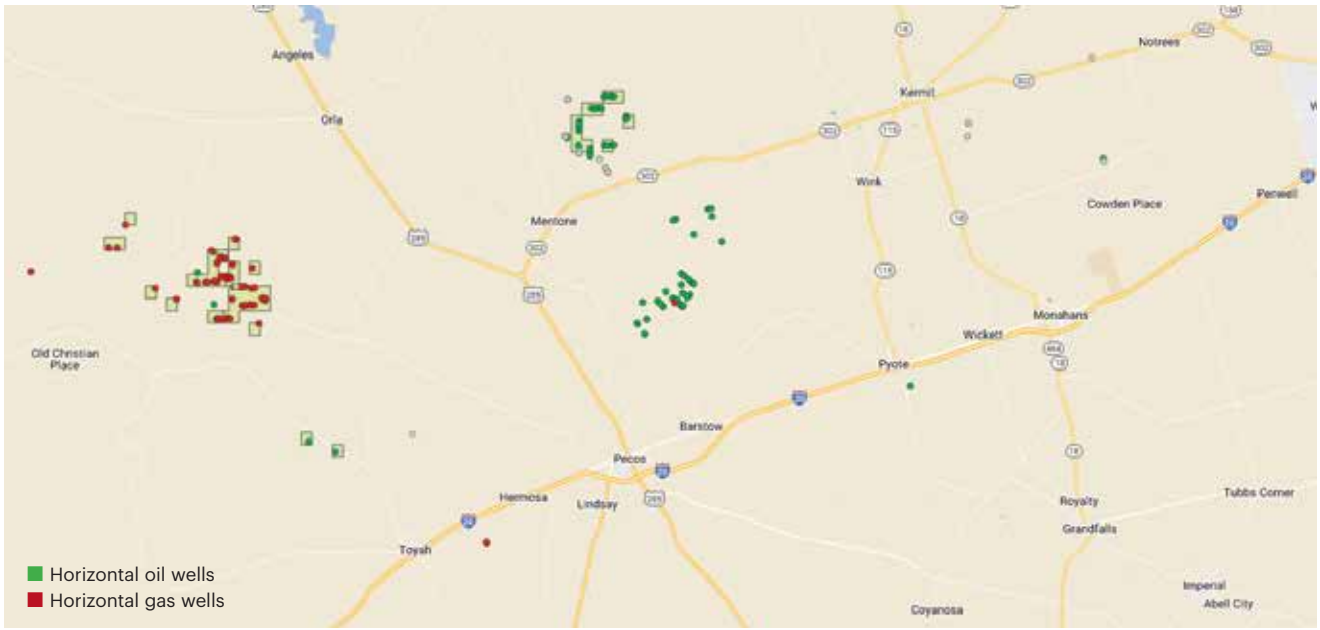
2018
Petro-Hunt acquires 119,000 net acres and 246 operated wells in the Williston Basin from SM Energy.

2022
Petro-Hunt expands into the Permian Basin through a handful of acquisitions in the Delaware Basin including 21,000 net acres from Admiral Permian.

2023
Petro-Hunt acquires a contiguous block of 7,500 net acres in Ward County, Texas, growing its Permian position to over 35,000 net acres.

2024
Petro-Hunt founder W. Herbert Hunt dies on April 9, 2024, at the age of 95.

Petro-Hunt's Delaware Basin Holdings



SOURCE: REXTAG, RAILROAD COMMISSION OF TEXAS

Petro-Hunt has quietly been growing a footprint on the Texas side of the Delaware Basin. NOTE: All Delaware Basin oil and gas wells operated by Petro-Hunt, according to available Rextag data.

PETRO-HUNT

(Left to right): A young William Herbert Hunt, Nelson Bunker Hunt and Lamar Hunt.

H.L. Hunt's sons, William Herbert Hunt and Nelson Bunker Hunt, discovered the massive Sarir Field in Libya in 1961. But the oil field, and Bunker Hunt Oil's assets, were eventually expropriated by the Libyan government of Muammar Gaddafi in 1973.

W.H. Hunt later founded Petro-Hunt in the 1990s. Marshall T. Hunt, the grandson of W.H. Hunt who serves as COO of Petro-Hunt today, grew up in that unique American culture.

Black-green crude might as well run through his veins.

"Oftentimes as kids in South Texas, we'd make trips out to a well site," Hunt told *Oil & Gas Investor*. "We were exposed to it at an early age."

He always knew that he'd like to get into the family's oil and gas business. But that didn't mean starting out working in the company's cushy Dallas digs.

Family members who took up the Hunt business would be required to put in their time in the oil patch.

"We worked in places like Mississippi, East Texas, West Texas and North Dakota, gaining experience from the ground up," Hunt said. "That really gave us the foundation and knowledge to be able to expand on learning the entire business–from the field all the way up to the corporate level."

The influence of family oil companies may have waned over the generations, but Petro-Hunt very much still sees a runway of growth into the future, Hunt said. The company produces about 41,000 bbl/d, making it the 16th-largest private oil producer in the U.S., per Enverus data.

But the list of private producers is set to shrink with the pending acquisitions of Endeavor Energy Resources (220,400 bbl/d), CrownQuest Operating (93,600 bbl/d) in the Permian Basin, and the acquisition of Aera Energy (78,000 bbl/d) in California.

Petro-Hunt has been active in the Permian's Delaware Basin since entering the play through an acquisition from Admiral Permian in 2022. The Admiral Permian deal included existing production and around 21,000 net acres in Reeves and Culberson counties, Texas.

Petro-Hunt complemented the Admiral Permian deal by acquiring around 4,000 net acres in Loving County, Texas, through a series of transactions. Last year, Petro-Hunt acquired a contiguous block of 7,500 net acres in Ward County, Texas.

PETRO-HUNT

Petro-Hunt operations in the Bakken, 2021.

Today, the company's portfolio spans over 35,000 net acres in the Delaware Basin, where Petro-Hunt operates three rigs, Hunt said.

Petro-Hunt is also running one rig in the Williston Basin, where the company has had a long history and still owns a sizable portfolio.

Petro-Hunt has been a pioneer in the Bakken and Three Forks formations: The company's predecessor entities began picking up leases in North Dakota in the 1940s.

The company grabbed headlines in 2012 when it sold a portion of its Williston position–81,000 net producing acres–to Halcón Resources (now Battalion Oil) for $1.45 billion.

Petro-Hunt is keeping its options open when it comes to future M&A.

The wildcatting E&P isn't opposed to jumping in somewhere new. Exploration runs in the family, after all.

The company also sees value in bolting on additional acquisitions in its existing operating areas.

"We're still opportunistic looking at all areas across the Lower 48," Hunt said, "such as the Haynesville, Permian, the Rockies region all the way up to the Williston."

But the Hunt family has diversified investments outside of oil and gas production. The Petro-Hunt side of the family has verticals focused on acquiring minerals and royalties in basins around the country. The Hunt family is also a part owner in the Placid Refining Co. and a refinery in Port Allen, La.

"We worked in places like Mississippi, East Texas, West Texas and North Dakota, gaining experience from the ground up. That really gave us the foundation and knowledge to be able to expand on learning the entire business–from the field all the way up to the corporate level."

MARSHALL T. HUNT, COO, Petro-Hunt

Petro-Hunt is the owner and operator of the Little Knife Gas Plant west of Killdeer, N.D., which processes natural gas volumes from the Little Knife field.

The family actively invests in real estate development, operates a private equity alternative investment division and enjoys ranching.

That the Hunt family's oil and gas enterprises have lasted through a third, even into a fourth generation, is an anomaly.

There's a widely held belief, by members of the Hunt family and other family businesses, that the situation starts to get messy by the third generation of family ownership. As the years go on, families can become distant and fragmented; business dysfunction can begin to ensue. Certain parts of the family might want to pursue a sale; other parts of the family might want to stay in the business for the long haul.

Succession planning is another major pitfall for family-owned companies. Sometimes, a younger successor just isn't ready to take over the family enterprise.

Other times, an outgoing senior executive refuses to truly cede control to a younger generation of leadership (If this sounds like an episode of HBO's award-winning show "Succession," the show, though fictitious, really wasn't far off).

Chalk some of the family's success and longevity up to luck, Hunt said.

"But also, at the same time, maybe it's being a close-knit family unit and seeing the work and work ethic that the generations before us have put in for us today," he said. "Knowing that we're working for the future generations to build upon the family business."

Hunt Oil is still around today, managed by a different branch of the family. In fact, Hunt Oil is actively marketing an expansive minerals and royalties package spanning around 20,000 net royalty acres in aggregate. The package includes interests in the Denver-Julesburg (D-J) Basin, the Permian and Uinta basins, the Midcontinent and East Texas, according to marketing materials.

"I think we see a lot of room for growth in the future," Hunt said.

W. Herbert Hunt died at age 95 on April 9, 2024. He and his family were inducted into Hart Energy's Hall of Fame in December.

Fixing a Hole

Family-owned oil companies might be less relevant today, but family capital hasn't completely left the oil and gas sector, according to Moelis & Co.'s Trauber.

The nature of their investment has just changed, with family office capital increasingly investing into energy-focused private equity funds or investing directly into operators themselves.

Banks and public markets have backed away from the oil and gas sector in recent years due to poor returns, environmental pressures and other reasons.

Private equity capital is still important for the sector, but there's a fraction of the amount of upstream-focused private equity capital deployed in the space as there was a decade ago.

But family office capital has stepped up to fill part of the void left in the wake of those exiting financiers, experts say.

Respondents in Haynes and Boone's Spring 2024 Borrowing Base Redeterminations Survey expect to see a "meaningful drop" in the use of equity capital markets this year, with the shortfall made up by growth in equity from family offices and private equity.

Family office and private equity are more expensive from a cost of capital standpoint, said Kraig Grahmann, a Haynes and Boone partner and the survey report's author.

"Without [Ira Yates'] effort, I think the Permian would still be exceptional, but it wouldn't be nearly as colorful or prolific."

RUSSELL ROEMER, vice president of oil and gas, Kinder Morgan CO_2

But family offices seem to be increasingly tapping oil and gas since operators have become more disciplined and focused on returning money to investors. Family offices also don't have the same kinds of environmental, social and governance (ESG) pressures that banks face right now.

"It has gotten bigger over time, the influence of these family offices," Trauber said.

He recalled a recent industry event hosting around 40 to 50 family offices, many of which represented coastal family money with no real ties to the oil and gas industry.

These non-energy families are asking a lot of questions about the energy business.

"[The event was] really meant to make non-energy-sophisticated investors more sophisticated about energy," Trauber said, "about the merits of the business, the cash flow generation of the business, the superior returns of the business today."

A family office may not move the needle for an oil and gas company on a one-off basis. But there's strength in numbers. Some family offices are banding together and pooling their money to invest in the oil and gas sector.

Last year, Wyoming natural gas producer PureWest Energy was acquired by a family office-led consortium for $1.84 billion in cash. The consortium included Petro-Hunt, A.G. Hill Partners, Cain Capital, Eaglebine Capital Partners, Fortress Investment Group, HF Capital and Wincoram Asset Management.

Petro-Hunt's Marshall T. Hunt now serves on the PureWest board. He thinks other family office-led consortiums could make similar moves in the future.

"I think what you'll see is these family offices coming in and doing equity-type investments in the oil and gas space," Hunt said.

"That was kind of unique to us where we're not the operator of the business," he said. "We made the investment, but we're not actively operating those assets."

From Iraan to the World

Friends and neighbors warned Ira Yates: Nothing would come of that barren land west of the Pecos River.

Ira Griffith Yates, a rancher, peanut digger and West Texas entrepreneur, operated a relatively successful dry-

KINDER MORGAN

A view of the Yates oil field in Pecos County, Texas. The field is operated today by Kinder Morgan Production Co.

goods store in Rankin, Texas, when he was approached in 1915 with a tempting proposition.

Businessman Thomas Hickox wanted to offload his 16,640-acre ranch property south of the river in Pecos County. The story holds, according to Yates' great-grandson, Ira John Yates, that Hickox proposed a trade: Yates' mercantile store in exchange for the River Ranch.

The offer appealed to the rancher, but friends urged Yates to take caution. The ranch across the Pecos River was often beset by drought. The land's boundaries were frequently disputed by neighbors since it went unfenced.

The ranch was also known for its "greasy" well water. Yates later recounted that "even buffalo know better than to cross the Pecos—that a crow would not fly over, and [the ranch] was not worth the taxes."

Yates went forward with the trade, despite the warnings. And for a time, his naysayers were right: The following years were difficult ones for Ira Yates and his wife, Ann. The ranch struggled to turn a profit.

By the 1920s, Ira Yates was on the hunt for something new.

The crude oil potential of West Texas was only just beginning to be understood at that time. The W.H. Abrams No. 1 well in Mitchell County, the first commercial discovery well in the basin, began producing in February 1920 before its gusher event in July. That well, while historically significant, was a small endeavor.

But the famed Santa Rita #1, brought online on university lands on May 28, 1923, put West Texas on the map with the discovery of the Big Lake oil field. Santa Rita #1 produced for 67 years before being plugged in 1990.

Ira Yates called upon Levi Smith, president of the Big Lake Oil Co. in nearby Reagan County. Smith also operated as manager for the Transcontinental Oil Co.

Yates convinced Smith to drill at the Pecos County ranch, though its location was unfavorable. Common knowledge at the time held that there was no oil to be found west of the Pecos River, but Yates and his drilling partners, Transcontinental and the Ohio Oil Co. (an ancestor of Marathon Oil) accepted the risk.

Sharing the lease with Transcontinental, Ohio Oil drilled four wells on the Yates ranch before finally striking oil on Oct. 28, 1926—Yates' 67th birthday. The I.G. Yates A No. 1 is known today as the discovery well for the Yates oil field, one of the most prodigious

KINDER MORGAN

I.G. Yates A No. 1, the 1926 discovery well for the prolific Yates oil field in Pecos County, Texas, is still in production today.

and geologically unique hydrocarbon reservoirs ever developed.

The oil discovery and ensuing bonanza made an instant millionaire out of Yates, who sold drilling leases to clamoring customers from his front porch after the first gusher came in.

It yielded the town of Iraan, Texas–pronounced like a combination of "Ira" and "Ann"–on acreage donated by the Yates family.

The Yates field has yielded nearly a century of fortunes for its stakeholders. It also yielded headaches from squabbling court battles and the Railroad Commission of Texas (RRC) field unitization process in 1976, when Marathon Oil became operator.

For Marathon Oil, the field was better known as The Crown Jewel. A 1981 article in The New York Times reported, "There is really no Marathon Oil without Yates."

Marathon Oil eventually sold its interest in the field to Kinder Morgan in 2003. This summer, Marathon agreed to a $17.1 billion sale to ConocoPhillips.

Yates, still one of the nation's largest oil fields by proved reserves, continues to produce after years of technical innovation. Secondary recovery techniques have been deployed at Yates to extend the life of the field since the late 1970s, after the unitization process.

Kinder Morgan Production Co. operates the Yates field today using a unique CO_2 flood process for enhanced oil recovery (EOR).

Russ Roemer, vice president of oil and gas for Kinder Morgan CO_2, said Yates uses immiscible CO_2 injection for EOR.

"An immiscible flood is essentially putting CO_2 as a gas into the reservoir," Roemer said.

The CO_2 effectively swells the oil, driving the sweet prize into the rock's fractures to drain into the oil column, where it's subsequently captured.

Other EOR projects, like Kinder Morgan's SACROC field unit in Scurry County, Texas, use miscible CO_2 floodin, where CO_2 injected under supercritical pressure acts more like a liquid in the reservoir than a gas.

"It's the only immiscible CO_2 flood of which I'm aware," Roemer said. "It's a prime example of West Texas can-do attitude and risk taking."

Ira G. Yates and the Yates field helped to make West Texas almost synonymous with "oil" in the public lexicon.

As for the pioneering I.G. Yates A No. 1, it's still in production today, after nearly a century and three modernizing recompletion projects.

But the legacy of Ira G. Yates isn't long-lost Texas history for his great-grandson, Ira John Yates. The West Texas oil field, the town of Iraan and the Pecos River have been consistent foundations throughout the life of the Austin native.

His mother, Pauline "Polly" Blanton, was the granddaughter of I.G. Yates and took an active role in managing the family land she co-owned.

"My mother maintained a significant personal interest in the property out there and the operation of the field," Yates told *OGI*.

As a child, he would travel with his mother as she petitioned the RRC and Texas General Land Office to force producers to clean up abandoned wells along the Pecos River. Yates himself became involved during the RRC's process to unitize the field in the mid-'70s.

"It was a very important education process for me," Yates said. "But more importantly, I learned the workings of the oil industry in the Yates field, the geology, the politics, all the money and arguing."

He also learned about the powerful toolset the RRC wielded: The bountiful production from Yates caused storage and transportation issues for producers in the late 1920s.

By the summer of 1928, the RRC had issued an order prorating production from the Yates field, the first fieldwide order of its kind in the state.

The proration model was deployed on a much larger scale after the discovery of the East Texas Oil Field in the 1930s. That model of dictating and controlling the rate of oil and gas production served as a core thesis in forming OPEC in the 1960s.

Today, Yates is focused on giving back–to the town of Iraan and to stakeholders of the lower Pecos River.

Yates formed Friends of the Pecos River, a 501c3 nonprofit, in 2021 with a mission to enhance water quality and quantity in that section of the river. He wants to see participation from Iraan schools to get kids involved in STEM and agriculture education.

The irony of his situation–contributing to environmental conservation efforts as the heir to a massive fortune made through fossil fuel extraction–isn't lost on Yates. Fellow mineral rights owners have had choice words for him over the years.

"And they're talking to the great-grandson of the owners," Yates said. "So, it's very, very difficult."

As the Yates field nears its first century in production, Kinder Morgan's plans call for drilling around 50 horizontal wells per year on the historic asset.

"Without [Ira Yates'] effort, I think the Permian would still be exceptional, but it wouldn't be nearly as colorful or prolific," Roemer said. OGI

40 YEARS OF CREATING VALUE WITH EXCEPTIONAL SERVICE

9,000+ CONSULTING PROFESSIONALS

6 CONTINENTS, 35+ COUNTRIES

ALVAREZ & MARSAL
ENERGY

A&M partners with energy companies and investors to navigate shifts in today's market.

We bring unmatched insights to help clients create value and build great companies.

A&M ENERGY SERVICES

Commercial, Pricing, Marketing
Mitigate inflationary pressure and enhance returns

Transaction Support
Optimize value and quickly stabilize organization for growth

Energy Transition
Execute strategies to achieve energy transition commitments

Organization & Culture
Drive organizational and cultural change

Strategy & Portfolio Management
Evaluate and optimize portfolio performance

Operational Improvements
Performance Improvement Expertise

A&M ENERGY CONTACTS

Al Carnrite | acarnrite@alvarezandmarsal.com

Renee Klimczak | rklimczak@alvarezandmarsal.com

Lee Maginniss | lmaginniss@alvarezandmarsal.com

Julie McLaughlin | julie.mclaughlin@alvarezandmarsal.com

Francois Bardi | fbardi@alvarezandmarsal.com

www.alvarezandmarsal.com

HARTENERGY

2024 EVENT CALENDAR!

The Industry's Comprehensive Resource for Live Content, Data and Analysis

The 2024 event schedule is designed to focus on the topics you want to hear about and to make scheduling your year even easier. We've decreased the number of events and pumped up the amount of content to make them larger, more informative and more engaging.

Save these dates and start planning your 2024 event schedule now!

TECHNOLOGY

NEW ENERGIES SUMMIT

August 27-28
Houston, TX

INVESTMENT

ENERGY CAPITAL CONFERENCE

October 3
Dallas, TX

INVESTMENT

A&D STRATEGIES & OPPORTUNITIES CONFERENCE

October 23
Dallas, TX

SHALE

DUG APPALACHIA CONFERENCE & EXPO

November 7
Pittsburgh, PA

LEADERSHIP

DUG EXECUTIVE OIL CONFERENCE & EXPO

Nov. 20-21
Midland, TX

2024 CONFERENCE & EXPO BROCHURE

2024 CONFERENCE ONLY BROCHURE

THE PRIVATE PRODUCER SHUFFLE

A wave of M&A has lifted new names into the rankings of the 100 top operators.

DEON DAUGHERTY
EDITOR-IN-CHIEF
ANDREW PRATT
CONTRIBUTING EDITOR

The historic consolidation trend across the U.S. E&P sector during the last 18 months is reshaping the landscape beyond the nameplate megamergers such as Exxon Mobil's acquisition of Pioneer Natural Resources. Private family companies founded by original wildcatters such as Hess Corp. and Endeavor Energy Resources are coming off the market to join the likes of Chevron and Diamondback Energy.

Among the net effects of $200 billion in M&A, a number of private companies have fallen off the list of Top 100 private companies compiled by Enverus in an exclusive partnership with *Oil and Gas Investor (OGI)*. A slew of newcomers to the Top 100 have taken their places.

The combination of M&A and the follow-on asset sales in 2023 between public and private operators played a significant role in the shuffling, Justin Lepore, the Enverus analyst who built the list, told *OGI*.

Among the top examples:

- In the Haynesville, TG Natural Resources acquired Rockcliff Energy, reducing the two spots those names held last year into one spot, which opened a position for a new name roll-up into the Top 100;
- In the Gulf Coast, Chesapeake Energy's asset sales led to both WildFire Energy and U.K.-based INEOS Energy joining the ranking;
- A Permian Basin acquisition elevated VTX Energy (from Delaware Basin Resources) to the list, and the entrance into the Permian of publicly traded Civitas Resources lowered Tap Rock's ranking and pushed out Hibernia Resources;
- Bakken Shale asset sales from public operators Ovintiv and Crescent Point led to big moves up the list for Grayson Mill Energy and Kraken Resources, respectively; and
- Rockies-weighted operators occupied fewer spots among the top 20 names on the list this year, with their positions taken by Permian- and Midcontinent-weighted operators.

"Private operators have driven much of the growth and been more sensitive to commodity-price changes than their public peers," Lepore said. "Privates have been more motivated by economic fundamentals and, in many cases, to grow production to become more attractive to takeout targets. Publics have prioritized inventory preservation, capital discipline and steady free cash flow. We expect this trend to continue and lead to moderating growth from U.S. shale, in aggregate."

During 2023, about 36% of oil production in the Lower 48 came from private operators; some 70% of those volumes came from the top 100 companies on this list, Lepore said. For gas production, the total contribution from private operators to Lower 48 production accounted for 39%, but the concentration of that share coming from the 100 operators on this list is slightly more than 80%.

"As a whole, this production is spread over a list of operators vastly larger than the universe of public operators, leading to a very long tail of smaller operators where incentives can be harder to discern and inventory is not often in basin core hotspots," he said.

This is the third consecutive year that Lepore has compiled the list with *OGI*. He sources public production data cleaned through Enverus' proprietary algorithms, reviews total operated production by producer in the Lower 48 over 2023, and then crunches the data to determine the weighting of production by region. GPS-tracked rig activity rounds out the dataset to provide insight on activity in 2024 through mid-June.

Permian Basin

The technological revolution in directional drilling and hydraulic fracturing has restored the Permian Basin's standing among the top U.S. energy producing regions, even after more than 100 years of production.

E&Ps pump more than 6 MMbbl/d of oil and 24 Bcf/d from Permian wells, and private companies are among the top producers.

Enverus data show 24 top privately held held companies drilling and producing in the Permian Basin, adding more than 1.1 MMbbl/d

A period of massive M&A has reshuffled the list of top 100 private producers.

SHUTTERSTOCK

"Private operators have driven much of the growth and been more sensitive to commodity price changes than their public peers."

JUSTIN LEPORE, Enverus analyst

of oil and nearly 4.4 MMcf/d of natural gas to U.S. energy production throughout 2023.

Privately held Mewbourne Oil of Tyler, Texas, produced 408,754 boe/d during 2023, while Endeavor Energy Resources of Midland generated 336,561 boe/d.

Continuous development of hydraulic fracturing and horizontal drilling techniques have helped make the Permian one of the most cost-effective places to drill. Success at producing abundant, affordable energy may shorten the list of both public and private companies drilling in the ancient Permian seabed as strong profits provide the funding for M&A.

If the transaction gains anti-trust approval, publicly traded Diamondback Energy will merge with Endeavor in a $26 billion transaction announced in February.

"The combination will create a premier Permian independent operator," Diamondback said in a news release when the sale was announced. Diamondback also is a top 10 Permian producer.

The Endeavor-Diamondback merger agreement was announced three months before Exxon closed its $59.5 billion acquisition of publicly traded Pioneer, the largest oil and gas producer in the basin. Exxon, which methodically expanded its presence in the Permian after the full potential of hydraulic fracturing became evident, now dwarfs all other producers in the basin.

Mewbourne has so far managed to stay independent despite the tsunami of acquisitions and mergers engulfing its rivals. Company President and CEO Ken Waits told *OGI* last year that the family-run company has had great success focusing on organic growth rather than finding a buyer or merger partner.

The company averaged 23 rigs in first-quarter 2024, far more than any other privately held company operating in the Permian, Enverus data shows. Mewbourne has been one of the most active players in the Delaware Basin of the Permian.

Rockies

The Williston, Denver-Julesburg and Powder River basins

Private E&Ps accounted for 36% of oil production in the Lower 48 in 2023.

SHUTTERSTOCK

are generating production at or near all-time highs, boosting the bottom lines of privately held E&P companies operating in the Rocky Mountain region.

Continental Resources, a top player in the Bakken Shale, averaged output of 591,315 boe/d in 2022, reported in 2023. Production totaled 690,299 boe/d across 2023, Enverus data show. That output established Continental, which founder Harold Hamm took private in 2022, as the top privately held E&P last year.

The second-largest private Rockies producer, Houston-based Hilcorp, gets its production in the region from the San Juan Basin of New Mexico and Colorado, and the Green River Basin of Wyoming. Hilcorp produced more than 1.5 MMcf/d of natural gas and 18,645 bbl/d of oil last year, Enverus data show.

Privately owned Grayson Mill Energy sold off its positions in the Powder River Basin in 2021 to focus on acquiring a large stake in the Bakken. The strategy helped make Grayson Mill the third-biggest private E&P with production of 148,466 boe/d.

Grayson Mill reportedly is exploring an acquisition in the $5 billion range. Publicly traded Chord Energy announced a $4 billion acquisition of Enerplus in 2024—an expansion it said was aimed at making Chord the largest producer in the Williston Basin.

Privately owned operator Terra Energy Partners became the fourth-largest privately owned producer in the Rockies by concentrating on the Piceance Basin in northwestern Colorado.

Much of Terra's production comes from the proven Williams Fork Formation in the Piceance. It's counting on deeper Mancos and Niobrara shales for future production. Terra brought nearly 618 Mcf/d to market, Enverus data show.

PW Consortium, the fifth-biggest privately held E&P, posted strong production from its $1.84 billion merger with PureWest Energy last year. PureWest focused on the Green River Basin of Wyoming. PW produced 604,956 cf/d.

Companies continue to produce profitably in the venerable Denver-Julesburg (D-J) Basin, which has attracted drillers since the 1860s and continues to generate more than 500,000 bbl/d of oil production.

Denver-based Bayswater Exploration and Production produced 34,937 bbl/d of oil and 88,834 cf/d of natural gas. It drills in the D-J and in the Permian.

Anschutz Exploration of Denver is one of the major holders of tracts in the Powder River Basin and is also drilling in the Piceance Basin, and the adjacent Uinta Basin in Utah. Auschutz produced 35,407 bbl/d of oil and 74,939 cf/d of gas.

Eastern U.S.

The focus of oil and gas production in the Eastern United States today is in the the Ohio and western Pennsylvania sections of the Appalachian Basin, which encompasses the Marcellus and Utica shales.

Less than 15 years ago, drillers were cautious about Utica's prospects because of the expected expense of tapping the estimated reserves of 38 Tcf of natural gas and 940 MMbbl of oil.

Today, Oklahoma City-based Ascent Resources and Encino Energy of Houston are among the top oil and gas producers in Ohio, where production from the Utica began in 2011. Enverus ranked Ascent as the second-largest producer among private E&P companies in 2023.

Ascent produced more than 2.4 MMcf/d of natural gas in 2023 from 862 wells, according to Enverus data. Encino sent more than 1 MMcf/d into the market from 1,090 wells.

Encino, the 10th-largest producer among private E&P companies in 2023, brought up 38,301 bbl/d from all its holdings while Ascent's output reached 19,892 bbl/d.

Utica gas and oil deposits are at average depths of about 8,000 feet, raising the cost of drilling vertical wells. Rapid advances in lateral drilling and hydraulic fracturing techniques brought production costs down substantially, and output ramped up rapidly after 2010, making the Utica a top natural gas play.

Infinity Natural Resources is a private E&P that's been buying up oily acreage in Ohio after initially focusing on dry gas production in southwest Pennsylvania. The firm has drilled some of the most prolific producing oil wells in the Ohio Utica.

Production in the Marcellus took off earlier than in the Utica, in part, because wells did not have to be as deep. Privately held companies that have been producing in the Marcellus Shale include PennEnergy Resources, Arsenal Resources and Apex Energy.

The average depth of Marcellus formations is between 6,000 and 7,000 feet. However, the location of hydrocarbon deposits in the formation requires drilling wells farther apart than in the Utica, increasing the per-acre costs per boe extracted.

The Energy Information Administration (EIA) estimates that the Marcellus contains about 410 Tcf of recoverable natural gas, and drilling is expected to surge once demand and prices recover sufficiently if regulatory obstacles can be overcome.

Some E&P capital spending is shifting away from the gassy Marcellus toward more oil-rich prospects in the Utica, both because of low gas prices and gas transport concerns.

Proximity to populated areas has slowed both pipeline construction and access.

The majority of the Utica is in New York, Ohio and Pennsylvania, but it extends into Maryland, New Jersey, Tennessee and Virginia, as well. Most of the activity in the Marcellus is in Ohio and Pennsylvania.

M&A activity in the region has focused not just on the size of potential production, but on maximizing access to and increasing the efficiency of pipelines and other infrastructure needed to bring gas to market.

Midcontinent

The Barnett Shale, where one of the richest deposits of natural gas in U.S. history is locked into rock underneath one of the most populated metro areas in the western United States, continues to be major play.

Denver-based BKV Corp. describes itself as one of the top 20 gas-weighted natural gas producers in the United States and the largest natural gas producer in the Barnett Shale, with 458,000 net acres and nearly 7,000 producing wells in the play.

Its Barnett holdings are in and near the Dallas-Fort Worth metroplex, primarily in Denton, Johnson, Parker, Tarrant and Wise counties. This proximity to the homes, businesses, and water supplies of 8 million people can make exploiting the Barnett more difficult than regions like the Permian that are in sparsely populated areas.

In addition, the Barnett is less permeable than other shale plays. Drillers must rely on heavy usage of hydraulic fracturing and horizontal drilling. While hundreds of miles of gas-gathering pipelines have been built in the play, Barnett gas must compete with production that is closer to the Gulf Coast industrial center and LNG export facilities.

E&Ps are overcoming the obstacles. Enverus research found BKV produced more gas from the Barnett than any other privately owned E&P company last year.

BKV produced 953,435 cf/d of natural gas from its entire portfolio, which includes gas from the Marcellus Shale in Pennsylvania as well as its core Barnett Shale holdings, Enverus research shows.

Not everyone relies on shale drilling to build its output. Merit Energy has taken a contrarian approach in the Midcontinent by acquiring mature wells. The Dallas-based company has picked up producing wells from companies that often are redirecting assets into shale plays. Merit operates in 12 states including Arkansas, Colorado, Kansas, Louisiana, New Mexico, Oklahoma, Texas and Wyoming.

Merit produced 598,713 cf/d of gas and 18,484 bbl/d of oil, Enverus data show.

Flywheel Energy says on its website that it is the largest producer in Arkansas' Fayetteville Shale. The Fayette Formation runs through Oklahoma and Arkansas, and is part of the Arkoma Basin.

Flywheel brought up 673,126 sq ft of natural gas a day, according to Enverus data. Drilling in the Fayetteville, which is named after a city in Arkansas, began in 2004. A strictly hydraulic fracturing play, drilling has risen and fallen as E&P companies and investors have looked for the most efficient strategies for exploiting the trapped gas.

Privately held BCE-Mach III, a partnership between Mach Resources and Bayou City Energy Management, owns gas properties in the venerable Anadarko Basin. The BCE-Mach III partnership extracted 444,094 cf/d.

The Anadarko Basin is in portions of Texas, Oklahoma, Kansas and Colorado. Sprawling 50,000 sq miles across the Southern Great Plains, the Anadarko produced the largest amount of natural gas of any area in the United States in the 1990s. Notable fields within the basin include the Hugoton-Panhandle Gas Field discovered in Kansas in 1922; the West Edmond Field; Union City Field; and the Elk City Field. Some of the deepest land wells on record have been drilled in the Anadarko.

Much of the success of private operators derives from continuous technological advances.

SHUTTERSTOCK

Gulf Coast

Low natural gas prices haven't stopped E&Ps from maintaining prolific production from the deep-well Haynesville Shale in 2024 in the Gulf Coast region.

A massive geological formation in southwestern Arkansas, northwest Louisiana and East Texas, the Haynesville saw gas flows surge beginning in 2008. The play represents one of the most spectacular success stories of the unconventional revolution, and its proximity to Gulf Coast exporters and users gives it added allure for investors compared to the Permian and Midcontinent.

Aethon Energy, which has been drilling profitable and high-producing wells as deep as 15,000 ft in the western Haynesville, is the No. 1 privately held producer in the play. In 2023, the Dallas-based company produced 2,523,070 cubic feet of natural gas a day from its multi-field portfolio, Enverus analysis shows.

Andrea Wescott Passman, Aethon COO, said in March that the company is finding "monsters" deep in the Haynesville and is drilling laterals as long as 1.5 miles to tap the potential. The company has midstream assets that help it get gas to market.

Houston-based TG Natural Resources, a major privately owned E&P operating in the Haynesville and Cotton Valley, produced an average of 1.5 MMcf/d, Enverus data indicates.

The Cotton Valley Formation underlies much of the northern Gulf of Mexico coastal plain from East Texas to Alabama. TG has tapped into Cotton Valley in East Texas and northern Louisiana.

The Lewis Energy Group has drilled into large portions of fields in Webb, La Salle, Dimmitt and McMullen counties in southwestern Texas, one of the most prolific regions for drilling into the Eagle Ford Shale. The Eagle Ford extends over 26 Texas counties from Eagle Pass and Laredo along the Mexican border through Temple and Waco.

Lewis's total production of 934,533 sq ft a day made it the fourth-largest privately held producer with Gulf Coast holdings.

Trinity Operating Group, which produced 963,162 cf/d in the first quarter, has drilled in both the Haynesville and Eagle Ford plays. Trinity says on its website that it drilled its first well in the Eagle Ford in 2018 and it moved into the Haynesville in 2019.

Privately owned drillers continue to produce gas from the Austin Chalk, a formation that overlays the Eagle Ford. The Chalk runs as shallow as 900 feet and as deep as 16,500 feet.

INEOS Energy has assets in the Giddings Austin Chalk region that include over 100 wells, production and exploration leases across 40,000 acres, its website states. Its assets in the Eagle Ford include 2,300 wells, production and exploration leases across 172,000 acres.

Verdun Oil also is a major player in the Eagle Ford and Austin Chalk.

