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THE OGI INTERVIEW

Southwestern's
NEW DIRECTIONS
CEO Bill Way shifts *SWN's* course

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THE OGINTERVIEW

FEATURES

COMMENTARY

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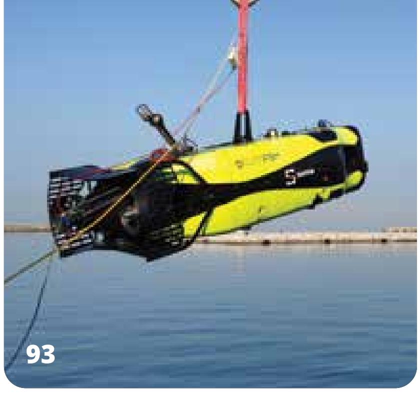

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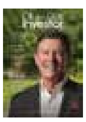
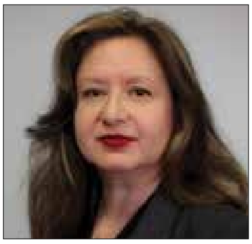


ABOUT THE COVER:
Jon Shapley photographed Southwestern Energy CEO Bill Way at the company's Spring, Texas headquarters in August.

Do Western ESG Standards, Clean Energy Aspirations Prop Up OPEC?

U.S. lawmakers resurrect NOPEC legislation with anti-fossil fuel context, inserting convoluted nuance into challenging geopolitics and complex industry dynamics.



DEON DAUGHERTY
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Congress has routinely offered up legislation to curtail OPEC's dominion over global oil markets during the last 20 years. And this year is no different.

In early August, a bipartisan group of lawmakers led by Sen. Chuck Grassley (R-Iowa), reintroduced the "No Oil Producing and Exporting Cartels Act," also known as NOPEC.

"We've seen time and again how OPEC has colluded to set global oil prices, bringing uncertainty and high prices to consumers around the globe," Grassley said.

NOPEC would authorize the U.S. Department of Justice to sue OPEC member nations for antitrust violations by closing up loopholes of sovereign immunity within The Sherman Act. The bill would make it illegal for collective foreign nations to limit production or distribution of petroleum products; set or maintain the price of any petroleum product or otherwise take action to restrain trade.

Current law renders the U.S. powerless to stop the world's 13 oil-producing nations from "coordinating oil production to manipulate prices, driving up costs for millions of Americans," said co-author Sen. Amy Klobucher, (D-Minn.).

Grassley's commentary during introduction of the bill covered a lot of ground. The cartel needs "to know that we are committed to stopping their anti-competitive" way of doing things; the U.S. focus should remain on developing domestic clean, renewable and alternative energy resources; and all the while, the U.S. must reduce its dependence on foreign oil, "especially when it's artificially and illegally priced."

It's an ambitious program for legislation that routinely fails.

The lawmaker's animosity toward OPEC's fossil fuel domination expressed in the same breath as his embrace of new energy sources piqued my interest. It puts into context a key paragraph that I've fixated on that's tucked inside a bit of light reading on my desk since June—the Energy Policy Research Foundation's "A Critical Assessment of the IEA's Net Zero Scenario, ESG, and the Cessation of Investment in New Oil and Gas Fields."

The 100+ page white paper is actually a weighty proposition. The forward written by Rupert Darwall, a senior fellow at the RealClear Foundation, alone is worth reflection. And that's where I found the OPEC idea that brings an interesting, perhaps alarming, thought into play.

Darwall posits that the International Energy Agency's roadmap published in its Net Zero by 2050 report repositions OPEC's role in global oil supply, taking its market share from currently around 37% to 52% in 2050, "higher than at any point in the history of oil markets."

Moreover, the analysis reckons that if oil demand exceeds the IEA's projections, and non-OPEC producers buckle under pressure of ESG investors to curtail oil production while OPEC cranks away at the IEA's stated policies scenario, then OPEC's market share grows to 82% by 2050.

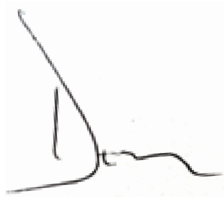
Let that sink in for a minute.

"Wittingly or otherwise, ESG investors are undermining the security interests of the West during a period of rising geopolitical tensions," Darwall wrote.

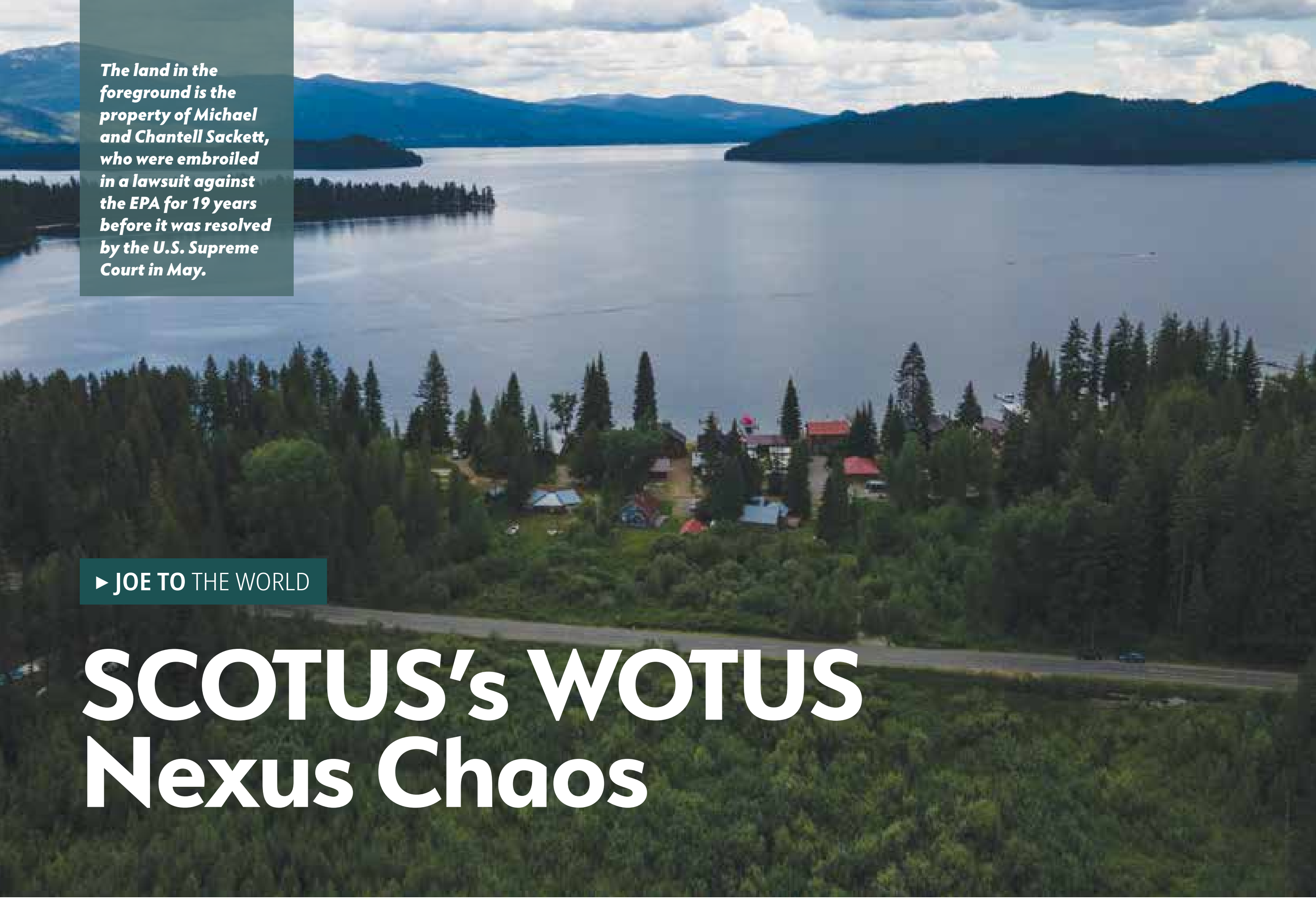
Meanwhile, OPEC and its allies (OPEC+) have extended a voluntary 1 MMbbl/d output cut—in place for July and August—through September. That's in addition to the 1.66 MMbbl/d some OPEC players have in place through the end of next year.

The fact of OPEC's market share means its decisions to adjust its production influence global oil prices; that's a benefit of being a cartel. So when the group lowers supply, the theory is that oil prices will increase, and the reverse also tends to be true.

The NOPEC lawmakers aim to stop OPEC from influencing the price of oil while the U.S. figures out how to pivot toward clean methods of producing oil and/or develop alternative fuels. We've seen OPEC's reaction toward U.S. policy indecision and fuel anxiety in the past. It's not comforting, nor does it support a logical argument to manage OPEC via scattershot political posturing. OGI



DEON DAUGHERTY
EDITOR-IN-CHIEF



The land in the foreground is the property of Michael and Chantell Sackett, who were embroiled in a lawsuit against the EPA for 19 years before it was resolved by the U.S. Supreme Court in May.

Pacific Legal Foundation

▸ **JOE TO** THE WORLD

SCOTUS's WOTUS Nexus Chaos

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To be clear, the problem with the language in parts of the federal Clean Water Act (CWA) has been a lack of clarity.

It goes like this: An oil and gas executive pondering a parcel of land asks what appears to be a simple question—Is it legal to operate here? But if that land is covered by the "Waters of the United States" (WOTUS) rule, the simple answer for many years has been: hmmm, good question.

In May, the Supreme Court (SCOTUS) put its stamp on the issue in a 9-0 ruling in Sackett v. Environmental Protection Agency that put to rest the uncertainty executives face in dealing with this particular law.

Except it didn't, at least not yet. And, just so we're clear, it might not—at least for a while.

The Clean Water Act, passed in 1972 and signed by President Richard Nixon, prohibits the discharge of pollutants into "navigable waters." How regulators have enforced the law, however, has fluctuated through the years and through presidential administrations.

The definition of which waters were protected under the law was originally a very narrow one, Jonathan Brightbill, Washington-based partner at Winston & Strawn and chair of its environmental litigation and enforcement practice, told me.

Over time, however, it broadened considerably to where, in an opinion by Justice Antonin Scalia in Rapanos v. United States, the rule seemed to cover "virtually any parcel of land containing a channel or conduit … through which rainwater or drainage may occasionally or intermittently flow."

But if a rule is issued in Washington, somebody is bound to hate it, and regulation begets litigation.

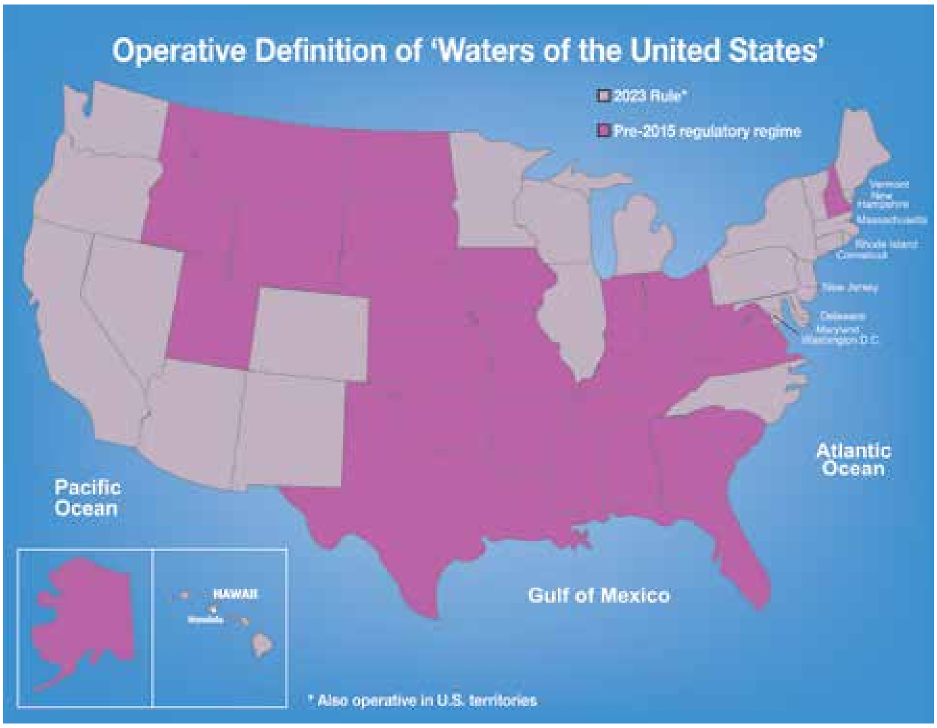
In this era, with this court, it's a regulation almost begging to be reined in.