Company data shows that Verdun owns more than 177,000 net mineral acres in the Eagle Ford trend in Dimmit, La Salle, Frio, McMullen, Live Oak, Atascosa, Karnes, Gonzales, and De Witt counties of Texas. It also owns 30,000 net acres in the Southern Giddings Chalk field centered in Washington County.

Verdun produced 173,004 cf/d and 54,520 bbl/d of oil, Enverus said. OGJ

SAVE THE DATE

NOVEMBER 20-21, 2024
MIDLAND COUNTY HORSESHOE ARENA
MIDLAND, TX

DUG EXECUTIVE OIL
CONFERENCE & EXPO

THE PERMIAN POWERS ENERGY SECURITY

The oil and gas (O&G) industry earned record profits in 2023, providing needed cash flow to fund their strategies in 2024. And while upstream O&G companies recognize geopolitical and macroeconomic uncertainty in the year ahead, they've also been given a clear mandate to secure supply in the short term while transitioning to cleaner energy.

Hart Energy's **DUG Executive Oil Conference and Expo** gathers industry leaders to provide a comprehensive view of global energy security, inflation, and the latest trends and technologies pertaining to the Permian Basin shale plays.

Don't miss connecting with more than 500 executives that attend **DUG Executive Oil Conference and Expo** each year.

SPONSORSHIP AND EXHIBIT OPPORTUNITIES

Let us help you build a sponsorship and exhibit package that meets your marketing objectives.
Contact: Darrin West | dwest@hartenergy.com

presented by: HARTENERGY

GOLD SPONSORS

Alvarez & Marsal | NSAI | PriorityPower

SILVER SPONSORS

Baker Hughes | Welltec

BRONZE SPONSOR

EnCap Investments L.P.

Top 100 Private E&Ps, FY 2023 (1-25)

2024 Rank	2023 Rank	Operator	Boe/d	Bbl/d	Mcf/d	% Liquids	Well Count	Average rig count (1Q 2024)	Key Region
1	1	CONTINENTAL RESOURCES	690,299	337,040	2,119,488	49%	5,102	20	ROCKIES
2	2	ASCENT RESOURCES	424,689	19,892	2,428,767	5%	862	3	EASTERN US
3	4	AETHON ENERGY	420,857	343	2,523,070	0%	1,899	7	GULF COAST
4	3	MEWBOURNE OIL	408,754	240,327	1,010,521	59%	3,310	23	PERMIAN
5	5	ENDEAVOR ENERGY	336,561	220,403	696,940	65%	3,372	11	PERMIAN
6	6	HILCORP	277,790	18,645	1,554,559	7%	20,431	1	ROCKIES
7	46	TG NATURAL RESOURCES	249,433	1,029	1,490,393	0%	2,410	4	GULF COAST
8	8	ENCINO ENERGY	216,926	38,301	1,071,731	18%	1,090	3	EASTERN US
9	9	TRINITY OPERATING	182,074	21,545	963,162	12%	1,527	5	GULF COAST
10	10	BKV CORP.	159,279	357	953,435	0%	5,977	0	MIDCONTINENT
11	11	LEWIS ENERGY GROUP	159,204	3,442	934,533	2%	2,300	2	GULF COAST
12	12	CROWNQUEST OPERATING	157,668	93,635	384,194	59%	1,524	5	PERMIAN
13	36	GRAYSON MILL OPERATING	148,466	93,414	330,289	63%	1,221	3	ROCKIES
14	14	MERIT ENERGY	118,296	18,484	598,713	16%	10,768	1	MIDCONTINENT
15	25	HG ENERGY	115,456	1,858	681,591	2%	94	2	EASTERN US
16	22	BIRCH OPERATIONS	113,340	74,585	232,526	66%	569	1	PERMIAN
17	15	FLYWHEEL ENERGY	112,198	-	673,126	0%	3,736	0	MIDCONTINENT
18	34	BCE-MACH III	108,892	34,866	444,094	32%	4,407	0	MIDCONTINENT
19	95	GEOSOUTHERN ENERGY	108,796	4,188	627,646	4%	308	2	GULF COAST
20	59	GBK CORP.	108,571	65,178	260,347	60%	541	1	PERMIAN
21	16	TERRA ENERGY PARTNERS	105,170	2,177	617,842	2%	7,039	1	ROCKIES
22	new	PUREWEST	104,885	4,050	604,956	4%	3,426	1	ROCKIES
23	23	PENNENERGY RESOURCES	100,881	841	600,237	1%	422	1	EASTERN US
24	19	CAERUS OIL & GAS	100,278	1,635	591,746	2%	7,282	1	ROCKIES
25	20	SABINE OIL & GAS	95,052	959	564,550	1%	572	3	GULF COAST

SOURCE: ENVERUS

*PRODUCTION IS AVERAGE GROSS OPERATED PRODUCTION OVER 2023, EXCLUDING ALASKA AND OFFSHORE

Top 100 Private E&Ps, FY 2023 (26-50)

2024 Rank	2023 Rank	Operator	Boe/d	Bbl/d	Mcf/d	% Liquids	Well Count	Average rig count (1Q 2024)	Key Region
26	32	PALOMA NATURAL GAS	92,160	-	552,957	0%	117	1	GULF COAST
27	24	CITIZEN ENERGY III	88,416	15,823	435,543	18%	655	2	MIDCONTINENT
28	33	NORTHEAST NATURAL	85,890	-	515,339	0%	150	1	EASTERN US
29	38	SCOUT ENERGY PARTNERS	83,939	25,239	351,990	30%	15,708	1	MIDCONTINENT
30	21	VERDUN OIL CO.	83,355	54,520	173,004	65%	1,302	2	GULF COAST
31	27	AERA ENERGY	82,737	77,692	30,164	94%	9,805	0	WESTERN US
32	28	SIMCOE	81,869	217	489,854	0%	3,615	0	ROCKIES
33	35	SURGE OPERATING	79,771	56,053	142,308	70%	806	3	PERMIAN
34	39	BTA OIL PRODUCERS	73,160	42,795	182,183	58%	448	3	PERMIAN
35	49	OLYMPUS ENERGY	72,318	-	433,910	0%	77	1	EASTERN US
36	17	TAP ROCK RESOURCES	69,137	38,247	185,337	55%	170	0	PERMIAN
37	31	JONAH ENERGY	68,543	3,325	391,264	5%	2,465	0	ROCKIES
38	30	PETRO-HUNT	67,247	41,265	155,878	61%	925	3	ROCKIES
39	new	INEOS ENERGY	66,036	47,705	109,978	72%	1,775	1	GULF COAST
40	40	MAVERICK NATURAL RESOURCES	64,951	16,207	292,420	25%	3,223	0	MIDCONTINENT
41	55	KRAKEN RESOURCES	62,564	49,625	77,629	79%	423	1	ROCKIES
42	100	GRIT OIL & GAS MANAGEMENT	61,426	36,647	148,675	60%	340	1	GULF COAST
43	42	CAMINO NATURAL RESOURCES	58,195	9,612	291,495	17%	201	3	MIDCONTINENT
44	41	BLACKBEARD OPERATING	54,888	25,079	178,847	46%	1,887	2	PERMIAN
45	50	SILVER HILL ENERGY PARTNERS	53,814	2	322,868	0%	86	1	GULF COAST
46	47	FASKEN OIL & RANCH	53,742	36,637	102,630	68%	1,286	2	PERMIAN
47	new	XCL RESOURCES	51,338	44,831	39,045	87%	179	4	ROCKIES
48	37	SLAWSON EXPLORATION	50,463	39,477	65,908	78%	556	1	ROCKIES
49	48	BAYSWATER E&P	49,743	34,937	88,834	70%	426	2	ROCKIES
50	new	WILDFIRE ENERGY	49,550	41,347	49,206	83%	1,433	1	GULF COAST

SOURCE: ENVERUS

Top 100 Private E&Ps, FY 2023 (51-75)

2024 Rank	2023 Rank	Operator	Boe/d	Bbl/d	Mcf/d	% Liquids	Well Count	Average rig count (1Q 2024)	Key Region
51	65	KIMMERIDGE TEXAS GAS	48,466	3,026	272,637	6%	288	2	GULF COAST
52	73	FRANKLIN MOUNTAIN ENERGY	48,383	38,568	58,888	80%	173	2	PERMIAN
53	75	ANSCHUTZ CORP.	47,898	35,407	74,939	74%	245	3	ROCKIES
54	45	SNYDER BROTHERS	43,472	52	260,500	0%	1,849	1	EASTERN US
55	89	VERDAD RESOURCES	41,456	29,900	69,331	72%	344	2	ROCKIES
56	51	CROWHEART ENERGY	41,181	6,189	209,917	15%	2,746	0	ROCKIES
57	81	KODA RESOURCES	40,086	6,116	203,807	15%	966	3	ROCKIES
58	58	SEQUITUR ENERGY	38,067	13,570	146,984	36%	443	1	PERMIAN
59	43	LIME ROCK	37,912	20,901	102,050	55%	1,078	0	MIDCONTINENT
60	80	FORMENTERA PARTNERS	36,109	16,821	115,715	47%	2,239	0	MIDCONTINENT
61	57	SPUR ENERGY PARTNERS	36,062	22,869	79,119	63%	2,750	1	PERMIAN
62	new	AMEREDEV II	35,921	21,379	87,250	60%	101	0	PERMIAN
63	new	VTX ENERGY OPERATING	34,252	24,964	55,727	73%	257	3	PERMIAN
64	70	GREYLOCK ENERGY	33,659	965	196,124	3%	2,366	1	EASTERN US
65	83	DISCOVERY NATURAL RESOURCES	32,516	13,944	111,423	43%	1,070	1	PERMIAN
66	new	ARSENAL RESOURCES	31,949	-	191,692	0%	103	0	EASTERN US
67	77	CITATION OIL & GAS	31,402	22,992	50,456	73%	2,640	0	MIDCONTINENT
68	66	R. LACY SERVICES	30,776	214	183,367	1%	230	0	GULF COAST
69	new	INFINITY NATURAL RESOURCES	30,683	8,851	130,991	29%	117	1	EASTERN US
70	63	PRESIDIO PETROLEUM	30,639	5,373	151,569	18%	2,233	0	MIDCONTINENT
71	61	ESCONDIDO RESOURCES	30,572	268	181,817	1%	172	0	GULF COAST
72	82	CANVAS ENERGY	30,215	12,307	107,439	41%	570	1	MIDCONTINENT
73	new	JAY-BEE O&G	29,992	624	176,202	2%	518	0	EASTERN US
74	92	PENNSYLVANIA GENERAL ENERGY	29,865	1	179,187	0%	186	1	EASTERN US
75	68	UPP OPERATING	29,669	242	176,471	1%	6,302	0	MIDCONTINENT

SOURCE: ENVERUS

Top 100 Private E&Ps, FY 2023 (76-100)

2024 Rank	2023 Rank	Operator	Boe/d	Bbl/d	Mcf/d	% Liquids	Well Count	Average rig count (1Q 2024)	Key Region
76	99	SENTINEL PEAK RESOURCES	29,397	27,097	13,773	92%	3,394	0	WESTERN US
77	86	89 ENERGY III	29,060	12,944	96,693	45%	255	1	MIDCONTINENT
78	93	CALYX ENERGY III	28,383	27	170,130	0%	135	0	MIDCONTINENT
79	new	URBAN OIL & GAS GROUP	27,994	1,944	156,247	7%	3,975	0	ROCKIES
80	97	LOGOS RESOURCES II	27,982	771	163,245	3%	1,356	0	ROCKIES
81	90	STEWARD ENERGY II	26,975	18,497	50,870	69%	217	0	PERMIAN
82	72	CARBON CREEK ENERGY	26,872	-	161,170	0%	4,121	0	ROCKIES
83	78	MORNINGSTAR OPERATING	26,494	5,209	127,691	20%	1,385	0	ROCKIES
84	new	PURSUIT OIL & GAS	26,091	-	156,547	0%	33	0	GULF COAST
85	79	BEDROCK ENERGY PARTNERS	25,716	178	153,208	1%	1,093	0	MIDCONTINENT
86	67	SUMMIT PETROLEUM	25,634	15,169	62,792	59%	328	2	PERMIAN
87	new	DE IV OPERATING	25,557	20,981	27,451	82%	259	5	PERMIAN
88	new	TRIPLE CROWN RESOURCES	25,074	12,044	78,182	48%	235	1	PERMIAN
89	69	BLUE DOME OPERATING	24,982	-	149,891	0%	34	0	GULF COAST
90	87	ZARVONA ENERGY	24,626	8,519	96,629	35%	1,420	0	PERMIAN
91	91	ENDURING RESOURCES	24,606	11,985	75,707	49%	979	1	ROCKIES
92	96	UINTA WAX OPERATING	23,710	19,997	22,269	84%	675	2	ROCKIES
93	new	TRP OPERATING	23,337	17,371	35,794	74%	162	1	PERMIAN
94	new	RIDGEMAR ENERGY OPERATING	22,642	17,024	33,708	75%	619	1	GULF COAST
95	new	ENSIGHT IV ENERGY MANAGEMENT	22,557	135	134,534	1%	168	0	GULF COAST
96	new	APEX ENERGY	22,248	28	133,315	0%	68	0	EASTERN US
97	94	ZAVANNA	21,795	8,303	80,950	38%	151	0	ROCKIES
98	new	PERMIAN DEEP ROCK OIL CO.	21,665	16,174	32,944	75%	70	2	PERMIAN
99	new	TRIBUNE RESOURCES	21,361	345	126,095	2%	265	0	EASTERN US
100	new	RIO O&G II	21,071	7,042	84,172	33%	52	0	PERMIAN

SOURCE: ENVERUS

Top 20 Private Oil Operators

Bbl/d Ranking	Boe/d Ranking	Operator	Bbl/d
1	1	CONTINENTAL RESOURCES	337,040
2	4	MEWBOURNE OIL	240,327
3	5	ENDEAVOR ENERGY	220,403
4	12	CROWNQUEST OPERATING	93,635
5	13	GRAYSON MILL OPERATING	93,414
6	31	AERA ENERGY	77,692
7	16	BIRCH OPERATIONS	74,585
8	20	GBK CORP.	65,178
9	33	SURGE OPERATING	56,053
10	30	VERDUN OIL CO.	54,520
11	41	KRAKEN RESOURCES	49,625
12	39	INEOS ENERGY	47,705
13	47	XCL RESOURCES	44,831
14	34	BTA OIL PRODUCERS	42,795
15	50	WILDFIRE ENERGY	41,347
16	38	PETRO-HUNT	41,265
17	48	SLAWSON EXPLORATION	39,477
18	52	FRANKLIN MOUNTAIN ENERGY	38,568
19	8	ENCINO ENERGY	38,301
20	36	TAP ROCK RESOURCES	38,247

Top 20 Private Gas Operators

Mcf/d Ranking	Boe/d Ranking	Operator	Mcf/d
1	3	AETHON ENERGY	2,523,070
2	2	ASCENT RESOURCES	2,428,767
3	1	CONTINENTAL RESOURCES	2,119,488
4	6	HILCORP	1,554,559
5	7	TG NATURAL RESOURCES	1,490,393
6	8	ENCINO ENERGY	1,071,731
7	4	MEWBOURNE OIL	1,010,521
8	9	TRINITY OPERATING	963,162
9	10	BKV CORPORATION	953,435
10	11	LEWIS ENERGY GROUP	934,533
11	5	ENDEAVOR ENERGY	696,940
12	15	HG ENERGY	681,591
13	17	FLYWHEEL ENERGY	673,126
14	19	GEOSOUTHERN ENERGY	627,646
15	21	TERRA ENERGY PARTNERS	617,842
16	22	PUREWEST ENERGY	604,956
17	23	PENNENERGY	600,237
18	14	MERIT ENERGY	598,713
19	24	CAERUS OIL & GAS	591,746
20	25	SABINE OIL & GAS	564,550

SOURCE: ENVERUS

Top 20 Private Permian Operators

Permian Rank	2024 Rank	Operator	Boe/d
1	4	MEWBOURNE OIL	408,754
2	5	ENDEAVOR ENERGY	336,561
3	12	CROWNQUEST OPERATING	157,668
4	16	BIRCH OPERATIONS	113,340
5	20	GBK CORP.	108,571
6	33	SURGE OPERATING	79,771
7	34	BTA OIL PRODUCERS	73,160
8	36	TAP ROCK RESOURCES	69,137
9	44	BLACKBEARD OPERATING	54,888
10	46	FASKEN OIL & RANCH	53,742
11	52	FRANKLIN MOUNTAIN ENERGY	48,383
12	58	SEQUITUR ENERGY	38,067
13	61	SPUR ENERGY PARTNERS	36,062
14	62	AMEREDEV II	35,921
15	63	VTX ENERGY OPERATING	34,252
16	65	DISCOVERY NATURAL RESOURCES	32,516
17	81	STEWARD ENERGY II	26,975
18	86	SUMMIT PETROLEUM	25,634
19	87	DE IV OPERATING	25,557
20	88	TRIPLE CROWN RESOURCES	25,074

Top 20 Private Rockies Operators

Regional Rank	2024 Rank	Operator	Boe/d
1	1	CONTINENTAL RESOURCES	690,299
2	6	HILCORP	277,790
3	13	GRAYSON MILL OPERATING	148,466
4	21	TERRA ENERGY PARTNERS	105,170
5	22	PUREWEST	104,885
6	24	CAERUS OIL & GAS	100,278
7	32	SIMCOE	81,869
8	37	JONAH ENERGY	68,543
9	38	PETRO-HUNT	67,247
10	41	KRAKEN RESOURCES	62,564
11	47	XCL RESOURCES	51,338
12	48	SLAWSON EXPLORATION	50,463
13	49	BAYSWATER E&P	49,743
14	53	ANSCHUTZ CORP.	47,898
15	55	VERDAD RESOURCES	41,456
16	56	CROWHEART ENERGY	41,181
17	57	KODA RESOURCES	40,086
18	79	URBAN OIL & GAS GROUP	27,994
19	80	LOGOS RESOURCES II	27,982
20	82	CARBON CREEK ENERGY	26,872

SOURCE: ENVERUS

Top 15 Private Midcontinent Operators

Regional Rank	2024 Rank	Operator	Boe/d
1	10	BKV CORP.	159,279
2	14	MERIT ENERGY	118,296
3	17	FLYWHEEL ENERGY	112,198
4	18	BCE-MACH III	108,892
5	27	CITIZEN ENERGY III	88,416
6	29	SCOUT ENERGY PARTNERS	83,939
7	40	MAVERICK NATURAL RESOURCES	64,951
8	43	CAMINO NATURAL RESOURCES	58,195
9	59	LIME ROCK	37,912
10	60	FORMENTERA PARTNERS	36,109
11	67	CITATION OIL & GAS	31,402
12	70	PRESIDIO PETROLEUM	30,639
13	72	CANVAS ENERGY	30,215
14	75	UPP OPERATING	29,669
15	77	89 ENERGY III	29,060

Top 15 Private Gulf Coast Operators

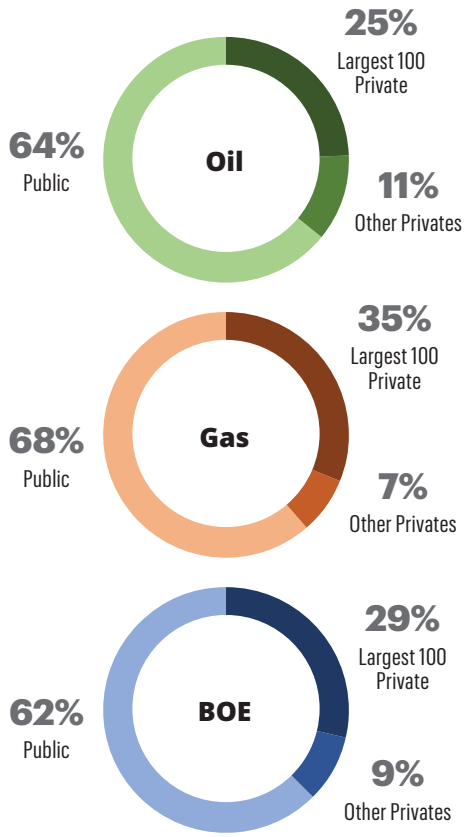
Regional Rank	2024 Rank	Operator	Boe/d
1	3	AETHON ENERGY	420,857
2	7	TG NATURAL RESOURCES	249,433
3	9	TRINITY OPERATING	182,074
4	11	LEWIS ENERGY GROUP	159,204
5	19	GEOSOUTHERN ENERGY	108,796
6	25	SABINE OIL & GAS	95,052
7	26	PALOMA NATURAL GAS	92,160
8	30	VERDUN OIL COMPANY	83,355
9	39	INEOS ENERGY	66,036
10	42	GRIT OIL & GAS MANAGEMENT	61,426
11	45	SILVER HILL ENERGY PARTNERS	53,814
12	50	WILDFIRE ENERGY	49,550
13	51	KIMMERIDGE TEXAS GAS	48,466
14	68	R. LACY SERVICES	30,776
15	71	ESCONDIDO RESOURCES	30,572

SOURCE: ENVERUS

Top 10 Private Eastern U.S. Operators

Regional Rank	*2024 Rank*	*Operator*	*Boe/d*
1	2	ASCENT RESOURCES	424,689
2	8	ENCINO ENERGY	216,926
3	15	HG ENERGY LLC	115,456
4	23	PENNENERGY	100,881
5	28	NORTHEAST NATURAL	85,890
6	35	OLYMPUS ENERGY	72,318
7	54	SNYDER BROTHERS	43,472
8	64	GREYLOCK ENERGY	33,659
9	66	ARSENAL RESOURCES	31,949
10	69	INFINITY NATURAL RESOURCES	30,683

SOURCE: ENVERUS



SOURCE: ENVERUS

BRING YOUR VISION TO LIFE!

GOTHAM IMAGE WORKS
A HART ENERGY COMPANY
25

CUSTOM VIDEO & EVENT PRODUCTION

Our sophisticated toolbox of 3-D animation and graphics, digital video production, state-of-the-art presentation technology and professional staging will turn your vision into reality with confidence.

From once-in-a-lifetime events to ongoing marketing programs, Gotham's strategic approach and ability to balance business goals and budget objectives turns clients into partners, and keeps them coming back.

Meetings, Conferences & Trade Shows

Corporate Video Communications

Global Production Services

A/V Installations & Exhibits

For more information contact:
David Skalsky | dskalsky@hartenergy.com
713.662.3636

Scan here to view our highlight reel

BEETALOO JUICE

US SHALE EXPLORES DOWN UNDER

Tamboran Resources has put together the largest shale gas leasehold in Australia's Beetaloo Basin, with plans for a 1.5+ Bcf/d play. Behind its move now to manufacturing mode are American geologists and E&P builders, a longtime Australian wildcatter, a U.S. shale rig operator and a U.S. shale pressure pumper.

NISSA DARBONNE
EXECUTIVE
EDITOR-AT-LARGE
@NissaDarbonne
ndarbonne@hartenergy.com
@NissaDarbonne

Bryan Sheffield first heard of an Australian shale opportunity in 2013.

He heard about it from his dad–Scott Sheffield, a more than 40-year wildcatter and the now-retired founding CEO of Pioneer Natural Resources, which was sold to Exxon Mobil in May.

The elder Sheffield had contacts in and out of Australia for years. Pioneer's predecessor–Midland-based Parker & Parsley Petroleum, which was co-founded by the younger Sheffield's late grandfather, Joe Parsley, who retired in 1984–bought Australia-based Bridge Oil in 1994 for some $330 million.

At the time, Parker & Parsley put Bridge's U.S. property into its own operations and made the Bridge entity its international subsidiary. Bridge's portfolio included production from conventional rock in the Timor Sea offshore Darwin.

When Bryan Sheffield's dad bought Bridge, "my father brought us to Australia a couple of times when I was in high school while he was growing the asset there. We spent a lot of time in Sydney and the outer areas."

He enjoyed it and was anxious to return. After graduating from Southern Methodist University in 2001, he found a Sydney-based energy-sector job with Credit Suisse First Boston.

Later returning to the U.S., he continued to work in finance until 2006 when starting school at Pioneer to learn how to make oil and gas wells. In 2008, he founded Parsley Energy, starting with Midland Basin wells his grandfather owned.

In 2013, his dad phoned. "He said, 'Bryan, I saw some logs. I've never seen anything like this in all the fields in the world.'"

The elder Sheffield had built producing properties from West Texas to Tunisia, Argentina, South Africa and Canada before eventually refocusing Pioneer to its Permian Basin roots upon U.S. wildcatters' success in extracting oil from tight rock.

He continued, "It's stacked pay." The reservoir is dry gas and looked like the Marcellus Shale, he added.

Bryan Sheffield was intrigued but said, "I'm about to IPO. I have to focus on the Midland Basin."

Yet it was noteworthy–for more than the play's description. "You could tell that he was excited. We always talked about the Permian Basin. For him to talk about something in Australia, I took a mental note."

Enter Aubrey

In 2015, Aubrey McClendon was on the front page of the Wall Street Journal–for buying into Australian shale gas. The late co-founder of Chesapeake Energy had been at the front of land grabs in nascent U.S. shale

Decades in the Making

When Bryan Sheffield looked at logs in 2020 of Beetaloo wells, it meant that other operators had looked at it before.

So why was the basin still open for new entry?

Sheffield, who was in the midst of selling his Permian-focused Parsley Energy at the time, said, "That's what I wanted to know: Why hasn't someone else picked it up?"

Altogether, operators and non-op partners have spent more than $600 million exploring the Beetaloo, according to a Tamboran Resources Corp. estimate.

Denver-based Robert L. Bayless Producer identified the Beetaloo as a shale basin in the mid-1990s, said Dick Stoneburner, Tamboran chairman.

"This is before the Barnett," Stoneburner noted. "This was very pioneering on [the late] Rob Bayless' part to identify a shale reservoir in Australia before much had been done in the United States, certainly from a horizontal standpoint. These guys were ahead of their time."

Pacific Oil and Gas had looked at

Left to right, Bryan Sheffield, the largest Tamboran Resources shareholder at press time; Scott Sheffield, multi-decade wildcatter who introduced Bryan to the Beetaloo Basin opportunity; and Chris Wright, chairman and CEO of Liberty Energy.

BRYAN SHEFFIELD

"So, I did a personal private placement with Tamboran [Resources]."

BRYAN SHEFFIELD, on his entry into Australia's Beetaloo Basin.

plays, namely the Marcellus and the Haynesville.

With a new startup, American Energy Partners, McClendon signed a deal to farm into the Beetaloo Basin.

The basin's 11,000 square miles are the equivalent of a dozen Midland Counties.

"And I am so upset because Aubrey has money and he's beating us on every Midland Basin deal [too] right now," Bryan Sheffield said.

"I could have been ahead of Aubrey. I could have beaten him, gone in and picked up some acreage for cheap halfway around the world. My father told me about it two years before."

McClendon died in 2016 "and the play kind of fizzled during a Northern Territory frac moratorium." The pause was lifted in 2018 but momentum had been lost.

And Sheffield was still busy building his Parsley Energy, which he sold in January 2021 for $7.6 billion to Pioneer.

Again, the Beetaloo

Australia found Sheffield again in 2020, while the Parsley sale was signed but not yet closed. "Funny enough," he said, "Tom Layman, one of the most conservative geologists I've ever met who I recruited from Chesapeake, told me at the end of 2020, 'Bryan, I just saw logs.'"

the Beetaloo in 1984 and drilled 12 verticals into the Velkerri through 1993. But it tapped the basin's conventional rock and results weren't good enough. Pacific Oil left.

Next, Sweetpea Corp. picked up permits in the early 2000s and drilled the vertical Shenandoah #1 in 2007 but to only 5,000 feet and stopped.

Falcon Oil & Gas took over four permits in 2009. It re-entered and deepened Shenandoah #1, renaming it the #1A, to 8,900 feet. In 2011, it did the first hydraulic frac job in an Australian shale.

In 2011, Hess Corp. farmed into Falcon permits. Hess had to leave a few years later, though, when activist investor Elliott Management persuaded it to sell down to only the Bakken and Guyana.

South Africa's Sasol partnered with Falcon, drilling three verticals and one horizontal in 2015 and 2016.

Around that time, Pangaea Resources drilled some wells in the westernmost Beetaloo. And Tamboran farmed out 75% of one of its permits to Santos.

Then the Northern Territory put a pause on completions. Very little was done in the Beetaloo for the next four years.

Dick Stoneburner, chairman, Tamboran Resources and Joel Riddle, CEO.

DANIEL ORTIZ

Layman had retired from Parsley in 2019. "He's very conservative. Everything he did was low-risk. He was very careful."

Sheffield had signed a confidentiality agreement with Sydney-based Tamboran Resources when considering whether to invest in the E&P. That Layman was enthusiastic about what he saw in the logs "caught my attention because I know that when a conservative geologist says there's something I should look at, then I should look at it."

The logs were from the Beetaloo. It was stacked pay. "And that makes me feel better because, if one horizon doesn't work, at least you have a chance to try to make another horizon work."

The rock of interest—the Velkerri—is similar to the Marcellus Shale. Total organic carbon (TOC) is up to 12%. Bottomhole pressure is 0.6 psi. Porosity is good.

Sheffield called Tamboran's chairman, Dick Stoneburner. On the one hand, Australia was off Sheffield's radar: He was building Formentera Partners, buying proved developed producing property onshore the U.S. with a model of paying out profits. He wasn't wildcatting.

"So, I did a personal private placement with Tamboran." The 7.4% stake closed in November 2021 for $20 million.

Now having equity in the Beetaloo, he bought into another interest-owner, Falcon Oil & Gas, which had a non-op in the same property with partner Origin Energy. The 8.66% stake cost $10 million. Sheffield gained an extra 2% overriding royalty interest for an additional $6 million. Falcon's cash on hand at the time was $8.4 million.

"I bought into Empire [Energy Group] also. I'm trying to spread my chips with all the players," Sheffield said.

Then, Origin, a top Australian utility, decided to divest its gas E&P business and focus on its power business.

In deals with Sheffield, Falcon and Origin, Tamboran became the largest Beetaloo acreage-holder, totaling 1.9 million net of the 4.7 million gross that are contiguous within the 7-million-acre basin.

And Sheffield became Tamboran's largest shareholder with 16.7% of outstanding common. At press time, the E&P planned to list on the NYSE in a U.S. IPO.

11K
square miles of the Beetaloo Basin

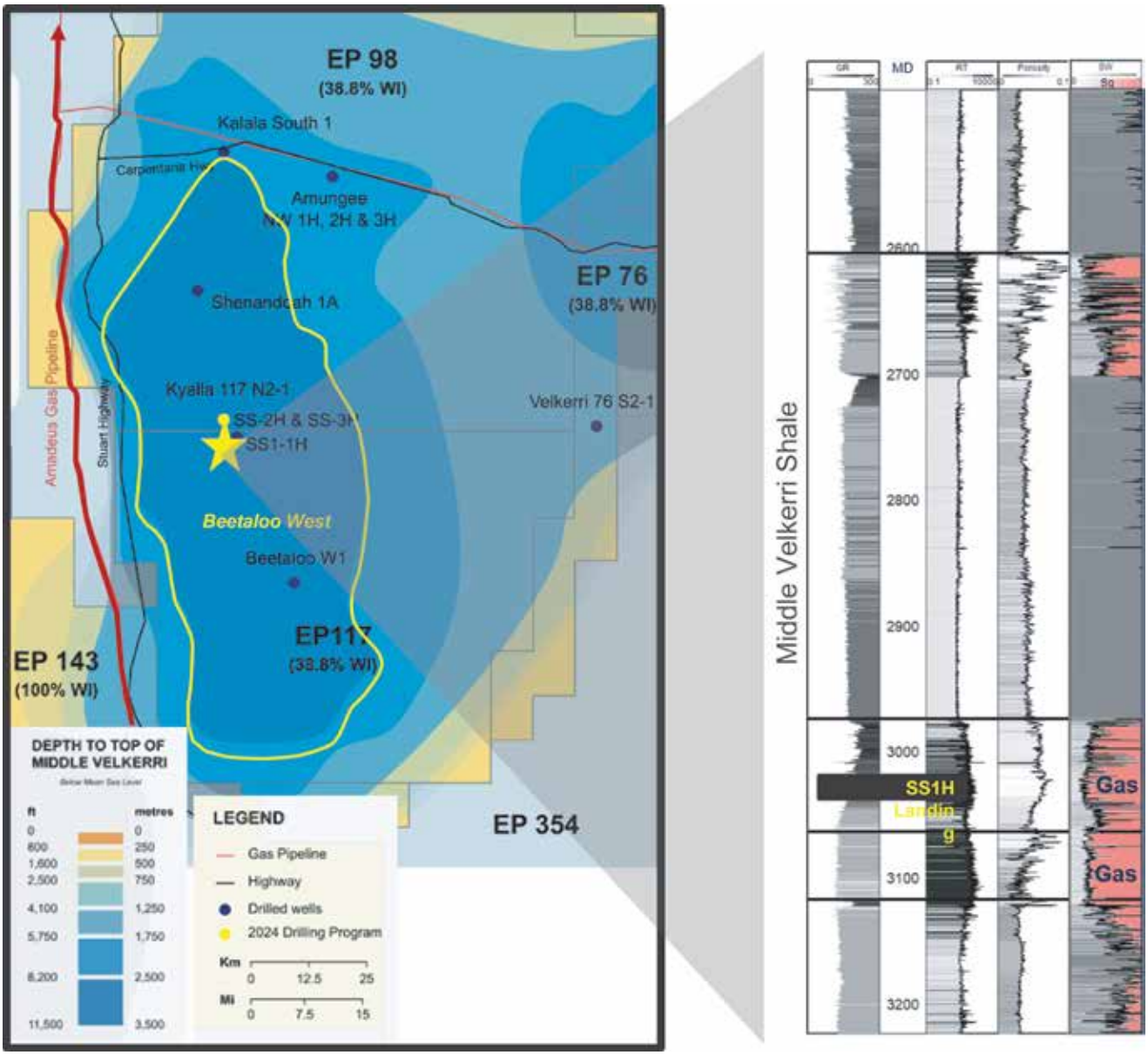
Stoneburner's Entrance

Stoneburner got involved in the Beetaloo when approached to join the Tamboran board in 2014. He was scheduled to speak at Hart Energy's DUG Australia conference in Brisbane that August.

He held renown Down Under as the geologist who was a lead developer of the Haynesville Shale with Petrohawk Energy beginning in early 2008, then making the Eagle Ford Shale discovery later in 2008.

He was already connected to Australia by way of BHP Billiton, which bought Petrohawk in 2012 for $15.1 billion. Stoneburner had stayed on for a year post-closing as president of BHP's new North American shale division that consisted of the Petrohawk asset.

Beetaloo Basin Sample Wells and SS1H Log



SOURCE: TAMBORAN RESOURCES

Beetaloo Basin wells to date have defined the Velkerri Shale's core. Tamboran Resources' most recent well, Shenandoah South #1H, was landed in the Middle Velkerri B, which is the primary target, at about 3,000 meters. The underlying Velkerri C is an additional target.

After the Hart Energy conference, Stoneburner dropped into Sydney to meet with Tamboran.

Joel Riddle, CEO, had joined the E&P in 2013. Prior, he had worked for offshore explorer Cobalt International Energy in the Gulf of Mexico and West Africa, and began his career in 1997 with Exxon Mobil, later joining Unocal and Murphy Oil.