"You have these Supreme Court decisions that said, 'well, no, the statute doesn't allow the regulation to be that broad,'" Brightbill said. "And you had this unusual circumstance where the regulation was out of sync with the Supreme Court precedent and the statute."

In 2015, the EPA under the Obama administration issued its WOTUS rule that expanded the definition beyond Supreme Court precedent. It was vacated by the courts and eventually repealed by the Trump administration. Trump's EPA introduced the Navigable Waters Protection Rule, which streamlined the definition of WOTUS to exclude groundwater, storm water runoff, ditches and artificial lakes, among others.

The regulation fit within the limits of the Supreme Court's rulings, Brightbill said. As acting assistant attorney general for the Environment & Natural Resources Division of the Department of Justice, he successfully defended it against preliminary injunctions in California courts and in appeals to the 10th Circuit in Denver.

The Trump-era rule was vacated in 2021 when the Biden Justice Department declined to defend it in a lawsuit. That led to the current WOTUS definition, which was published in January and took effect in March. It is not operative due to litigation.



Source: EPA

Regulations involving the definition of "waters of the United States" vary by state.

Source: Pacific Legal Foundation, Google Earth, Hart Energy

The land where the Sacketts wished to build their house is about 100 yards from Priest Lake in Idaho.

What is water?

Which brings us to the Sackett case. In 2004, the EPA ordered the Sacketts to stop backfilling their property near Priest Lake in Idaho. The Sacketts wanted to build a house there, but the agency determined that the backfilling affected wetlands on their tract.

The Sacketts sued, contending the wetlands on their property, which is about 100 yards from the edge of the lake, do not constitute "waters of the United States." They argued that their wetlands do not feed directly into navigable waters and are therefore not covered by the CWA. The EPA countered that they were covered because they are adjacent to waters that do feed the lake.

The opposing arguments in the Sackett decision reflect those that emerged in Rapanos, a 2006 case involving wetlands. Because its opinion represented a plurality, not a majority of the court, it did not set a precedent.

In Scalia's plurality opinion, wetlands needed to have a "continuous surface connection" with navigable waters to be covered by CWA. In contrast, Justice Anthony Kennedy provided a "significant nexus" test in his opinion, meaning an adjacent wetland would be covered by the CWA if it had a significant effect on the water quality of navigable waters. The EPA enforced the law using Kennedy's definition, which raises another question: What does "significant" mean?

"When you use words like that, you give federal agencies substantial discretion to come in and interpret what they mean," Peter Whitfield, Washington-based partner at Sidley Austin, told me. "I believe it's one of the reasons why this case ended up back before the Supreme Court."

In the Sackett case, the court ruled the wetlands on their land are not "waters of the United States" because they lack a continuous surface connection with the lake. The majority opinion, written by Justice Samuel Alito, established precedent and is now law, Whitfield said.

Are we clear?

So, the Sacketts achieved clarity—they get to build their house. What about everybody else with an interest in the definition of WOTUS?

The EPA revised its rule in accordance with the Sackett decision and, in late July, sent it to the Office of Management and Budget for vetting. A public release of the new rule was promised by Sept. 1, well after this issue of *Oil and Gas Investor* went to press.

A SCOTUS decision and revised rule would seem to clear things up. But if a rule is issued in Washington, somebody is bound to hate it, and regulation begets litigation. Previous rules have been tied up in the courts, not to mention dumped by subsequent administrations.

Water quality is also not an exclusively federal domain. The CWA states that individual states have primary authority over land and water use, so various state regulations can hinder projects, as well.

But hey, if you want to celebrate the clarity that SCOTUS has bestowed upon plans for your new project, by all means, go for it. Just don't assume you're in the clear. OGI

▸ **ENERGY** POLICY

Biden Faces Energy, Climate Headwinds

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There is a clear political backlash underway against climate change policies, sustainability and ESG in the U.S. and globally as populist movements grow more vocal about their resentment of green policies and their impacts on energy prices, economics and personal freedom.

This movement is strong in the U.S., where Republicans have used hearings and the legislative process on Capitol Hill and in state capitals to focus on ESG practices in investment and lending decisions. The U.S. Supreme Court's recent ruling overturning decades of collegiate affirmative action has further propelled ESG to the center of the nation's political discourse.

While ESG is being debated more broadly in Congress and in Republican-controlled state capitals, energy remains the point of the spear when it comes to this backlash, not just in the U.S., but globally. Oil prices are rising again around the world as OPEC maintains aggressive supply restraint. According to the International Energy Agency, world demand is at an all-time high while supply fell in July by 910,000 bbl/d as a result of Saudi Arabia leading an OPEC+ production cut. This is not good news for western politicians looking at upcoming elections.

The situation is particularly troubling for the Biden administration. The White House has been touting recent drops in oil and gasoline prices and its successes in climate policies—taking credit for recent domestic production increases—and has begun campaigning on a theme of "Bidenomics" amid some improvement in several economic indicators. Yet, higher oil, gasoline and diesel prices, which are likely to continue their increase into 2024 and the looming presidential election, will make the economic case harder to make.

You can feel the backlash across the pond in Europe as well. In the UK, where Prime Minister Rishi Sunak's Conservative party is down by 20 points in opinion polls, Sunak is proposing to reverse green policies enacted by former Conservative Prime Minister Boris Johnson, such as tighter emissions restrictions on cars, and is strongly opposing the Labour Party's plan to stop new oil and gas licensing on the North Sea. More broadly, across Europe, high energy prices and a lack of stable supply is spurring debates over green initiatives and providing fuel for populist opposition campaigns.

In the U.S., the administration has fewer policy options than it has had in the past when it comes to confronting high oil prices. It has already depleted the Strategic Petroleum Reserve, which is now at its lowest level since 1983 following the sale of 300 million barrels.

Increasing domestic production is also an unlikely option. While oil production is already at all-time highs, there are some ominous signs for what lies ahead. For instance, the Baker Hughes oil and gas rig count fell in July for the eighth consecutive month, hitting the lowest level of active rigs since March 2022. Investors remain skeptical in investing in oil and gas companies, as they continue to prefer returns over growth, and higher labor, equipment and supply costs are eating into bottom lines. Finally, options for securing additional non-U.S. supplies are limited. Saudi Arabia remains committed to lower output, other OPEC nations are barely able to meet their quotas, Russia is off the table for sanctions, and sanctions remain in place for Venezuela and Iran.

Importantly, Biden administration policies and actions continue to be in conflict with increasing domestic production, despite rhetoric asking producers to pump more oil. The Bureau of Land Management (BLM) is proposing rules to significantly increase the cost of exploration and production by increasing royalty rates, fees for holding leases and bonding requirements. The administration has been dragging its feet on offshore leasing and only holds lease sales when mandated by Congress to do so. In July, the administration quietly agreed to a number of stipulations as part of a "sue and settle" agreement with environmental groups that threatens to remove millions of acres from potential future leasing in the Gulf of Mexico.

With an election year quickly approaching, candidates are scrambling to take positions that show they are on the right side of the energy and climate debate. Fundamentals seem to indicate that oil and motor fuel prices are going to be higher in 2024, and Saudi Arabia, Russia and the rest of OPEC will determine where they will stand as we edge toward election day. With high energy prices, anti-domestic oil and gas policies and a recent polling showing 57% of Americans disapproving of its handling of climate change, the Biden administration finds itself in a difficult place heading into election season. OGI

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Private equity is coming back to the upstream sector, perhaps with as much as $15 billion raised this year. But that drop in the bucket is dramatically outweighed by the forecasted market supply needed to prevent a short fall of $4.9 trillion by 2030.

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ACTIVITY HIGHLIGHTS

ANADARKO BASIN PRODUCTION AVERAGED 386,700 BBL/D IN 2022

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► **ACTIVITY** HIGHLIGHTS

FOCUS ON: ANADARKO BASIN

E&Ps continue to tap the Anadarko Basin, despite the Midcontinent play being down notably from its peak production profile a few years ago.

Anadarko crude oil production averaged approximately 386,700 bbl/d during 2022, according to data from the U.S. Energy Information Administration (EIA).

But from the start of 2023 through the end of July, Anadarko crude production has averaged about 423,000 bbl/d, per EIA data; output is forecasted to average about 434,000 bbl/d during September.

The Anadarko Basin is home to several well-known E&Ps, including Continental Resources, Devon Energy and Exxon Mobil.

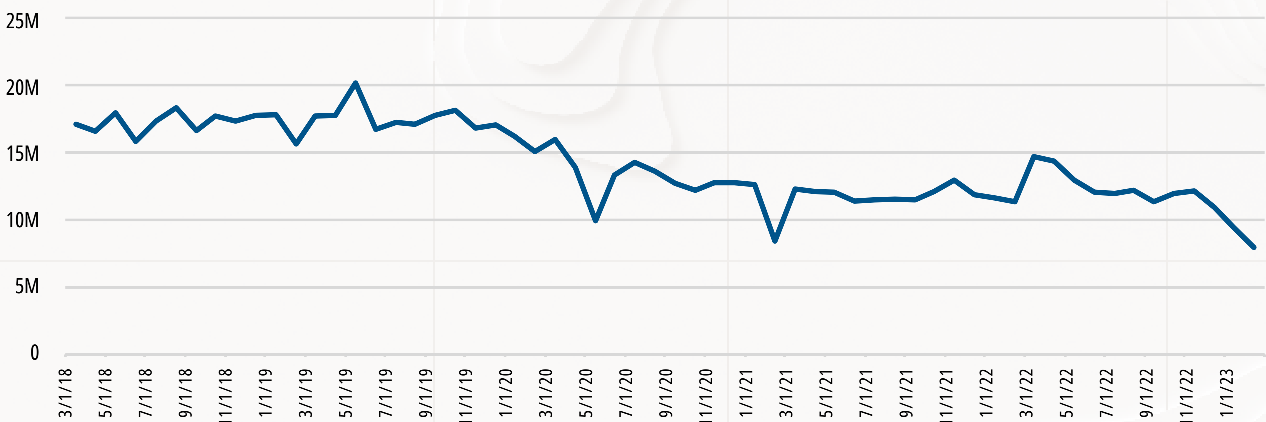
Crude oil output from the Anadarko is being led out of Kingfisher County, Okla., where production reached more than 132.5 MMbbl over the past year.

The second-largest oil-producing county in the Anadarko was Grady County, Okla., where output was 107.5 MMbbl in the past year. Canadian County, Okla., ranked third at 73.7 MMbbl.

The Texas Panhandle is also getting in on the Anadarko action: Ochiltree County, Texas, was the seventh-largest producer of crude in the basin; Wheeler County, Texas, was No. 10.

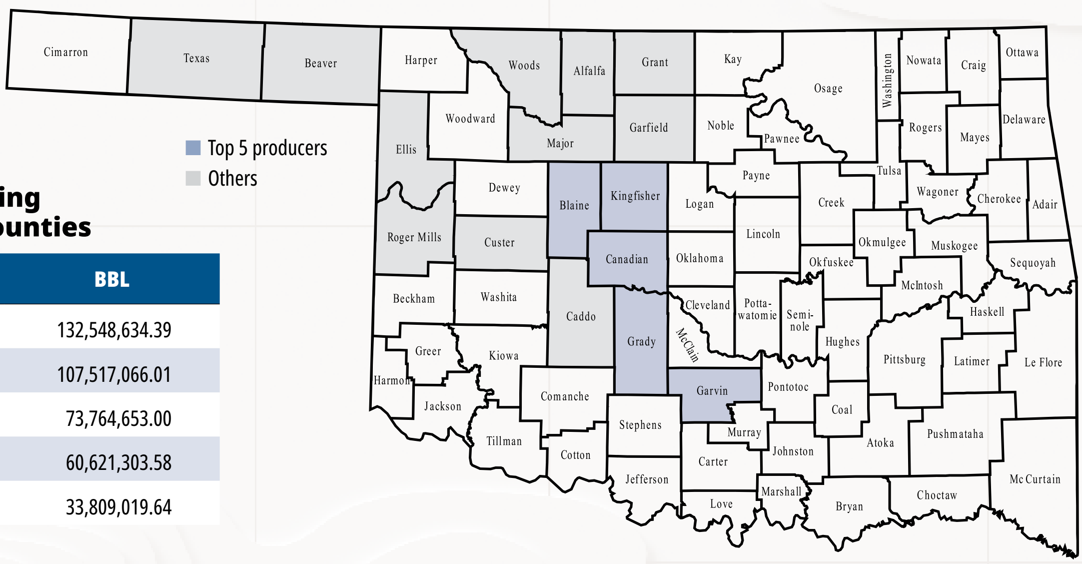
Anadarko Basin monthly oil production

(2018-2023)



Top 5 producing Oklahoma counties

Oil production	BBL
Kingfisher, Okla.	132,548,634.39
Grady, Okla.	107,517,066.01
Canadian, Okla.	73,764,653.00
Blaine, Okla.	60,621,303.58
Garvin, Okla.	33,809,019.64



Source: Rextag

▸ ACTIVITY HIGHLIGHTS

PERMITS

Producers continue to obtain drilling permits in the prolific Permian Basin, but E&Ps are also planning activity for Colorado, Wyoming and North Dakota.