Pat Elliott, Tamboran chairman, had formed the Beetaloo explorer in 2009 after having success in Australian coal-seam gas.

Stoneburner said of the visit, "I met Pat, Joel and a few of the other board members." That was mostly the extent of the team. "It was a pretty bare-bones group."

Tanumbirini #1

When Riddle had joined a year earlier, Tamboran's exploration licenses ranged from eastern Australia to Ireland, Northern Ireland and Botswana.

Riddle said, "We had a pretty colorful portfolio at the time. I spent the first six months in the job locked in a room with my technical team, which at the time consisted of a few consultants, and I had them explain or attempt to explain the technical rationale for all the assets we owned."

Riddle proposed to the board that Tamboran fully focus on the Beetaloo. Its sole interest in the basin was 25% in a permit in which Santos was the operator.

By 2014, when Stoneburner visited, Santos had just drilled the Tanumbirini #1 vertical.

Stoneburner looked at the log. "While we didn't have a full analysis," he said, "it looked very attractive.

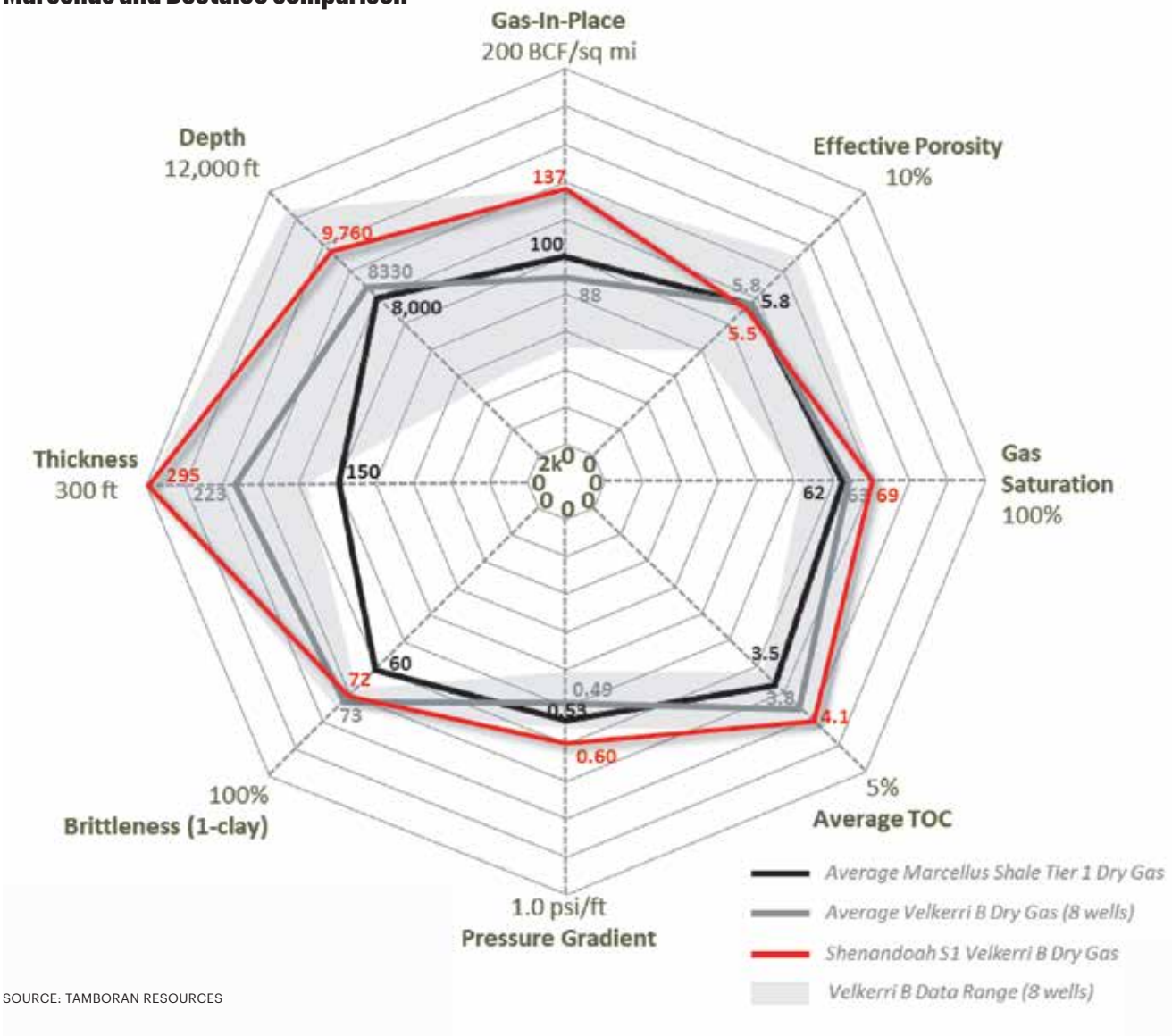
"That got me even more interested: It wasn't just a speculative play, but a real play based upon the first contemporary log, really, being run in the basin."

Stoneburner joined the board. Elliott and Riddle were

Bryan Sheffield, Tamboran's lead investor, and Joel Riddle, Tamboran's CEO, at the Shenandoah South #1H last summer as it was being drilled by Helmerich & Payne's FlexRig 469.

BRYAN SHEFFIELD

Marcellus and Beetaloo comparison



SOURCE: TAMBORAN RESOURCES

Tamboran Resources' findings in the Beetaloo's Velkerri B formation show characteristics similar to the Marcellus Shale.

also able to recruit another geologist, Fred Barrett, who had co-founded U.S. tight-gas developer Bill Barrett Corp.

In 2021, Stoneburner became chairman, prior to Tamboran's Australian IPO.

"Pat had been chair since the beginning in 2009," Stoneburner said. "The general rationale was, as we were going public, to have an American chairman with some name recognition within Australia.

"Not that Pat didn't have it, but I kind of fit the bill. So, I became chairman."

Precambrian

The story of the Beetaloo is nearly as old as Earth itself. The rock of interest—the 2,600-foot-thick Velkerri—was deposited some 1.4 billion years ago in the Proterozoic eon of the late Precambrian era.

At the time, the Velkerri was a sea of blue-green algae before Pangaea was formed. The eon spanned some 2 billion years, culminating with the Cambrian Explosion about a half-billion years ago.

"There aren't near as many critters, if you will, living about 1.4 billion years ago," Stoneburner explained. "Life didn't really explode until about 600 million years ago. And since then is when most of the North American shale reservoirs were deposited."

For its age, one would think the Velkerri would be over-mature, but "these rocks don't know how old they are," Stoneburner said.

Core pulled by past explorers contained "weird fossils," geologists Matthew Silverman with Denver-based Robert L. Bayless Producer and Thomas Ahlbrandt with Australia's Falcon told fellow geologists in 2011 in an American Association of Petroleum Geologists presentation.

They described the Beetaloo as an aborted rift basin rather than an intracratonic sag.

Stoneburner said, "This is the only 1.4-billion-year-old sedimentary rock that has been preserved in the world. There aren't a lot of sedimentary basins around that are Precambrian.

"Before Cambrian, there's just not a lot of sediment. You have granitic rock. But then, you have something like the Velkerri where you actually have preserved, 1.4-billion-year-old rock."

Left to right, John Lindsay, H&P president and CEO, and Hans Helmerich, chairman, in H&P's Tulsa, Okla., command center with FlexRig 469 shown drilling the Shenandoah South #1H in Australia.

HELMERICH & PAYNE

Middle Velkerri B

The lateral target is primarily the Middle Velkerri B at between 8,000 and 11,000 feet. "It's probably three to four times older than the oldest shale reservoir in North America," Stoneburner said.

"I wasn't concerned about the generation of what we call thermal gas as opposed to biogenic gas. What I was concerned about was that it would be over-mature—that you would have a basin that's that old, that you're either going to have the gas diminished or potentially a lot of inerts.

"You could have a lot of CO_2; you could have a lot of nitrogen, which is common in Australia to begin with."

Instead, vertical and horizontal tests showed the gas to be 92% methane with between 2% and 4% CO_2. "So, you have very high-quality gas that we don't have to process any liquids out of. We basically just have to strip the CO_2."

The Velkerri C member also tested well. "It's very comparable," Stoneburner said.

1,500
Human population of the basin

Unchanging Facies

The Beetaloo's core of 5 million acres became concentrated through uplifts, erosion and other geological events. So, facies are unchanging in the acres.

"You just have a core area that you can kind of depend on being pretty consistent," Stoneburner said. "In this case, you have 5 million acres. It's the core of the basin; everything else is gone. This is just one solid blue-green algae in three different [Velkerri A, B and C] blankets."

For horizontal development, "this is as good as it gets. There's very little faulting. It's a very quiet basin."

It's not your typical sweet spot. Riddle said, "The whole basin is sweet." In holes made in the Velkerri north, south, east and west, "there it was, right where it was supposed to be."

Pressure rather than rock quality will define the basin's tiers in the case of the Beetaloo, Stoneburner said. At the core's northernmost end, it's 0.43 psi per foot, while other wells show 0.6 psi.

The lower-pressure area will work, "but it's just not going to work as well as a rock that's got 0.6. You pack more gas in 0.6 than you can in 0.43," Stoneburner said.

"So, you're going to get higher flow rates and higher EUR. They'll both work, but pressure always creates a better volume, a better resource."

The surface- and minerals-rights situation is also quiet. The Northern Territory owns the land and minerals. "It's similar to what you might see in the Gulf of Mexico," Riddle said. "There's no private land out here."

The terrain is quiet, too. Across the 5 million acres, there's no remarkable difference in elevation or vegetation. The 5 million acres are "flat scrub. It's development-ready," Riddle said.

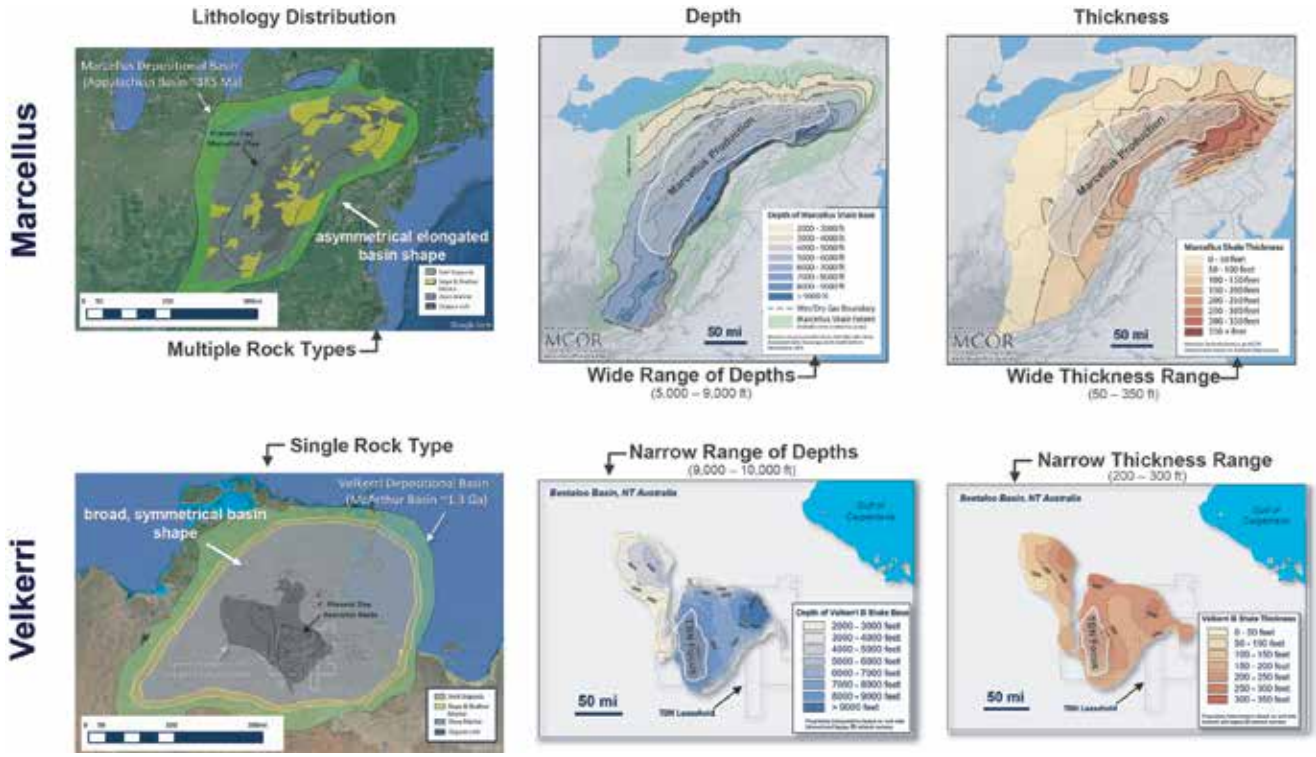
As for the surface lease-holders, four ranches hold 99-year leases on most of the land.

The Wells

Tamboran's data points come from 21 wells that have been drilled through the Middle Velkerri by it and others. Tamboran participated in seven; it's the operator of four.

Its newest well, Shenandoah South #1H, was drilled in August by a Helmerich & Payne shale-level super-spec

Marcellus and Velkerri comparison



SOURCE: TAMBORAN RESOURCES

An analysis of the Velkerri shale and Marcellus by lithology distribution, depth and thickness.

FlexRig3, flowing 3.2 MMcf/d its first 30 days from a 1,644-foot lateral in a 295-foot section of Middle Velkerri B. It underwent a 10-stage frac.

The 60-day rate was 3.0 MMcf/d; the 90-day rate, 2.9 MMcf/d.

Normalized for a 10,000-foot lateral, the 30-day rate would have been 19.5 MMcf/d.

The pressure gradient was approximately 0.6 psi per foot; the initial wellhead pressure, 4,611 psi.

Tamboran has a 38.75% working interest; its partners are Sheffield's Daly Waters Energy and Falcon.

The rig reached total depth in 21.5 days, averaging 500 feet per day.

Another new well, Amungee NW #3H, was drilled by H&P in September but it's been DUC'ed, awaiting arrival of a Liberty Energy frac spread later this quarter.

The #3H hole was made from the same pad as the year-old Amungee NW #2H that was drilled by another rig operator in 38 days. The H&P rig did the newer job in fewer than 18 days—the fastest rate yet in the Beetaloo, according to Tamboran.

The Tanumbirini #1V, drilled in 2014, was completed in 2019 and flowed 1.2 MMcf/d, settling to 0.4 MMcf/d. After a COVID-related shelter-in-place order was lifted, the well was reopened, flowing 10 MMcf/d initially and averaging 2.9 MMcf/d in its first 90 hours.

Two Santos-operated horizontals that were made in 2021—Tanumbirini #2H and #3H—flowed 2.1 MMcf/d and 3.1 MMcf/d, respectively, in their first 30 days from between 2,000 and 2,200 feet of lateral in each. The #2 had been on test longer without tubing yet, resulting in reduced reservoir pressure when formal testing began.

The 10,000-foot rate would have been 9.5 MMcf/d and 15.5 MMcf/d for the two wells. Tamboran was non-op in these with 25% working interest in each.

"The Tanumbirini #3H ended up being the best flow rate the basin had seen up until that point in time," Riddle said.

A U.S. Shale Job

The laterals weren't very long, but it was clear that the early wells' design wasn't correct for a true U.S.-style shale completion, Stoneburner said.

"There are two things any horizontal shale well needs: 5.5-inch casing and, in a reservoir of this depth and this pressure, 15,000-pound wellhead equipment."

Combined, up to 100 barrels can be pumped into the lateral per minute in that treatment. Santos had the 15,000-pound equipment but the casing was 4.5 inches.

"They would only get 60 barrels a minute," Stoneburner said.

Tamboran also made a hole in the Beetaloo with 5.5-inch casing but had 10,000-pound equipment. "So, it was also hamstrung, if you will, in pumping the rate that's necessary to effectively stimulate the rock."

Tamboran's recent Shenandoah South #1H is the first well to have been made with both 5.5-inch casing and 15,000 pounds. Riddle said, "So, the performance is a 65% greater flow rate than Tanumbirini #3H."

Stoneburner added, "And a much flatter decline."

H&P, Liberty Energy

The trouble with getting both the hole and the frac to U.S. shale standards was behind Tamboran's push to enlist U.S. shale driller H&P and pressure-pumper Liberty Energy into the Beetaloo.

Riddle said, "Our mindset was that we have to import the

technology that had been developed for the last 20 years."

In addition to making a $14.1 million investment in Tamboran in 2022, H&P sent a FlexRig3 last year. It's operated by both the crew onsite and remotely from H&P's Tulsa, Okla., headquarters.

While the short-lateral Shenandoah South #1H and the Amungee NW #3H were each drilled in about 18 days, the vertical Tanumbirini #1 had been drilled in 2014 in 100 days.

The H&P contract is for one FlexRig until August 2025 with a 10-year option for up to five additional rigs.

Pressure-pumper Liberty Energy followed H&P with a $10 million investment last year and had a frac spread on a ship to Australia in mid-June. Liberty has a two-year preferred-supplier deal.

Tamboran's Shenandoah South #1H last year had a D&C cost of $19 million. The next wells are expected to D&C for $26 million with 10,000-foot laterals and bigger frac jobs, including more stages.

Later wells, upon moving into manufacturing mode, are expected to cost $16 million each at 9,800-foot depth and 60 stages.

Next Plans

Having the H&P rig now, Tamboran's laterals going forward will be 2-milers, Riddle said. At some point, it expects to make 3-mile laterals.

Two new-drills are expected by year-end, resulting in two drilling spacing units (DSUs) totaling 51,200 gross acres around one of the new wells, Shenandoah South #2H.

The 23 pads and six wells per pad will result in 138 wells, Tamboran reported.

For proppant, it hopes to have a local sand mine in place in 2025. Prospective locations are numerous in the field, it reported.

Baker Hughes is also providing services for the wells planned for this year and next. Also having a presence in Australia are Halliburton and Schlumberger, "so we're not going to be short of potential options for oilfield services," Riddle said.

All of Tamboran's wells are shut in for now. It plans to put in a 40 MMcf/d gas compression and dehydration plant and lay a 20-mile pipe to the nearby Amadeus pipeline. The 40 MMcf/d is expected to be online in the first half of 2026.

The pipe runs along the western side of Tamboran's acreage, traveling north to Darwin and beginning some 600 miles south near Alice Springs. It also provides access to Australia's East Coast gas market, which is expected to be short gas later this decade.

Stoneburner said, "Think how fortuitous it is that we found the best part of the field and it's only 20 miles away from 12-inch pipe."

Up to 2 Bcf/d

With takeaway in place, Tamboran expects to drill up to 200 wells. Eventually, capacity is to total up to 2 Bcf/d.

Amadeus' owner, APA Group (not related to Apache Corp. owner APA Corp.), plans to lay a new, northbound, 42-inch pipe alongside the existing pipe and a new 30-inch pipe to the southeastern Australian market.

A gas field at Alice Springs, Mereenie, had supplied the Northern Territory gas market, beginning some 30 years ago.

"But over time, that field has reached legacy status with limited upside," Riddle said.

An offshore field, Blacktip, operated by Italy-based ENI SpA, was supplying the Northern Territory with gas but it's drying up. The Northern Territory's power producer, Power & Water Corp., has been taking gas instead from a Darwin LNG plant under a pre-existing emergency-services agreement.

Once Tamboran's volume to satisfy indigenous demand is assured, its excess production will be sold as LNG.

1.4B years
Age of the Velkerri rock

'Something New'

In April, the awaited Liberty frac spread was being refurbished to make it remote-operations-ready. As of mid-June, it was expected to arrive in Australia later this summer.

Liberty had been asked for frac spreads abroad before, "but we've always had all of our fleets busy," said Chris Wright, chairman and CEO.

"We've never had any spare equipment and I'm never willing to go to a customer and say, 'Hey, sorry, we got better work overseas. We're taking your fleet away.'"

But Liberty is building new digiFrac fleets now. "We have some older equipment coming off the back end that's going to be idle."

So it agreed to send one to Australia. The other reason Wright was convinced, "really, is Bryan Sheffield," he added. Parsley Energy had been a good customer.

Sheffield got in touch with Wright about needing a modern frac spread in Australia. "Hey, look, I want to make this Beetaloo Basin work," he told Wright.

The opportunity reminded Wright of the mid-1990s. At the time, his Pinnacle Technologies was part of an East Texas Cotton Valley breakthrough: a water frac on tight gas.

Prior best practice had held that a gel frac was necessary

Building the Team, Board

Faron Thibodeaux joined Tamboran Resources as COO in 2021. Joel Riddle, Tamboran CEO, had worked with him when they were both at Unocal, then Chevron in Indonesia.

From Indonesia, Thibodeaux had joined Apache Corp., working on the E&P's assets in Egypt, Suriname and Australia. In 2014, just prior to Apache selling its Australian unit in 2015, Thibodeaux was put in charge of Apache's Permian operations, thus he became well familiar with the rock, rig and frac spread needed to do a U.S. shale job.

For Tamboran's COO job, "there was one call I made and it was to Faron," Riddle said. "I consider Faron to be one of the best in the business."

After enlisting Thibodeaux, Tamboran hired a team in 2021 out of Pioneer Natural Resources, keeping the group based in the Irving, Texas, area. Among them was Jaime Lopez, a Pioneer completion engineer who trained Bryan Sheffield in the aughts while Sheffield worked at Pioneer.

Sheffield's grandfather Joe Parsley said in a 2014 interview with his University of Texas alma mater's Cockrell School of Engineering that, before he wanted Bryan to take over his Permian Basin wells in 2008,

in the Cotton Valley. An operator, Union Pacific Resources Group, did a mostly water frac on a well. The cost fell from $4 million to $1 million. The gas flow was the same or more after 14 months online.

The idea was taken to George Mitchell, whose Mitchell Energy & Development Corp. had been trying for more than a decade to make economic amounts of gas from the Barnett Shale.

Mitchell gave the water frac a try. It worked. From there, the U.S. shale-gas revolution began.

"It was something new, getting economic gas out of shale," Wright said.

'Go' Boxes

Taking the American shale revolution on the road the past two decades, though, has been impeded in various countries by myriad facts. Most of the time, it's the lack of economic amounts of hydrocarbon resource or the resource is stranded.

But in some areas, there is a ban on hydraulic fracturing or a political regime known for ignoring contracts and property rights.

Australia is different, though. It checked Wright's "go" boxes.

"And this is a giant basin," he said. "This is gas-in-place similar to the Marcellus."

While Australia's offshore production puts it among the top three LNG exporters, its population center in the southeast is increasingly gas-short. "They need new gas or they're going to be importing gas from their own northern and western [LNG] coasts."

Liberty President Ron Gusek told Hart Energy in April, "H&P was out in front of us by a year. They shipped the rig [to Australia] last year and we will ship the frac fleet this year."

The North American frac fleet is unparalleled, he added. "The amount of work that gets done on a daily basis in North America is unrivaled."

The Australian opportunity "is intriguing to us. The potential scale of the Beetaloo Basin is really quite something … I don't know how that will play out. We shall see. It's very early days … with only a handful of wells there.

"But it's geographically well-located [near] the Asian [LNG] market. So, we view that as quite an exciting possibility."

'That Exact Room'

The Beetaloo's depo-center is flanked on the west by the town of Daly Waters. In time, Riddle said, "that's going to be 'The Town.'"

Visiting Daly Waters virtually via Google's street view is remarkable for the odd appearance of structures and an intersection–and both of the roads are paved.

Otherwise, the 1,900-mile highway from Adelaide to Darwin features hypnotic sameness–red soil and brush–awakened at times by three-trailer-plus road trains.

The basin's population is about 1,500–about one person per 7 square miles.

The town is "on the map," though: the Australian hikers' pub map, that is.

Daly Waters Pub, established in 1930, is somewhat legendary in the outback. Anyone who's traveled through will have at least a handful of images from the watering hole on their iPhone.

"We focus on the important things in life, such as cold beer and filling [the] wine glass up past the line," the pub advertises. The beer is very good and "no one is entirely sure why," but "between you and me, it's probably more because it's bloody hot outside and you're in the middle of the outback."

There's beef 'n barra on the barbecue, "the loin of kangaroo will get you hopping and the crocodile slider might make you a bit snappy."

Tim Carter, the owner, expanded the pub to include a motel, cabins, bunkhouses and campgrounds. "Unattended children will be given an energy drink and taught to swear," a sign warns.

Visitors leave a flag from their home country and a bra.

When at the Shenandoah South #1H drill job last year, Sheffield spent a night at Carter's camp. The place is other-worldly. "It's a movie," Sheffield said.

Carter has cattle horns affixed to his electric wheelchair's steering wheel. His riding companions include Kevin, a chocolate lab; Black, a goat; and Polly, a horse. Kevin often rides; Polly eats from a bucket Carter hooked onto one of the horns.

Sheffield said of his visit, "I came out of my room and [Carter's] looking at me, sitting there waiting for me. He said, 'Did you know that a man named Aubrey McClendon was here a few years ago, staying in that exact room?'"

Full stop.

Sheffield began talking to Carter. "He said, 'When is this play going to happen? Aubrey came and now you're here in the middle of the outback.'"

Sheffield told him, "It's going to happen. It just takes time. I'm working on it." OGJ

5M

acres that compose the Beetaloo cor

he "didn't know much about the oil business.

"So [Bryan's dad] Scott [Sheffield] hired him at Pioneer and let him work with the engineers for a few months, with the geologists for a few months, out in the field for a few months, in accounting—he worked in all the departments that make up an oil company."

Tamboran's board filled out over the years, too. Joining Riddle were Tamboran founder Pat Elliott, U.S. shale developer Dick Stoneburner and Fred Barrett, co-founder of U.S. tight-gas operator Bill Barrett Corp.

Joining since 2014 are John Bell, Helmerich & Payne's senior vice president of international and offshore operations; Ryan Dalton, who was CFO at Bryan Sheffield's Parsley Energy; Stephanie Reed, a partner in Sheffield's Formentera Partners and who had been a Parsley senior vice president; Andrew Robb, a former Australian trade minister; and David Siegel, a senior adviser to Apollo Global Management.

While Bryan Sheffield owns 16.7% of Tamboran, investment manager CREF holds 10.6%. Additional shareholders include Morgan Stanley Australia Securities, 6.4%; an affiliate of The Baupost Group, 5.7%; H&P, 5.1%; Liberty, 4.6%; Siegel, 3.1%; Pat Elliot, 1.4%; and Riddle, 1.2%.

Rise of a Shale Man

Kyle Koontz takes the reins of BPX's rapid onshore growth amid big changes at BP.

JORDAN BLUM
EDITORIAL DIRECTOR
@JDBlum23
jblum@hartenergy.com

DENVER–A child of the oil industry, Kyle Koontz grew up in the boom-and-bust 1980s, deciding a career in energy wasn't worth the cyclical risk.

But as an architectural engineer in Oklahoma City, the advent of the shale boom ultimately proved too tempting to resist.

He worked his way up with SandRidge Energy and joined BP not long before the British energy supermajor made its big shale splash by acquiring the onshore U.S. assets of BHP, eventually launching the BPX Energy brand.

Koontz recently took over as the CEO of BPX after his predecessor, Dave Lawler, who also held the title of BP America president, stepped down just days after BP CEO Bernard Looney was removed for personal relationships with employees.

Koontz, who was BPX's COO of development, was quickly appointed to take over the onshore U.S. operations. In London, BP interim CEO Murray Auchincloss had the interim tag removed in January, bringing leadership stability back to the company.

Now, Koontz is excited to be tasked with leading BPX's rapid, planned growth in U.S. shale in the Permian's Delaware Basin, the Eagle Ford and, eventually, in the Haynesville Shale, as natural gas prices recover.

Koontz sat down with Oil and Gas Investor *in BPX's Denver headquarters to discuss the past and future of the shale producer. In this month's relaunch of E&P magazine, Koontz also discussed BPX's field development plans in more technical detail.*

Q&A

Jordan Blum: You took over as CEO in October. Obviously, you're not new to BPX, but how has it been stepping into the new role, hitting the ground running and ramping up production with all the change in the BP corporate and BPX leadership?

Kyle Koontz: The role is different; it's much wider. But it's more than just business. Culture is a really big part of what we do. It's something I've been passionate about. One of the things that's new a little bit for me is that this is the farthest away I've been from the business–not being in the day-to-day–probably for the first time in my career. That's been a bit of an adjustment. The way I've tried to adapt is empowering the right leaders that have the right attributes in terms of character and integrity. It was an adjustment to turn over the reins and let them go do their thing. But I committed that I wouldn't be an over-the-shoulder type of leader, and so far, so good.

I think we had a bit of an adjustment period, both myself and the organization. My predecessor [Dave Lawler] was a big part of what we built here with a great legacy. And there were some structural changes we had started that we had to see through. A lot of the transition through the end of the year was just getting used to the new normal. The team came back strong in January. We had a town hall early in the year. The energy was strong. There were some quotes I got from people saying, "We

BPX Energy CEO Kyle Koontz stands outside his office in the BPX headquarters on the outskirts of downtown Denver.

MICHAEL CIAGLO

haven't heard this much buzz since 2017." There's renewed purpose, and it's shown in the numbers in the business. We're ahead of schedule in our production growth plans, and it's showing up big for BP.

JB: You mentioned some structural changes, and that's both in the U.S. and U.K. But how has BPX really been impacted?
KK: Very, very little. There'll be some indirect impacts, obviously, but that's one of the things that I wanted to get clear upon my appointment. "What is the expectation going forward? Is it similar to what I've come to expect?" And, yes, the response was, "We want you guys to continue to run the business headquartered in Denver. The growth strategy stays in place." Really, there weren't any material changes between us and BP. There's a lot of change going on in BP but, I think, using Murray's language, it's a simpler, more focused company. And that's what we've tried to do. There's a lot more learning going from us back to BP than what was happening in the past. That's something Murray asked me to do in the new role. We typically would take a lot of learning from BP, take their expertise. It's one of the unique advantages we have of being a part of BP is, they're well capitalized.

It's one stakeholder instead of many, which simplifies things a bit. It's like being a very large private equity company, but your sponsor is one big energy company. And there's no exit. We're part of the long-term strategy.

JB: It seems like you see some advantages to being headquartered in Denver, even though all the assets are now in Texas and Louisiana.
KK: Especially in the post-COVID world, geographic location for some of what we do is not as key. The technology has been enabling.

When we first moved up here, proximity to assets was a driver. The asset base changed, but no regrets. Denver's been a great fit. There are direct flights to London, so it's easy to get in and out. Denver has a really cool pioneering spirit, which really fits our culture of innovation. It's been a great recruiting tactic. A lot of companies have moved out of Denver, unfortunately. Through different consolidations and acquisitions, folks relocate to Houston. But we've been a big beneficiary of talent in that regard.

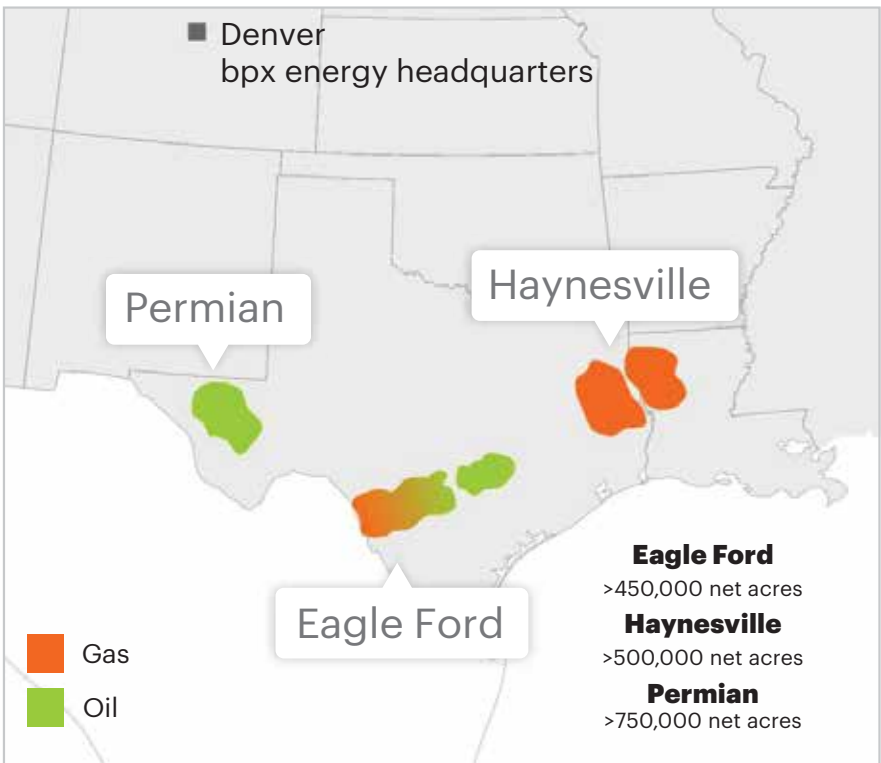
JB: There was the big acquisition with BHP, which has been more than five years now. Can I get your take on just how big a deal that was for BPX, and how things slowed not long after with the pandemic? How is it now finally being in ramp-up mode and really starting to take advantage of those assets more?
KK: It was a very significant asset purchased for BP and, in context, it's the biggest one since ARCO [Atlantic Richfield Co.] over 20 years. There was a ton of capability we needed to gain, and we had to do it on the fly because we'd already made the deal. The good thing is, the assets had been a bit capital-starved, so there was a good opportunity to boost investment and get activity going, but we didn't have the luxury of growing into it. We had to hit the ground running from day one. We took over operations, and we stood up additional rigs and frac crews to try to save leasehold that BHP had already given up on. And it was worth it. We saved a lot of acres and a lot of inventory from doing that, but it was a bit challenging and chaotic.

We had 13 rigs running, and then the pandemic happens. I remember March 9 [2020]. It's when the world turned. We stood down all rigs but one in 45 days. We were one of the fastest responders of any of our counterparts. And then, nine months later, we were back to 11 rigs. So, that was kind of a vicious extreme case of what can happen in this business. But since we got back to work, we've been consistently building and growing the asset.

JB: You're at about nine rigs now? Is that right? Of course, you can do more with each rig now than you could just a few years ago.
KK: Absolutely. Nine to 10 rigs for 2024 is the range. We planned on running five rigs in the Permian. But we dropped a rig this spring because we're drilling so much faster. So, four rigs will get us the same footage now.

JB: How do you feel about just the portfolio right now? Do you feel comfortable, or do you see any changes on the horizon?
KK: We love the portfolio. We're kind of hitting our stride, so to speak. We've been mostly doing lease-obligation drilling for the last couple years, but we're now in growth mode in the Permian. We're drilling way beyond lease obligations. We've got three central facilities built out as part of our multiyear strategy to build the field out. Now, we're feeding volumes into that. We just brought on the third one [a few] weeks ago. That's called Checkmate. We have

BPX's Core Positions



SOURCE: BPX

BP employees tour and discuss BPX's Grand Slam centralized processing facility in the Permian.

BPX

one more compression project in the Permian that's the last big project. Now, we're looking at just optimizing each parameter, just trying to squeeze every dollar of investment we can.

The Eagle Ford is really exciting. There's a ton of runway there. What we like about the Eagle Ford is it's a much bigger acreage position. It's about a half million acres compared to just under 80,000 in the Permian, but it's got exposure to different commodity windows. We've got oil, gas, rich gas and condensate. You've got all these fluid windows, but the rock's great, the deliverability is great, so they all produce really well. We shifted capital away from some of the gas assets to more oil-weighted assets, just seeing where the market was going with commodity prices.

In the Haynesville, we slowed our activity down, but it's a premium gas asset. We've got some of the best acreage in the play. We started ramping down late last year. We're down to one rig; it's obligation drilling. Then we've deferred completions to late in the year or next year. We like the Texas side [of the Haynesville] as well, but the acreage quality is higher on the Louisiana side, so that's been our focus. Our core strategy will be built around that, and we will work into the Texas side as we can.

We have high-quality inventory; we're in the core of the core of all the basins we're in. I like the focused concentrated position. I think it fits well with where we're headed with BP focusing on just high-quality assets, and then delivering on those assets.

I don't see any big changes happening. I do think we are going to need to add inventory. Renewals of assets is always a strong part of the growth strategy, but one of the benefits of having the core position and the size of the BHP deal is we have the luxury of time. We're not pressed to do anything, so we really want to make sure we buy right. It's a big part of making value on acquisitions. We bought the BHP deal at $50/bbl oil. That was important, because we had to slow activity down in the pandemic that wasn't planned. Price appreciation and some of the technology that we've infused have helped us make sure we did well in that investment.

JB: You said eventually you'll need more inventory, but there's no urgency. Do you think the growth would likely come in the Permian?

KK: I don't know. I think we just don't want to be so rigid that we're not opportunistic. We want to still look at deals, screen deals, and then a lot of it is just what's right for BP. What's the timing? We always look at deals even though we haven't bought anything major. Since the BHP deal, we've done a lot of smaller deals and cashless swaps and acreage trades. It's pretty remarkable how much activity we've been able to do with very little capital outlay. This is all portfolio refinement, trading out with partners, blocking up units and getting our average lateral end up. But we estimate we've delivered over $1.5 billion of value just through those type of deals. Our deal teams are still very busy. Like I said, we have the luxury of time, and so we're going to use it. If we find the right deal, then we'll certainly bring it to BP and consider it.

JB: You have the goal of 650,000 boe/d by 2030. I think you're over 400,000 boe/d now. So, you're ramping up pretty quickly. The 2030 volumes would more than double the numbers from 2022. Can I get your take on how fast you're moving up and just what the future holds?

KK: It equates to about a 10% annual growth rate, and so

we will keep on that trajectory. The volumes get big towards the end of the decade as we increase investment in gas. If the market's favorable, then we'll be able to achieve those growth rates. I have very high confidence in that plan. But, also, if the market's not favorable, then we'll adjust. But we want to show visibility to be able to grow at that pace. Even with the mix of investment we're doing right now, it's highly profitable at these prices.

I think the Haynesville and the Hawkville [gassy southwestern Eagle Ford], as we get towards the end of the decade, are activated through reducing our spend on non-drilling and completion costs in the Permian. For the last couple of years, we've been spending quite a bit of money building out the [Permian] field gathering system. We decided to own and operate that ourselves to maximize flow assurance and speed of service, so we can connect and build right when we need it. It also allowed us the ability to electrify the field, which has given us reliability, uptime and a reduced emission profile. All of that took several years to build out. We're kind of winding down that spend now, and we'll be able to reallocate that capital to more gas growth.

JB: You mentioned targeting more of the liquids in the Eagle Ford. I assume that's happening in the Permian, too. Can you say in terms of how weighted you are in the two basins right now versus what you were?

KK: The Permian has the biggest capital allocation. Eagle Ford is kind of a close second. But, purely upstream capital through the bit, they're pretty comparable. We do have some continuous growing obligations on rich gas assets in the Eagle Ford. But any discretionary capital is going to the oil. The oil mix is comparable, but Permian could deliver more oil for just total volume. And we have a higher ownership percentage in Permian, so we get better net oil per dollar invested. That's the plan going forward. I don't see any major changes in capital.

So, we've shifted capital to the liquids. No change to Permian. We were already at development pace there. That was predicated a lot on building out the capacity.

JB: I'll pivot a little bit. How's the longer-term view of gas? Obviously, there's a lot more bullishness beyond the present.

KK: We still love gas. It's a great commodity, very clean burning, and I think it's going to be really important for the future, including the transition. Some of our biggest operational gains were coming out of the Haynesville and, with some of them, we were able to leverage back into the Permian and the Eagle Ford. The Hawkville has a ton of running room as well. But, I think, just given the dynamics, gas is going to be more volatile and that's what we've seen. It's going to be important to maintain flexibility and try to be nimble to navigate that market.

JB: You're lining up some DUCs in the Haynesville. Are you doing that in other basins, too, or is that really just a Haynesville specific thing right now?

KK: It's just Haynesville specific. The maximum efficiency you get in frac operations is running a consistent frac crew. The guys get to know our guys, they develop a bit of synergy and that's how you get the manufacturing mode going. The Haynesville work was already down to so little that we just deferred the rest of those completions into late next year, but it's not a very high well count and we're hoping it's just a short-term duration.

JB: Going back to early days and the shale boom, all the majors really missed out on that first wave of the shale boom. Can I get your take on how BP, and maybe the rest of the industry as well, caught up and took more of a leadership role?

KK: I'll speak in the context of BP for that, but we were slow, and we were slow to make decisions, slow to act, slow to operate. When I got here in 2016, we were kind of in the middle of trying to change all that. We had to act more like an independent. But, along the way, we were able to learn quite a bit from the major side as well, particularly in safety leadership and systems and process. It'll be interesting to see how that progresses forward because a lot of the smaller companies with the simpler structure can make decisions faster and they can iterate faster.

I think what's shifting now is because the expectation of investors is a higher standard than what it used to be. Before, it was a very empirical model. You hear a lot of things like statistical play. Well, that means we can't fundamentally describe or forecast the results, so we just run statistics and then we'll extrapolate. I think the majors, though, were used to going much more beyond that in terms of science and predictability, more sophisticated models, more sophisticated subsurface understanding. What we've been able to do, and I'm really proud of, is kind of merge those capabilities. We had to have a little bit of an empirical nature to our business, fail small and fail fast so that we can continue to grow and learn. But we can't afford to be catastrophically wrong either. I think merging that scientific approach from a major with the nimbleness of the independent mindset has been kind of the secret recipe for BPX.

JB: Going back to the Permian, can you give more of an overview of building out your electrical substation network and electrifying 95% of the well sites in the Permian?

KK: We wanted to power the field, but we couldn't rely on a third party to build all that up for us. What we did is, we made a deal with our utility partner to buy directly off the transmission line, and then build out the system to step it down where we needed it, when we needed it. One of the unique advantages by doing that is we could customize the load design. We're able to run Halliburton's electric frac fleet off our grid, which is a big electrical load and most local grids aren't designed for that. But we designed for that from the beginning. We had never done it before either, so that was a little bit of a learning curve, but we knew about what the load capacities would be and how fast we need to draw on it. That's given us a unique advantage. Almost all of our sites now are fracked off the grid with e-frac, and all of our drilling rigs are outfitted with transformers with Nabors so that we can drill off the grid, as well. We use the electricity to our advantage. Once you have the power set, you can tap into it for multiple uses, such as saltwater transfer pumps. We can also do electrical submersible pumps that we run in some zones. Electrification has been a good bet.

One of the big benefits is, we had basically 99.9% plant availability for our first CDP [central delivery point] that we built right in the middle of COVID. It was the simplest of the three designs, but it's performed at a very high level. The high reliability of electrical compression does really well at scale. It's also been a huge benefit in reducing our overall CO_2-equivalent emissions. We're down almost 40% from when we started back in 2019.

CEO Kyle Koontz tours BPX's Grand Slam centralized processing facility in the Permian.

BPX

JB: And you've basically eliminated routine flaring, right?

KK: We've never flared just to sell the oil where we didn't have a gas market. There was some flaring due to process subsets in the field, just the way the field was built out. As we started building the new infrastructure, we also started retrofitting the existing gathering lines, and the main advantage was getting low-pressure gas service and compression in the gathering lines. Then we started making some adjustments and modifications to the existing well facilities. It's about 150 wells that we call legacy sites that we had to go do some retrofitting and modification. All the new sites don't have tanks at the well site, so they have no flares at the well site. They just go through three-phase separation, and they're piped to our CDP. The CDP has a flare, but it's only there for safety and process subsets. So, we almost eliminated the flaring.

We had about 17% of our total gas stream that we were basically just burning. Part of the inspiration for how we built out the CDPs and deciding how many and where was, how do we sell all that gas? It was very cost prohibitive to put a vapor-recovery unit at every well site, but we could do it at scale at the CDPs. We captured 5%-6% more residue gas at our central facility, and that goes into the sales line. That's the gas we used to be flaring, and now we're down well below 1%.

JB: And the last facility under construction now is called Crossroads, right? Did it used to tentatively be called Royal Flush?

KK: Yes, Crossroads is the compression station for next year. There's been some different iterations in the design. Originally it was five full CDPs. As we blocked up acreage, and we've fine-tuned the designs and the development schedule, we were able to whittle that down to three CDPs and one compression station. The compression station will help us for increasing the gas-to-oil ratio over time. The reservoir is built where more gas will come out—a solution as the pressure drops. That compression will give us the ability to service all of that gas to keep the oil utilization high.

JB: You're a Texas native. I wanted to get your take on just how you got into the industry. You started out with architectural engineering right at Oklahoma State University and then switched to the archrival University of Oklahoma, eventually.

KK: The short answer is: I was born into it. I was born in 1979. The oil price went over $140/bbl, which was a record at the time. My dad and mom were both in the business. They worked for an operator out of Midland. By '86, oil was under $30/bbl. My dad had several businesses that he ultimately wasn't able to keep, and that left a deep impression on me. One, that the energy business was very dynamic, very volatile. It was a really exciting business to be in; it was also a bit painful. It changed the course of my life. We moved several times in several years. My dad changed jobs. I ended up in the Dallas-Fort Worth area growing up in Grapevine. But that kind of left a bad taste in my mouth, so I didn't really want to pursue energy.

So, I went into architectural engineering. I was a structural project manager for two years for a great firm out of Tulsa. I moved to Oklahoma City with that firm to get married. I had met my wife in college. At that time, it was 2006, with the full-on shale boom going, led by

MICHAEL CIAGLO

Chesapeake primarily, but also Devon Energy. There was a new company that Tom Ward was putting together after leaving Chesapeake called SandRidge Energy. There was a big run on petroleum engineers. When I heard what petroleum engineers were making as starting salary versus what I was making as a project manager, I thought, "Man, I'm in the wrong business."

It was a calculated risk. My parents thought I was crazy, but I went back to the oil patch. I went back to OU. I was able to get on with SandRidge and intern during the summers while I was finishing up school. It was a really unique experience just because there was so much activity, so much growth. It was an empirical model; there was a lot of trial and error. It was just a great training ground for an eager young professional. I got to spend a lot of time with senior leadership, see how decisions were made, how capital was allocated, just learn the business top-to-bottom, and I got to prospect over 1,000 wells in the first three years. It was just a tremendous volume of experience and work, which I'm super grateful for. And it's been a big part of why I've been able to keep accepting bigger roles and responsibilities for a relatively short career. I just realized what a dynamic business this is. It's so much different than designing buildings not to move. So, I just leaned in and went for it. And now here I am in Denver.

JB: I take it your parents don't think you're crazy anymore.
KK: (laughing) They've gotten over it.

JB: How was it going from SandRidge to private equity-backed Templar Energy and then, eventually, to BP in 2016?
KK: It was a bit crazy, frankly, but I'm really grateful for all those experiences. One of the things I was very interested in early on was reading about guys like (Continental Resources founder) Harold Hamm and (Devon Energy co-founder) Larry Nichols and a lot of those great leaders in energy, and how they were well-rounded businessmen and oilmen. The more you can learn about the business, the better you can make decisions. A lot of the leaders that I worked with at SandRidge had gone out and joined Dave Le Norman, who's a veteran in the private equity world. I had an opportunity to go over and join that team, and that was a fantastic experience.

That was also a very active time, a lot of deal flow, made a lot of great friends, a lot of great mentors and just great experiences. One thing that drew me to join BP was leadership, and it was at the individual level through Dave Lawler, who recruited me over, but also the dynamic of an integrated international oil company. You can make decisions to lead big bodies of peoples. That was a different skillset that I didn't have. I figured I'd try it out, see how it went, and it's been a good fit.

JB: Of late, BP is still very much embracing the energy transition. However, and you may not want to use this word, there's a pivot back to oil and gas.
KK: Oil and gas have always been cornerstones of the strategy. I think we've learned some lessons, and we are now going to move at the pace of societies, and we're going to be pragmatic about it. BPX fits within that. It's the resilient hydrocarbon strategy. Not only do we need to be profitable, but we need to be environmentally sensitive and conscious about how we impact the Earth and the communities around us.

We also need to be very cost-conscious because pricing, as you know, is pretty volatile in this business. We can't rely on high pricing like we maybe have in the past as an industry. We've got to be competitive, and we've got to go after those margins just like manufacturing companies do, just like digital companies do. And try to learn from those industries as much as we can. The better we do that, the more we can learn, because we can learn in a much faster cycle time than BP. Then it can help BP, as well. I don't think the focus has shifted as much as maybe what we've chosen to highlight. And I think the way we talk about it is a little bit different now. But it's always been core to the strategy. OGI

This interview has been edited for clarity and length.

A&D STRATEGIES & OPPORTUNITIES CONFERENCE

OCTOBER 23, 2024
THOMPSON HOTEL
DALLAS, TX

CONSOLIDATIONS CONTINUE IN 2024

But will deals face headwinds from policy uncertainties and increased capital competition from alternative energy sources? At Hart Energy's **23rd A&D Strategies & Opportunities Conference** our featured speakers will cover:

- Individual deals made in 2024 and the activity trends in each basin
- What's next for transactions in M&A and joint ventures.
- How to deal with uncertainty in a politicized environment
- Private and public companies exploring the latest macro trends in A&D
- Balancing the need for shareholder returns with finding additional inventory

Save the Date, Plan to Attend, Join the Discussion!

A&D Strategies & Opportunities Conference brings together key capital providers and seasoned industry executives for frank discussions about the money that drives the oil and gas business. These executives will share insights on the current issues and look at the challenges that lie ahead.

Don't miss the annual event where deals are actually made!

SPONSORSHIP OPPORTUNITIES

The **A&D Strategies & Opportunities Conference** is a premier meeting ground for sponsors to reach executive managers from E&P operators, financiers, and dealmakers.

For more information, contact Jeremy Bunnell, Associate Publisher
jbunnell@hartenergy.com | 713 260 5204

GOLD SPONSORS

Alvarez & Marsal | Chesapeake Energy | NSAI

BRONZE SPONSOR

EnCap Investments L.P.

presented by: HARTENERGY

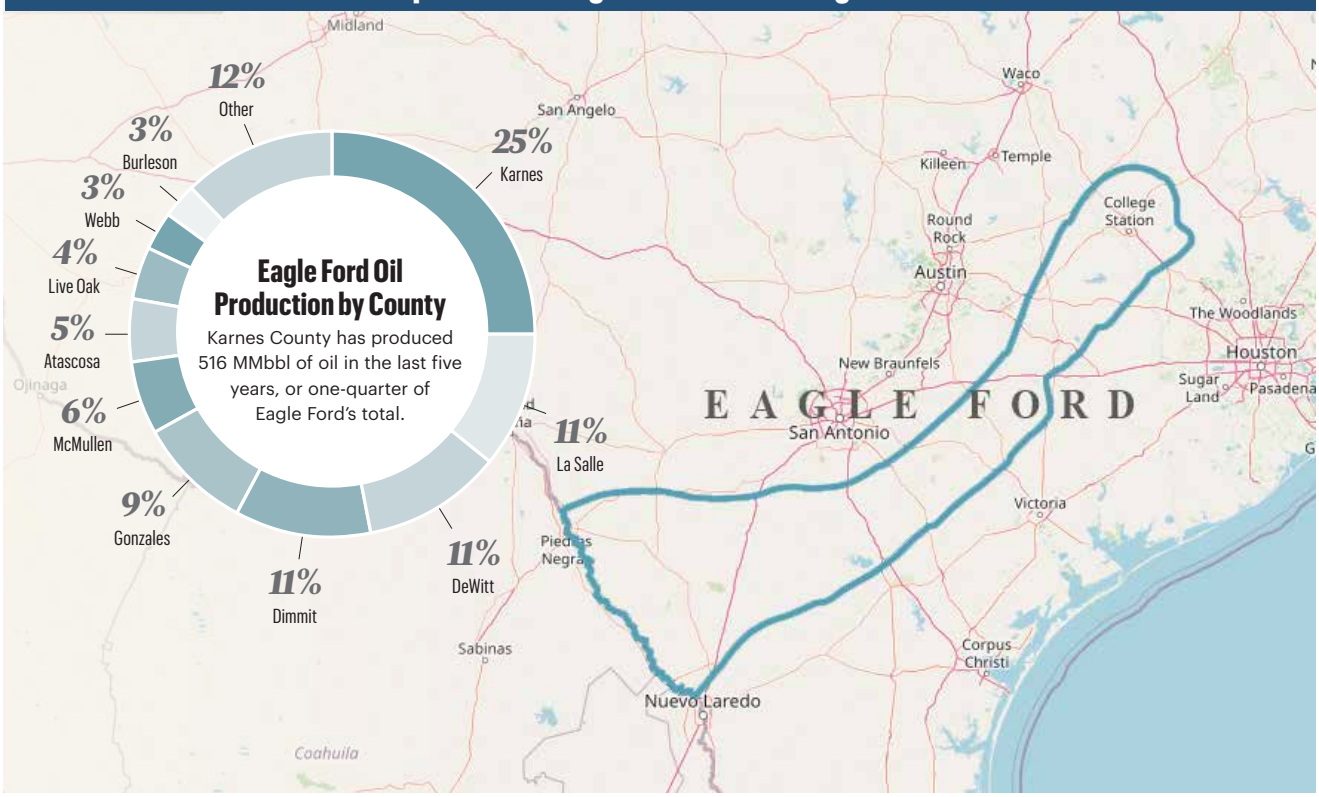

The Eagle Ford Shale has averaged
37.6 MMbbl
a month over the last five years.

COURTESY OF CONOCOPHILLIPS

BASIN FOCUS: EAGLE FORD SHALE

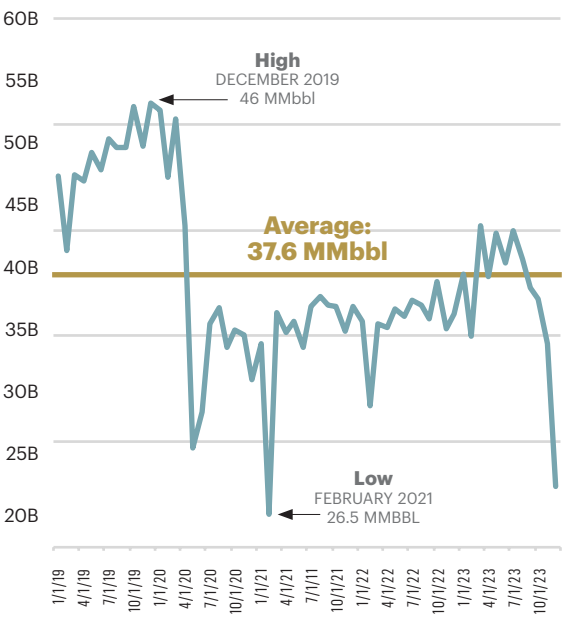
The Eagle Ford is the second-most prolific shale play in the U.S., trailing only the Permian Basin.

Top Oil Producing Counties in the Eagle Ford



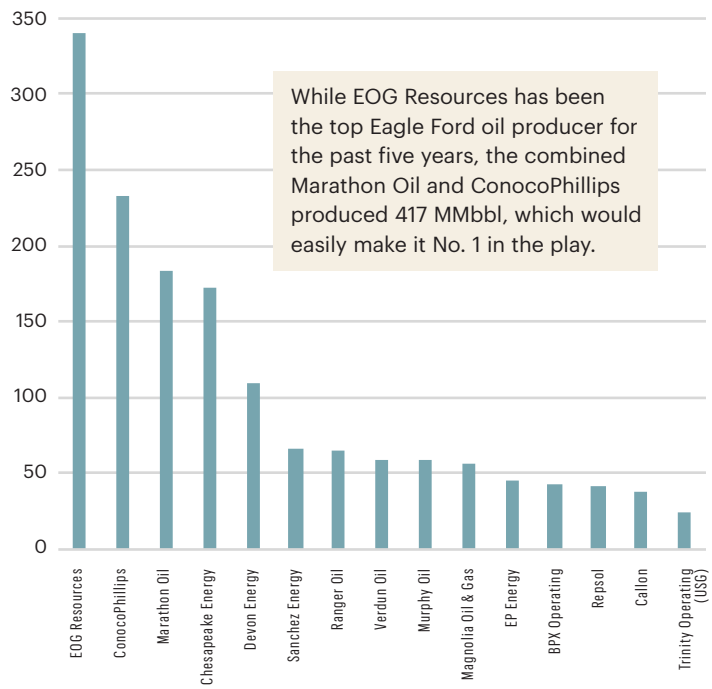
Eagle Ford Oil Production

Monthly, bbl



Top Eagle Ford Operators

Oil Production, MMbbl, 2019-2023



While EOG Resources has been the top Eagle Ford oil producer for the past five years, the combined Marathon Oil and ConocoPhillips produced 417 MMbbl, which would easily make it No. 1 in the play.

SOURCE FOR CHARTS AND MAPS: REXTAG

PERMITS

Reeves County, Texas, in the Permian Basin, led all counties in well permits.

Permitted Wells by County

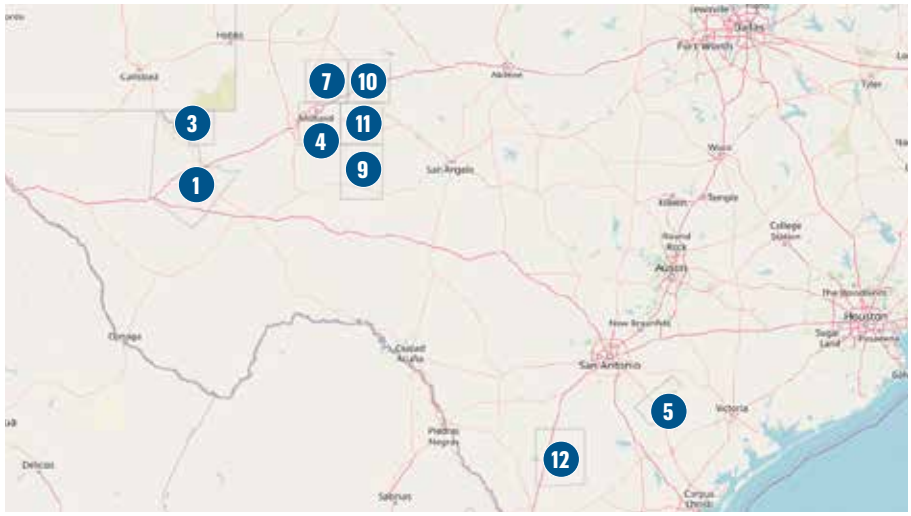
Rank	County	Well Count
1	Reeves, Texas	53
2	Weld, Colo.	52
3	Loving, Texas	46
4	Midland, Texas	43
5	Karnes, Texas	39
6	Campbell, Wyo.	34
7	Martin, Texas	30
8	Dunn, N.D.	28
9	Reagan, Texas	24
10	Howard, Texas	23
11	Glasscock, Texas	21
12	La Salle, Texas	20
13	Rio Blanco, Colo.	16

Permitted Wells by Operator

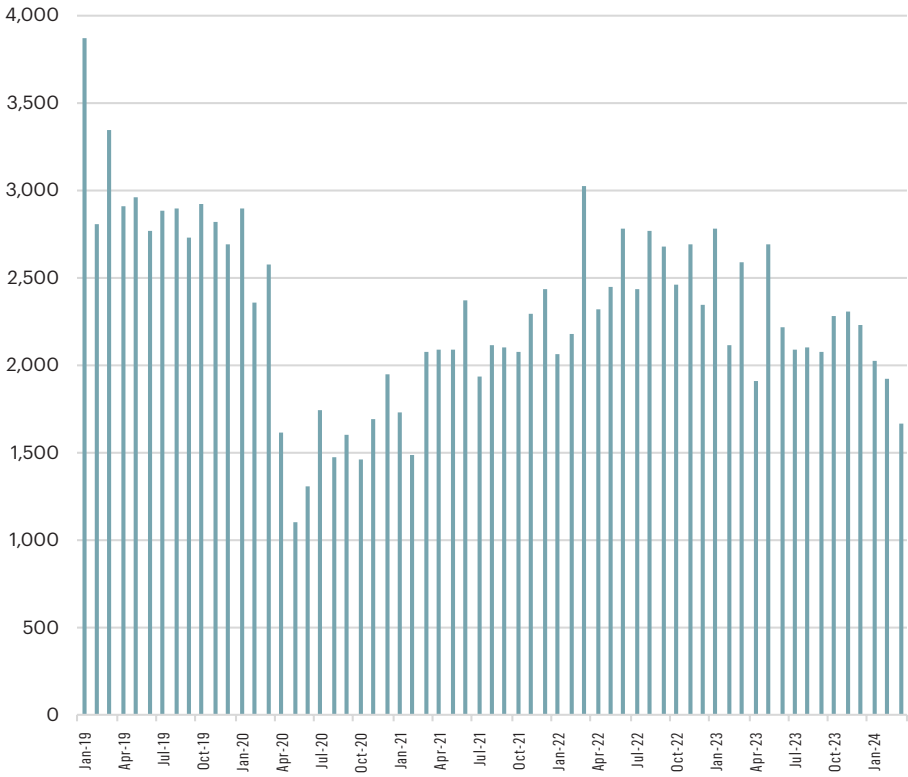
Operator	Well Count
EOG Resources	39
Anshutz Exploration	36
Pioneer Natural Resources	34
Chevron	24
Nickel Road Operating	24
Occidental Petroleum	21
BPX Operating	21
CrownQuest Operating	21
Verdad Resources	20

Permitted Wells by State

State	Well Count
Texas	542
Colorado	129
North Dakota	66
Oklahoma	53
Wyoming	51
Louisiana	17



U.S. Well Permits Issued Monthly



Marathon Deal Expands ConocoPhillips' Multi-basin Reach

The $22.5 billion acquisition marries complementary assets in the Permian, Eagle Ford, Bakken and Anadarko.

CHRIS MATHEWS
SENIOR EDITOR, SHALE/A&D
@chrismathews52
cmathews@hartenergy.com

The combination of ConocoPhillips and Marathon Oil will yield an even larger U.S. super-independent producer with a footprint across the Lower 48, from the Bakken to South Texas' Eagle Ford with a healthy swath of Permian Basin in between.

But the all-stock $17.1 billion deal—including Marathon's net debt, the total is $22.5 billion—also brings together two of the oldest and most storied brands in the U.S. oil and gas sector.

Both companies can trace their roots to the breakup of John D. Rockefeller's Standard Oil Trust by the U.S. Supreme Court in 1911—a landmark decision giving rise to modern antitrust laws.

And experts wonder if a tie-up between ConocoPhillips and Marathon will face antitrust scrutiny by a particularly active U.S. Federal Trade Commission, which since last year has been dissecting several high-profile oil and gas deals.

ConocoPhillips, with a market value of more than $125 billion, is already one of the nation's largest oil and gas producers.

The E&P is among a handful of public super-independents with market values of more than $50 billion, including EOG Resources ($68 billion) and Occidental Petroleum ($53 billion). Diamondback Energy, following its $26 billion acquisition of Endeavor Energy Resources, is also expected to join that exclusive market cap club.

Multi-Basin Madness

Adding Marathon's multi-basin portfolio across the Lower 48 will yield an even larger super-independent. ConocoPhillips and Marathon have highly complementary asset bases across four major U.S. basins: the Permian's Delaware Basin, the Eagle Ford Shale, the Bakken and the Anadarko Basin.

Marathon's position in South Texas presents ConocoPhillips with significant future upside, said Andy O'Brien, senior vice president of strategy, commercial, sustainability and technology for ConocoPhillips, during a May call with analysts.

The combined company will have around 490,000 net acres and production of nearly 400,000 boe/d across the core of the Eagle Ford. Marathon Oil's Eagle Ford assets will add about 1,000 new primary locations for future drilling.

ConocoPhillips also sees significant future upside from refrac opportunities in South Texas.

"We've been implementing new refrac techniques across our existing Eagle Ford position," O'Brien said. "It's expanded our refrac inventory at cost of supplies that compete with our Tier 1 opportunities."

ConocoPhillips also sees upside for new-drill and refrac opportunities in North Dakota's Bakken Shale.

The two companies have highly contiguous footprints in the southern portion of the Bakken, where ConocoPhillips plans to look at drilling longer 3-mile lateral wells. On a pro forma basis, the company will have well over a decade of drilling inventory located in the Bakken, O'Brien said.

The Marathon deal also gives ConocoPhillips longer roots in the prolific Permian Basin, the Lower 48's top oil-producing region.

Marathon's Permian portfolio is concentrated in the Delaware Basin of West Texas and New Mexico. Marathon has acreage across the core of the Delaware oil play in Lea and Eddy counties, N.M. But the company is also a leader in delineating the deeper Woodford interval from its Delaware acreage on the Texas side of the basin, Texas Railroad Commission (RRC) data show.

"Our existing [Permian] asset base is clearly much larger in size, making the Marathon acreage position more of a traditional bolt-on," O'Brien said, "adding 400 more locations to our already deep inventory base."

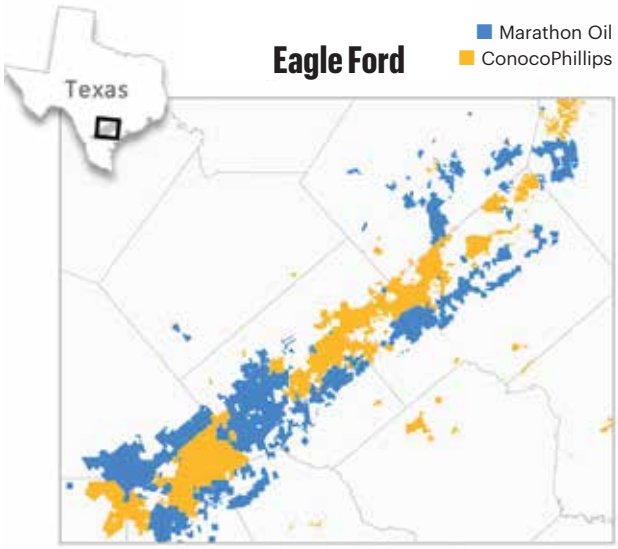
ConocoPhillips had gotten much deeper in the Midland side of the Permian through its $9.7 billion stock acquisition of Concho Resources in 2021.

The Marathon acquisition gives ConocoPhillips additional acreage in the Oklahoma Anadarko Basin.

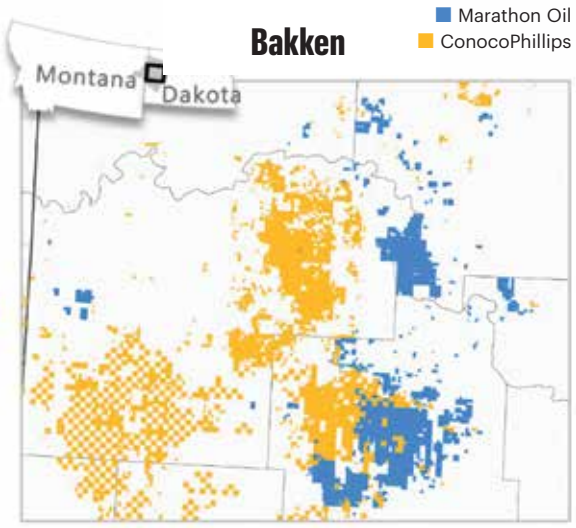
"The Anadarko Basin is primarily focused on natural gas," O'Brien said. "We see this as a call option on normalization of U.S. gas fundamentals, driven by growing power- and LNG-related demand."

Quest to Divest?

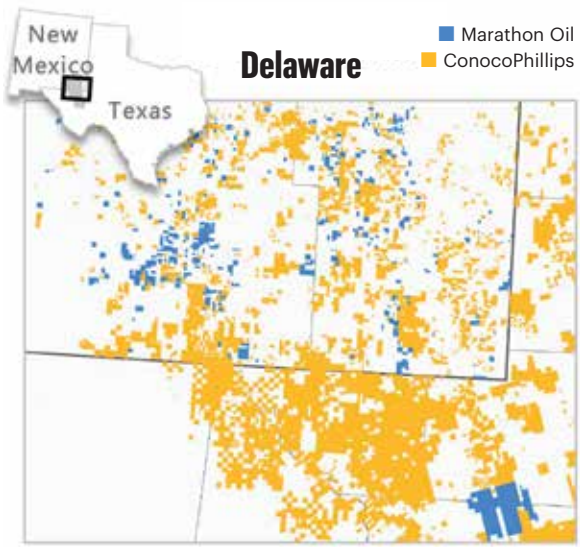
ConocoPhillips Chairman and CEO Ryan Lance said the company has laid out a



The ConocoPhillips and Marathon Oil combination would yield a premier Eagle Ford operator with pro forma production expected to average 380,000 boe/d.



ConocoPhillips and Marathon would combine for 800,000 net Bakken acres. Bakken production is expected to average 220,000 boe/d.



The pro forma ConocoPhillips-Marathon combined footprint in the Delaware Basin would include 800,000 net Delaware acres with average production of 580,000 boe/d.

SOURCE: CONOCOPHILLIPS

$2 billion disposition target over the coming years after closing the Marathon acquisition.

"I think people recognize we've been pretty good rationalizing the portfolio quite a bit over the last number of years," Lance said during the call.

With the Marathon acquisition, ConocoPhillips recognizes the opportunity to find and monetize pieces of the combined portfolio that may not compete for capital going forward.

ConocoPhillips will look across its entire portfolio when considering divestitures, Lance said.

"It's not focused on one area or another," he said.

Other producers that have closed major acquisitions are beginning to tap the divestiture market to deleverage.

APA Corp., parent company of Apache Corp., recently sold $700 million in non-core Texas assets to pay down debt associated with its acquisition of Callon Petroleum.

In one transaction, APA divested a large portfolio of assets in the Eagle Ford and Austin Chalk in a sale to WildFire Energy I.

APA also monetized mineral and royalty interests in the Midland Basin in a separate transaction.

Occidental Petroleum is wading deeper into debt to make a $12 billion acquisition of CrownRock, a private E&P with a deep inventory in the Midland Basin. To reduce debt, Occidental plans to sell up to $6 billion in non-core U.S. assets.

The company is reportedly exploring a sale of assets and acreage in the southern Delaware Basin that could fetch more than $1 billion.

Occidental is reportedly working with a financial adviser to market the assets in the Barilla Draw region in Reeves County, Texas.

FTC Scrutiny?

The FTC has been particularly active amid a record amount of corporate consolidation in the U.S. oil patch.

The Ohio Oil Co. and the Continental Oil and Transportation Co.–predecessors of Marathon Oil and ConocoPhillips, respectively–were born out of antitrust scrutiny when Standard Oil was broken apart.

Over a century later, analysts believe the combination of ConocoPhillips and Marathon Oil is likely to receive close scrutiny by the FTC.