Martin County, Texas—located within the core of the Permian's Midland Basin—saw the hottest well-permitting activity in the past month, according to data from Rextag. Other counties in the Midland Basin, including Midland, Reagan, Glasscock and Upton counties, also raked in notable permitting activity.

The Permian's more western Delaware Basin is also getting attention from producers: Loving and Reeves counties, Texas, both landed in the top five most-active counties for well permitting.

Texas led the way in permitting, with 507 well permits issued in the past month. Colorado ranked No. 2 with 109 issued permits.

Weld County, Colo., in the core of the Denver-Julesburg Basin, brought in 19 well permits, Rextag data show.

Moving north from Weld County, E&Ps are also drilling down into permitting in Wyoming's Powder River Basin. Converse County, Wyo., saw 29 well permits issued; Campbell County, Wyo., saw 11.

And drillers haven't forgotten the Bakken—Williams and McKenzie counties, N.D., brought in a combined 40 well permits in the past month.

Permitted wells by state

State	Well Count
Texas	507
Colorado	109
North Dakota	55
Wyoming	55
Oklahoma	19
Louisiana	15

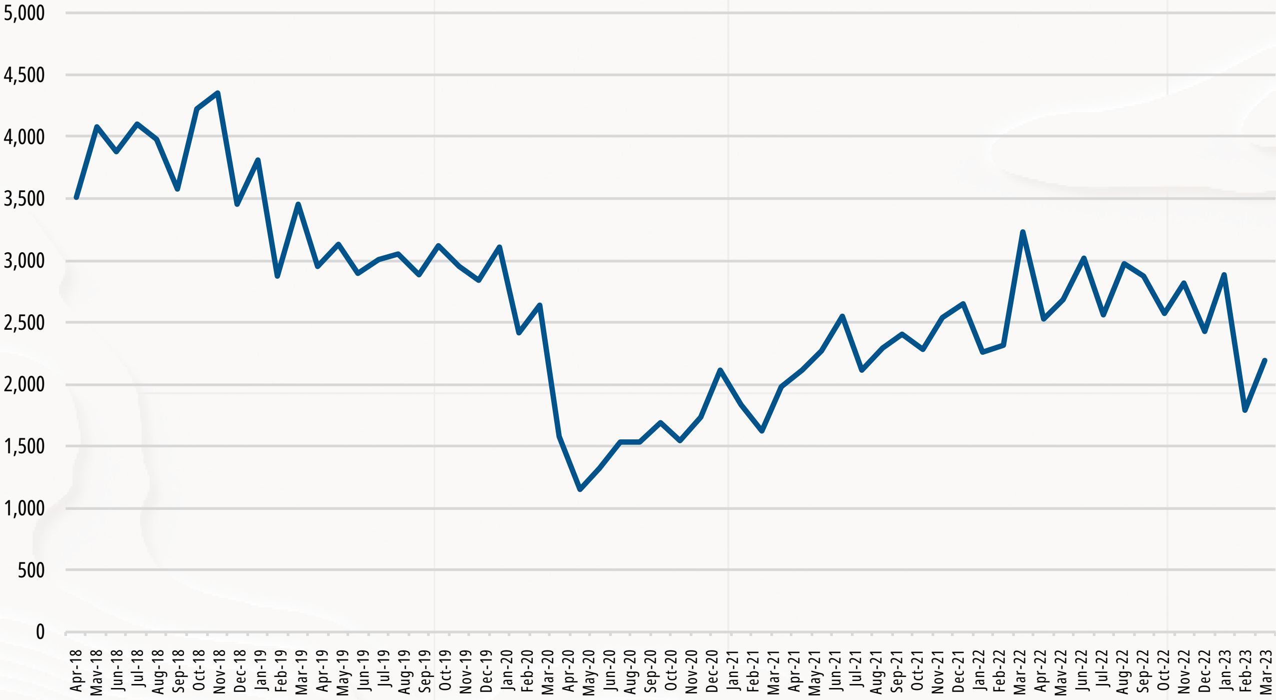
Permitted wells by operator

Operator	Well Count
PDC Energy	42
EOG	38
Pioneer Natural Resources	31
DE IV Operating	30
Endeavor	28
Fundare Resources	24
PDEH LLC	21
Windsor Energy Group	21
Anshutz Exploration	20

Permitted wells by county

County	Well Count
Martin, Texas	93
Loving, Texas	35
Midland, Texas	35
Reeves, Texas	31
Converse, Wyo.	29
Reagan, Texas	25
Williams, N.D.	22
Glasscock, Texas	19
Weld, Colo.	19
McKenzie, N.D.	18
Upton, Texas	14
Webb, Texas	14
Dunn, N.D.	13
Karnes, Texas	13
Campbell, Wyo.	11

PERMITS ISSUED



Source: Rextag

SilverBow May Hunt for More Eagle Ford Scale After $700MM Deal

SilverBow Resources could look for additional scale in the Eagle Ford through M&A after buying Chesapeake Energy's South Texas assets—its eighth deal in the play.

An oil pump unit can be seen in the Eagle Ford in South Texas. Oklahoma City-based Chesapeake Energy Corp. lined up a deal to sell its remaining South Texas acreage to Houston-based SilverBow Resources for $700 million, the companies announced in August.

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SilverBow Resources is adding greater scale in the Eagle Ford as **Chesapeake Energy** exits the basin to focus on gassier regions.

Oklahoma City-based Chesapeake Energy lined up a deal to sell its remaining South Texas acreage to Houston-based SilverBow Resources for $700 million, the companies announced in mid-August.

SilverBow agreed to pay $650 million in cash at closing, another $50 million cash in a deferred payment 12 months after closing—and a possible $50 million contingency payment based on future commodity prices.

The deal came together after nearly a year of evaluation and discussions between SilverBow and Chesapeake, SilverBow CEO Sean Woolverton said during a second-quarter conference call with analysts.

"The strategic impact of this transaction is transformational for SilverBow as we expect to become the largest public pure-play Eagle Ford operator on a pro forma basis," Woolverton said. "This transaction marks the eighth acquisition that we have made over the last two years and represents the largest to date."

The deal is expected to add between 31,000 boe/d to 33,000 boe/d of net production to SilverBow's Eagle Ford footprint during the fourth quarter.

SilverBow estimates that the proved developed producing PV-10 value of the acquired production is about $850 million based on Aug. 4 strip prices. Gabriele Sorbara, managing director of equity research at **Siebert Williams Shank & Co.**, said the firm's estimates are closer to $600 million based on current prices.

On top of adding production, the deal also deepens SilverBow's drilling runway in South Texas with undeveloped inventory.

SilverBow will add about 300 gross drilling locations in the Eagle Ford and Austin Chalk, with about two-thirds of the incremental inventory in the Chalk and one-third in the Eagle Ford, Woolverton said.

The company also believes there are more benches within both the Eagle Ford and Austin Chalk that SilverBow can target beyond the 300 future locations, he said.

"We like that there's a ton of inventory that's well-delineated, well proven-out by drilling on the asset, as well as by offset activity," Woolverton said. "Then, as we always do, we think we'll unlock incremental inventory as we take control of the asset."

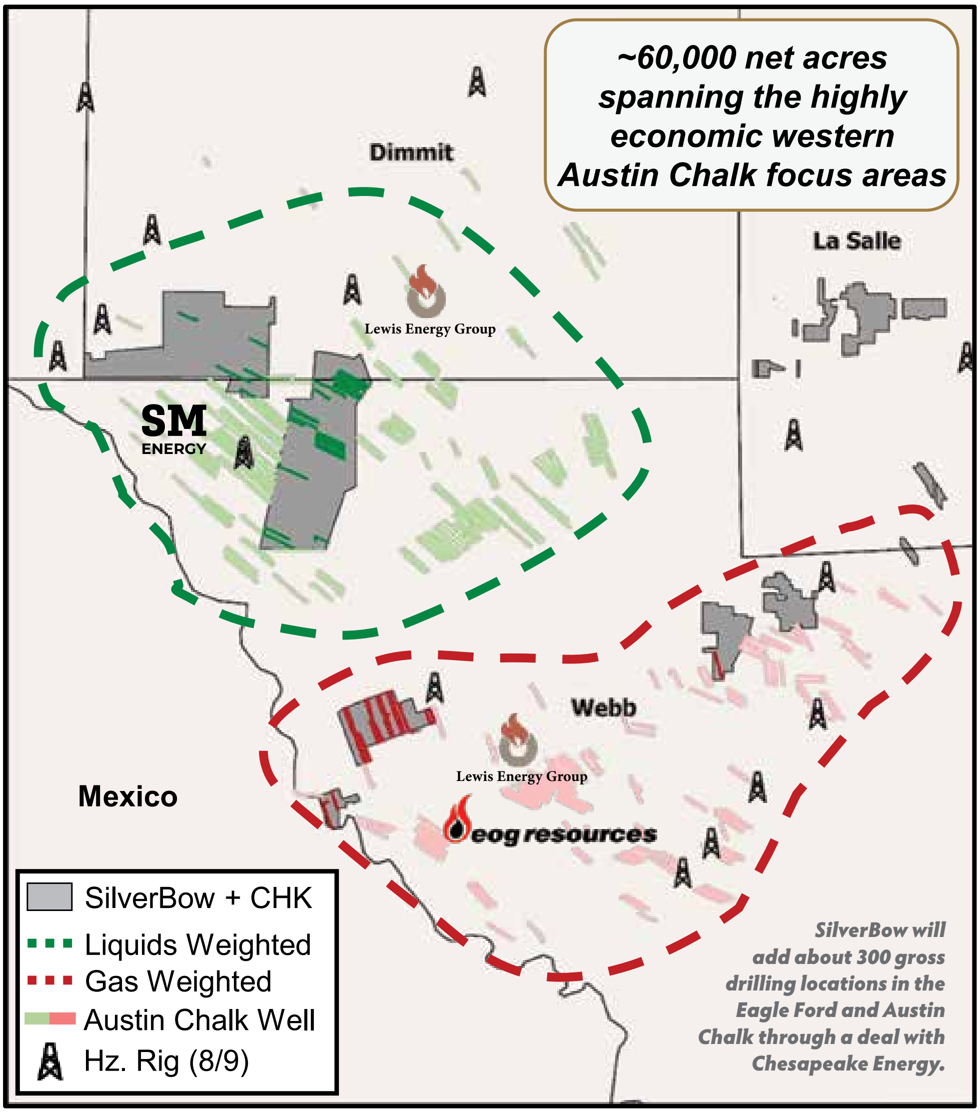
Chesapeake's capital program for its legacy South Texas asset ran two rigs and one frac crew. Chesapeake is bringing 16 wells online there in the immediate future—and SilverBow likes that it's acquiring the asset as production ramps up, he said.

SilverBow anticipates a similar level of drilling activity after taking control of the asset; analysts at **Truist Securities** are forecasting a one-rig, one-frac crew program for the acquired assets.

SilverBow intends to finance the transaction using cash on hand and debt. The deal is expected to be "leverage neutral" at the end of 2023, and SilverBow aims to reach a 1.0x leverage ratio by year-end 2024.

"There's a significant amount of free cash flow that's going to be generated from [the asset]," Woolverton said. "We're going to quickly de-lever the asset so there will be additional capacity within the balance sheet to do future deals."