The deal is primed for FTC intervention "given the increased regulatory scrutiny for oil and gas deals and Conoco's existing scale," said Andrew Dittmar, principal analyst at Enverus Intelligence Research.

"Working in its favor for approval is the multi-basin nature of the Marathon assets versus concentrated regional exposure like the recent large combination in the Permian," Dittmar wrote in a report.

Siebert Williams Shank & Co. Managing Director Gabriele Sorbara also expects some FTC scrutiny to arise but ultimately anticipates that the deal will close.

The commission previously requested additional information regarding the largest energy industry deals signed last year–Exxon Mobil's Pioneer acquisition, the Chesapeake-Southwestern merger and Chevron's $53 billion acquisition of rival Hess Corp.

To close the Pioneer acquisition, Exxon agreed to an FTC order barring Pioneer Chairman and CEO Scott Sheffield from sitting on the Exxon board; Sheffield has since fired back at the FTC's complaint. OGJ

Is Devon Next to Join the Spree?

The E&P has looked hard at some companies, but remains one of the few large players not engaged in the M&A frenzy. So far.

DEVON ENERGY

DARREN BARBEE
SENIOR MANAGING EDITOR, DIGITAL
dbarbee@hartenergy.com

ConocoPhillips agreed to a $17.1 billion deal to buy Marathon Oil in late May, but it certainly wasn't the only target Conoco had zeroed in on during the past several months.

Deal master Stephen Trauber, chairman and global head of energy and clean technology at Moelis & Co., was with "some Conoco guys" a couple of days before Diamondback Energy's February announcement that it would acquire Endeavor Energy for $26 billion.

ConocoPhillips had hoped to grab Endeavor while Exxon Mobil and other large companies were preoccupied with their own deals. They were nonplussed to see their prize plucked away by Diamondback.

Likewise, Trauber said ConocoPhillips had joined the hunt for CrownRock, but Occidental Petroleum ultimately stepped in to buy it for $12 billion.

Another company was also looking: Devon Energy.

Trauber said ConocoPhillips wasn't feeling pressure to do a deal–mostly.

"They remain one of the largest independent upstream companies in the world, so they didn't need to do this deal," Trauber told Hart Energy the day after the Marathon deal was announced. "On the other hand, this deal created real value for the company, and they did lose out on a couple of other deals that made great strategic sense. And this one remained there."

Even as ConocoPhillips is poised to add assets in the Permian Basin, Eagle Ford Shale and Bakken Shale, another suitor has a strikingly similar asset base–Devon.

Devon's Hard Look

Devon had also recognized that the companies being acquired by Diamondback, Occidental and ConocoPhillips would pair nicely with their assets.

"Look, it's no secret that Devon also looked hard at CrownRock and Endeavor," Trauber said.

Now, Devon stands as one of the few large public companies yet to do a deal in the current phase of consolidation.

The other, EOG Resources, has historically less frequently pulled the trigger on large-scale transactions.

But Devon is different, Trauber said.

"It's a part of Devon's DNA to be acquisitive," he said.

Similar to ConocoPhillips, Devon's assets match up with Marathon's in the Bakken, Permian and Eagle Ford.

Could Devon play spoiler in the ConocoPhillips-Marathon deal, just as Occidental played spoiler to Chevron's attempts

"It's a part of Devon's DNA to be acquisitive."

STEPHEN TRAUBER, chairman and global head of energy and clean technology, Moelis & Co.

to buy Anadarko Petroleum in 2019? Occidental eventually won out, paying $38 billion for Anadarko and assuming another $46 billion in debt.

Trauber is doubtful.

"In this case, you're talking about a very large, very well-capitalized company in Conoco with a strong strategic fit, strong synergies [with Marathon]," he said. "So, I just don't see going after this company as necessarily a winning hand right now given [that] Conoco is intent on getting it done. It's always hard to intercede on somebody else's deal, anyway."

ConocoPhillips is also likely to achieve at least $500 million in cost savings, though Trauber guesses synergies will be higher than that figure.

For one, Marathon and ConocoPhillips have offices in close proximity and "you don't need both offices," he said. "So, there's going to be substantial layoffs and huge synergies."

But that's the point of consolidation.

"What we're seeing now happens in all mature industries, is you start to see consolidation," he said. "We can gain efficiencies and cost savings and utilize the lower cost of capital and generate better returns."

Public Attractions

Last year, Devon CEO Rick Muncrief said that the company's participation in M&A would have to clear a "high bar," and the approach to a deal would be disciplined and thoughtful–something "we can sell that to shareholders–that it's the right thing to do."

Rick Muncrief

Notably, Devon had reportedly made inroads with the Bakken's Enerplus Corp. Chord Energy ultimately bought Enerplus for $4 billion in a deal that closed at the end of May.

Devon, EOG and other potential buyers still have some opportunities elsewhere, although they are dwindling, particularly in the Permian.

Two that jump to the top of the page: Permian Resources and Matador Resources. However, neither company is necessarily an easy pick-up.

Matador's executives have made the case that the company is doing just fine on its own and should continue to build "brick by brick rather than doing a big transaction," Trauber said. The $7.7 billion market cap company would be a natural fit with Devon's acreage in New Mexico's Delaware Basin.

"They have a very unique and strong culture and they would like to remain independent, subject to somebody coming in with a very strong offer," he said. "But their strong desire is to remain independent."

Permian Resources finds itself in a different position, with financial sponsors that own sizable pieces of that company. The company's top shareholders include an entanglement of private equity funds: Blackrock, Vanguard Group, Riverstone Holdings and EnCap.

Private Attractions

On the private side, Franklin Mountain would likely command somewhere in the "$3 billionish range," Trauber said. The company could fit in with EOG, Devon, Permian Resources or Matador.

But for the larger companies, such a transaction would be a tuck-in not on the scale of the $20 billion deals seen in the Permian and other basins.

"It's not going to move the needle in a big way, like a sizable deal with significant synergies and great strategic overlap would have," Trauber said.

A considerably more lucrative private E&P may be Fort Worth, Texas-based Double Eagle, which has amassed at least 40,000 net acres. The company's Permian oil production averaged about 38,700 bbl/d in January, according to the Texas Railroad Commission.

Again, Trauber sees Double Eagle in an enviable position.

"I'm very, very knowledgeable of that situation…. Look, they've got a data room open. Anybody can make a bid anytime. I am sure that Devon will take a look at that, and I'm sure that others will take a look at that, including everybody who has just bought into the Midland."

But if a seller is in Double Eagle's shoes, "why would you want to try to do a deal right now?" with Exxon just coming off a massive deal to acquire Pioneer Natural Resources, he said. ConocoPhillips is also tied up with a deal, along with Chevron, Occidental and Diamondback.

Double Eagle Can Wait

Each company is, potentially, a sensible strategic buyer of Double Eagle's assets.

"And so, why would you want to sell now until those guys become free and [are] able to compete against each other for what is a high-quality asset?" he said. "I would argue that, why not wait until the fall? There's no rush for them to have to go sell. Why not wait until all of these guys become free and are able to now look at another transaction?"

Devon could step in now with a significant offer for Double Eagle. But the company could just as easily say, "Thank you for your interest, but I want to see what everybody else is willing to pay."

Trauber also addressed rumors about a possible sale of SM Energy, saying the company is in a unique category.

"I think everybody that is sub-sized in today's marketplace should feel like they're a potential target," he said. "I know there's been rumors about SM and other people coming together."

The stumbling block is an asset base that is split between the Eagle Ford and the Permian.

"I think there are some [potential buyers], but there's a limited universe," he said.

Worth noting: Devon, with an extensive portfolio in the Permian, made its most recent deal in August 2022 when the company closed a $1.8 billion acquisition of Valdus Energy in the Eagle Ford. OGJ

ENERGY CAPITAL CONFERENCE

OCTOBER 3, 2024
THOMPSON HOTEL
DALLAS, TX

WHERE'S THE MONEY?

What's influencing investment decisions, asset development and market dynamics? At the **29th Annual Energy Capital Conference,** leading industry insiders and forecasters will discuss:

- How will energy dynamics and politics affect the industry
- What's the best way to finance your strategies
- Opportunities, solutions and challenges

Save the Date, Plan to Attend, Join the Discussion!

The **Energy Capital Conference (ECC)** offers insights on the latest paths to access and deploy capital and new strategies to enhance your business plans. Join 300+ corporate leaders, financial executives, and institutional investors across the energy business and hear from expert speakers providing actionable intel and market trend analysis.

SPONSORSHIP OPPORTUNITIES

Energy Capital Conference is a premier meeting ground for sponsors to reach executive managers from E&P operators, financiers, and dealmakers.

For more information, contact Jeremy Bunnell, Associate Publisher
jbunnell@hartenergy.com | 713 260 5204

GOLD SPONSORS

Akin

Alvarez & Marsal

NSAI

BRONZE SPONSOR

EnCap Investments L.P.

presented by: HARTENERGY

Franklin Mountain Climbs M&A Target List

A relative nobody in a 2018 acreage auction, it's now one of the largest private U.S. oil producers.

CHRIS MATHEWS
SENIOR EDITOR, SHALE/A&D
@chrismathews52
cmathews@hartenergy.com

Franklin Mountain Energy was a relative nobody when the company bid for New Mexico acreage in a 2018 Bureau of Land Management (BLM) lease auction.

"Everyone thought we were crazy," said Audrey Robertson, executive vice president of finance and co-founder of Franklin Mountain.

Several big public E&Ps were lured by the BLM's tempting offer: a chance to buy drilling rights for undeveloped acreage in the core of New Mexico's Delaware Basin.

Successful bidders included large-cap independents like Occidental Petroleum and Marathon Oil. Matador Resources, operating under a stealthy alias, later revealed itself as the top bidder in the federal lease sale.

"But people thought, 'Who the heck is Franklin Mountain?'" Robertson said during Hart Energy's Super DUG conference in Fort Worth, Texas.

It wouldn't take long for the industry to learn. Today, the E&P is one of the largest privately held oil and gas producers in the nation, according to data from Enverus

Franklin Mountain's Delaware Basin Acreage

SOURCE: REXTAG

HART ENERGY

Intelligence Research.

And among private Permian Basin E&Ps, Franklin Mountain owns some of the most attractive and coveted drilling inventory left across the entire basin.

Experts and analysts believe Franklin Mountain will be a target for acquisition by a larger player seeking drilling runway in the Delaware Basin.

The Denver-based E&P could fetch somewhere in the "$3 billionish range" through a sale, Stephen Trauber, chairman and global head of energy and clean technology at Moelis & Co., recently told Hart Energy.

The growing E&P has an experienced leadership team charting its course. Co-founders Paul Foster, Jeff Stevens and Scott Weaver previously founded El Paso, Texas-based Western Refining. Western Refining completed a $5.8 billion sale to Tesoro Corp. in 2017, before Tesoro sold to Marathon Petroleum for $23 billion.

Robertson previously worked at a big private equity firm before founding her own fund focused on minerals and non-operated investments. The Western team eventually became investors in Robertson's fund.

Between 2017 and 2018, the thesis for developing a New Mexico-focused Delaware Basin E&P was born. By combining a private equity-backed position with the big, blocky acreage packages from the BLM auction, Franklin Mountain could put together a substantial undrilled Permian portfolio.

"If it worked, it would be beautiful," Robertson said, "but there were a lot of things that had to happen."

"Namely, we probably needed a quarter of a billion dollars in one day in September," she said.

Franklin Mountain is currently producing around 50,000 boe/d from its blocky acreage position in Lea County, New Mexico.

But just a few years ago, output averaged only around 50 boe/d from a handful of legacy wells Franklin Mountain picked up through acquisition.

The BLM lease sale in September 2018 gave Franklin Mountain around 4,000 acres of undeveloped virgin rock in Lea County.

Later that month, the company added another 4,280 net acres through the acquisition of OneEnergy Partners Operating, a portfolio company of private equity firm Carnelian Energy Capital.

Trust the Process

It took heavy lifting for Franklin Mountain to grow into one of the Permian's top private producers.

The company financed operations out of its own pockets for its first 33 months in business. Franklin Mountain didn't want to go public, and it also didn't want to bring in additional outside investors, Robertson said.

"That was mostly driven to the fact that we wanted to make these operating decisions based on the asset," she said. "We didn't want to have to answer to anyone else."

Franklin Mountain didn't turn to banks early on, either. And frankly, the big banks probably wouldn't have loaned Franklin Mountain the money it needed.

"They probably would not have agreed with our path, to be honest," Robertson said.

A series of countercyclical investments–zigging when most of the rest of the big publics zagged at the direction of their squawking investors–helped Franklin Mountain get to where it is today.

Operators around the nation were slashing drilling activity and cutting budgets when Franklin Mountain picked up its first rig in late 2020; oil prices languished around $38/bbl.

"I would say it was a hostile energy environment coming off of negative oil prices," Robertson said. "But we had conviction that we had the right asset and we had the right team, so we were moving forward."

Oil prices had rebounded to around $62/bbl when Franklin Mountain's first well pad came online in July 2021.

Franklin Mountain also prioritized building out its own infrastructure needs in the Delaware Basin, like midstream takeaway.

"It led to us having partnerships with midstream providers, landowners, regulators and trying to build long-standing opportunities for growth," Robertson said.

The company did start to approach banks for financing around the time it was drilling the first well pad. Franklin Mountain had invested $100 million into its drilling program at that point; the company was looking for a $40 million bank revolver.

But Franklin Mountain, drilling its first wells, was a relative newcomer to the upstream sector. Several major banks weren't willing to lend the money.

However, small- and medium-sized banks—Bank of Oklahoma (BOK Financial Corp.) in particular, Robertson said—were willing to play ball with Franklin Mountain.

"Great banks like Comerica, UMB Bank and Fifth Third jumped in and we got our $40 million revolver," Robertson said.

Today, Franklin Mountain's credit revolver includes 16 bank lenders and hovers in the range of $1 billion.

"And it will always be led by Bank of Oklahoma because of that support they gave us early on," she said.

M&A Mayhem

Public E&Ps are clamoring for Permian Basin drilling inventory, and they're willing to pay up.

The frenzied hunt for drilling runway fueled a record amount of corporate M&A and asset transactions in the Permian Basin.

Several of the basin's largest producers—Pioneer Natural Resources, Endeavor Energy, CrownRock and others—were snapped up in a matter of months.

ConocoPhillips recently announced a $17.1 billion acquisition of Marathon Oil, a deal that will further consolidate the Permian Basin. The deal also includes complementary positions in the Eagle Ford, the Bakken and Midcontinent.

After exits by numerous private equity-backed E&Ps, there are fewer M&A opportunities left hiding in pockets around the basin.

It's why private companies like Franklin Mountain stick out so much as potential M&A targets, said Andrew Dittmar, senior M&A analyst for Enverus Intelligence Research, during the 2024 Enverus Evolve conference.

Other private M&A targets include family-owned oil companies like Mewbourne Oil and Fasken Oil & Ranch.

There are also a handful of interesting private equity-backed E&Ps still growing in the Permian: One is Double Eagle IV, which is building an attractive position in the Midland Basin. That company is reportedly exploring a sale in the range of $6.5 billion.

Ameredev II, backed by EnCap Investments, has also grown a sizable footprint in the Delaware Basin. Matador Resources purchased Ameredev II for $1.9 billion in mid-June.

FireBird Energy II, backed by private equity firm Quantum Energy Partners, is also building a Midland Basin position, including leases in Midland, Upton, Glasscock and Crane counties, Texas.

FireBird II is developing the popular benches and exploring some deeper intervals on the western side of the Midland Basin. The company currently holds the bulk of its leases and production in Upton and Midland counties. OGJ

Hydrogen: Getting to FID, Locking in Offtake

Hydrogen players are working to find buyers and pursue incentives to move projects forward.

VELDA ADDISON
SENIOR EDITOR, ENERGY TRANSITION
@VeldaAddison
vaddison@hartenergy.com

It's been called a unicorn, but there has been no magic involved in the Advanced Clean Energy Storage project (ACES Delta) in Utah being developed by Mitsubishi Power and Chevron.

Its story is rooted in partnership, planning, proven technologies and proximity to infrastructure. The hub—which will initially convert more than 220 megawatts (MW) of renewable energy into 100 metric tonnes per day of hydrogen to be stored in two gigantic 4.5-MMbbl salt caverns—is under construction with startup expected in 2025. The project will provide long-duration energy storage to be dispatched when needed to the grid.

"Once it does go operational, we think that it will serve as a blueprint for other projects to follow. We're already seeing it right now in the market, and we're happy to see that," Michael Ducker, president and CEO of MHI Hydrogen Infrastructure, told *Oil and Gas Investor*. "Of course, we're looking to emulate some of what we've done at that project in other projects across the U.S. and globe."

Across the world in Saudi Arabia, nearly two dozen banks and investment firms came together to clear the path for an $8.4 billion hydrogen plant. The NEOM Green Hydrogen Company JV, comprised of ACWA Power, NEOM and industrial gases company Air Products, secured an exclusive 30-year offtake agreement with Air Products for all of the ammonia that will be produced from hydrogen at the facility. When complete, the plant will produce up to 600 tonnes per day of hydrogen in the form of green ammonia by year-end 2026.

The hydrogen projects are among the few with announced commissioning dates that have made it past the final investment decision (FID) stage amid the global clean energy drive. It's a destination that many hydrogen producers hope to reach. However, the road has been bumpy. Hydrogen is a promising decarbonization tool but it can be more expensive compared to fossil fuel-based products. Developers need to lock in buyers to move projects forward. Policy could help, but uncertainty—particularly in the U.S. regarding demand and qualifications for hydrogen production tax credits—remains.

> *"We think that it [ACES Delta] will serve as a blueprint for other projects to follow."*
>
> **MICHAEL DUCKER,** president and CEO, MHI Hydrogen Infrastructure

Sluggish Investment

Insights shared in a joint report by the Hydrogen Council and McKinsey & Co. show the pipeline of hydrogen projects has surpassed 1,400 globally, representing about $570 billion worth of investments and 45 million tons per annum of clean hydrogen through 2030.

However, investment decisions are sluggish. Of the projects with a known commissioning date, only one-quarter have passed FID, accounting for 7% of the total announced investments, according to the report.

"It's important to remember that when it comes to low-carbon hydrogen, we're looking to build in a short few years what it took literally decades or centuries for previous energy transitions to establish," Mark Klewpatinond, global business manager of hydrogen for Exxon Mobil Low Carbon Solutions, said during a hydrogen conference in Houston. "While the energy transition is underway, we appreciate that there's still a tremendous amount of work to be done. This is a long-term proposition that requires no small amount of investment and effort. Now is the time to tackle these challenges."

Klewpatinond pointed out hydrogen's more expensive price over incumbent fuels and stressed the need of society to cover the required costs to develop infrastructure and convert customers.

"We can achieve this by enabling market-driven, technology-neutral policies that activate and build on nascent demand, coaxing these new markets to life," he said.

SOURCE: MITSUBISHI POWER AMERICAS

Mitsubishi Power says the long-duration energy storage capability of the salt caverns will help improve resource adequacy and decrease costs by capturing excess renewable power when it is abundant and dispatching it back on the grid when it is needed.

MITSUBISHI POWER AMERICAS

Electrolyzers for the ACES Delta project in Utah.

"At present, a lack of sufficient policy support and market uncertainty is undermining this development."

The U.S. Bipartisan Infrastructure Law made available $7 billion to establish regional hydrogen hubs in the U.S. and $1 billion to help spur demand, while the Inflation Reduction Act's clean hydrogen production tax credit is intended to incentivize developers.

"But at present it's still not sufficient to activate hydrogen's potential," Klewpatinond said.

"What we specifically need is clarity and assurance that the Treasury will incentivize hydrogen produced from different technologies, enabling key projects like Exxon Mobil's Baytown project, which are instrumental in building America's economy at a cost acceptable to consumers," he added.

The company plans to use natural gas to produce up to 1 Bcf/d of hydrogen, capturing more than 98% of the associated CO_2 and storing it underground.

"It would be the largest low-carbon hydrogen project in the world. The carbon capture and storage project enabling this hydrogen plant would also be one of the largest, and it could store up to 10 million tons of CO_2 annually, and double our current carbon capture and storage capacity," he said. "The Baytown project has been designed to deliver very low carbon intensity hydrogen as a result of additional significant investments made by Exxon Mobil. For example, the project will benefit from low carbon intensity or differentiated natural gas resulting from significant investments that we have made to reduce emissions in our Permian operations."

Pending FID, which is expected in 2024, and other conditions, the facility could start up in 2027 or 2028. The project would represent about 10% of the Biden administration's 2030 goal for clean hydrogen supply.

Reaching FID

ACES Delta's FID predates the Inflation Reduction Act.

During the conference, former Mitsubishi Power Americas CEO Paul Browning said the project isn't a

unicorn, as some people call it. Instead, a confluence of factors enabled ACES Delta to come together: a creditworthy offtaker plus a desirable location with access to renewable energy, water, storage and infrastructure that includes pipelines within feet—not miles—to the offtaker's fence line.

The project will provide fuel via pipeline for Intermountain Power Agency's (IPA) 840-MW combined cycle gas turbine power plant, which is adjacent to the ACES Delta hub. IPA's IPP Renewed Project is set to replace a retiring 1,800-MW coal-fired power plant. Its gas turbines will run on 30% hydrogen fuel at startup in 2025, but that percentage could increase to 100% by 2045.

In his current role as a co-founder of Energy Transition Finance, Browning helps companies navigate the U.S. Department of Energy's Loan Programs Office (LPO) application process. He worked with Mitsubishi when the company submitted its loan application to the DOE.

Reaching bankable FID sooner requires having a debt mindset, Browning said. When seeking federal funding, realize that any government agency has rules to follow and stakeholders to satisfy. "If you try to cut corners on that, you're just going to be delaying your project and increasing the cost," he said.

There is no magic, secret sauce or mystery to getting there.

"It's hard work. It's thoughtfulness. It's having the right partners and putting one foot in front of another," First Ammonia CEO Joel Moser said.

It's Finance 101, he added, mentioning fixed price construction, firm credit off-takers and inputs/feedstock that are either fixed price or hedged.

"It's a closed box where the entire project is de-risked the same as we've done historically for gas-fired generation and for any kind of projects financed. So, there's nothing new," Moser said. "We just have to approach it on project finance basis, de-risk everything, get to project close and start building enough of these.... We all have to succeed. This market has to get big enough that the products have their own trading market."

At that point, the sector can evolve from the "kindergarten of project financing" one at a time to being industrial producers, he added.

First Ammonia is targeting FID in 2024 for a green ammonia project it is developing in Texas. The green ammonia will be produced from renewable hydrogen at the Port of Victoria. The company has lined up an agreement to deliver green ammonia to Uniper, but the global market for the product is still developing.

"There is not at this moment in the world today commercial quantities of this product being produced. So, there's no big surprise that there isn't a traded market," Moser said. "So, when it reaches the status of being a traded commodity as green ammonia separate from conventional ammonia, we can move on to financing our projects, our companies, in the way that industrial companies do."

Like electrolytic hydrogen, the clean derivative product is more expensive than its fossil fuel counterpart but it is becoming cheaper. The story is the similar for green methanol, which is used as fuel. HIF Global combined captured CO_2 with electrolytic hydrogen to create synthetic methanol, which is then refined into gasoline, at a demonstration plant in southern Chile.

"Porsche is an investor in our company, and they actually buy all the fuel that we produce from there. And it is no way economic," HIF Global COO Brooke Vandygriff said of the demonstration plant during the conference. "It is truly a proof of concept to prove to the world that drop-in fuels can be made today. And by teaching the regulators and policy makers that we can produce these fuels, they will catalyze and incentivize them to write the policy that supports these project developments."

At least, that is the hope.

"If you try to cut corners... you're just going to be delaying your project and increasing the cost."

PAUL BROWNING, former Mitsubishi Power Americas CEO

Policy, Collaboration Needs

Hydrogen players are awaiting more details on the hydrogen production tax credit.

The proposed regulation, intended to incentivize low-carbon hydrogen production, offers a credit ranging from $0.60 per kilogram (kg) of hydrogen produced to $3/kg, depending on the lifecycle greenhouse gas (GHG) emissions from hydrogen production, including its power source. It is based on three pillars: additionality, regionality and time matching. Since the proposed guidance was unveiled in December 2023, industry reaction has been mixed.

Vandygriff said, "they made it very difficult to navigate and really squashed a very nascent industry from taking off. I just need them to solidify the policy so that we can move forward with our project.... Until the regulations are solidified and in law, we cannot get to FID because we don't know how to calculate the hydrogen tax credit. And then we don't know how to value our offtake product because of that. And then we can't get somebody to sign a long-term contract for a cost of a product that they don't know."

HIF Global plans to use wind energy along the U.S. Gulf Coast to produce hydrogen, which will be used to make eFuels in Matagorda, Texas. The $6 billion project expects to produce about 1.4 million tons per year of eMethanol by 2027 and capture about 2 million tons per year of CO_2.

Companies, including HIF Global, are also trying to scale to bring down costs.

"Manufacturing must scale so that the equipment cost can come down. The hydrogen production component of the plant is by far the most expensive part," Vandygriff said. "We do really need the cost of the electrolyzers to go down over time if we want to replicate these plants and really capture some market in the green fuel space."

As a company that has made it beyond FID, Ducker sees the value in collaboration. He called it "absolutely critical" for getting projects of this magnitude and complexity off the ground to overcome gaps and scale. OGI

Occidental, BHE Renewables Form JV to Extract Lithium

The joint venture takes shape as companies aim to meet growing demand for a key ingredient for rechargeable batteries, electronics, energy storage and electric vehicles.

VELDA ADDISON
SENIOR EDITOR,
ENERGY TRANSITION
@VeldaAddison
vaddison@hartenergy.com

Occidental Petroleum is partnering with Berkshire Hathaway Energy's BHE Renewables to extract lithium from geothermal brine, the energy producer said in early June.

The joint venture takes shape as companies aim to meet growing demand for lithium. The focus for traditional oil and gas players entering the space has been on direct lithium extraction (DLE), a proven–though not yet at-scale–technology that uses either adsorption, ion exchange or solvent extraction to remove the critical metal from brine.

Occidental subsidiary TerraLithium has patented DLE technologies that process lithium-containing brine into high-purity lithium and has already started a project at BHE Renewables' Imperial Valley geothermal facility. The two aim to demonstrate the feasibility of using the TerraLithium DLE technology to produce lithium in an environmentally safe manner, Occidental said in a news release.

"Creating a secure, reliable and domestic supply of high-purity lithium products to help meet growing global lithium demand is essential for the energy transition," said Jeff Alvarez, president and general manager of TerraLithium. "The partnership with BHE Renewables will enable the joint venture to accelerate the development of our direct lithium extraction and associated technologies and advance them toward commercial lithium production."

Upon successful demonstration, BHE Renewables plans to build, own and operate commercial lithium production facilities in Southern California's Imperial Valley, according to the release.

Iowa-headquartered BHE operates 10 geothermal power plants in Imperial Valley, where the company said it recovers heated geothermal brine from reservoirs up to a mile or more belowground to create steam that spins a turbine, creating electricity.

The JV will pursue development of additional commercial lithium production facilities beyond Imperial Valley and license the technology.

DLE is considered a more environmentally friendly method of lithium extraction, requiring less land and extraction time when compared to traditional methods involving hard rock mining and use of solar evaporation ponds.

SHUTTERSTOCK

Geothermal power and lithium production at the edge of the Salton Sea near Calipatria, Calif. in Imperial Valley.

However, the technology is not without barriers, despite the resource potential.

"It is fair to recognize that extraction of lithium from geothermal brines comes with several unique challenges that include high levels of associated minerals and heat," TD Cowen analysts said in a research note. "For OXY, the JV is a win-win as BHE appears to bear most of the capital risk for OXY to prove its DLE concept."

BHE said the JV is working to refine the DLE process further to ensure it achieves performance outcomes before moving to commercial production.

BHE currently processes about 50,000 gallons of lithium-rich brine per minute to produce 345 megawatts of energy from its Imperial Valley plants. The company said it expects to produce about 90,000 metric tons of lithium carbonate equivalents (LCE) per year–equivalent to about 11 million EV car batteries annually–from its existing geothermal plants.

Analysts put the timeline toward the end of the decade, if successful.

"By that point, BHE's lithium production would aggregate to 3% of total demand," TD Cowen analysts said. "By reference, the most active DLE development in the U.S. currently, operated by Standard Lithium in the AR Smackover, targets an initial plant that processes 3k gpm [gallons per minute] of brine for ~6ktpa of LCE production, suggesting that lithium concentration at BHE's Salton Sea assets is fairly analogous."

Besides Occidental and Standard Lithium, others advancing DLE projects in the U.S. include Exxon Mobil and Albemarle. OGJ

TRANSITION IN FOCUS

Carbon Management

Aera Energy Lands $2.8MM in DOE DAC Funding

The U.S. Department of Energy (DOE) awarded California-based Aera Energy subsidiary Aera Federal a $2.8 million cooperative agreement contract as part of the department's Regional Direct Air Capture (DAC) Hubs Initiatives, the company said.

Located in the Kern County Belridge Oil Field in California, the project aims to be among the first in development for the state's full-scale DAC plus storage network of regional hubs. Funds, the company said, will go toward a feasibility study to establish the viability of DAC as a business and technology for large-scale decarbonization in California.

The study, funded in part by the DOE and Aera, was scheduled to begin in May and end in April 2026. Aera's partners include Battelle Memorial Institute, Mosaic Materials and CarbonCapture Inc., according to the release.

Exxon Mobil Taps Technip, Turner for EPC for Louisiana CCUS Project

Technip Energies and Turner Industries have been selected to carry out engineering, procurement and construction for a carbon capture, utilization and storage (CCUS) system being built by Exxon Mobil Low Carbon Solutions Onshore Storage in Louisiana, according to a news release.

The system will be capable of conditioning, compressing and transporting, for eventual storage, up to 800,000 metric tons per year of CO_2, Technip said in a news release. It will be owned by steel manufacturer Nucor Corp.

France-based Technip will carry out front-end engineering design, while Turner will be responsible for construction.

Nucor plans to utilize the system to reduce greenhouse gas emissions from its manufacturing plant in Convent, La. The site produces direct reduced iron (DRI), which is mixed with recycled scrap to make higher-grade steel products, Technip said in the release.

"The CCUS system is designed to enable the Nucor facility to produce DRI with up to 80% less greenhouse gas emissions than traditional blast furnace iron production," Technip said.

Hydrogen

Element Fuels Progresses Plans for Hydrogen-powered Refinery, Power Plant

With a construction start in sight, a complex that will transform shale oil into lower carbon fuels, hydrogen and electricity is moving into the detailed engineering phase following completion of site preparation and preconstruction work.

Texas-based Element Fuels Holdings said it received the permitting it needs to construct and operate the planned facility, which is located on a 240-acre site inside the Port of Brownsville. When the first-of-its-kind complex, billed as a "hydrogen-powered clean fuels refinery and combined-cycle power plant" comes online in 2027, it will be capable of producing more than 160,000 bbl/d of finished gasoline, diesel and jet fuel.

"A permit for a greenfield refinery of this size, scope and functionality has not been granted in the United States since the 1970s," Element Fuels Co-CEO John Calce said in a statement. "This speaks to the innovative approaches we are taking to address climate and sustainability concerns in cleaner, greener ways that are new to the refinery space."

McDermott will provide front-end engineering design services, including offsites and utilities, for the project.

Element Fuels said it will use naphtha reforming to produce hydrogen, which will also be recycled. The process involves use of high-gravity U.S. shale oil–such as the light crude produced in the Permian's Delaware Basin. The facility is expected to produce enough hydrogen to meet all of the refinery's needs. Excess hydrogen will be used to generate electricity, which will be made available to the Electric Reliability Council of Texas (ERCOT).

Construction is expected to begin in first-quarter 2025.

Geothermal

Utah FORGE Marks Geothermal 'Breakthrough'

UTAH FORGE

Utah FORGE drilling site.

The Utah Frontier Observatory for Research in Geothermal Energy (FORGE) said it made a major geothermal breakthrough, having established enhanced connectivity, fluid flow and energy transfer between two enhanced geothermal system wells.

The project is part of a global field lab managed by the University of Utah's Energy & Geoscience Institute and sponsored by the U.S. Department of Energy.

"These stimulations and the short-term circulation test are the culmination of more than two years of planning and in-depth data analysis," John McLennan, the professor who oversaw the activities, said in a news release. "Enfranchising the knowledge gained from previous activities, and with advice from a diverse team of specialists from industry and academia, the Utah FORGE

team was able to achieve outstanding results."

The production well was hydraulically fractured in eight stages over a two-week period. Four stages were injected. To locate fractures intersecting the injection well, fiber optic cables were monitored. "The recorded fiber optic signatures highlighted intervals of fracture intersection or proximity," Utah FORGE said. "These intervals were selected and perforated for subsequent stimulation. Stimulating both wells ensured connectivity."

Connectivity was established with no induced seismicity greater than magnitude 1.9, according to the release. A circulation test followed stimulation. Utah FORGE said water was injected—at up to 15 bbl per minute—into the well for nine hours. That led to up to

8 bbl per minute of production, with an efficiency rate of about 70% recovery. Hot water produced confirmed the potential of enhanced geothermal systems (EGS), Utah FORGE said.

Next steps include more fieldwork, including a 30-day circulation test planned in July, according to a news release.

Renewable Natural Gas

BP's Archaea Energy, Republic Services Startup Indiana RNG Facility

BP ARCHAEA ENERGY/REPUBLIC SERVICES

The Fort Wayne plant can process 6,400 cf of landfill gas per minute into RNG.

BP-owned Archaea Energy and waste disposer Republic Services have brought the first of more than 40 landfill renewable natural gas (RNG) plants online as part of their Lightning Renewables joint venture (JV).

The two companies marked the startup of the Archaea Modular Design (AMD) plant at Republic's National Serv-All Landfill in Fort Wayne, Indiana, according to a news release. Such projects involve turning methane that emits from decomposing waste at landfills into pipeline-quality gas. The RNG is used in the same ways as fossil gas but it has a lower carbon intensity. The fuel source is already playing a role in lowering emissions in the U.S. as the number of RNG projects grows.

Instead of taking the custom build route for RNG plants, BP Archaea utilizes a modular design. Its RNG facilities are built on skids with interchangeable components. The design allows for faster builds than previous industry standards, the company said.

The Fort Wayne RNG facility is designed to process 6,400 cf of landfill gas per minute into RNG, according to the release. Based on the U.S. Environmental Protection Agency's Landfill Gas Energy Benefits Calculator, that's enough gas to heat more than 25,000 homes annually.

The JV's planned buildout of RNG plants is expected to be largest of its kind for landfill RNG in the U.S. It is also expected to lift Republic's landfill gas-to-energy portfolio to more than 100.

Archaea and Republic Services plan to bring another RNG plant online in Indiana later this year. The 2,000-scfm AMD RNG plant will be located at Republic Services' Sycamore Ridge Landfill in Pimento, Indiana, south of Terre Haute.

Solar

Enbridge, EDF's Fox Squirrel Solar Project Goes Online

North American energy company Enbridge and EDF Renewables North America began commercial operations on the 150-megawatt (MW) Fox Squirrel Solar Phase I, according to a news release.

Comprised of 1.4 million panels and 159 inverters, Fox Squirrel represents the "largest" onshore renewable energy project developed by EDF, the companies said.

Once all three phases are completed by year-end 2024, Fox Squirrel is expected to produce 577 MW, making it the largest utility-scale solar developments east of the Mississippi River.