Premier Austin Chalk position in the South Texas core



Source: SilverBow

Woolverton said SilverBow equity could be a currency the company uses longer-term on other acquisitions. While the SilverBow A&D team has been focused on landing the Chesapeake deal, there are other opportunities in the company's sights, he said.

Chesapeake aims for gas glory

With its latest divestment package, Chesapeake finished the selloff of its Eagle Ford footprint for about $3.53 billion—largely in-line with market expectations, according to analysts at **Jefferies Equity Research**.

In February, Chesapeake struck a deal to sell its black oil Eagle Ford assets to **INEOS Energy**, a subsidiary of British chemical company **INEOS Group**, for $1.4 billion; the transaction closed in May.

Chesapeake sold its Brazos Valley acreage footprint to **WildFire Energy I** for $1.43 billion earlier this year.

Chesapeake's exit from the Eagle Ford transitions the E&P into a pure-play natural gas company focused on positions in the Marcellus and Haynesville shale plays, Chesapeake President and CEO Nick Dell'Osso said in a news release.

The company anticipates that proceeds from the latest Eagle Ford divestment will further enhance its balance sheet and share buyback program.

Truist Securities analyst Neal Dingmann wrote in an August report that the proceeds could also drive future acquisitions for Chesapeake.

"Outside of acquisitions/repurchases we expect the company to focus on increasing its LNG exposure, through both U.S. & international based pricing agreements," Dingmann said.

Chesapeake entered into a heads of agreement (HOA) on **Energy Transfer's** Lake Charles LNG project to supply the liquefaction facility with volumes of natural gas to produce 1 million tonnes per annum of LNG, Chesapeake said in its second-quarter earnings report.

After liquefaction, the LNG will be purchased by trading house **Gunvor Group** under a previously announced 15-year agreement.

—Chris Mathews, Senior Editor, Shale/A&D

In Midland, Endeavor is 'The Clear Belle of the M&A Ball'

Who might be the winning buyer and what's in the asset package? J.P. Morgan Securities analyst Arun Jayaram takes a deep dive.

Endeavor Energy Resources' future-well inventory "stands out as the clear belle of the M&A ball" in the Midland Basin as other operators look to buy replacement inventory, according to **J.P. Morgan Securities** analyst Arun Jayaram.

Could similarly Midland-focused **Pioneer Natural Resources** buy it? At a J.P. Morgan dinner in June, Pioneer president and COO Rich Dealy, who will become CEO Jan. 1, "reiterated the company's interest in Endeavor at the right price," Jayaram reported.

"But [he] underscored that Pioneer's current acreage position and inventory have the operator poised for success over the coming 10 [years] to 15 years, regardless."

Dealy told Hart Energy this spring that Pioneer has 15,000 high-graded future-well locations in inventory and a total of more than 25,000.

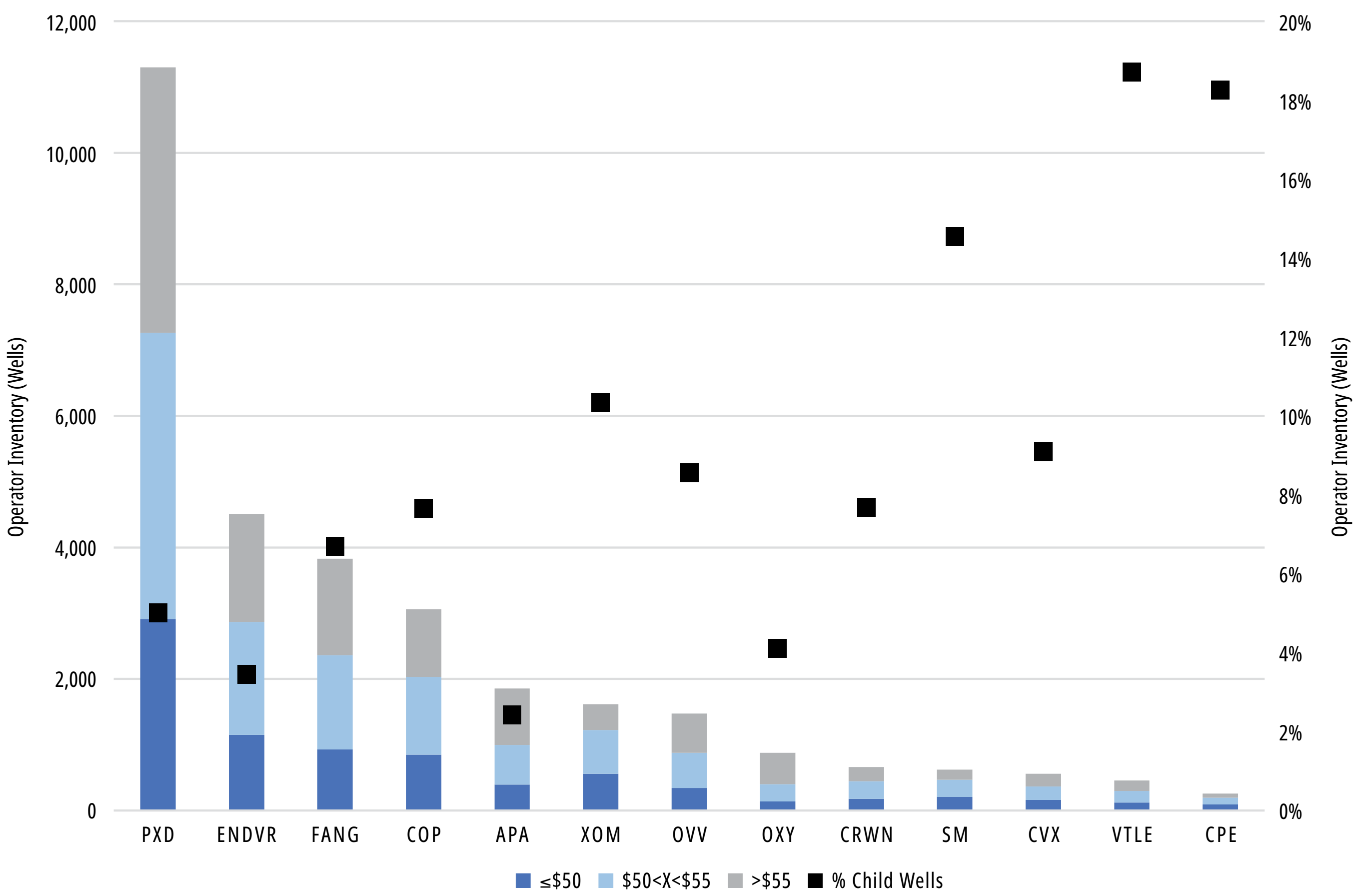
"At [their] current development pace, operators with the most Midland Basin inventory include **APA [Apache] Corp.**, **ConocoPhillips**, Pioneer and privately-held Endeavor," Jayaram reported in June.

Pioneer has the most potential well sites at $65-plus WTI with more than 11,000. But at its drilling pace, this inventory would be depleted in 25 years, according to the J.P. Morgan analysis. APA has roughly 1,850 potential well sites, but its current pace means it would deplete this inventory in 55 years.

Endeavor is second to Pioneer with inventory, coming in at more than 4,000 at $65 WTI. At its current drilling pace, Endeavor's inventory life is 14 years.

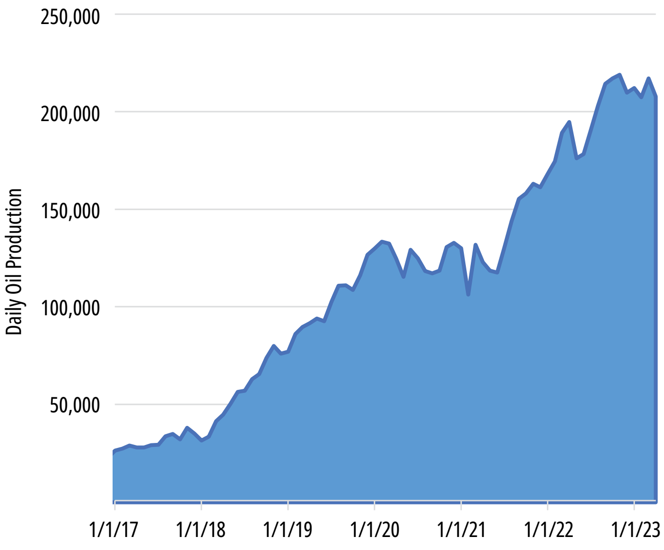
The 44-year-old Endeavor is the fifth-largest U.S.

Midland Basin inventory by breakeven - PM coverage + select integrateds & privates

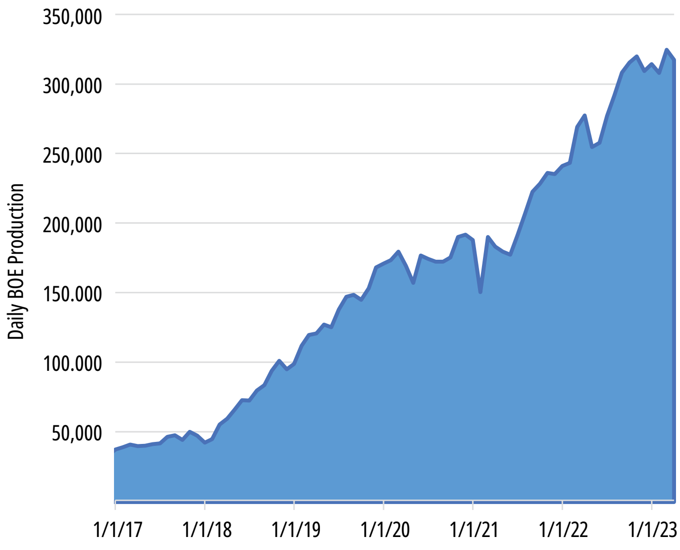


Source: J.P. Morgan Securities, citing Enverus data

Historical oil production



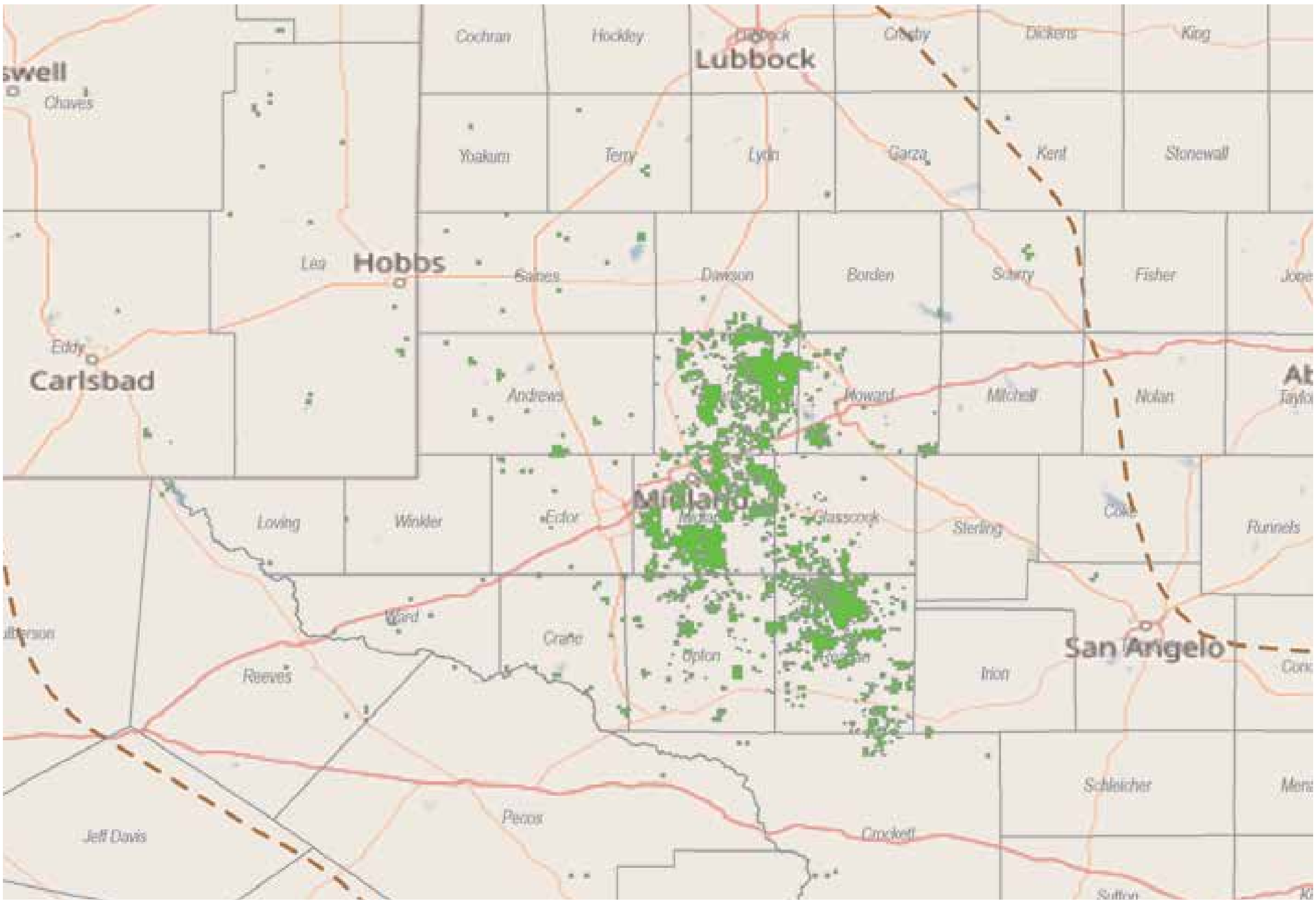
Historical BOE production



Source: Enverus

Endeavor is the fifth-largest U.S. privately held E&P, according to an Enverus analysis published by Hart Energy in May, with a production rate of 279,764 boe/d at 69% oil.

Endeavor acreage position



Source: Rextag

The 44-year-old Endeavor has developed a large acreage position in the core of the Permian's Midland Basin.

privately held E&P, according to an **Enverus** analysis published by Hart Energy in May, with a production rate of 279,764 boe/d at 69% oil.

Ranked higher is newly private, multi-basin **Continental Resources**, followed by Appalachia-focused **Ascent Resources**, Permian-focused **Mewbourne Oil** and Haynesville-focused **Aethon Energy**.

Speculation in October of 2018 was that Endeavor was for sale for an estimated $10 billion or more. At the time, Endeavor's production was 64,000 boe/d; strip was about $70.

Earlier that year, **RSP Permian** went for $9.5 billion to **Concho Resources** (now part of ConocoPhillips), and **Energen** sold to **Diamondback Energy** for $9.2 billion.

Energen had some 180,000 net Permian acres; RSP, 92,000 net acres.

"Historically, Endeavor has often been linked to both **Exxon Mobil** and Pioneer [as potential buyers], and we found it interesting that Endeavor was a topic of conversation in our interactions with Pioneer [in June]," J.P. Morgan's Jayaram reported in July.

He added that Pioneer CEO Scott Sheffield "has never been shy about his desire to acquire Endeavor and marry the two" in the past. Both Pioneer and Endeavor are focused entirely on the Midland Basin.

"Endeavor's footprint is enhanced by its largely contiguous nature, which allows the company to extend lateral length for increased capital efficiency, optimize facilities and infrastructure investment and limit exposure to offset activity of other operators," Jayaram wrote.

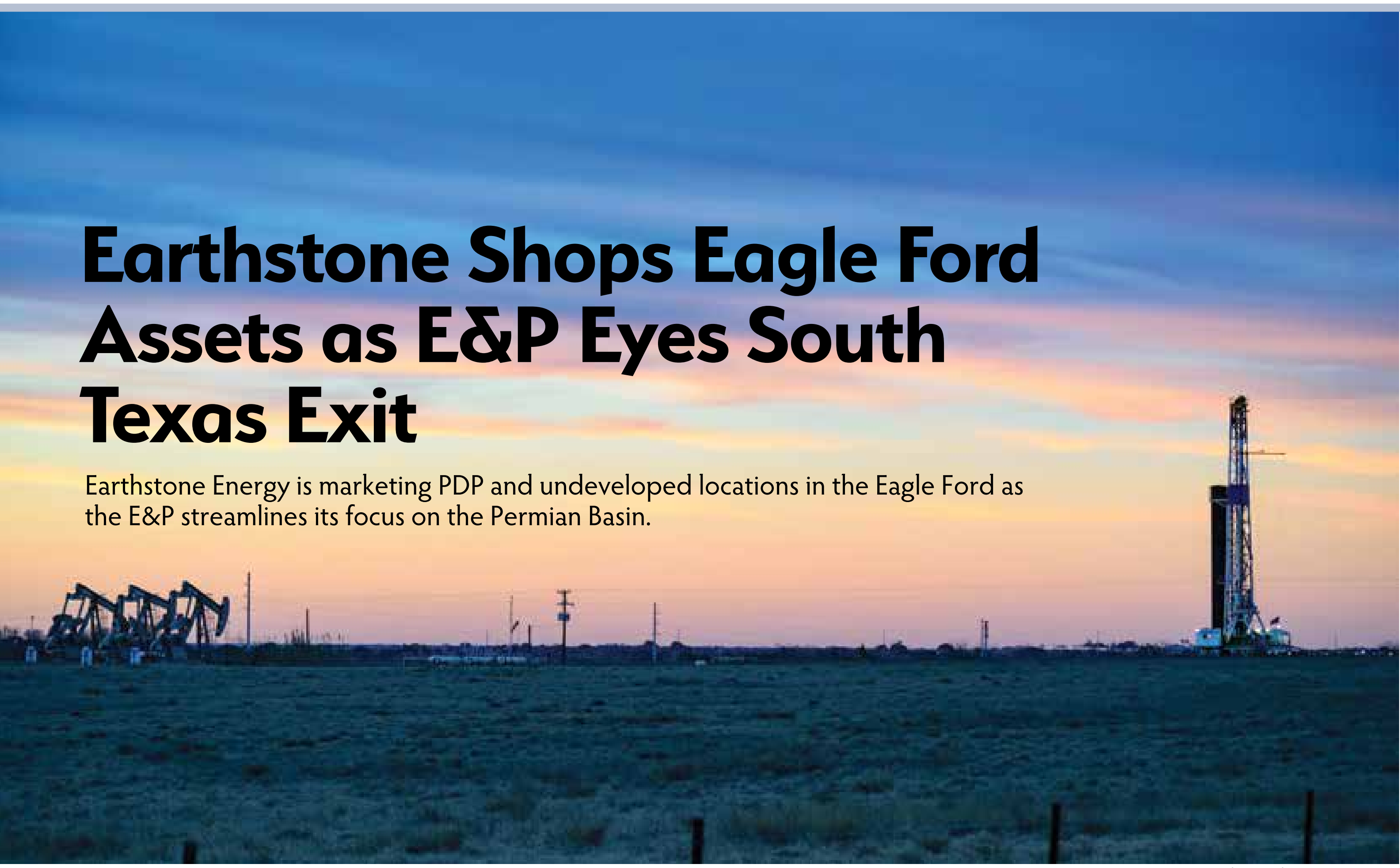
Enverus Senior M&A Analyst Andrew Dittmar reported recently that "there are just about 15 private companies remaining in the Permian that have more than 100 locations, and the lion's share of those are long-time private companies like Endeavor, Mewbourne and **BTA Oil Producers** that are significantly less likely to pursue a sale than the typical private equity-sponsored portfolio company."

Mewbourne's founder, Curtis Mewbourne, passed away in 2022. The family's intention is to continue as an independent company, president and CEO Ken Waits told Hart Energy in June.

—Nissa Darbonne, Executive Editor-at-Large, Hart Energy

Earthstone Shops Eagle Ford Assets as E&P Eyes South Texas Exit

Earthstone Energy is marketing PDP and undeveloped locations in the Eagle Ford as the E&P streamlines its focus on the Permian Basin.



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Earthstone Energy is marketing an Eagle Ford asset as the E&P sheds non-core properties and prioritizes investment in the Permian Basin.

The Woodlands, Texas-based Earthstone is offering to sell production and acreage in northeast Karnes County, Texas, and in southern Gonzales County, Texas.

Earthstone has retained **Opportune Partners** as exclusive financial adviser for the sales process.

The Eagle Ford asset includes low-decline net production of around 1,300 boe/d (83% oil) from 33 horizontal wells. Opportune said the PV-10 value of the asset's proved developed producing (PDP) is around $95.5 million.

The 33 operated PDP wells are also being marketed as high-quality candidates for EOR. The wells are situated in an "EOR fairway" with more than 200 EOR projects from Houston-based **EOG Resources,** offsetting the position, marketing materials show.

Developing EOR projects on the Eagle Ford asset is expected to add around 3.2 MMboe of incremental reserves.

The opportunity also includes eight proved undeveloped drilling locations—three targeting the Lower Eagle Ford and five in the Austin Chalk.

A sale of the Eagle Ford asset would represent a full exit of the play for Earthstone, marketing materials indicate.

Earthstone declined to comment on its sales process in the Eagle Ford.

Permian has prowl

Earthstone reduced its scale in the Eagle Ford in recent years. The company held approximately 3,000 net leasehold acres in the Eagle Ford at year-end 2022, down from 12,700 acres at year-end 2021, according to data from Earthstone regulatory filings.

In July 2022, Earthstone sold Eagle Ford interests in Fayette and Gonzales counties, Texas, for a cash consideration of about $25.6 million before closing adjustments. The deal included a non-operated asset in the Eagle Ford which Earthstone sold alongside the operator's sale, Earthstone said in an investor presentation.

Meanwhile, the E&P has focused its growth in the prolific Permian Basin—the Lower 48's top oil-producing region.

Earthstone entered the northern Delaware Basin in February 2022 with its acquisition of **Warburg Pincus**-backed **Chisholm Energy** in a deal valued at $604 million.

The company later acquired Midland Basin assets from private E&P **Bighorn Permian Resources** in an $860 million deal.

In August 2022, Earthstone added New Mexico assets from **Titus Oil & Gas Production** and **Titus Oil & Gas Production II** in a $627 million transaction.

The deals continued in 2023. In August, Earthstone scooped up assets from Delaware Basin E&P **Novo Oil & Gas** for $1 billion, acquiring 66.66% of Novo, while Minneapolis-based **Northern Oil & Gas** snagged the remaining 33.33% interest for $500 million.

After closing the Novo deal, Earthstone will have more than 223,000 net acres and proved reserves of 460 million boe in the Permian, President and CEO Robert Anderson said during the company's second-quarter earnings call. Earthstone announced officially closing the deal on Aug. 15

Four of the company's five drilling rigs will be focused on the northern Delaware, he said.

"Our recent announcement and pending close of the Novo acquisition supplements this strategy with our asset base shifting further to focus on the prolific Northern Delaware Basin to which the large majority of our capital activity will be dedicated going forward," Anderson said.

Andrew Dittmar, director at **Enverus**, said Earthstone isn't the only public E&P streamlining its portfolio focus around the Permian.

Houston-based **Callon Petroleum** recently exited the Eagle Ford in a $551 million sale to **Ridgemar Energy Operating**, backed by **Carnelian Energy Capital Management**.

The company also acquired Delaware Basin assets from **Percussion Petroleum Operating II** for $249 million in cash and approximately 6.3 million shares. The $1.13 billion in collective A&D closed in July and positions Callon as a Permian Basin pure-play E&P.

Earthstone's transition to a Permian pure-play E&P and exiting the Eagle Ford could also be attractive for investors and analysts, Dittmar said. There could also be opportunities for the company to realize increased cost synergies if its operations are concentrated in a single basin, as opposed to spread across multiple regions.

And when it comes to acquiring undeveloped inventory for future drilling, E&Ps big and small continue to tap the Permian, he said.

Growth in U.S. oil production is being driven by volumes from the Permian. The International Energy Agency forecasts U.S. crude output will grow to 13.6 million bbl/d in 2028—primarily led by light tight oil developments from the Permian.

More monetization

Earthstone divested more than $100 million of its non-core assets in the past year. That includes about $56.1 million in non-core property sales during the first half of 2023—$54.2 million of which occurred during the second quarter, U.S. Securities & Exchange Commission filings show.

And as the company grows in the Delaware Basin, Earthstone has pruned part of its Midland Basin portfolio. In May, Earthstone divested around 1,280 acres and 44 producing wells in Midland County, Texas, and about 800 undeveloped acres in Reagan County, Texas, for net proceeds of $56 million.