Fox Squirrel, which is owned in partnership with Enbridge, was built to help meet central Ohio's increasing power demand, which could double by 2028, the release said.

Renewable company Blattner was the project's engineering, procurement and construction contractor.

HighPeak, Priority Power Advance WildHorse Solar

Midland Basin oil producer HighPeak Energy and Priority Power commissioned the nearly 10-MW WildHorse Solar Farm in the Flat Top operating area in Texas, the companies said.

Developed and owned by Priority Power, the facility in Howard County is expected to produce enough electricity to power nearly 3,700 homes and reduce more than 18 million metric tons (MMmt) of CO_2 emissions. Electricity generated at the solar farm will power HighPeak's operations, a move the company said will lower costs and minimize greenhouse gas emissions.

"The 10 megawatts generated from this project will reduce our power costs, shield us from summer spot power price spikes and reduce our carbon footprint," HighPeak President Mike Hollis said in a statement. "HighPeak has been energizing our drilling rigs with grid power, and we are now drilling with power directly supplied by West Texas sunshine."

Completion and commissioning of the solar farm came as power needs in the Permian Basin continued to surge, operators diversified their power sources and as competition for power—including from data centers and bitcoin miners—heat up along with temperatures and prices. OGJ

Hirs: Why Energy Networks Are Tough to Control

Traders arbitrage faster than regulators can resolve bottlenecks.

ED HIRS
DEPARTMENT OF ECONOMICS, UNIVERSITY OF HOUSTON
@dhirs
edhirs@edhirs.com

Ed Hirs lectures on energy economics at the University of Houston, where he is an Energy Fellow in the College of Liberal Arts and Social Sciences.

U.S. utilities regulators are facing criticism because of volatile prices in natural gas and electricity markets, but they aren't necessarily to blame. At least not entirely. Market fundamentals, such as increased demand due to Russia's invasion of Ukraine, have driven some of the volatility. Regulated market designs, even in "deregulated" markets, are driving the rest of the volatility.

Meanwhile, the nation's public service commissioners and federal regulators are positioned to address issues only after they become problems. In that sense, the regulators are always trying to clean up the mess rather than getting in front of changing economic conditions. Consumers and taxpayers end up paying the price.

Today, forecasts are for electricity demand to increase by 50%, with natural gas demand also expected to grow, despite efforts to decarbonize the energy system.

Rules generally prohibit the bodies that regulate utility systems from making direct investments in those systems, so regulators—concerned about meeting future demand—are limited to finding ways to accommodate investments in new generators and natural gas supplies.

At the micro level, the regulators deal with connections across grids of wires and pipelines. At each of these connections, or nodes, regulators evaluate the commodity price and who has physical or financial control of the spigot. This is what drives most regulatory decision making. Unfortunately, focusing on the market at the individual spigots means regulators are often surprised when their actions create other bottlenecks across the larger market.

Bedeviled by Bottlenecks

In "The Unsustainable Costs of Partial Deregulation," the late energy markets economist Paul MacAvoy described a simple network economy consisting of a triangle of nodes A, B, and C. If the nodes were connected by a pipe or a wire, then the product could flow efficiently from one to the other, and the impact of adding supply at one node or changing consumption at another would impact the markets at each of the other nodes. If bottlenecks were present, these would be immediately obvious by price differences at the nodes.

Energy professionals depend upon interconnected markets and often profit from arbitrage opportunities long before market participants and regulators can effectively address them. In 2000-2001, natural gas entered Waha at $2.50/mcf and exited in Southern California at $12.50/mcf. Had there been sufficient pipeline capacity between the nodes, the 2000-2001 California energy crisis may have been averted.

In the winter storm of February 2021, natural gas and electricity markets across the nation reeled from the extraordinary spike in natural gas prices in Texas—even in those states that are themselves net exporters of natural gas and electricity to the rest of the nation. One regulator asked, "Was this price gouging or anti-competitive, monopolistic behavior by bad actors?" The answer is yes.

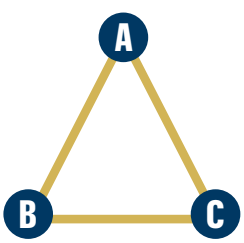
Of course, the defining characteristic of both price gouging and monopoly is a large price-over-cost margin. In markets characterized by low price-cost margins, it is because the sellers really are competing on price or because there is effective or even too effective price regulation.

MacAvoy showed that regulated electricity and natural gas transmission companies do not earn a return on capital that is competitive on Wall Street. That is, Wall Street will choose other industries such as software, or consumer goods, or defense, or tech, or food, rather than investing in additional transmission capacity. Obvious bottlenecks that would be relieved by new wires or pipes have persisted for decades. Therefore, consumers suffer. And state regulators are looking to clamp down on profiteering rather than addressing the root cause.

Government price regulation, even in "deregulated" markets, causes energy bottlenecks and eliminates profit opportunities for infrastructure companies. The traders and hedge funds gain more arbitrage opportunities.

A prime example is the ERCOT market in Texas. In 2023, the market overcharged consumers more than $12 billion through November. Had Texas made a one-time investment of $12 billion in new natural gas power plants, that overcharge may not have happened. Texans will face that same skewed market design for the foreseeable future.

State regulators in Texas and across the nation are stuck. Building infrastructure will certainly cost consumers and taxpayers money, but not building it is costing them even more. To meet current and future needs, state legislators and Congress must revisit their market designs now. Regulators cannot keep up with the growth in consumer demand and the evolving energy supply portfolio. OGI



'The Simple Network' as described by the late energy markets economist Paul MacAvoy.
SOURCE: ED HIRS

Private E&Ps Pursue Dollars Amid Change

Producers contend with roiled capital markets as consolidation alters the strategic landscape.

MARK DRUSKOFF
CONTRIBUTING EDITOR

The dividing line between the private and public capital markets has blurred for upstream oil and gas companies in need of financing. This new reality is reshaping the world of private capital, private equity providers and the producers they back.

At the same time, the onshore U.S. upstream industry is experiencing a fundamental reorientation as consolidation alters the landscape. Upstream operators looking to grow and thrive in such an environment must contend with these realities with a financing toolkit that is itself being reforged.

Private/Public Capital Sources

The public market has been relatively closed to new upstream issuances, with a handful of initial public offerings (IPOs) filed by onshore U.S. E&Ps during the last four years. But that doesn't mean the public markets haven't been a source of capital for private upstream companies.

"[Private producers have] largely accessed capital markets by being bought," said Jeff Nichols, partner with Haynes and Boone.

Several companies appeared poised for public offerings in recent years, but most of them were swept up in the recent consolidation wave.

Colgate Energy Partners was widely expected to file an IPO in 2022, but ended up merging with publicly traded Centennial Resource Development. The $7 billion "merger of equals" transaction created the largest pure-play E&P in the Delaware Basin. The pro forma company adopted a new name, Permian Resources, and within a year returned to growth mode.

Colgate's founders and co-CEOs, Will Hickey and James Walters, retained their roles at the new E&P, and Centennial CEO Sean Smith is executive chairman of the board.

Under their leadership, Permian Resources bought Earthstone Energy in 2023 in a $4.5 billion deal that increased the independent's leasehold to more than 400,000 net acres and its production to 300,000 boe/d.

Earthstone, backed by EnCap Investments and Post Oak Energy Capital, had itself previously rolled up a number of portfolio companies in the Permian.

"Like all the other private equity investors, we have been an active participant in the consolidation," said Frost Cochran, founding partner

Oil and gas drilling equipment.

SHUTTERSTOCK

"We'll see a large number, if not all, of the private equity-backed Permian and Haynesville, probably Eagle Ford, operators consolidated into larger public entities."

FROST COCHRAN, founding partner and managing director, Post Oak Energy Capital

Refinery and storage facilities of oil and petroleum products.

SHUTTERSTOCK

and managing director of Houston-based Post Oak Energy Capital.

Post Oak invested in Earthstone in 2022 through a $280 million private investment in public entity (PIPE). Cochran now serves on the board of Permian Resources.

As a result of all the portfolio companies that have been rolled up into Permian Resources, more than one-quarter of Permian Resources is controlled by a quintet of private equity firms: Pearl Energy Investments, EnCap Investments, Riverstone Investment Group, NGP Energy Capital Management and Post Oak.

Riverstone Energy Limited (REL), a publicly traded affiliate of Riverstone, has given some insight into the payoff: its investment has generated a multiple on invested capital (MOIC) of 1.51x from its share of the Permian Resources investment.

Post Oak has also ended up holding stakes in other private companies. The firm is a large shareholder in SilverBow Resources, said Cochran, adding, "There's been a lot of drama around that company."

Earlier this year, Eagle Ford-focused SilverBow was actively pursued by Kimmeridge Energy Management, a

ASSET-BACKED SECURITIZATION EMERGES AS GROWING FINANCE OPPORTUNITY

In basins that lack an obvious consolidator, a relatively new type of financing has emerged called PDP (proved developed producing reserves) asset-backed securitization (ABS).

EnCap-backed Raisa Energy innovated its use back in 2019. Raisa closed the industry's first rated securitization of oil and gas wells in late 2019. Since that time, the firm has closed three additional transactions, securing $1 billion in gross proceeds through securitization of almost 13,000 wells in 60 counties across 10 states, according to company materials.

Most of the securitizations have been private companies, said Haynes and Boone Partner Jeff Nichols, who has advised on several ABS transactions. Securitization will only cover existing wells, he said, but it enables upstream operators to access capital that they can invest elsewhere.

Securitization offers much higher advance rates compared to traditional reserve-based lending (RBLs)—roughly 80 to 90% versus 40% to 50%, Nichols said.

Still, he said, "There's no free lunch."

Long-term hedging is required to put ABS buyers at ease, and the cost can be significant.

Other private companies that have tapped ABS financings include Green River Basin operators Jonah Energy, which raised $750 million, and PureWest Energy, which raised $965 million in a pair of transactions. In the Anadarko Basin, Maverick Natural Resources, backed by EIG Global Energy Partners, conducted a $640 million ABS.

While many of the publicly disclosed ABS deals involve natural gas-weighted producers, Nichols said the commodity is not as important as characteristics of production and the pricing environment.

"You just need a stable production curve and a good price curve to hedge," he said. The Permian could be an "ideal" basin because many areas have demonstrated steady production over many years, and certainty of production is key to an ABS.

private equity firm turned activist investor. Kimmeridge made several acquisition overtures but ultimately withdrew its bid in April. In May, Crescent Energy made SilverBow a $2.1 billion buyout offer to create the second-largest Eagle Ford Shale operator.

Crescent Energy is itself a publicly traded acquisition vehicle. In late 2021, KKR merged its Independence Energy with Contango Oil & Gas to form Crescent Energy. The company focuses on low-decline production and holds large positions in Texas, primarily the Eagle Ford, and in the Rockies, primarily in the Uinta Basin, which has become increasingly competitive.

KKR includes Crescent Energy within the infrastructure segment of its business, which globally holds $61 billion of assets under management. KKR maintains a 15% stake in the company and Chairman John Goff holds 5%, according to company filings. The head of KKR's energy real assets business, David Rockecharlie, serves as Crescent Energy's CEO. KKR is itself publicly traded.

Opportunities, Risks

Private equity's foray into the public markets has been enabled by the historic consolidation trend in the upstream space. The last 24 months have seen more than $200 billion worth of E&P transactions announced. ConocoPhillips' $22.5 billion acquisition of Marathon Oil in May is the latest, but it's unlikely to be the last.

"We'll see a large number, if not all, of the private equity-backed Permian and Haynesville, probably Eagle Ford, operators consolidated into larger public entities," Cochran said.

He flagged ConocoPhillips and Apache Corp. as two large players that may need to get more active in the acquisition game.

Conspicuously absent from the M&A frenzy is Devon Energy. Conoco's bid for Marathon came after it missed the window to buy both CrownRock, which Occidental is purchasing, and Endeavor Energy Partners, two companies that Devon Energy examined closely, Moelis' Stephen Trauber told *Oil and Gas Investor*.

There are parallels between the current wave of consolidation and industry restructuring that took place in the late 1990s, a time of megadeals like Exxon's merger with Mobil and Chevron's combination with Texaco, which resulted in plenty of assets coming into the market, Cochran said. A similar theme should play out in the current environment.

Apache announced the sale of $700 million in non-core assets in May following a January agreement to acquire Callon Petroleum for $4.5 billion. Occidental disclosed plans to sell up to $6.4 billion in assets once it closes its acquisition of CrownRock. The buyers of most of those assets will presumably be private capital-backed operators, Cochran said.

Haynes and Boone's Nichols said onshore U.S. assets are in much greater demand now than at the turn of the millennium, and that should drive even greater activity. Plus, a net effect of widespread M&A is that plenty of talented management teams will be available to pursue those opportunities.

"For every consolidation, there's a new management team that is out there looking for new properties and raising money," Nichols said.

"In 12 to 24 months, there might be a dozen management teams out there who are backed by private equities and looking for the next set of properties to buy."

Private equity will be busy backing teams to acquire non-core assets, Cochran said.

Pipeline valves at an oil and gas processing plant.

SHUTTERSTOCK

"We are seeing an emphasis on business models focused on cash flow generation, which provides return optionality without relying on outright sales to meet return targets."

SEAN O'NEILL, co-founder and managing partner, Old Ironsides Energy

"I know we're doing that," he said, adding that other upstream private equity investors are likely to also be in the mix. The next two years will likely yield an increase in newly formed private equity-backed companies.

Daniel Rioux, co-founder and managing partner of private equity firm Old Ironsides Energy, told *OGI* that future divestitures from the consolidation trend will fuel more new private producers.

"We foresee additional opportunities to fall out as companies digest mergers and plan for the path forward," he said. "In particular, we believe consolidation will create opportunities in non-core areas for teams with track records of execution in these areas."

Consolidation is welcomed by private players and should spawn a range of new companies. However, the reaction—or some might say overreaction—of federal regulators gives pause. Primarily a concern of larger players, insiders say that private equity-backed companies should still tread carefully.

Post Oak's Cochran questioned recent moves by the U.S. Federal Trade Commission targeting most of the largest E&P consolidation announcements made since October. Former Pioneer Natural Resources CEO Scott Sheffield was barred from joining Exxon Mobil's board of directors following the agency's "second request," a process that delays closing to allow more time for FTC investigation, in the Exxon-Pioneer merger. The agency said Sheffield had worked to fix prices. Sheffield has asked the agency to vacate the order; the agency has declined to do so.

Cochran took issue with the FTC's findings.

With a global market for crude oil, "no U.S. citizen except for the president of the United States" has any influence over commodity prices, he said.

Moreover, Cochran said, private equity and the companies they capitalize are important to driving innovation and efficiency in the industry, but from the standpoint of oil markets, "we're a rounding error."

Still, he posed the question, "Will the FTC do something else irrational?"

It's not just the supersized independents and majors that are apparently in the FTC's crosshairs. Some private equity-backed deals have been impacted by the FTC, as well, Cochran said.

New and Old Funding Tools

Despite the expanding supply of assets coming to market, don't expect a return to the once-prevalent build-and-flip business model for private equity-backed companies, these financiers say. In the current market environment, financial discipline and shareholder returns have become paramount for private equity-backed companies.

"We are seeing an emphasis on business models focused on cash flow generation, which provides return optionality without relying on outright sales to meet

WATCHING THE UINTA: XCL PETITIONS THE FTC TO APPROVE ALTAMONT ACQUISITION

In March, EnCap Investments-backed XCL Resources petitioned the U.S. Federal Trade Commission (FTC) for approval of its acquisition of Altamont Energy. The petition was required under a prior agreement EnCap Energy Capital Fund XI struck with the FTC in 2022, which required the private equity group to sell off EP Energy's Utah oil business.

"Without this divestiture, Salt Lake City refiners would likely have faced increased prices for Uinta Basin crude oil, whether from EnCap alone, or as part of a small group—and would likely try to pass on those costs to consumers," said the FTC's Bureau of Competition Director Holly Vedova.

Terms of the agreement required EnCap and XCL to obtain prior approval before acquiring another producer of waxy crude with output of more than 2,000 bbl/d in the Utah counties of Duchesne, Uintah, Utah, Grand, Emery, Carbon and Wasatch.

Altamont's position was built from assets acquired from the defunct Linn Energy in the Wasatch and Green River formations in 2018. After four initial vertical wells, Altamont drilled eight horizontal wells. Altamont hired Houlihan Lokey in August 2023 to begin a sales process that included reaching out to more than 300 different parties, according to the petition. XCL was the highest bidder and executed a purchase and sale agreement in early 2024.

XCL Resources was begun in 2018 with a commitment from EnCap. The company has assembled a position of 45,900 net acres in Duchesne and Uintah counties where it owns and operates 135 horizontal wells producing black and yellow waxy crude oil and natural gas, the petition stated. XCL has three active rigs and is drilling 70 new wells per year on average.

Refinery demand from the nearby Salt Lake area stands around 90,000 bbl/d, while Uinta Basin waxy crude production has reached 140,000 bbl/d. At issue is concern that consolidation in the basin might result in high prices and decreased supply for the Salt Lake area, but oversupply has obviated that issue, the petition states.

In 2023, the basin saw 214 new horizontal wells drilled by a raft of operators beyond XCL Resources and Altamont, the petition showed. Other Uinta operators include Anschutz Corp., Berry Corp., Caerus Uinta, Crescent Energy (through its Javelin Energy Partners subsidiary), Finley Resources, KGH Operating, Middle Fork Energy Partners (formerly Koda Resources), Ovintiv, Scout Energy, Uinta Wax Operating and WEM Operating.

EnCap is reportedly exploring a sale of XCL Resources. Jefferies has been retained to run a sales process, and the company could fetch more than $2.8 billion including debt.

Meanwhile, the FTC is accepting public comment on XCL's pending application to purchase Altamont.

Antelope graze near gas production in Wamsutter, Wyo.

SHUTTERSTOCK

"We foresee additional opportunities to fall out as companies digest mergers and plan for the path forward."

DANIEL RIOUX, co-founder and managing partner, Old Ironsides Energy

return targets," said Sean O'Neill, co-founder and managing partner at Old Ironsides Energy.

Companies need to focus on distributions, but not to the detriment of their balance sheets with the addition of large debt, Cochran said.

"It's a much more complex set of equations to maintain a distribution model in a more mature company than just a pure growth company," he said.

Post Oak expects management teams to provide quarterly or semi-annual distributions to investors within two years of acquiring a new property, Cochran said. That has a significant impact on company finance, usually requiring a significantly higher amount of equity upfront to purchase new assets and then maintaining modest leverage levels to pay for drilling.

Finding equity could get tougher, too.

The pool of potential private equity providers has narrowed, Cochran said.

"New York generalist private equity firms are out of the business now and there's just fewer of us that work with fewer management teams."

O'Neill said upstream private equity fundraising has been down in recent years as capital left the space due to ESG pressures and poor returns from many general partners. He estimated upstream dry powder is down almost by half from five years ago and nearly 80% from 2014. The lack of capital available within the space has placed a higher emphasis on quality management teams with assets, with fewer general partners providing capital to platform teams to look for something to buy, he said.

Regarding debt, companies are still utilizing reserve back loans (RBLs) but are less reliant on them than as in times past, Cochran said. High commodity prices make that possible. UpCurve Energy, one of Post Oak's portfolio companies focused on the Southern Delaware Basin, has enough cash flow from production to fund development, he noted.

Some larger banks have left the RBL space, said Old Ironsides' Rioux, but smaller regional banks remain active lenders.

Universal Change

Banks are lending only against proved, developed producing (PDP) wells at conservative price decks with tightened advance rates and hedging requirements, Rioux said. Private credit offers an alternative, as direct lenders moved into the space after the flight of traditional capital providers, but the high cost of debt is making companies think about how they use it.

Private credit markets, Cochran said, are "not as deep as you would think," which limits the amount of accessible capital.

The availability of capital is a positive, but doing deals is not a slam dunk. The bid-ask spread in the A&D market remains wide in many cases, O'Neill said. Negotiations can drag out as buyers must compete against the seller's hold case and other options, like asset-backed securitizations, which can provide liquidity when an outright exit isn't possible.

Although recent M&A activity has shown that buyers are willing to pay for scale and inventory, O'Neill said, "Valuations remain cheap in many areas, particularly those without natural consolidators."

Still, some sweet spots exist for assets below a certain size or within certain asset classes, such as non-operated working interest or minerals.

"Private buyers are the logical owners of most of the sub-$1 billion assets that will be shed as the domestic oil and gas industry reshuffles after major consolidation," Cochran said. OGJ

Kissler: Are We Set Up for a Summer Natural Gas Rally?

A warmer-than-normal season could jolt prices.

DENNIS KISSLER
BOK FINANCIAL SECURITIES

Dennis Kissler is senior vice president of Trading for BOK Financial Securities. He is based in Oklahoma City.

Natural gas prices have been subdued for most of the first half of 2024, and with good reason: overproduction, coupled with light weather-related demand. However, as we go into summer and the second half of the year, there has been some speculation that the lows that we've been seeing will reverse.

First, here's where we stand right now. As of mid-June, storage is still near a 30% overage of the five-year average. Any seasoned trader would tell you that a surplus of this size will keep a bearish tone to prices in the longer term. Still, buyers remain waiting in the weeds for a cheap entry to one of the most dynamic trading products of the commodity complex.

Meanwhile, gas futures prices are almost impossible to trade in the short-term because they're so heavily influenced by weather. Traders have an old saying: When it's extremely cold, natgas prices get extremely hot!

That saying rings as true as ever. For example, this past winter, a two-week cold spell in January took prices up more than 34%. That's even with all the supply surplus we had. However, this price gain didn't last. By late February, prices were back to making new lows near $1.50/MMBtu.

What happened? On one hand, volatility is in a commodity's nature. Still, on the other hand, even the most educated fundamental economist can look like a third-grader when trying to explain how an oversupplied product can move up 34% in price in just a few days. A jump of that size just doesn't seem to make sense, given the fundamentals.

The short answer is that price extremes to the downside can cause supply gaps or perceived supply gaps in the near future. We witnessed this effect when Chesapeake Energy and EQT Corp. curtailed new production and slowed drilling programs because of unfavorable prices. In EQT's statement, released in early March, the company cited warm winter weather and consequentially elevated storage inventories as its reason for curtailing nearly 1 Bcf/d of gross production beginning in late February and continuing through March. As one might expect, gas prices rose on the news.

However, that drop in production wasn't the only factor driving up prices; the other is the increased adoption of green energy. Because it's seen as a cleaner alternative to burning coal, natural gas is increasingly being used to power underdeveloped electric grids in most parts of the globe, including the U.S.

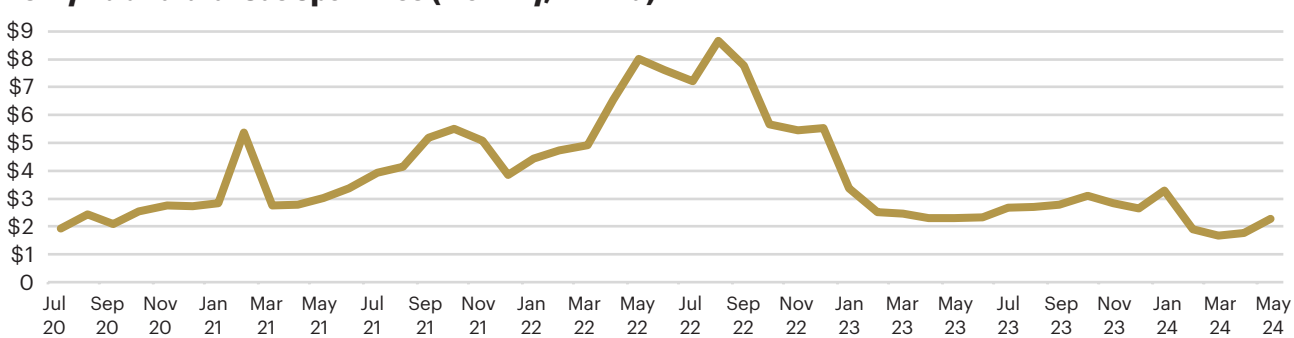
That's been positive for U.S. exports. In fact, the current volume of U.S. LNG exports is near 12 Bcf/d, up over 12% from 2022 levels. By 2027, the volume of North American LNG exports is expected to rise to 22-25 Bcf/d, depending on who you ask. Personally, I believe the upper end of those numbers is the most likely scenario.

So, what does all this mean for prices through the remainder of the year? As of mid-June, prices remain historically low and the downside price pattern looks limited.

Nevertheless, weather, as always, is the wild card. A warmer-than-normal summer followed by a colder-than-normal winter could create a price shock to both traders and consumers.

On the flip side, a mild weather pattern could keep the brakes on prices and, given the abundance in storage, keep a tight lid on any rallies. That said, one thing is for sure: the longer prices stay historically low, the larger the eventual supply gap will grow. Then, when a price shock does happen, it just might surprise many to the upside. OGI

Henry Hub Natural Gas Spot Price (monthly, MMBtu)



SOURCE: EIA

Offshore Guyana: 'The Place to Spend Money'

Exxon Mobil, Hess and CNOOC are prepared to pump as much as $105 billion into the vast potential of the Stabroek Block.

PIETRO D. PITTS
INTERNATIONAL MANAGING EDITOR
@PietroDPitts
pdpitts@hartenergy.com

Three companies. Ten projects. Twelve years. One prolific offshore block.

And a combined capex that could reach as high as $105 billion.

The consortium of Exxon Mobil, Hess Corp. and China National Offshore Oil Corp. (CNOOC) has already made final investment decisions (FID) worth $54.5 billion on six projects in the Stabroek Block offshore Guyana. Moving forward is simply a matter of figuring out the best way to exploit a resource estimated at 11 Bboe.

Alistair Routledge, the president of Exxon Mobil Guyana, said the resource figure was based on a lot of analyses but also a lot of uncertainty. Each partner is working with its own numbers, he said during a panel discussion at the Offshore Technology Conference (OTC) in May

"The six initial [projects] are developing around 4.9 billion oil equivalent barrels. So, we are already getting close to developing half of that resource through the commitments that we've made to date. That still leaves another 6 billion," Routledge said. "We're basically working through that resource base to understand it, [and] one of the particular areas of focus … is the gas resource."

He reiterated that the figures were resources, not reserves. Future updates to the resource estimate could take time owing to the huge amount of data to sort through and understand.

"Our focus has actually shifted to: are we moving the resource into project execution? We are focused on getting those matured," Routledge said. "We are very encouraged with the work that has been going on with all the technical teams around concepts and maturing the understanding of that resource, both from a reservoir static and dynamic performance perspective."

Combined production from the first phase of development will reach 1.33 MMbbl/d by 2027, according to Exxon.

"In general, if you look at the entirety of Exxon's portfolio, this is the place that they want to spend money," Rystad Energy Senior Vice President and Head of Latin America

Phase 1: Existing Stabroek FIDs

FID Date	Project #	Project Name	FID US $B	FPSO Name	Initial Capacity (bbl/d)*	Start Date
June 2017	1	Liza Phase 1	$4.4	*Liza Destiny*	140,000	Late-2019
May 2019	2	Liza Phase 2	$6.0	*Liza Unity*	220,000	Mid-2022
September 2020	3	Payara	$9.0	*Prosperity*	220,000	Late-2023
April 2022	4	Yellowtail	$10.0	*ONE GUYANA*	250,000	2025
April 2023	5	Uaru	$12.7	*Errea Wittu*	250,000	2026
April 2024	6	Whiptail	$12.7	*Jaguar*	250,000	2027
Phase 1: Existing Stabroek FIDs			**$54.8**		**1,330,000**	

NOTE *: INITIAL NAMEPLATE CAPACITY BEFORE DEBOTTLENECKING.
SOURCE: EXXONMOBIL CORP. AND HESS CORP.

Phase 2: Future Stabroek FIDs

FID Date	Project #	Project Name	FID US $B	FPSO Name	Initial Capacity (bbl/d)*	Start Date
2025	7	tba	$12.7	tba	250,000	2028
2026	8	tba	$12.7	tba	250,000	2029
2027	9	tba	$12.7	tba	250,000	2030
2028	10	tba	$12.7	tba	250,000	2031
Phase 2: Future Stabroek FIDs			**$50.8**		**1,000,000**	

NOTE *: INITIAL NAMEPLATE CAPACITY BEFORE DEBOTTLENECKING.
SOURCE: ESTIMATES FROM WELLIGENCE ENERGY ANALYTICS AND HART ENERGY

"In general, if you look at the entirety of Exxon's portfolio, this is the place that they want to spend money."

W. SCHREINER PARKER, senior vice president and head of Latin America, Rystad Energy

W. Schreiner Parker told *Oil and Gas Investor (OGI)*.

A second phase of development will require four new FPSOs in Stabroek over the near term. The last project sanctioned by the consortium, Whiptail in April 2024, cost $12.7 billion with associated FPSO production capacity of 250,000 bbl/d. Assuming future projects will be of the same magnitude, the combined FIDs will total about $51 billion and add at least 1 MMbbl/d of production.

Parker expects the consortium to spend an average of about $10 billion per year between 2025 and 2030, mostly on development but also on exploration.

The expense will not divert Exxon from its "build one, design many" mindset in Guyana. Parker expects the consortium to move forward with construction of the FPSOs. Welligence Energy Analytics Vice President Andre Fagundes agrees.

Andre Fagundes

"Our valuation model considers the installation of five additional FPSOs at Stabroek by 2029 with a total capex of $52 billion, and followed by two additional [FPSOs] in 2030 and 2031," Fagundes told *OGI*. He doubts the consortium will be constrained by finances.

"Given the exceptional fiscal terms and projected production growth, we estimate the projects to be practically self-funded from their own free cash flow," Fagundes said. "Consequently, we believe that the project partners are financially equipped to support this development."

Stabroek is located approximately 120 miles offshore Guyana and covers 6.6 million acres. The block is equivalent in size to 1,150 U.S. Gulf of Mexico (GoM) blocks and contains multiple prospects and play types, according to Hess.

Exxon Mobil Guyana operates Stabroek and holds a 45% interest. Its local partners include Hess Guyana Exploration (30%) and CNOOC Petroleum Guyana (25%).

Quick Rise

Guyana was colonized by the Dutch in the 17th century, but by 1815 had become a British possession. It is the third-smallest country in South America after Suriname to its east and Uruguay to the south. It is almost twice the size of Tennessee with a population of about 800,000.

Exxon initiated exploration offshore Guyana in 2008 and drilled its first exploration well, Liza-1, in 2015. That well encountered over 295 ft of high-quality oil-bearing sandstone reservoirs and was safely drilled to 17,825 ft in 5,719 ft of water.

"Guyana is a long-time gold producer and also had a history where there was this big belief that there was going to be the 'El Dorado,' the big find of oil in Guyana," Exxon's Routledge said during OTC.

"Well, finally we have it and it's catapulting Guyana up the league tables and becoming a true emerging powerhouse of energy in South America, and a vital source of energy ... in a world that needs that diversity of supply to give us all security and affordability of energy supply," he said.

To grasp the impact of the "big find," consider that oil production is responsible for Guyana's GDP soaring from $1.1 billion in 2005 to $14.7 billion in 2022, according to the World Bank.

Exxon's first three Stabroek projects–Liza 1 (using the *Liza Destiny* FPSO), Liza 2 (*Liza Unity* FPSO) and Payara (*Prosperity* FPSO)–produce just north of 600,000 bbl/d, analysts estimate.

"In terms of the production, we're kind of in a little bit of a plateau here in 2024 to 2025, but it will essentially double between next year and 2030 off the back of all that investment that's going to take place between 2025 and 2030," Rystad's Parker told *OGI*.

The fourth, fifth and sixth Stabroek projects have been sanctioned but have yet to start producing. All will use FPSOs with production capacity of 250,000 bbl/d.

Yellowtail, sanctioned in April 2022, will use the *ONE GUYANA* FPSO with first oil expected in 2025; Uaru, sanctioned in April 2023, will use the *Errea Wittu* FPSO, with first oil expected in 2026. Whiptail, sanctioned in April 2024, will use the *Jaguar* FPSO, with first oil expected in 2027.

Follow the Money

Exxon's Routledge said about one-third of the capital spend in Guyana was on the wells that are drilled, another third on subsea umbilicals, risers and flowlines (SURF), and the remainder on the FPSOs.

"We tend to focus on the FPSOs because that's what we see every day, and when we go offshore, we get to land on those, and that's where our workforce is. But the reality is, most of the work goes into what sits on the seabed or indeed the wells that go down into the reservoirs," Routledge said.

Stena Drilling and Noble Corp. are Exxon's main drilling contractors. They have provided the Stabroek consortium with six deepwater rigs, which are operating at a "benchmarking and industry-leading pace," Routledge said.

"They set an aspirational goal just a year and a half ago that they would achieve zero/five/35 in the drilling operations. And that was zero safety incidents, less than 5% non-productive time and 35 days to drill and complete these deepwater wells. They have already achieved wells in less than 30 days, drilled and completed, which in all the benchmarking you look at just sets a new level of performance," Routledge said.

Each of the FPSOs in Stabroek can store up to 2 MMbbl of oil. Exxon's cargo lifts can total 1 MMbbl, so the FPSOs need to unload a cargo every four days.

"Sometimes we're using the very large crude carrier (VLCC), which are 2 MMbbl vessels. They will take two separate cargoes, so we will attach them to one of the FPSOs, lift a 1 MMbbl cargo, and then they'll disconnect and either go to one of the other terminals or reconnect afterwards. These are vast vessels, and once connected are less than 492 feet apart in the ocean," Routledge said, adding it takes around 24 hours to pump 1 MMbbl from the FPSO onto the carriers.

'Tiger Economy'

"Guyana is a tiger economy moving at a rapid pace and

"Guyana is a tiger economy moving at a rapid pace and this is probably the last time you will see such a development in the world. So, if you are in the oil business and you're not in Guyana, you're missing out."

PETER R. RAMSAROOP, head of Guyana Office for Investment

this is probably the last time you will see such a development in the world," Guyana Office for Investment Agency Head Peter R. Ramsaroop told *OGI* on the sidelines of OTC. "So, if you are in the oil business and you're not in Guyana, you're missing out."

Ramsaroop said that the next wave of Guyana's economic growth would focus on agriculture sustainability, food security, climate security and energy security. Ramsaroop said Guyana would "lead CARICOM (Caribbean Community) in those areas."

Ramsaroop said the government of President Mohamed Irfaan Ali plans to continue to grow the country while ensuring that the people benefit. He warned that Guyana needed a lot more skilled people.

"Like Dubai or Qatar, we are out of resources. If you win a contract to build a 20-mile road or a bridge, you have to bring your people," Ramsaroop said. "We're working on new immigration policies and making it easier for work permits over time. But by 2030 plus, we may have around 3 million people in Guyana."

The country occupies 83,000 square miles, or about the size of Great Britain, he said. But Great Britain's population is about 65 million. "For us to develop Guyana to the level that Guyana is being developed, you need people." Ramsaroop reiterated.

"We have a low-carbon development strategy. We have the lowest deforestation rate. We're doing things in a sustainable manner, but don't tell us to keep our people poor," Ramsaroop said. "If the other option is to cut our $95 billion forest down, we won't do that [either]."

Guyana's impressive growth story has attracted the attention of government and companies alike. Chevron's $53 billion all-stock offer for Hess is as much about Guyana as much as it is about Chevron adding assets in the GoM, offshore Southeast Asia and in the Bakken Shale.