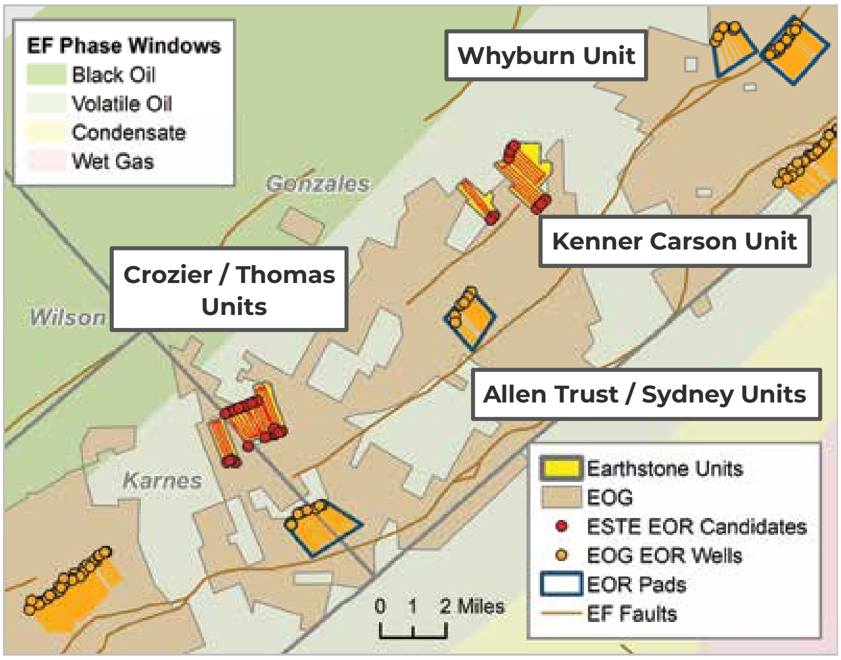
The company also sold about 38,000 net acres and 780 gas-weighted vertical wells in the Sugg Ranch and Hunt fields for $21 million last year.

Earthstone also plans for another roughly $100 million in non-core divestitures over the next 12 months to 18 months, CFO Mark Lumpkin said on the call.

"It's not sizable, but there are things that would streamline our operations for sure," Lumpkin said. "We don't know if we're going to be successful in selling assets, but we'll sell what makes sense to sell."

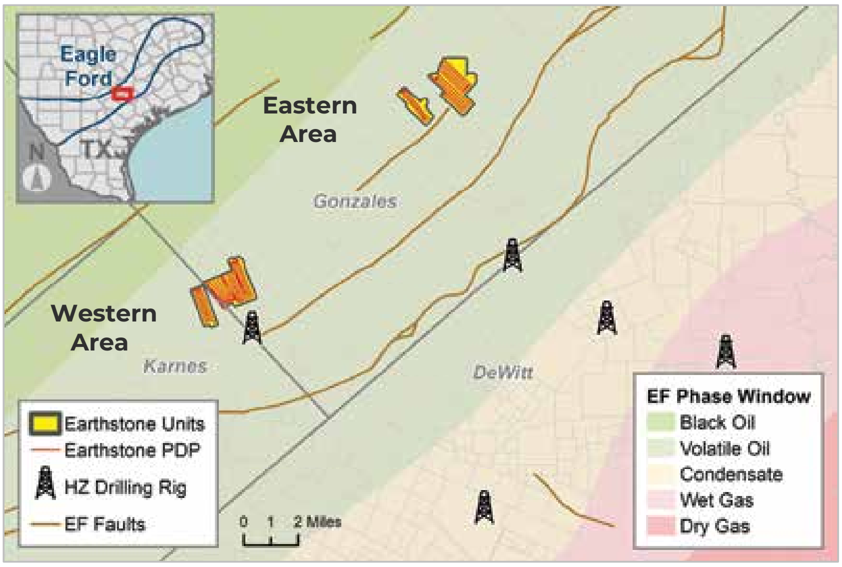
—Chris Mathews, Senior Editor, Shale/A&D

Earthstone EOR candidates



The 33 PDP wells in Earthstone's Eagle Ford position are being marketed as high-quality candidates for enhanced oil recovery, due to EOG's EOR activity in the area.

Asset map and key stats



Source: Opportune

Earthstone Energy aims to sell acreage in the black oil window of the Eagle Ford, according to marketing materials from Opportune Partners.

Diamondback Eyes Further Sales After Exceeding $1B Divestiture Target

Permian Basin pure-play Diamondback Energy monetized more midstream assets in the second quarter—part of a broader plan to reduce debt and shed non-core assets that don't compete for capital.

Shutterstock

Diamondback Energy reached its non-core $1 billion divestiture target during the second quarter—and the Permian Basin pure-play might not be done marketing assets.

In July, Midland, Texas-based Diamondback Energy sold a 43% equity ownership in the OMOG crude oil gathering system, the company disclosed in second-quarter earnings. The interest was picked up by midstream company **Plains All American Pipeline**.

OMOG JV LLC operates about 400 miles of crude oil gathering and regional transport pipelines, as well as approximately 350,000 bbl of crude storage in Midland, Martin, Andrews and Ector counties, Texas, according to Diamondback regulatory filings.

Diamondback said the divestiture generated gross proceeds of $225 million.

The Permian E&P has announced or closed $1.1 billion in non-core asset divestitures since launching the sale program. Diamondback had previously planned to raise $500 million through asset sales but upped its 2023 divestiture target to $1 billion earlier this year.

Despite exceeding its goal by year-end, Diamondback might be looking to monetize more assets.

In a July 31 research report, analysts at **TD Cowen** noted that Diamondback ended the second quarter with $742 million in assets held for sale—suggesting that "further proceeds are likely on the way that would favorably build cash reserves towards further capital returns."

That's up from $143 million in assets held for sale reported in first-quarter earnings in May.

Diamondback also ended the second quarter with $587 million in equity method investments on its balance sheet.

"[Diamondback] did not increase its non-core asset sale target but continues to have significant value in its midstream assets and equity method investments that may be monetized down the road," **Siebert Williams Shank & Co.** Managing Director Gabriele Sorbara noted.

Diamondback is using proceeds from its asset sales in part to pay down debt. The company's total debt fell to around $6.7 billion in the second quarter, down from about $7 billion in the previous quarter.

The company aims to continue deleveraging in the third quarter through free cash flow generation, proceeds from divestitures that are set to close and reducing its income tax receivable.

Diamondback highlighted its divestitures but also made headway on blocking-and-tackling leasing activity during the quarter, President and CFO Kaes Van't Hof said on the company's earnings call with analysts.

The company spent $145 million on second-quarter property acquisitions related to Permian Basin leasing activity.

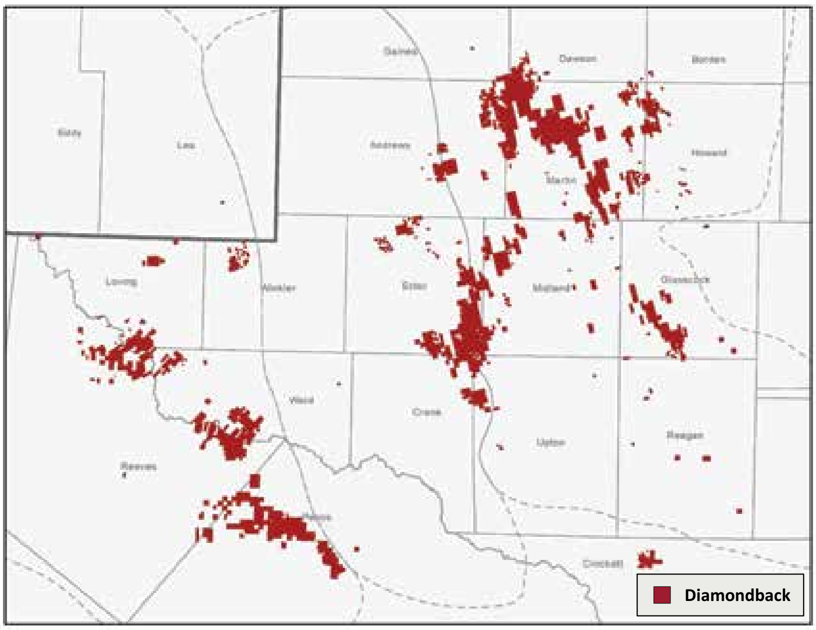
"We've been looking at leasing some of the deeper rights in the Midland Basin across some of our positions, so that's tied to some of those purchases in the cash flow statement," Van't Hof said.

Diamondback's business development team is also making offers on undeveloped interests and non-operated positions the company doesn't own in its operating areas.

The E&P anticipates that capital spending will fall by around 5% to between $650 million and $700 million in the third quarter as Diamondback begins to see the benefits of lower well costs and lower drilling activity. The company also expects to see cash capex fall further in the fourth quarter.

"Both raw materials (including steel, diesel and sand) and service costs continue to decline, setting us up for lower completed well costs as we head into 2024," Chairman and CEO Travis Stice said in a letter to shareholders.

—Chris Mathews, Senior Editor, Shale/A&D



Source: Diamondback Energy

Permian pure-play Diamondback Energy has around 476,000 net acres across the Delaware and Midland basins.

UPSTREAM

• **Chevron** has completed its previously announced acquisition of **PDC Energy's** 275,000-acre positions in the Denver-Julesburg Basin (D-J Basin) and 25,000 net acres in the Delaware Basin.

The acquired assets include acreage positions adjacent to the company's existing operations in the D-J Basin and will add more than 1 billion boe proved reserves. The deal also adds PDC's 25,000 net acres in the Permian Basin's Delaware, which are held by production, according to the release.

Bruce Niemeyer, Chevron's president for America's Exploration & Production, said Chevron welcomes PDC Energy into the fold.

"Our companies have similar cultures, with a focus on safe and reliable operations, teaming to deliver results, and benefiting the communities where we operate. PDC's high-quality assets open up even greater opportunities in important U.S. basins where Chevron already has a strong presence," Niemeyer said.

• **Kimbell Royalty Partners** has agreed to buy Permian Basin and Midcontinent assets from a private seller for $455 million cash, the largest in the company's history.

The deal builds on Kimbell's existing Permian position which remains Kimbell's leading basin for production, active rig count, DUCs, permits and undrilled inventory.

The targeted oil and gas mineral and royalty interests are located in "core positions of the Permian" and Midcontinent, with more than 4,000 gross producing wells on more than 1 million gross acres, the company said in a press release.

The Permian represents approximately 64% of the reserve value, with approximately 36% in the Midcontinent, the company said. The acreage is concentrated in the Delaware (49%), Midland (10%) and Midcontinent (41%).

The Permian acreage consisted of 13,477 net royalty acres. The acreage includes 1,613 gross producing wells in Delaware and Midland basins with current net production of 2,362 boe/d, 72% liquids and 28% gas.

The seller's Permian acreage had 11 rigs actively drilling as of June 30, offering exposure to operators including **EOG Resources**, **Occidental Petroleum** and **ConocoPhillips** in the Delaware Basin and **Pioneer Natural Resources**, **Endeavor Energy Resources** and **SM Energy** in the Midland basin.

Kimbell expects the acquisition to be immediately accretive to distributable cash flow per unit, with an estimated "acceleration of accretion in 2024 and 2025."

• **SM Energy** completed a previously reported acquisition of 20,000 net acres in Dawson and north Martin counties, Texas.

The acquisition cost the company $90.6 million, less than the previously reported amount of $93.5 million. The transaction includes approximately 1,250 boe/d net production, approximately 90% oil, and is expected to house a rig in the fourth-quarter 2023.

Aside from this acquisition, the company scooped up an additional 2,800 net acres near its first quarter leasehold acquisition of 6,300 net acres in the Midland Basin.

• South Texas operator **Magnolia Oil & Gas** closed a $40 million bolt-on acquisition in the Giddings Field outside of the company's core development area.

Magnolia is focused on the Austin Chalk, where it holds 22,800 net acres in a well-delineated, low-risk position in the core of Karnes County, Texas. The company also holds about 460,000 net acres in the Giddings area, which it describes as a "re-emerging oil play with significant upside and what we believe to be substantial inventory."

Magnolia President and CEO Chris Stavros said the company remains committed to a disciplined approach toward capital spending, generating moderate annual production growth, attaining high pre-tax margins and providing steady and consistent free cash flow.

"Earlier this week we successfully completed a small bolt-on oil and gas property acquisition in the Giddings area for approximately $40 million," he said. "This asset purchase, which is outside of our core development area in Giddings, was a direct result of the extensive knowledge we have gained through operating in Giddings as well as some of our appraisal efforts."

Stavros also said Magnolia's board recently increased the company's share repurchase authorization by 10 million shares, allowing "us to opportunistically repurchase our shares into next year."

• After failing to find any deal opportunities in the first quarter, **Sitio Royalties** bounced back with several Permian Basin acquisitions in the second quarter.

Sitio closed multiple Permian deals valued at nearly $248 million in aggregate during the quarter, funded with 27% equity and 73% cash.

During the second-quarter earnings call, Chris Conoscenti, CEO of Sitio Royalties, said the assets were acquired for "no overhead" and credited Sitio's massive rebound to the relationships they have developed over the years with sellers.

"This relationship-based approach to generating and executing on minerals acquisitions is a true differentiator and has been a staple of our growth strategy for many years," he said. "We acquired these assets for less than 7x next 12 months' cash flow and, in aggregate, expect them to be approximately 6% accretive to our second-half 2023 discretionary cash flow per share at current strip pricing and a payout ratio of 65%."

Sitio's second-quarter acquisitions added 13,705 net royalty acres (NRAs) to its position in the Permian, which the company sees as a key focus area. The 13,705 NRAs are equal to 7% of its Permian Basin position. About 82% of the interests were picked up in the Delaware Basin and 18% in the Midland Basin.

• **WhiteHawk Energy** closed on the acquisition of Haynesville Shale mineral and royalty interests in northwestern Louisiana and eastern Texas, the company's second acquisition in the Haynesville this year.

WhiteHawk also announced it had entered into an acquisition finance facility with a "top tier institution" for $100 million. WhiteHawk did not name the institution. The company will draw $20 million from the facility to pay for the Haynesville acquisition from **Mesa Minerals Partners II LLC**, according to an Aug. 7 press release.

Earlier this year, WhiteHawk announced a $105 million acquisition of mineral and royalty interests in the Haynesville.

The company expects to utilize additional borrowing from the facility to fund future acquisitions of mineral and royalty assets upon the agreement of the institution.

WhiteHawk manages approximately 850,000 gross unit acres within core operating areas of the Haynesville and Marcellus shales, including interests in more than 2,500 producing horizontal wells. The company's Haynesville royalties cover approximately 375,000 gross unit acres in the play.

• **Strike Energy** has entered into a binding scheme implementation deed with **Talon Energy** to acquire all issued shares of Talon, according to an August announcement by Strike.

In addition, Talon intends to demerge its Mongolian asset in a move that will potentially benefit its shareholders. The company made it clear, however, that there is no guarantee this demerger will take place, nor that it will provide additional value for its shareholders if it does, according to the announcement.

Talon's board of directors has unanimously endorsed the scheme. Talon's Perth Basin business alone has an implied offer price of A$0.2122 (US$0.14) per share, which is an approximate 21% premium to the company's closing price as of Aug. 11. If the deal proceeds as expected, shareholders of Strike will own approximately 89% of all issued Strike shares, while Talon shareholders will own approximately 11%, according to the announcement.

As part of the deal, Strike has agreed to provide Talon with an interim convertible funding facility amounting to A$6 million (US$3.8 million), which will be used to fund Talon's capital requirements. The deal has the capacity to generate an initial annualized revenue of more than A$82 million (US$52 million) from the Walyering gas field alone, according to the announcement.

• **Empire Petroleum** has closed on the acquisition of **COERT Holdings 1's** interests in the three assets owned by Empire and located in New Mexico, the company said on Aug. 10.

The purchase price of about $6.7 million includes $5 million in cash by **EEF Acquisition**, which is a wholly owned subsidiary of Empire's largest shareholder, **Energy Evolution Master Fund.**

EEF Acquisition has been assigned an undivided 90% ownership interest in the assets. Empire has been granted a three-year option to purchase the interests for about $5 million.

"Since we acquired our New Mexico assets from **XTO** in May 2021, we have evaluated opportunities to increase our ownership position through the purchase of non-operating interests," said Mike Morrisett, president and CEO of Empire, in a press release. "We appreciate the support of EEF in the funding of the Transaction with COERT. This structure provides

Empire with additional flexibility to accelerate our targeted ongoing and future asset development programs designed to strategically grow the business and build near and long-term value for our shareholders."

SERVICES

• **Patterson-UTI Energy** completed the acquisition of **Ulterra Drilling Technologies**, a global provider of specialized drill bit solutions, in a cash and stock deal worth about $780 million.

The deal included $370 million cash and 34.9 million shares of Patterson-UTI common stock.

Patterson-UTI CEO Andy Hendricks said Ulterra's shared culture of innovation and commitment to superior service quality "make this a truly exciting combination."

"Ulterra's industry-leading position in the North American PDC drill bit market complements Patterson-UTI's longstanding history of operational excellence and innovation," Hendricks said. "This strategic acquisition, along with our recent announcement to merge with **NexTier Oilfield Solutions**, further advances our strategy to enhance our positions in drilling and completions."

Hendricks said the Ulterra portfolio provides key advantages to the company, including its presence in overseas markets.

In connection with the transaction, **Blackstone** entered into a voting agreement for Patterson-UTI's NexTier's $5.4 billion merger. Blackstone will vote the shares of Patterson-UTI issued in the transaction and held by the stockholder at the time of the Patterson-UTI special meeting to facilitate the merger with NexTier.

When combined with NexTier, Hendricks said the three companies will create the most comprehensive set of data for drilling and completions in the U.S., "enhancing our analytics capabilities and allowing us to better support our customers' objectives to improve well economics."

MIDSTREAM

• **TC Energy** is selling a 40% interest in its Columbia Gas Transmission and Columbia Gulf Transmission pipelines in a deal with **Global Infrastructure Partners (GIP)**.

TC Energy is divesting a 40% stake in the pipeline systems for $3.9 billion (CA$5.2 billion) in cash, the company announced in a July 24 news release.

The Columbia Gas and Columbia Gulf pipeline systems will be organized in a joint venture partnership between Calgary-based TC Energy and private equity firm GIP. The two companies will jointly invest growth capital to enhance the systems' capacity and reliability, in addition to annual maintenance and modernization investments.

TC Energy will continue to operate the pipelines after closing, which is expected to occur in the fourth quarter.

GIP is expected to fund gross capital expenditures of around $1 billion annually over the next three years to cover its 40% stake in the gas pipelines.

The Columbia Gas and Columbia Gulf pipelines, which TC Energy acquired in 2016 in a roughly $13 billion deal, collectively span more than 15,000 miles.

The nearly 12,000-mile Columbia Gas Transmission system reaches from New York state into major markets in the Midwest and Southeast. The roughly 3,300-mile Columbia Gulf Pipeline serves natural gas demand in Louisiana, Mississippi, Tennessee and Kentucky.

The Columbia assets also supply nearly 20% of the nation's LNG export capacity, according to TC Energy.

In November, TC Energy said it aimed to sell more than CA$5 billion in assets or minority positions in the company's 2023 divestiture program.

"To date, we have advanced our deleveraging goals by delivering on our $5 billion+ asset divestiture program ahead of our year-end target, while maximizing the value of our assets and safely executing major projects, such as Coastal GasLink and Southeast Gateway," TC Energy President and CEO François Poirier said.

• **Plains All American Pipeline (PAA)** disclosed that its subsidiary was the buyer of **Diamondback Energy's** 43% interest in a Permian Basin pipeline.

A subsidiary of **Plains Oryx Permian Basin** acquired Diamondback Energy's interest in the **OMOG JV LLC** for approximately $225 million with $145 million net to PAA's interest. The deal closed on July 28th.

The OMOG JV LLC operates about 400 miles of crude oil gathering and regional transport pipelines, as well as approximately 350,000 bbl of crude storage in Midland, Martin, Andrews and Ector counties, Texas, according to Diamondback.

• **WaterBridge NDB**, a portfolio company of **Five Point Energy**, has entered an agreement with **Devon Energy** to form a produced water infrastructure system, **NDB Midstream**.

In connection with the transaction, Devon and NDB Midstream entered into a long-term agreement in which Devon committed all of its produced water within a large area of mutual interest, including an initial dedication of about 52,000 acres and contribution of 18 saltwater disposal sites with about 375,000 bbl/d of permitted capacity.

The system consisted of approximately 210 miles of produced water pipelines for gathering, transportation, disposal and reuse.

As part of the deal, Devon received a 30% equity interest in NDB Midstream as well as a commitment by Five Point to fund a portion of the initial build of the system expansion.

The partnership between two technical leaders will yield the largest private water infrastructure system in the prolific Stateline region of the Delaware Basin in Loving County, Texas, and Lea and Eddy counties, N.M., WaterBridge said.

The partnership will provide Devon with a significant increase in permitted water handling capacity, "delivering both reliable flow assurance and access to abundant resources and infrastructure to support Devon's future drilling plans and the company's produced water reuse and recycling operations," said Greg Horne, Devon vice president of marketing and midstream who serves as a board member of NDB Midstream.

As part of the transaction, NDB Midstream is developing a large-scale water transportation, handling and recycling system in the area, primarily located on land owned by Five Point's land management platform, DBR Land. OGI

Are Non-Ops the New Alternative Financing for M&A?

Earthstone Energy CEO Robert Anderson talks about teaming up with non-op Northern Oil & Gas to buy Permian Basin operator Novo Oil & Gas.

DARREN BARBEE
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The $1.5 billion acquisition of Novo Oil and Gas—which closed Aug. 15—represents an unusual deal structure that may become more common.

The three-way deal between Earthstone Energy and non-op partner Northern Oil & Gas, which is footing one-third of the bill, was born of necessity, Earthstone CEO Robert Anderson said at the Texas Independent Producers & Royalty Owners Association (TIPRO) summer conference.

Anderson said he knew going into the evaluation of EnCap Investments-backed Novo's Permian Basin assets that "we weren't going to be able to write a check for a billion and a half dollars." He added that Earthstone wasn't eager to issue debt to EnCap, which is already the company's largest shareholder.

Instead, the company turned to NOG, with talk of a creative partnership on the deal from the very beginning.

"That was key … getting into the valuation from day one," Anderson said. "Second of all, it was being like-minded that [Northern] buy the asset or value the asset the same way an operator does and not like some financial institution that may haircut PDP [proved developed producing] non-op at a much greater discount."

That meant that Earthstone would have to make some concessions to NOG and commit to a drilling program, Anderson said.

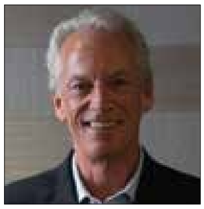
"It handcuffs us a little bit, but we underwrote a certain number of wells per year, anyway," he said. "So, they were a great partner."

For NOG, it was the second such deal this year in which it has paired with a company in a transaction. In June, it closed on a similar purchase of a 30% non-operated stake in Forge Energy II Delaware in a deal that paired it with Vital Energy.

Asked on the sidelines at TIPRO whether non-operated companies might be regular partners for acquirers going forward, Anderson told Hart Energy it depends on several factors.

"It's operator-specific personally, and it's the size, but I think it could," he said. "I don't know that it's public or private. It's more the size of the transaction.

"Access to capital is a little bit hard, right? So, if you can bring in a partner that sees eye-to-eye the way you see the asset, it's better to have 50% of a good thing than 100% of a bad thing for your company."



"Access to capital is a little bit hard, right? So if you can bring in a partner that sees eye-to-eye the way you see the asset, it's better to have 50% of a good thing than 100% of a bad thing for your company."

—Robert Anderson, ***CEO, Earthstone Energy***

Anderson noted that reserve-based lending has become far more expensive, as well. Some 18 months ago, rates for RBL debt were 3% and have since skyrocketed.

Anderson noted that as far back as 2007, he has used a similar strategy with a third party to buy assets in the Giddings Field.

"I'm used to carving down the assets so that we can swallow [an acquisition]," he said, noting that maintaining contacts and knowing the NOG team led them to partner.

Looking to future Permian deals, Anderson gave a sober assessment of the deal landscape.

"I think it's going to get harder," he said. "I think there's just going to be less Permian deals. So, we're going to start to have to look at maybe the fringe plays or plays that don't have three or four–seven zones like we see in the central part of the core of New Mexico.