Hess' assets in Stabroek instigated a spat between Chevron and Exxon, drawing in CNOOC as the latter two claim they have a right of first refusal (ROFR) to Hess' interest. Arbitration among the three companies continues.

Chevron's deal with Hess could close in 2025, TD Cowen managing director David Deckelbaum wrote in an April commentary.

Routledge told *OGI* that "Our balance sheet is in good shape [and] what we are looking for are just good investments."

"We are not in position to make any decision on other equity in Stabroek Block right now, but we are focused on [finding] the right opportunities—whether in Guyana or elsewhere in the world," he said. "And if they compete [financially], then we have the resources to get after them." OGI

Stabroek Block Offshore Guyana

EXXON MOBIL, HART ENERGY

Stabroek Block Offshore Guyana

SBM OFFSHORE

The Liza Destiny *FPSO operates in Liza Phase 1.*

LIM WEIXIANG

The Liza Unity *FPSO operates in Liza Phase 2.*

SBM OFFSHORE

Prosperity *FPSO operates in Payara.*

Paisie: OPEC+ Will Be Able to Manage Prices

Disappointing economic news has contributed to a drop in oil prices.

JOHN PAISIE
STRATAS ADVISORS

John Paisie is president of Stratas Advisors, a global research and consulting firm that provides analysis across the oil and gas value chain. He is based in Houston.

At the time of last month's column the price of Brent crude had broken through $90/bbl and the price of WTI had broken through $85/bbl.

Since then, oil prices have fallen off significantly, with Brent crude breaking temporarily below $80/bbl. The oil market sold off even with the news that OPEC+ had agreed at its June meeting to extend production cuts through the rest of the year, with eight producers agreeing to maintain their voluntary cuts of 2.2 MMbbl/d at least through March.

The selloff stemmed, in part, from OPEC+ also announcing intentions to trim the cuts through September 2025. This part of the agreement raised concerns about the possibility of OPEC+ bringing barrels back to the market before additional supply is warranted by demand.

We think the oil market overreacted to the announcement because it is our view that OPEC+ will continue to be proactive in aligning supply with demand—and will, for the most part, be able to manage the inherent challenges of maintaining discipline and cohesion among the members.

Consistent with this view is OPEC moving away from publishing an estimate of demand for OPEC crude in its monthly reports to publishing an estimate of demand for OPEC+ crude. The publishing of the broader estimate for OPEC+ highlights the level of cooperation among the 12 OPEC members plus the additional 10 oil producers, including Russia.

Another reason for the drop-off in oil prices has been the series of disappointing economic news associated with the major economies. In the U.S., the broader unemployment rate that includes discouraged workers and those holding part-time jobs for economic reasons has increased to 7.1% while the number of job openings based on the JOLTs report (Job Openings and Labor Turnover Survey) decreased to 8.06 million in April, which is the lowest since February 2021.

While China's export data surprised to the upside (increasing by 7.6% in comparison to the previous year), domestic demand continues to be muted, as indicated by retail sales of consumer goods increasing by only 2.3% in April, which is the smallest increase since December 2022. The growth in retail sales of consumer goods has been on a downward path since November 2023, when the growth rate (year-on-year) was around 10% after rebounding back to the level typical of the pre-COVID period.

Because of disappointing economic data and oil demand growth so far this year—and the outlook for the rest of the year—we have reduced our oil demand growth forecast for 2024 to 1.3 MMbbl/d in comparison to our previous forecast of 1.4 MMbbl/d. During the third quarter, we are forecasting total oil demand to increase by 1 MMbbl/d in comparison to third-quarter 2023.

Additionally, we are forecasting:

- China product demand will increase by 0.14 MMbbl/d during the third quarter in comparison with third-quarter 2023;
- India product demand will increase by 0.50 MMbbl/d during the third quarter in comparison with third-quarter 2023; and
- U.S. product demand will increase by 0.51 MMbbl/d during the third quarter in comparison with third-quarter 2023.

Besides the extent of economic growth, there are structural factors that will affect future oil prices. One such structural factor will be the penetration of electric vehicles. Recently, there has been significant discussion in industry and media reports around a slowdown in EV sales. Looking only at sales totals of BEVs and PHEVs combined, a slowdown is not directly evident, but indications of a slowdown or deceleration in sales is clearer when looking at EV market share gains and when filtering out PHEVs.

In contrast to the upward trend in unit sales of EVs over the past two years, EV market share gains clearly decelerated, with 2023 showing an increase of 2.7 percentage points, roughly half of that seen in 2022, and also smaller than the gain seen in 2021.

Year-to-date data point to a further reduction to around 2.3 percentage points, and a far more drastic weakening (to less than 1 percentage point) if rapid PHEV growth in China is factored out.

Some key factors contributing to the sluggish growth of global EV adoption include the following:

- Relatively higher initial cost compared to ICEs;
- Phasing out of EV subsidies in many major markets;
- Insufficient EV charging infrastructure; and
- Vehicle demand contraction due to high inflation and interest rates.

While EV market share growth over the past one to two years has not been as robust as it was between 2019 and 2022, Stratas Advisors expects the duration of this slowdown to be largely limited. OGI

Pitts: Oh, What a Tangled Web the Supermajors Weave

Exxon and Chevron and Guyana and Venezuela—'Let's Make A Deal' meets 'Love, South American Style.'

PIETRO D. PITTS
INTERNATIONAL MANAGING EDITOR
@PietroDPitts
pdpitts@hartenergy.com

Exxon Mobil and Chevron, supermajors that dominate the North American energy space, are now jostling in the South American energy space.

The two are pursuing arbitration over a portfolio-changing opportunity offshore Guyana in the prolific Guyana-Suriname Basin. A resolution could come later this year.

SHUTTERSTOCK

The Stabroek Block offshore Guyana is Exxon's most promising asset. There, Exxon (45% interest) leads a consortium that includes Hess Corp. (30%) and China National Offshore Oil Corp., or CNOOC (25%). Exploration started in 2015 and first oil was reached in December 2019.

So far, the companies have found recoverable resources in Stabroek of over 11 Bboe. Production is expected to reach 1.3 MMbbl/d by 2027 from six developments that will utilize six FPSOs. As many as 10 FPSOs may be needed to develop the resource base.

But Exxon's tenure in Guyana hasn't been without issues. In its early days, Exxon was accused of striking a sweetheart deal with the prior government, which had zero experience negotiating oil contracts. Later, issues related to flaring drew more negative attention.

Now, the issue is Stabroek.

Chevron's $53 billion purchase of Hess, announced in October 2023, is the second-largest deal among U.S. companies in the last 12 months. The deal involves assets in the Bakken Shale, but also gives the company a foothold in Guyana. The purchase has been delayed because Exxon and CNOOC both claim right of first refusal on Hess' interest in Guyana. Hess shareholders approved the deal in late May.

Exxon and Chevron have endured love-hate relationship with South American governments. That's been true in Argentina, Brazil and Ecuador, as well as Guyana. The most recent example is next door to Guyana, in Venezuela, and involves perceived links between the American companies and Washington.

On the love side, the government of Venezuela's President Nicolás Maduro views Chevron as a darling. Cash-strapped PDVSA hasn't been able to return production to the 3.2 MMbbl/d range seen in 1997 owing to years of oil rents mismanagement and the heavy weight of U.S. sanctions.

But production has risen from lows during the COVID-19 pandemic to average 817,000 bbl/d in first-quarter 2024, according to OPEC, in great part due to the so-called "efecto Chevron," or Chevron effect.

U.S. restrictions on Venezuela don't apply to Chevron, which has a special license issued by the U.S. Office of Foreign Assets Control (OFAC) that allows the company to operate there.

On the hate side, Exxon may be the most despised international oil company to have ever operated in Venezuela.

One reason is that Exxon took its wrongful asset expropriation cases in the mid-2000s to international arbitration.

The second reason is that the Maduro government perceives the supermajor as backing Guyana's claim to the Essequibo region over Venezuela's.

Can Exxon and Chevron really make a love connection in Guyana? Will Chevron's presence in Guyana ease tensions between Guyana and Venezuela?

The drama continues to unfold. OGJ

Belcher: Just When You Thought You Had Enough Regs

New EU rules create additional hurdles for U.S. gas producers and LNG exporters.

JACK BELCHER
CORNERSTONE GOVERNMENT AFFAIRS
@JackBelcher1
jbelcher@cgagroup.com

Jack Belcher is a principal at Cornerstone Government Affairs, where he focuses on regulatory affairs, risk management and ESG matters within the energy and transportation sectors.

Yet another methane regulation has been issued that will be impactful to U.S. oil and gas producers and exporters.

This one follows the recently released EPA OOOO or "Quad O" rules requiring air emissions reductions, Subpart W rules requiring emissions detection and reporting, and the new methane fee, which have varying degrees of impacts to U.S. producers.

The new regulation comes from the European Union (EU), which finalized, in late May, new and comprehensive regulations that will have far-reaching impacts, including on U.S. industry. Intended to reduce methane emissions from across the entire energy sector, the EU Methane Regulation (EUMR) will impact some U.S. producers more than others.

Producers who are already engaged in significant methane leak monitoring, reporting, and verification (MRV) by adhering to the Oil and Gas Methane Partnership (OGMP) 2.0 standards or natural gas certification standards will be less impacted by the EUMR than those who are not. Larger producers are more likely than smaller ones to be adopting and applying.

Additionally, since natural gas is a fungible, global commodity, the EUMR requirements will impact U.S. producers of gas volumes that may become part of LNG export cargoes by requiring greater MRV. This will mean that oil and gas producers of all sizes, with production destined for Europe as LNG, will need to monitor, quantify and report emissions data.

Those producers will also be required to utilize third parties to verify their reported emissions as compliant with the highest level OGMP 2.0 standards or other gas certification standards. There is no exemption for small operators and producers under the EUMR standard, so small operators will also need to comply.

"Maintaining access to EU markets will require U.S. natural gas operators to comply with all elements of the new regulations, including increased monitoring and reporting, comprehensive Leak Detection and Repair (LDAR) programs, restrictions on venting and flaring, higher standards for new facilities, and increased transparency and accountability," said Roy Hartstein, president, Responsible Energy Solutions, which serves as a third-party verifier and auditor for certified natural gas producers.

"Some of the largest producers in the United States have proactively engaged in methane emissions reduction by deploying advanced technology and pursuing certifications, such as the MiQ Standard for Emissions Performance, giving these companies a competitive advantage in meeting the EU requirements," he said, noting that while producers have been at the forefront of implementing emissions reductions and certification, the entire value chain–from gathering and transmission to LNG delivery–must now align their operations with these requirements..

While the EUMR will create more overall burdens for U.S. producers and the natural gas value chain, compliance with other U.S. requirements will help enable producers meet the EU requirements, and going through the certification process will help producers achieve compliance with those requirements by introducing them to the processes that are reducing overall emissions in the U.S. gas value chain.

U.S. producers are mixed on their reaction to the EUMR, with smaller producers most upset about the added burden of compliance.

"The energy industry is harnessing ingenuity and innovation to create cutting-edge technologies that are reducing energy usage, detecting leaks, streamlining operations, and driving down methane emissions," said Tim Tarpley, president of the Energy Workforce & Technology Council, stressing that innovation, not overregulation, is the solution to reducing methane emissions.

EUMR is another step in the implementation of the EU's Green Deal and is the first legal attempt by Europe to reduce methane emissions in both the United States and globally. It aligns with the Global Methane Pledge, a commitment by 155 participating countries that was initiated by the United States and EU during the 2021 COP26 UN Conference to reduce methane emissions.

So, how is the U.S. natural gas industry currently performing in terms of reducing methane emissions?

According to a study of U.S. EPA data performed by Ceres and the Clean Air Task Force, natural gas production rose 40% between 2015 and 2022 while methane emissions from production fell by 37%, indicating that the industry is already doing an excellent job of reducing methane emissions. In the race to achieve emissions reductions, the U.S. natural gas industry appears to be well on its way to success, with some operators already well positioned for the new EUMR while others will have some work to do to fully comply. OGI

AROUND THE WORLD

BRAZIL

3R, Enauta Merge to Create Large Brazilian Independent

A merger agreement between 3R Petroleum Óleo e Gás and Enauta Participações aims to create a diversified Rio de Janeiro-based independent competing head-to-head with Prio, currently the largest independent operator in Brazil, according to Wood Mackenzie.

Operations under the combined businesses could surpass 100,000 boe/d in production, Wood Mackenzie Upstream Research Analyst Amanda Bandeira said in a research report.

"This is a complementary merger between the two companies. Enauta adds expertise in offshore operations, while 3R Petroleum, with a more diversified portfolio, brings to the table heavy onshore operations experience," Bandeira said.

Wood Mackenzie sees the newly combined operation focusing first on integration, but constantly looking for new inorganic growth opportunities in Brazil or even internationally.

"Mid-term, stronger cash generation and the combined expertise of both companies can also open space for the new company to be exposed to riskier activities such as exploration. Both companies have exploration acreage that hasn't seen activities due to other capital investment priorities," Wood Mackenzie Upstream Research Analyst Vinicius Diniz Moraes said in the report.

Mexico

Mexico's First Female President Likely to Stay Course on Energy

SHUTTERSTOCK

Claudia Sheinbaum Pardo, newly elected president of Mexico.

Claudia Sheinbaum Pardo, a physicist of Jewish heritage, overwhelmingly won Mexico's presidential election, making her the country's first woman president, and the first woman president in North America.

Sheinbaum holds a doctorate in energy engineering from the National Autonomous University of Mexico (UNAM).

Sheinbaum isn't a believer in the "absolute privatization model," which she said hasn't worked in Mexico. During her campaign she promised to continue with national and sovereign development plans for the Federal Electricity Commission (CFE) and state-owned Petróleos Mexicanos (Pemex), which follows the same line as Mexico's outgoing President Andrés Manuel López Obrador, who founded the Morena Party.

SURINAME

Third Suriname Find for Petronas, Exxon Could Support 100,000 bbl/d FPSO

Petronas Suriname E&P, a subsidiary of Malaysia's state company Petronas, and Exxon Mobil's recent deepwater find at the Fusaea-1 well offshore Suriname in Block 52 could underpin a 100,000 bbl/d FPSO development, according to Wood Mackenzie.

The well was spud in February 2024 and successfully drilled to a total depth of 5,227 m, encountering several oil- and gas-bearing Campanian sandstone reservoir packages, Petronas said in a press release. The Fusaea-1 exploration well is about 170 km offshore Suriname and 9 km east from the Roystonea-1 find, Petronas said.

This is the third hydrocarbon discovery in Block 52. Further evaluation is being undertaken to determine the full extent of this discovery and its potential for an integrated development with the recent Roystonea-1 and Sloanea-1 discoveries, Petronas said.

"We understand Roystonea and Fusaea's recoverable resources are approaching 400 million barrels," said Mark Oberstoetter, Wood Mackenzie's head of Americas (non-Lower 48) upstream, in a May research report. The discovery's resource base would support such a development, he said.

Venezuela

Wirth: Chevron Won't Put 'New Capital into Venezuela'

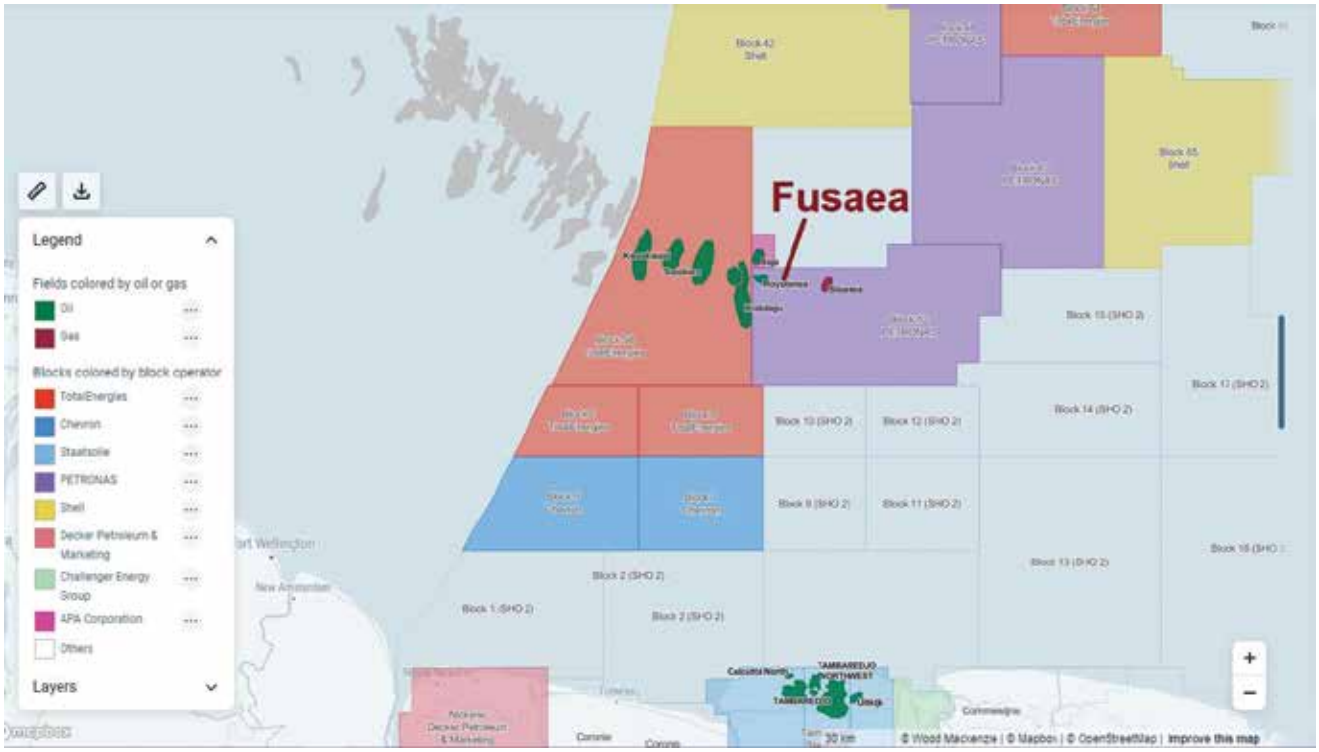
Chevron, the only American company with authorization to still operate in U.S.-sanctioned Venezuela, isn't planning any new capex in the South American country, CEO Mike Wirth said during the company's first-quarter earnings webcast.

"I'll just remind you. We're not putting new capital into Venezuela right now. All the spending is really self-funded from the cash from operations," Wirth said, in response to analyst questions about its operations there.

"We've been lifting oil and bringing it to the U.S., which has been helpful for the U.S. refining system, not just ours but others as well," Wirth said.

The U.S. Office of Foreign Assets Control (OFAC) recently issued General License (GL) No. 44A in replacement of GL 44, which was issued by OFAC in October and expired in April. GL 44 authorized transactions in Venezuela spanning the production, lifting, sale and export of oil and gas to the payment of invoices and new investments.

The newer GL 44A, issued on April 17, mandated a 45-day wind-down period for most companies through May 31. The move came after Venezuela failed to live up to



SOURCE: WOOD MACKENZIE

Petronas' 400 MMbbl discovery could be enough to support a 100,000 b/d FPSO.

election reforms the U.S. government had demanded.

However, GL 44A doesn't impact Spain's Repsol or Italy's Eni, which have comfort letters that allow them to continue operating.

GL 44A doesn't impact Chevron either, since the company can still operate in Venezuela under GL 41, issued by OFAC for the company alone. Since being issued GL 41 in November 2022, Chevron has significantly boosted production.

Repsol Plans to Double Oil Production in Venezuela

Repsol has signed an agreement that will allow it to incorporate two new fields in Venezuela and effectively double its production at its Petroquiriquire joint venture (JV), CEO Josu Jon Imaz said during the Spanish company's first-quarter 2024 earnings webcast.

The two fields, Tomo Polo and La Seba, currently produce an average 20,000 gross bbl/d. Petroquiriquire is currently producing around 20,000 gross bbl/d with contributions mainly from the Barúa Motatán and Mene Grande fields, Imaz said.

"So that means that we are–thanks to this agreement–doubling the current production of Petroquiriquire," Imaz said.

Repsol holds a 40% interest in Petroquiriquire. The Venezuela Petroleum Corp., a subsidiary of state-owned Petróleos de Venezuela (PDVSA), holds a majority 60% interest.

Imaz said the agreement would positively impact the JV and allow for potential synergies, improved recovery factors and increased cash flow. Imaz said the JV will help PDVSA to repay its financial debt to Repsol.

Imaz said work at the Perla gas field, or Cardón IV project, offshore Venezuela with Italy's Eni SpA continues despite the recently reimposed sanctions by the U.S. OFAC.

"The comfort letter that was issued by the American Department of State ... gives us some kind of comfortability about the operations we have in Venezuela," Imaz said.

"We lift cargoes and we swap shipping some diluents to Venezuela in the framework of this operation," Imaz said, referring to the swap deals that OFAC allows Repsol and Eni to conduct in Venezuela.

ConocoPhillips Looks to Scale Portfolio, But Citgo Auction Not a Factor

ConocoPhillips continues to watch the drama around the auction of Citgo Petroleum, the U.S. refining affiliate of Venezuela's state-owned PDVSA–and for good reason.

The company is more concerned about the debt it's owed by Venezuela than adding a refining arm to its portfolio.

"We're watching that process. Look, we're a creditor in that process. So, we're owed quite a bit of money by the Venezuelans," ConocoPhillips Chairman and CEO Ryan Lance said in May during the company's first quarter 2024 webcast, responding to an analyst question.

"We're not trying to become an integrated refining major with ... refining in our portfolio. This is the way to protect what's owed the company and the credit that we have against the Venezuelan government," Lance said.

ConocoPhillips' assets in Venezuela were expropriated in the OPEC country during the tenure of late Venezuelan President Hugo Chávez.

"So, we're watching that and following that process pretty closely, but that's to get the money that they owe us for the judgments that we have against the Venezuelan government for the expropriation of our assets," Lance said. OGI

INFLUENTIAL
WOMEN
IN ENERGY

presented by: HARTENERGY

NOW ACCEPTING NOMINATIONS FOR 2025

Oil and Gas Investor invites you to nominate an exceptional industry executive for its 8th Annual **Influential Women in Energy** program. Help us celebrate women who have risen to the top of their professions and achieved outstanding success in the energy industry.

Past honorees have included professional women from entrepreneurs to producers, midstream operators, service companies and the financial community. They've represented varied disciplines including engineering, finance, operations, banking, engineering, law, accounting, corporate development, human resources, trade association management and more. All nominees will be profiled in a special report that will mail to *Oil and Gas Investor* subscribers in March 2025.

NOMINATE HERE

Nominations Deadline:
September 20, 2024

hosted by:

Oil and Gas Investor

hartenergy.com/women-in-energy

Same Game, Fewer Players

The midstream M&A market typically follows the E&P sector by a few months. But some aspects of the market are different this time around.

SANDY SEGRIST
SENIOR EDITOR, GAS AND MIDSTREAM
@segrist_sandy
ssegrist@hartenergy.com

In May, Exxon Mobil completed its record-breaking $60 billion buyout of Pioneer Natural Resources in the Permian Basin. In the same month, Hess Corp. shareholders approved the company's $53 billion sale to Chevron.

The deals draw a curtain on some of the M&A frenzy in 2023, one of the most active seasons in E&P history. At the same time, the midstream sector saw the curtain opening on an intensifying M&A market.

In all of 2023, the midstream market saw about $21.9 billion in M&A deals, according to energy research firm Enverus. Through first-quarter 2024, the midstream sector had already reached $12.5 billion, and more deals followed in the second quarter, primarily in the Permian Basin.

In May alone, Kinetik announced a $765 million deal to purchase Durango; Phillips 66 struck a deal to buy Pinnacle Midstream for $550 million; and Energy Transfer bought WTG Midstream for $3.2 billion.

Industry veterans say it's not surprising. Increased M&A activity usually hits the midstream sector about six months after it hits E&Ps, and it's typical that many of the major deals have been focused on the Permian, the hottest oil patch in the nation.

This time around, however, the field is changing.

The consolidation trend that enveloped E&Ps over the last four years has been mirrored in the midstream market. Times have generally been good. Strong demand for crude and NGL, and expected growth in the natural gas market, has meant that midstream services are in high demand.

Gregory Davis

However, the number of major players on the field has been shrinking, and network growth has largely flattened. That's changed the way M&A deals happen, analysts say.

"Is the world expanding?" Gregory Davis, a partner with EIV Capital, asked during a midstream panel session at Hart Energy's Super DUG conference in May. "No, I think it's shrinking."

Last Man Standing

In 2020, Forbes ran an article by investment adviser Roger Conrad with the headline "Best

"What is driving buying by large midstream companies is the slowdown in development opportunities.

HINDS HOWARD, portfolio manager, CBRE

Meritage Midstream Services' Steamboat natural gas processing plant in Converse County, Wyo., was commissioned in 2020. The company was purchased by Western Midstream in 2023 for $885 million to expand Western's presence in the Powder River Basin.

MERITAGE MIDSTREAM SERVICES

Midstream Energy Companies: Safe And Worth Buying."

The list of 10 included a lot of today's heavy hitters in the sector: Enterprise Products Partners, Kinder Morgan, Plains All American and Enbridge.

However, three of Conrad's top 10–Magellan Midstream Partners, Crestwood Equity Partners and Enable Midstream Partners–no longer exist.

Energy Transfer, one of the M&A market's more aggressive players, bought Enable in December 2021 and Crestwood for $7.1 billion in August 2023. ONEOK, which did not make Conrad's 2020 list, bought Magellan in September 2023.

Brad Iles

"Over the last 10 years, I think we've seen a 60% reduction in the number of publicly traded companies," said Brad Iles, CEO of Brazos Midstream, during the Super DUG panel. The remaining public companies are still interested in M&A but have become more selective about what they buy, he said.

Buyers' Market

One analyst said large firms are looking to buy but have shifted their priorities on the assets they think would specifically help them.

"What is driving buying by large midstream companies is the slowdown in development opportunities," wrote Hinds Howard, portfolio manager at CBRE, in an email to Hart Energy. "With production growth less robust these days, there is less need to build new infrastructure, so buyers are deploying capital into bolt-on acquisitions to shore up their existing footprints of assets."

Organic growth, meanwhile, has been stagnant. The growth capex, not including M&A, for the major midstream firms declined 30% from 2019 to 2020, according to East Daley Analytics.

Howard said the resulting market currently favors the buyers. Smaller firms have fewer potential buyers and funding options, and generally have to deal with investors looking for a return. The prices for the firms, therefore, face some downward pressure.

"Sellers in midstream are mostly private equity-backed companies, so one of the things driving M&A is the need for those private equity owners to achieve an exit on their investment," he said. "Exit options are more limited in midstream these days, because there is no viable (master limited partnership) IPO market to work in tandem with a private sale process, and because there are fewer midstream companies remaining to buy assets, limiting competition in bid situations."

A master limited partnership (MLP) is a business venture in the form of a publicly traded limited partnership. It combines the tax benefits of a private

partnership with the liquidity of a publicly traded company. MLPs largely backed out of the midstream market in the 2010s after they were hit by a period of low commodity prices and government policy changes that took away their advantages.

Meanwhile, most large companies have spent the last few fiscal years paying off debt and, therefore, have flexibility with their financial options.

"(Public companies) also have lower leverage and are able to make acquisitions without disrupting their capital allocation situations," Howard said. "So, lower multiples make M&A a reasonable allocation of capital as a means to grow their businesses, especially with synergies."

It's not a pressure-free situation for the large companies, however. To keep up with the other public companies on the market, firms need to grow their footprint and diversify their operations.

"Building scale and having the ability to offer integrated solutions are important factors as well," Howard said. "I would expect these bolt-on acquisitions continue and assets consolidate into even fewer larger players over time."

Scaling Up and Verticality

When Energy Transfer bought WTG in May, Ajay Bakshani, East Daley Analytics director of midstream equity, noted it was "the end of an era."

The last large-scale private midstream company in the Permian Basin agreed to a $3.25 billion deal. WTG facilities touch 25 counties in West Texas, include more than 1 Bcf/d of natural gas processing capacity, and have more than 10 rigs operating in the system.

However, the purchase offered ET more than the chance to expand its Permian network. WTG midstream offered eight online natural gas processing plants and 150,000 bbl/d of NGL processing capacity.

When Phillips 66 bought Pinnacle Midstream, the deal included the 220 MMcf/d Dos Picos natural gas processing plant, an asset that "integrates well with into Phillip 66's existing downstream infrastructure."

Kinetik's purchase of Durango allowed the company to strategically extend its Delaware Basin reach into New Mexico.

"One of the main drivers (of M&A) is the need for scale and vertical integration," Bakshani said. "KNTK's acquisition of Durango extends it further into New Mexico, making it one of the largest G&Ps (gathering and processing) in that western portion of the Delaware. PSX and ET's acquisitions reflect the strategy of vertical integration–scooping up Permian G&Ps to drive downstream NGL volumes."

Vertical midstream purchases have been a major mover for M&A activity this year. Many of the companies buying up midstream operators are from outside the sector.

Sunoco, a Dallas-based gas station company, bought New Star Energy, one of the largest independent liquids terminal and pipeline operators in the U.S., for $7.3 billion in January. The largest natural gas producer in the U.S., EQT, is in the process of buying its old midstream spinoff Equitrans for $14.13 billion.

E&P Matador announced the purchase of Ameredev II for $ 1.9 billion in June. The deal included Piñon Midstream, which had just announced a project to expand its Dark Horse amine treating facility in New Mexico.

The Sharks and Fishes

Bakshani said there are still plenty of midstream targets available and several companies looking to buy.

East Daley considers Enterprise, Targa Resources, Williams Cos. and Plains All American Pipeline, along with the typically aggressive Energy Transfer, as the companies most likely to consider acquisition.

The companies have large asset bases that can easily add and benefit from bolt-on acquisitions, and are currently in a financial position with positive free cash flow and low leverage that allows them to make a move. (Kinder Morgan has leverage at 4X but may still be looking to buy, Bakshani said.)

Where the companies are looking to buy depends on their immediate needs, though the most active midstream sector of the country will probably be the most active shale basin in the country–the Permian.

"The areas of production activity and growth will continue to be the primary focus areas," Howard said.

Bakshani said all the attention on the Permian may drive some companies to look elsewhere for bargains.

"The Permian has been hot and is expected to stay hot, but those assets will sell at a premium, as we have seen," he said. "We definitely expect more privates to get scooped up as well. WTG was the largest private G&P operator, but there's still others remaining (Brazos, Canes Midstream, Salt Creek Midstream to name a few)."

The Brazos network consists primarily of natural gas pipelines in the Delaware and Midland basins, as well as a gas processing plant. Canes operates natural gas, crude and NGL pipelines in the Midland Basin and has five plants, according to the company's website. Salt Creek has more than 800 miles of crude, natural gas and NGL pipelines in the Delaware Basin, along with a gas processing facility.

During the Super DUG discussion, Iles said Brazos focuses on building a system his company is satisfied with in the long term.

"How we think about building a business at Brazos is, we want to build a business that we could hold forever," Iles said. "And we believe that if we can build a business like that, those are the types of business that are attractive. Somebody will want to own a business like that."

Along with a quality build, Iles said midstreamers could also use a key resource, information from their suppliers.

"A lot of the M&A activity that we've seen in the upstream world seems to be very driven by inventory, and as a midstream guy, [midstream companies] don't always have a really transparent view as to what inventory looks like," he said. "We traditionally aren't able to get that level of information."

The lack of transparency between a supplier and midstream company can make future M&A deals more difficult.

"I'm not sure that all midstreamers truly understand the lack of inventory they have on their system," he said. "My hope is that we're going to see some publicly traded companies begin to question, 'What is our true inventory here?'"

Outside the Permian

With the exception of EQT's purchase of its own spinoff, Equitrans (ETRN), midstream M&A activity outside of the Permian has not been that active, Howard said.

"The big players in the Marcellus have their asset bases,

> *"One of the main drivers (of M&A) is the need for scale and vertical integration."*
>
> **AJAY BAKSHANI,** director of midstream equity, East Daley Analytics

Pinnacle Midstream's Dos Picos natural gas processing plant, shown during construction in early 2021, went into operation in October 2022. Phillips 66 reached an agreement to purchase Pinnacle for $550 million in May, strengthening its natural gas assets in the Midland Basin.

PINNACLE MIDSTREAM

and there doesn't seem like as much room for M&A as a means to break into that market," Howard said. "It is conceivable that EQT sells off some of the old ETRN assets, and it is conceivable that someday Marathon Petroleum rethinks its ownership of the dominant processing business MPLX holds, but there are just fewer players with larger market share in that region, so there are fewer small private players left."

Other basins have some emerging opportunities, Bakshani said.

Production of natural gas has been rising in the Eagle Ford in South Texas. In April, TotalEnergies announced it was increasing its natural gas production capacity by 50 MMcf/d in the play to strengthen its position in the U.S. LNG value chain.

The attractiveness of shale plays near the Gulf Coast, where the majority of U.S. LNG processing and export take place, will increase the value of midstream companies operating in those areas, such as the Eagle Ford and the Haynesville, Bakshani said.

Howard pointed out that midstream operators with tie-ins to LNG facilities along the Gulf Coast are also attractive.

Basins in the upper Rockies have also seen some activity.

"The Anadarko and D-J (Denver-Julesburg)/Rockies also have potential," Bakshani said. "We see Western Midstream and EnLink as attractive targets, and they have strong G&P positions in these basins. They could also be a consolidator and try to create a more dominant position by scooping up privates in those areas, as WES did at the end of last year with its acquisition of Meritage (Midstream Services)."

Moving Forward

While opportunities remain, the future M&A activity in midstream will likely take place between parties that will take a less compromising look at the potential deals, Davis said.

"Consolidation should create opportunities to shed non-core assets," he said. "Midstream is a little bit different," however, as the big public companies tend to be very reluctant to let go of their assets.

With fewer companies overall, that could mean that fewer assets will be on the market. There are still plenty of opportunities, however, for companies that understand the business and are willing to take on challenges.

"So, there aren't as many folks out there competing for assets as there were 10 years ago," Davis said. "The opportunity set is, you really have to have a clear vision of what you're going to do. At the end of the day, I think the service level we provide is what will ultimately differentiate us." OGJ

Segrist: West Texas Hold 'Em

The consensus is that the Permian Basin needs another major gas pipeline soon. Midstream companies are trying to figure out when ... and who will make the move.

SANDY SEGRIST
SENIOR EDITOR, GAS AND MIDSTREAM
@segrist_sandy
ssegrist@hartenergy.com

Call it pipeline poker.

Some of the biggest names in the midstream business are seated at the table—Energy Transfer, ONEOK, Targa Resources and private company Moss Lake. The rules are simple: Whichever company can ante up with a final investment decision (FID) first wins.

Producers, analysts and midstream companies have predicted that another natural gas pipeline in the Permian will be needed before the end of 2026. A major pipeline generally takes two years to build. To meet the expected timeframe, an FID needs to be made so work can start during third-quarter 2024.

There are four major projects proposed, all pipelines with a projected capacity of at least 1.5 Bcf/d or more of natural gas. The players decide if and when it's time to deal.

Filling the Matterhorn

At some point during summer, the Matterhorn Express Pipeline is set to enter service, probably to basin-wide celebrations in the Permian.

"We could see gas in there, probably as early as (July)," said Jason Feit, an adviser at Enverus. The line-filling and pressurizing process can take weeks. "It probably won't be until September or October that it's fully up and running, and those 2.5 Bcf/d are moving forward."

Feit is the author of a report that studied the Permian's natural gas pipeline capacity.

The FID on the Matterhorn Express, a joint venture among WhiteWater Midstream, EnLink Midstream, Devon Energy and MPLX, was made in May 2022. The project is a 580-mile, 42-inch diameter line going from the Permian Basin to Katy, Texas, near Houston.

Oil producers have been awaiting its arrival since summer 2023.

The Permian is the country's second-most productive natural gas basin, behind Appalachia. Unlike Appalachia, the gas in the Permian is a byproduct, as producers are far more interested in the more lucrative crude business.

While gas production has fallen along with gas prices in other U.S. basins, the Permian's natural gas output has continued to increase. The U.S. Energy Information Administration reported that Permian gas production rose by 143 MMcf/d from April to May, at a time when prices at the regional Waha hub in Pecos, Texas, either hovered near or under $0, and when producers sought to avoid flaring access gas as much as possible.

Meanwhile, E&Ps in maturing parts of the play have watched their gas-to-oil ratios increase as the shale play matures.

Prices for WTI have stayed above $70/bbl for most of the last three years.

The natural gas pipelines out of the basin have been at or near capacity since halfway through 2023, even after two capacity expansion projects added 1 Bcf/d of extra takeaway capacity to the field.

> *"At the end of the day, the takeaway is there's gas demand going forward, and it's just going to grow materially."*
>
> **JASON FEIT,** adviser, Enverus

Once the Matterhorn Express opens, a backed-up gas transport system will finally flow freely to demand along the Texas Gulf Coast.

Oil producers can bring up more crude, unworried about the associated gas that they were unable to get rid of previously. Prices at the Waha Hub may rise enough to provide gas producers with a noticeable profit.

And that freedom will last about 18 months, give or take. Then, the Permian's expanding gas production will bring Matterhorn to capacity again, unless another pipeline is ready to take the growing load.

Volume, Demand and Timing

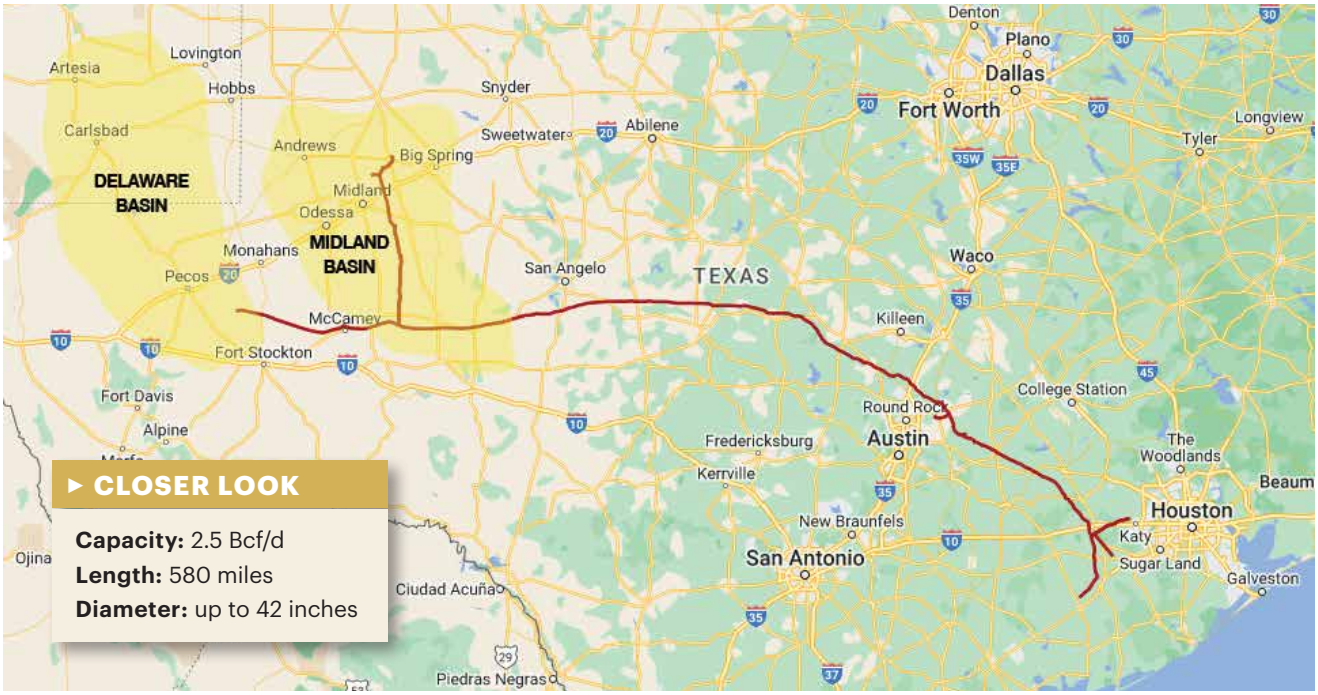
Feit said the midstream companies with new pipeline plans are more than likely focusing on the behind-the-scenes work. It's primarily a competition of lining up suppliers who are willing to buy capacity commitments.

"They're all looking for long-term take-or-pay contracts for the pipe to justify the investment," he said. "Obviously, they need gas to be committed to (the pipeline project) for more than a couple of years."

The process can be tricky. Even though Permian producers have plenty of natural gas to ship, there are some reasons the shippers would be hesitant to sign a fixed-rate multi-year commitment for a fixed amount of capacity, RBN Energy analyst John Abeln pointed out in an April blog.

First, the people who agree to ship gas must worry about the price they commit to paying. Ideally, the shipper would commit to a price that

Matterhorn Express Gas Pipeline



SOURCE: REXTAG

was lower than the current spread between the gas supply point and the destination. The problem is that the current price may be too high because of a capacity bottleneck.

"When a spread is based on a bottleneck, and you fix the bottleneck, the spread collapses," Abeln wrote.

Also, if a supplier's natural gas production drops, the company could be contracted to pay for pipeline capacity it does not use.

Feit said, however, that the future market for natural gas along the Gulf Coast looks about as firm as it could.

"You've got obviously a huge buildout of 10 Bcf/d in the next few years of LNG," he said, pointing to the many LNG export projects under construction along the Texas and Louisiana coasts. "Gas-fired power generation is a big demand. You've got (Artificial Intelligence), which is going to drive more demand."

Feit said the development of solar and wind power is a wild card for the industry, as it's difficult to predict how it will affect the development of power generation overall.

"But at the end of the day, the takeaway is there's gas demand going forward, and it's just going to grow materially," he said.

Four-and-a-Half Pipes

As demand grows, the four proposals have different characteristics that Permian shippers may want to consider. None of the developers have reached FID.

ONEOK's Saguaro Connector is designed to move 2.8 Bcf/d of natural gas from the Waha Hub to the Mexican border. It's the shortest of the proposed Permian pipelines, but it would connect to a future pipeline in Mexico, which would then ship the gas to an LNG terminal on Mexico's West Coast. The LNG project has yet to go to FID. The company said it would not go forward with the project until the LNG plant has reached FID.

In March 2023, Targa received approval from the Texas Railroad Commission to build Apex, a 563-mile, 42-inch diameter pipeline with an estimated capacity of 2 Bcf/d. The line would take gas from the Midland Basin to Port Arthur, Texas, near LNG facilities on the Texas and Louisiana border.

Energy Transfer proposed the Warrior Pipeline in 2022. The 260-mile project has an estimated capacity of 1.5 Bcf/d to 2 Bcf/d and would ship gas from the Permian to interconnects on Energy Transfer's network south of Fort Worth, Texas. ET executives said in February that the pipeline has commitments for 25% of its capacity.

Energy Transfer also just acquired WTG Midstream in a $3.25 billion deal. WTG's network, which is primarily east of the Midland Basin, would give ET an advantage in developing the pipeline, several analysts said at the time of the acquisition.

The DeLa Express is the newest proposed project for taking Permian natural gas. It's the longest, at 690 miles. It's the only proposed pipeline that would cross into another state, with current plans showing a termination at LNG facilities at Lake Charles, La. It's also the furthest from any planned construction. Moss Lake Partners, the private firm planning the line, have a target construction start date in 2026.

Waiting to Deal

With DeLa Express holding off, the other three projects will be worth keeping an eye on over the next few months, though midstreamer Kinder Morgan may play a wild card.

The company has proposed a 500 MMcf/d expansion of the Gulf Coast Express, a pipeline that already connects the Midland and Delaware basins to the Corpus Christi, Texas, area. The expansion could happen rapidly, and its implementation could give the other midstream companies a "buffer," Feit said, of a few months before making a decision with an FID on their larger projects.

Right now, the demand is a bit spread around between the projects," Feit said.

"Someone just needs to step out in front and become the lead project. Then, more demand will flock to them, and you'll get an FID." OGJ

Classic Rock: Refracking Vintage Eagle Ford Wells

SilverBow Resources, ConocoPhillips and Devon are among E&Ps seeing positive results.

JAXON CAINES
TECHNOLOGY REPORTER
jcaines@hartenergy.com

With inventory always a concern for operators, some E&Ps are returning to shale plays–particularly the Eagle Ford Shale–to forage through wells that may yet have some meat on the bone.

Fracking operations typically produce only about 10% of the available oil in place from a reservoir.

Since the early days of fracking, companies have improved most aspects of operations, from water use and proppant loading to the number of stages and the spacing of wells. Now they're turning to vintage wells, some drilled years ago with more primitive methods, to squeeze out more barrels.

The upside is that refractured wells have the potential to provide considerable value across an operator's asset base, although results have been mixed. Generally, they provide a healthy amount of initial product followed by a massive decline.

The locus of attention for refracs has most recently been seen in the Eagle Ford, with large and small E&Ps returning to the play.

In first-quarter 2024, for instance, SilverBow Resources implemented a successful refrac program in the Eagle Ford. Many of the company's legacy wells were originally completed with what the company termed "less than optimal completions."

"From a completion standpoint, we almost can look at the refracs numbers that we provided on to get a sense of how these wells were originally fracked," Sean Woolverton, CEO of Silverbow, told analysts during the company's May earnings call. "Many of them had cluster spacing of 50 to 100 feet and pretty big, significant stage spacing and had proppant intensities probably in the 1,200 pounds per foot or less."

In SilverBow's first two refracs–the Shannon 1H and Idylwood 01H–SilverBow increased the number of stages to every 19 ft and increased proppant loads to 2,000 lb/ft.

The Shannon 1H and Idylwood 01H saw production skyrocket from 20 boe/d in the Shannon 1H to 475 boe/d. The Idylwood 01H, which was not producing, averaged 355 boe/d after refracturing.

Each was completed for less than $4 million and demonstrated IRRs of more than 100%. SilverBow estimates that the projects will achieve payout in less than 10 months and plans for additional refracs in 2024.

"The initial results [of our refrac program] clearly show that restimulating existing wells with larger jobs in tighter cluster spacing can materially enhance well productivity," Woolverton said. "We have more than 100 refrac opportunities across our portfolio and we are moving additional refracs into this year's program."

SilverBow's success in the Eagle Ford can be attributed to its approach to wells it plans to refracture: going back into the well, cementing in a brand new liner and starting over in terms of the completion. The company also uses artificial lift methods at the outset to ensure no significant drop-offs after initial production returns.

"Why we have confidence is, we've got the long-term production from other operators that have done it over the last couple of years using similar techniques there that they used on ours," Woolverton said. "We've got about 45 to 60 days of production thus far and production is actually holding fairly steady."

SilverBow is currently drilling a 10-well pad developing four stacked zones: the Upper and Lower Eagle Ford and the Middle and Lower Austin Chalk.

Conoco, Devon's Aggressive Approach

While Silverbow was initially cautious about venturing into Eagle Ford refracs, larger competitors ConocoPhillips and Devon Energy took a more aggressive approach.

After announcing a deal to buy Marathon Oil in a $17.1 billion deal, ConocoPhillips' footprint in the play will expand to about 490,000 net acres averaging 400,000 boe/d across the core of the Eagle Ford. With the newly acquired acreage, ConocoPhillips sees significant future upside from refrac opportunities in South Texas.

"We've been implementing new refrac techniques across our existing Eagle Ford position... It's expanded our refrac inventory at cost of supplies that compete with our Tier 1 opportunities," Andy O'Brien, senior vice president of strategy, commercial, sustainability and technology for ConocoPhillips, said during a call with analysts.

Devon brought online 26 infill wells and completed 25 refractured wells in the first quarter, resulting in an oil growth rate of

7% year-over-year.

"I would say the wells that we are putting online this year, approximately 25 refracs, compete very favorably with the wells that we're drilling on a heads-up basis [with] new well construction." Devon COO Clay Gaspar told analysts earlier this year.

While SilverBow, ConocoPhillips and Devon have seen success in the Eagle Ford through refracturing from mature wells, not every E&P sees the benefit.

EOG Resources executives have said they don't see the value in restimulating older wells.

After multiple well tests conducted across their multi-basin portfolio, Jeffrey Leitzell, executive vice president and COO of EOG, said that the company is better off drilling new wells in a new location or offsetting an existing completion, citing concerns with current refracture technology.

"For refrac technology, I think there's still a long ways to go," he said. "There's pretty crude approaches to where you kind of do some Hail Mary fracs or have to install expensive additional casing strings, and you never quite get the product activity uplift that you're looking from an actual new well."

Fine-Tuning Fracs

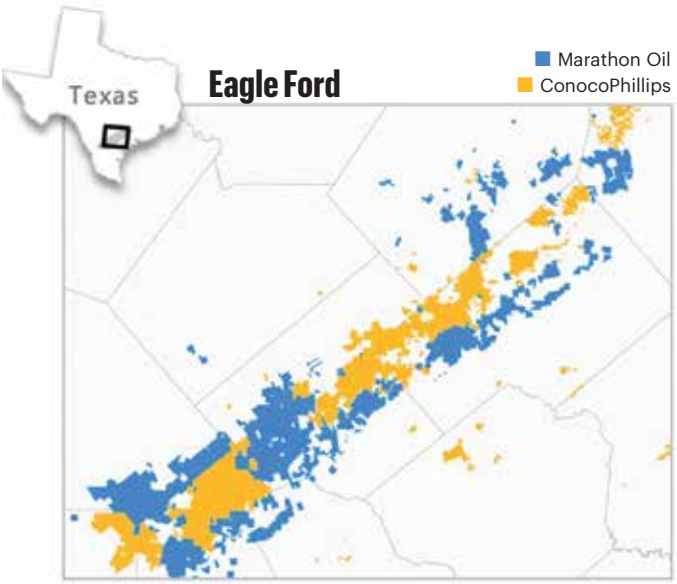
However long the journey, the initial results have intrigued ConocoPhillips, SilverBow and others enough to prioritize learning more about their acreage and how to improve wells, the earliest of which were drilled in the play in the late 2000s.

Devon sees a promising refrac program developing.

"When you start fine-tuning a little bit and look at more recent performance, some of the work that we're doing, you see some really encouraging results," Gaspar said. "And that's on the back of making sure that we understand the well construction, the opportunity from a geology standpoint, that initial completion design and really focusing on the best opportunities."

SilverBow also decided to learn from both the successes and missteps of early Eagle Ford peers to help them weigh the risks and rewards of their new refrac program.

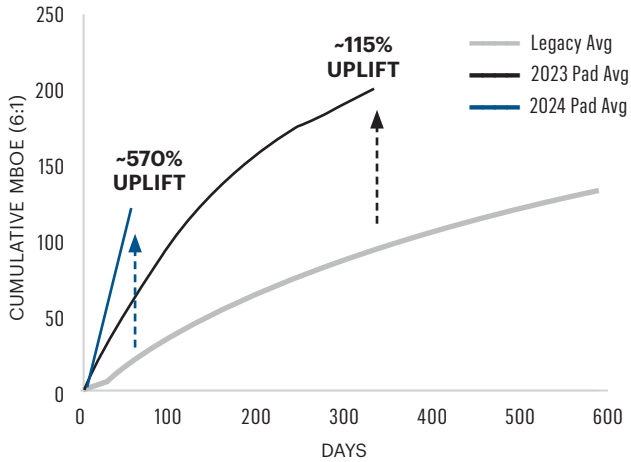
"We've looked at other operators to see how their wells performed to kind of put a risk percentage on consistent performance…. You do run into risks around mechanical issues going back into wells, but in talking with other operators, they're seeing high percentages there," Woolverton said. "What's always great when you do acquisitions is when you unlock even more value on than what you paid for." OGJ



SOURCE: CONOCOPHILLIPS

ConocoPhillips has acquired Marathon Oil and their Eagle Ford acreage, reaching nearly 400,000 boe/d of production

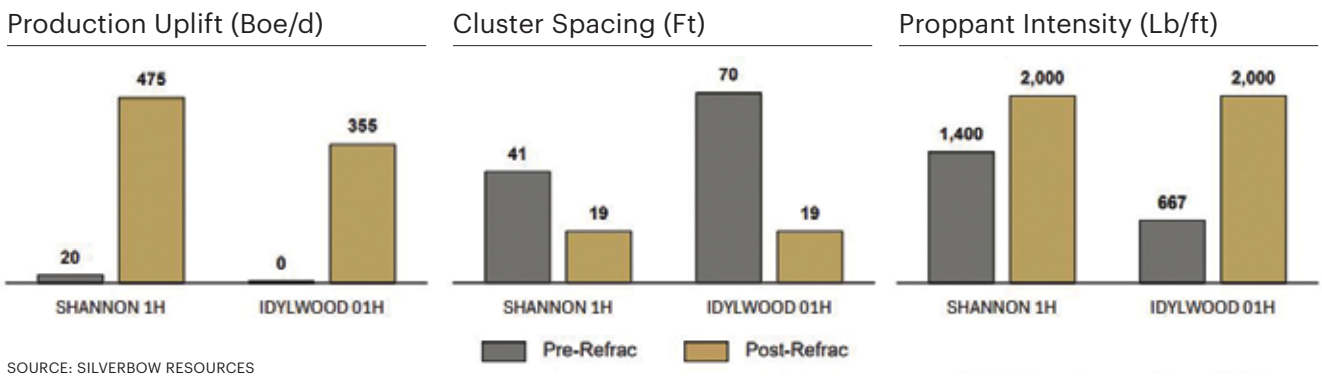
Western Eagle Ford Productivity



SOURCE: SILVERBOW RESOURCES

SilverBow's Eagle Ford productivity has experienced a 570% uplift due to their refrac program

SilverBow Unlock Inventory



SOURCE: SILVERBOW RESOURCES

SilverBow Resources first-quarter refrac saw increased well productivity from an increase in cluster spacing and proppant intenstity.

Exxon Mobil Goes Long with Permian's Poker Lake Well

Supermajor bets on its technical prowess with 20,000-ft well in New Mexico.

JAXON CAINES
TECHNOLOGY REPORTER
jcaines@hartenergy.com

The Permian Basin may awe with its prolific oil and gas production, but the real work happens in the shale play's basement.

Beneath the Permian is a sprawl of thousands of feet of lateral wells that E&Ps are constantly working to improve and lengthen. In 2010, the average length of a Permian lateral was 3,870 ft, according to the U.S. Energy Information Administration. By 2022, laterals were more than 2.5x longer, averaging 10,064 ft.

In 2019, Surge Energy boasted a 17,935-ft (3.4-mile) well, although Rystad Energy noted in 2022 that, over time, productivity in longer laterals generally became comparable to shorter horizontal wells. Diamondback Energy President and CFO Kaes Van't Hof, once skeptical of drilling even longer wells, recently conceded that 4-mile wells will likely be needed in secondary zones to compete with the best of the Permian.

And as technology evolves and techniques improve, some operators have set their sights on routinely pushing past the 12,500-ft to 15,000-ft mark to maximize productivity and reduce costs.

The most recent E&P to swing for the fences: Exxon Mobil, with a 20,000 ft well in Poker Lake, N.M.

"Historical trends indicate that the average lateral length of horizontal land wells continues to increase with time. The average lateral length in the Permian in [third quarter 2022] was 10,000 ft with the average approaching 11,000 ft today," William Dacus, Permian wells manager for Exxon Mobil, told Hart Energy. "As the industry continues to optimize completion and production techniques, it will strive to drill longer wells to reduce cost per lateral foot."

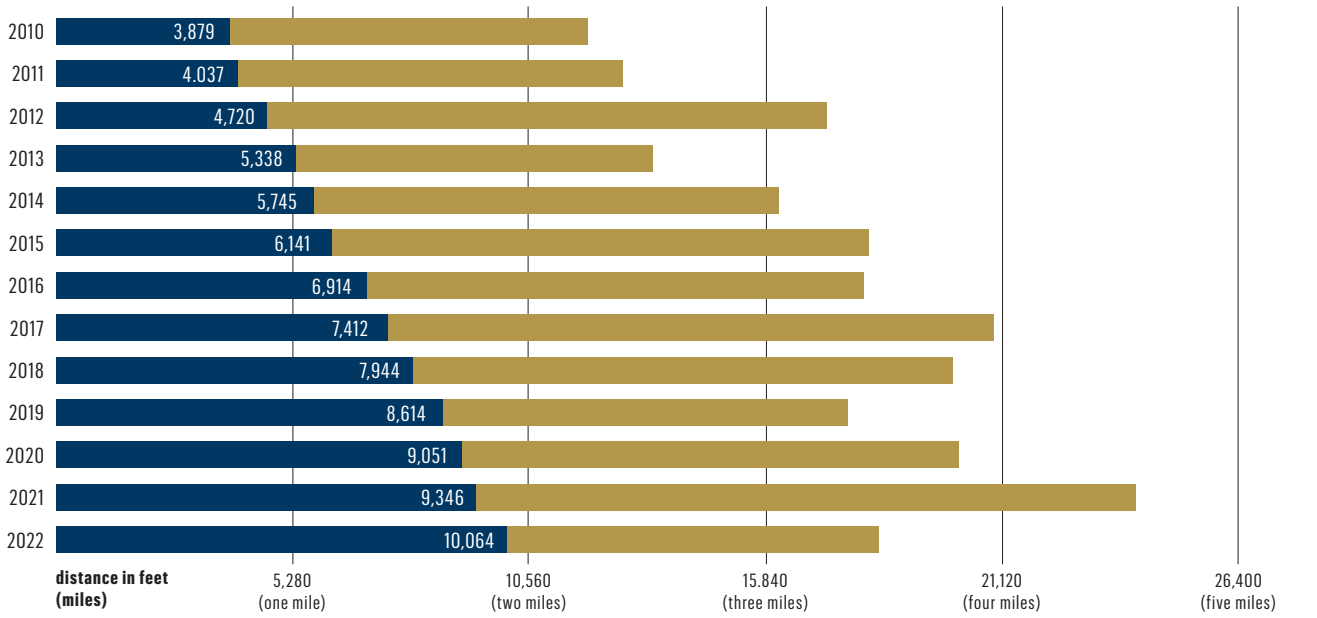
Responsible for 20 of the longest wells drilled globally, Exxon is no stranger to lateral wells. But the crown jewel of operations prowess is the Poker Lake well.

Poker Lake, drilled by Nabors' X12 rig, is the longest lateral in the Permian at more than 20,000 ft.

To drill the well, Exxon had to take lessons from previously drilled wells, taking into consideration which tools would work best and which new technologies to deploy.

"We leveraged these learnings and our engineering and operations expertise as

Permian Basin Annual Average and Maximum Lateral Length per Well (2010-2022)



SOURCE: ENVERUS
NOTE: 2022 VALUES REFLECT DATA BETWEEN JANUARY AND SEPTEMBER.

EXXON MOBIL

Exxon Mobil facilities at Poker Lake, N.M. Poker Lake, drilled by Nabors' X12 rig, is the longest lateral in the Permian at more than 20,000 ft.

"As the industry continues to optimize completion and production techniques, it will strive to drill longer wells to reduce cost per lateral foot."

WILLIAM DACUS, Permian wells manager, Exxon Mobil

we planned and executed our 4-mile laterals in Poker Lake," Dacus said. "Key rig and equipment selection considerations were related to operating torque limiters and the fluids system. Another important consideration is choosing a well design and directional tools that deliver the most favorable wellbore for casing run and completions."

Rotary steerable tools were used in the intermediate and production sections to minimize dogleg severity. Additionally, innovations such as larger outer diameter (OD) casing, extended wireline spools and a hydraulic control unit with tapered work string were pivotal in optimizing completion and drill-out operations.

Each well was drilled in less than 30 days, with frac operations taking about 11 days per well and frac plug drill out averaging 12 days per well. Even with the success of the Poker Lake project, Exxon faced challenges. A well exceeding 3 miles in length will inherently have issues, Dacus said. Problems arose with the well's high operating torque and weight transfer past 3 miles. Frac plug drill out also presented a challenge.

"Running an additional mile of production casing in the lateral was a concern. However, emphasizing wellbore quality proved to be beneficial for both the casing run and drill out of frac plugs. Different wireline units and tapered work strings were utilized when compared to shorter lateral wells," Dacus said. "Production casing was partially air-filled during deployment to allow the casing string to be floated while running to reduce the effective weight."

Poker Lake proved to be a learning experience for Exxon, driving home the importance of wellbore quality and the need for a diversified and tailored approach to tackling longer laterals. Looking ahead, plans are already in motion for rig upgrades and further optimization efforts, ensuring Exxon Mobil remains at the forefront of lateral well drilling technology.

"Rig upgrades have been performed to address learning from the initial drilling campaign," Dacus said. "Plans to assess drill out work string design, frac plug selection and frac cluster placement for future campaign is ongoing. Further costs and performance optimizations will continue as we expand our 4-mile lateral capabilities." OGJ

EVENTS CALENDAR

Investment and networking opportunities for industry executives and financiers.

Scan me

EVENT	DATE	CITY	VENUE	CONTACT
2024				
SGA Operations Conference 2024	July 22-24	Nashville, Tenn.	DoubleTree by Hilton Nashville Downtown	southerngas.org
SPE/IADC Asia Pacific Drilling Technology Conference and Exhibition	Aug. 7-8	Bangkok, Thailand	Bangkok Convention Center at CentralWorld	spe-events.org
SPE Energy Transition Symposium	Aug. 12-14	Houston	Hyatt Regency Baytown	spe-events.org
KIOGA 2024 Annual Convention & Expo	Aug. 18-20	Wichita, Kan.	Century II Performing Arts & Convention Center	kioga.org
SPE Artificial Lift Conference and Exhibition	Aug. 20-22	The Woodlands, Texas	The Woodlands Waterway Marriott & Convention Center	spe-events.org
IMAGE 2024	Aug. 25-30	Houston	George R. Brown Conv. Ctr.	aapg.org
New Energies Summit	**Aug. 27-28**	**Houston**	**Hilton Americas-Houston**	**hartenergy.com/events**
IADC Advanced Rig Technology	Aug. 27-28	Austin, Texas	Hyatt Regency Hotel	iadc.org
Gastech Exhibition & Conference	Sept. 17-20	Houston	George R. Brown Conv. Ctr.	gastechevent.com
GPA Midstream Convention	Sept. 22-25	San Antonio, Texas	Marriott Rivercenter on the River Walk	gpamidstreamconvention.org
SPE/ATCE	Sept. 23-25	New Orleans	Ernest N. Morial Convention Center	atce.org
SHALE INSIGHT 2024	Sept. 24-26	Erie, Pa.	Bayfront Convention Center	shaleinsight.com
Energy Capital Conference	**Oct. 3**	**Dallas**	**Thompson Dallas**	**hartenergy.com/events**
2024 Gas Machinery Conference	Oct. 6-9	Tampa, Fla.	Tampa Convention Center	southerngas.org
SPE Asia Pacific Oil & Gas Conference and Exhibition 2024	Oct. 15-17	Perth, Australia	Crown Perth	spe-events.org
A&D Strategies and Opportunities Conference	**Oct. 23**	**Dallas**	**Thompson Dallas**	**hartenergy.com/events**
IPAA Annual Meeting	Oct. 28-29	Boca Raton, Fla.	The Boca Raton Resort	ipaa.org
Offshore Windpower Conference & Exhibition	Oct. 28-30	Atlantic City, N.J.	Atlantic City Convention Center	cleanpower.org
SEG 4D Forum	Nov. 4-6	Galveston, Texas	Grand Galvez	seg.org
ADIPEC 2024	Nov. 4-7	Abu Dhabi, UAE	Abu Dhabi National Exhibition Centre	adipec.com
DUG Appalachia	**Nov. 7**	**Pittsburgh**	**David L. Lawrence Convention Center**	**hartenergy.com/events**
International Geomechanics Conference	Nov. 18-21	Kuala Lumpur, Malaysia	TBD	igsevent.org
DUG Executive Oil	**Nov. 20-21**	**Midland, Texas**	**Midland County Horseshoe Arena**	**hartenergy.com/events**
National Pipe Line Conference	Nov. 28-29	Houston	Omni Houston Hotel	plca.org
SPE Thermal Well Integrity and Production Symposium	Dec. 2-5	Banff, Alberta, Canada	The Fairmont Banff Springs	spe-events.org
2025				
SPE Hydraulic Fracturing Tech Conference and Exhibition	Feb. 4-6	The Woodlands, Texas	The Woodlands Waterway Marriott & Convention Center	spe-events.org
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Tuesday, odd mos.	Fort Worth, Texas	Petroleum Club of Fort Worth	adamenergyfortworth.org
ADAM-Greater East Texas	First Wed., odd mos.	Tyler, Texas	Willow Brook Country Club	etxadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.org
ADAM-Permian	Bi-monthly	Midland, Texas	Petroleum Club of Midland	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.org
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin, Texas	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Petroleum Club of Houston	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	hefg.net
Houston Producers' Forum	Third Tuesday	Houston	Petroleum Club of Houston	houstonproducersforum.org
IPAA-Tipro Speaker Series	Third Tuesday	Houston	Petroleum Club of Houston	ipaa.org

Email details of your event to Jennifer Martinez at jmartinez@hartenergy.com.
For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com/events.

Oil and Gas Investor

COMPANIES IN THIS ISSUE

This index refers to the pages of the story or news item in which the company is first mentioned. Advertisers are in boldface.

The Tesla, the Airport, a Scandal and a Swimming Pool

The summer of 2024 won't be powered by an EV. And it won't be in the Anthropocene epoch.

NISSA DARBONNE
EXECUTIVE
EDITOR-AT-LARGE
@NissaDarbonne
ndarbonne@hartenergy.com
@NissaDarbonne

"I captured me one of them environmentalists," goes a joke I heard recently.

In the story, Charles, who was at a Permian Basin well pad, phoned Chuck, who could hear Charles' partner Charlie laughing in the background.

"You did what?" a shocked Chuck responded.

"I captured me one of them environmentalists!" Charles repeated excitedly, thrilled by his prowess.

"Why'd you do that?" Chuck asked, while hurriedly processing all the different legal ramifications of what Charles has done as well as his own duty to see that the hostage is freed.

Charles said, "He drove up onto the well pad and I captured him. Blocked him in!"

To simply say "Let him go" isn't going to work. Chuck's running through a mental deck of oilfield psychology. He draws a wildcard.

"Well, how do you know he's an environmentalist?" Chuck asked.

Charles replied, "He's driving a Tesla!"

Chuck had been pranked.

But if the Naïve Bayes classifier worked, one probability could be that the Tesla was the only vehicle left on the rental lot. And the battery was nearly dead.

The guy was just looking for an e-frac to plug into.

Hemingway might title this story "The Lost Man and the EV" or "A Farewell to Charge" or "For Whom the Battery Tolls."

At Houston airports, an EV fill-up is free–when able to find an open EV slot.

This summer, finding any kind of open parking spot is difficult. Garages and economy lots were nearly full the first week of June, according to the Houston Airport System's online real-time count.

And it's not just in Houston: U.S. air travel this summer is setting new records, according to Transportation Security Administration data. The June 6 count of TSA screenings was 2.82 million passengers, up 27% from the 2.22 million who went through checkpoints on 2023's first Thursday of June.

Not an EV.

SHUTTERSTOCK

It also exceeded the pre-pandemic volume, 2.62 million, for that date in 2019.

An early indicator of this summer's travel season came the Friday of Memorial Day weekend: 2.95 million screenings–the most ever on any day–TSA reported.

None of the air travel was with an EV.

But there was big geology news this spring: An International Union of Geological Sciences (IUGS) committee voted against demarcating the current Holocene epoch as having ended in the mid-20th century.

It would have resulted in naming the start of a new one, the Anthropocene epoch–a time when humans are affecting Earth.

The IUGS' Subcommission of Quaternary Stratigraphy (SQS) voted 4-12 against it in March.

It didn't go without scandal. "Eleven of those who voted, including 10 of the 'no' votes, were ineligible to do so because they had exceeded their term limits," Yale's School of the Environment reported at its e360 site.

"When the chair and a vice chair of the SQS objected, they were removed from executive duties."

Meanwhile, at press time, a remarkable human feat was completed: turning an NFL field into an Olympics tryouts swimming pool. The work was done in three weeks on the Indianapolis Colts' field at Lucas Oil Stadium for Team USA trials that were scheduled for June 15-23.

The competition pool and two warm-up ones hold some 2 million gallons of water sourced from a nearby river.

It's unlikely the job was done by an EV. OGI

CREATING THE FUTURE OF ENERGY, TODAY

CARBON CAPTURE | HYDROGEN | GEOTHERMAL
OILFIELD ELECTRIFICATION | EMISSIONS

NEW ENERGIES SUMMIT

AUGUST 27-28, 2024

HILTON AMERICAS-HOUSTON | HOUSTON, TX

Today's oil and gas technologies hold significant potential to address future energy challenges. Innovations in drilling have unlocked previously inaccessible natural gas reservoirs, providing a bridge toward a lower-carbon energy future. Industry influencers will discuss advancements in carbon capture, utilization, and storage (CCUS) technologies which offer a promising avenue for reducing greenhouse gas emissions.

Join Hart Energy in Houston to hear from the industry's top experts showcasing today's innovations to solve future energy challenges.

Leading Speakers Include:

The Macro Perspective on the Energy Transition:
Where Are We Now? And Where Are We Going?
SPEAKER: **Cindy Yeilding**, Senior Vice President (retired), **BP America**

The Growth of Geothermal Energy in the U.S. and Around the World
SPEAKER: **Ajit Menon,** Vice President, Geothermal, **Baker Hughes**

Setting Sights on Carbon Sequestration: The Surge in Class VI Wells
SPEAKER: **Ole Engels,** New Energies Director, **Baker Hughes**

SCAN HERE FOR AGENDA

SCAN HERE TO REGISTER

SPONSORSHIP & EXHIBIT OPPORTUNITIES

The New Energies Summit is a premier meeting ground for sponsors to reach executive and managers from Renewable Energy Companies, Natural Gas Producers and Operators, Capital Providers and Midstream Operators.

LEARN MORE & CONTACT:

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

SPONSORED BY: Alvarez & Marsal | NSAI | Moss Adams | bpx energy | Crowe | Mustang Cat | Wright & Company, Inc.

presented by: HARTENERGY

Inspiring the Next Generation of Game Changers

THE FUTURE of our country and our world depends on game changing thinkers – technologists, engineers, geologists – who are determined to discover what's next, with the understanding that hydrocarbons will be essential and irreplaceable for decades to come. Continental Resources will lead the way by producing clean, reliable, affordable, abundant American energy.
We are America's Energy Champion.

Continental RESOURCES