"And it's going to get harder for the acquirers. And then scale, too, right? The big guys are looking for very large transactions. There's probably only a few of those left."

But, referring to a talk earlier at TIPRO by NGP Energy Capital's Patrick McWilliams, Anderson said he is encouraged by private equity firms that are raising money.

"All these private equity firms are raising money. They've got to put it to work somewhere. And those guys [have] the creative juices that will create the next play for us to take a look at." OGI

Paisie: Oil Demand to Eclipse Supply

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.

In our June article, we put forth the view that oil prices would move upward, in part because OPEC+ would remain proactive in adjusting supply. During the last month, this view has proven to match actual market dynamics, with OPEC+ further reducing production (mainly Saudi Arabia and Russia) and in response, the price of Brent crude breaking through the 200-day moving average and increasing from \$74.65/bbl at the beginning of July to \$86.24/bbl at the close of the week ending Aug. 4.

Where oil prices go next will be driven, as usual, by a combination of supply/demand fundamentals and other factors, including macroeconomics, geopolitics and sentiment of oil traders.

We are forecasting that oil demand will outstrip supply during the third and fourth quarters, with global oil demand increasing by 1.9 million bbl/d during the third quarter in comparison to second-quarter 2023, and by an additional 100,000 bbl/d during the fourth quarter. China's demand is forecasted to increase by 220,000 bbl/d during the third quarter and by an additional 480,000 bbl/d during the fourth quarter.

While we are forecasting increased oil demand, we are also expecting that the market will remain concerned about the challenges being faced by the major economies (U.S., China and EU).

Although the U.S. economy has been growing, as evidenced by the Commerce Department's initial estimate for second-quarter GDP growth of 2.4% on an annual basis, nearly half of the economic growth in the second quarter was contributed by consumer spending, which is occurring while consumer debt is at an all-time high, as is the interest rate being applied to the debt.

The latest data pertaining to China's economy continue to indicate that economic growth will remain muted because of weakness associated with China's manufacturing sector, slowing growth in the service sector and a debt-ridden property market. Additionally, China's inward foreign direct investment declined to the lowest level since 1998 in the second quarter.

Europe continues to be hindered by elevated inflation and increasing interest rates, and is likely to face further energy-related challenges in the coming months.

There are increasing geopolitical risks that could affect the oil market. Despite the recent peace talks taking place in Saudi Arabia, the Russia-Ukraine conflict continues, with Ukraine ramping up attacks on territory outside of Ukraine, including the recent attack on Novorossiysk, where Russia has a Black Sea port. It is also near where the Caspian Pipeline Consortium (CPC) operates an oil terminal for transporting oil from Kazakhstan.

While the attack only resulted in a temporary ban on the movement of ships in the CPC water area, such an attack highlights the risk of the conflict expanding and having an impact on oil-related infrastructure. Developments in the Persian Gulf involving Iran exhibit another conflict that presents risks for oil-related infrastructure. Recently, Iran has armed its Revolutionary Guards' navy with drones and missiles with a range of 600 miles. Concurrently, the U.S. has offered to place guards on commercial ships going through the Strait of Hormuz.

The sentiment of the oil traders has shifted from bearish to bullish. During the last five weeks, the net long positions of traders of WTI positions have increased by 188% and are now at the highest level since April 18. The net long positions of traders of Brent have also increased substantially during this period.

Looking forward, we think that oil prices will moderate moving into fourth quarter, in part, because the gap between demand and supply will not be as great as some market participants are currently expecting. While there have been announced production cuts by some members of OPEC+, other producers have been increasing production. For example, Libya's production has been restored since the disruption earlier this month from internal conflict. Nigeria's production reached nearly 1.25 million bbl/d in June, which is an increase of 25,000 bbl/d in comparison to May, and Nigeria is looking to increase production to 1.7 million bbl/d by November. Furthermore, Venezuela increased its oil exports in June to around 716,000 bbl/d, which is an increase of 8% above its May exports. We are also forecasting additional supply from non-OPEC producers.

An upside risk to the price expectations stems from geopolitics that would result in disruption to oil production and oil movement. As highlighted above, such a development could come from the Russia-Ukraine conflict and from the tensions between Iran and the U.S. A downside risk to the price expectations stems from an economic downturn, which remains a possibility, given the underlying fragility of the major economies. A mitigating factor for the upside risk is the spare production capacity that could be brought online in the event of a geopolitical-related event. A mitigating factor for the downside risk is that the central bankers could shift away from tightening to more accommodating monetary policies; however, we view the downside to be a more substantial risk than the upside. OGI

Stocks Hang Tough in a Rough First Half

Energy led the S&P 500 in 2022, but macroeconomic factors have weighed down the sector this year.

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The energy sector lost its perch as the top performer on the S&P 500 during the first half of 2023, but a regimen of capital discipline has helped to insulate an industry historically hypersensitive to boom and bust cycles.

The S&P's measure of the sector's performance—which includes upstream, midstream and downstream companies—showed that between Jan. 3 and June 30, overall stock values fell nearly 4%. Only the utility sector did worse, dropping nearly 8%. Analysts said macroeconomic factors such as plunging commodity prices hurt the energy sector's standing, but a focus on low debt and efficiency has also brought resilience.

A 12-month performance snapshot reflecting July 26, 2022 to July 26, 2023 shows the energy sector with upside of nearly 18%. A fading likelihood of a recession is helping the industry's prospects in the second half of 2023, analysts said.

The performance numbers are from the S&P select sectors. S&P Global states that each sector "is a highly-liquid index designed to track a major economic sector. The indices are intended as tools for investment professionals, allowing them to tailor benchmarks for core portfolios by accounting for changing market conditions."

S&P Global would not release the full list of companies in the S&P Energy Sector. Yardeni Research said the index is made up of three integrated oil and gas companies—Exxon Mobil, Chevron and Occidental Petroleum; 13 E&Ps, including Marathon Oil and Pioneer Natural Resources; three refining companies, including Phillips 66; and four oil and gas storage and transportation companies such as Kinder Morgan.

The index performance underscores a common refrain among oil and gas executives who lament that the space remains undervalued. Nevertheless, they continue to boost dividends. Low share prices have also made it cheaper for companies to repurchase shares.

The level of decline varied among individual companies' stock performance.

During the first half of 2023, shares of Devon Energy fell 17%, Chevron's stock fell almost 11% and Exxon Mobil's shares rose less than 1%. Natural gas giant EQT gained almost 23% per share, and stock in oilfield services firm Baker Hughes increased 9% for the period.

Stock market performance analysis is a moving target, and each comparison is a snapshot.

"You're coming off its best outperforming year in over a decade," said David Deckelbaum, managing director at TD Cowen.

David Deckelbaum

"The intent of the return-on-capital model was to lower volatility of investments over time, so I think in the range-bound commodity world, the stocks have actually been fairly resilient. I think a lot of that is balance sheet strength and this return-of-capital approach that lowers that volatility," he said.

Mark Sadeghian, a senior director at Fitch Ratings, said last year's higher commodity prices are relevant to the sector analysis.

"Pricing was exceptionally high. WTI had an average of around $95. If you look at where we've been year-to-date, which would include the first two quarters, WTI has been around $75, so it's a $20 drop and it's 21% drop," Sadeghian told Hart Energy. "Henry Hub natgas has been even worse, in a certain way. It was $6.50 or so last year, and now it's … sub $2.50," or a drop of more than 60%.

He also said many energy companies are better suited to withstand any downturn with the better balance sheets and lower debt that are hallmarks of the industry's current strategy of greater discipline and responsibility.

Scott Lander, chief investment officer at Horizon Investments, said the greater responsibility does not matter to his firm as much as a lower likelihood of a global or U.S. recession.

"They just need to run their business. I couldn't care less what they are doing on the responsibility side," Lander told Hart Energy. "They're doing what they are supposed to be doing on that front."

Lander said Horizon Investments will invest more in energy companies this quarter; he declined to offer specific investment figures, but did say its engagement will go from a meaningful underweight position in energy to a meaningful overweight position.

Ryan Keys, founder and president of Triple Crown Resources, said the larger picture shows energy companies in strong health, with no bankruptcies and some companies with low debt and good returns. With these strengths—and a change in commodity prices—investors could come sprinting back to energy once again.

"It might take a year or two to get there," he said. "Those who pile in later are going to miss the boat." OGI

Kissler: Buffet and LNG—What Does it Mean?

Market Watchers

DENNIS KISSLER
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Dennis Kissler is SVP of Trading for BOK Financial Securities. He is based in Oklahoma City.

In case you missed the news, Berkshire Hathaway, owned by multi-billionaire Warren Buffett, has agreed to purchase an additional 50% stake in the Cove Point LNG facility—a move with a $3.3 billion cash price tag. While that's chump change for the "Oracle of Omaha," the move is being interpreted by some as a bet on energy infrastructure—and it's certainly raising public awareness of LNG.

Although Berkshire Hathaway's recent purchase has turned some heads, it's not the company's first foray into LNG—or Cove Point, for that matter. Berkshire Hathaway Energy, which is a unit of Berkshire Hathaway, already operates the Chesapeake Bay, Md.-based facility. The recent purchase puts its total ownership at 75% upon closing, while a unit of Brookfield Infrastructure Partners owns the remaining 25%.

Nevertheless, while Buffett's latest move is not his entrance into the LNG space, it can be read as signaling his commitment to it. After all, Cove Point is one of the few functional facilities in the country that can export LNG. This commitment is something both LNG producers and natural gas investors should feel very positive about. Berkshire Hathaway's purchase has generated broader attention to not only LNG but also the energy needs that will need to be met in the future as the global economy moves toward cleaner burning fuel.

What this means for LNG and gas producers

In the long term, LNG likely is going to be the price savior for gas producers. I think we'll see more LNG terminals, as well as expansions, constructed. Cumulative movement of LNG is expected to increase approximately 57% from second-quarter 2023 to second-quarter 2026. That figure could actually be higher, depending on government legislation. I also believe LNG's growth will alleviate a lot of the excess natural gas supplies that we are currently seeing in storage facilities, as well as some of the gas production today that is landlocked. It's important to remember that gas pipeline infrastructure is still lacking in the Northeast. Hopefully, that will change somewhat.

While the Mountain Valley Pipeline is an on-again/off-again project, I do believe it will be having some flow by 2025.

Looking globally, Asia's consumption of LNG had been down in recent months, partly due to China's weaker-than-expected economic rebound. That has been good news for Europe, as the region has been using LNG to replace pipelined Russian gas. However, China is currently constructing multiple mega-power plants. These plants will be powered by natural gas that will be supplied mostly by LNG, so Asian demand likely will expand substantially over the next couple of years.

Meanwhile, the Russian-Ukrainian conflict likely will persist and become more volatile once we move into late fall and early winter. That, of course, will continue to impact the energy market, but no matter the outcome of the conflict itself, Europe's appetite for U.S-supplied LNG isn't going away anytime soon and possibly will increase. That said, a colder than normal winter in the U.S or Europe, or both, could change gas prices very quickly.

On that note, gas prices have been below expectations due to a mild May and June weather pattern in the U.S. While July has been very hot in southern and western states, the average of overall U.S cooling demand days has actually come in below the last three years' averages to date, hence the excess storage. European gas storage has also refilled at a much quicker rate than most analysts expected, due to both the weather and continued gas flows from Russia. Consequently, looking forward, a possible winter squeeze on prices like we witnessed back in 2022 is becoming less probable.

And so, while Buffett's latest move is positive in the sense that more people know what LNG is, the bigger story is what LNG can do for the energy market in the short- and long term. We might now get an answer to the two natural gas market woes—excess supplies and landlocked production—and a stride forward to meeting the cleaner-burning energy needs of the future. While forward prices will still be hard to predict, it seems LNG should place a more solid floor under natural gas producers. OGI

▸ M&A

NOG's Non-Op M&A Strategy 'Will Keep Us Very Busy,' CEO Says

Northern Oil & Gas landed some of its biggest transactions to date in recent months, including several in the Permian Basin. In a Hart Energy exclusive interview, NOG CEO Nick O'Grady and President Adam Dirlam said they see a long runway for the E&P's non-operated M&A strategy.

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Northern Oil & Gas has been on a hot streak of acquisitions, particularly in the Permian Basin. In mid-August, Minneapolis-based NOG closed a deal to acquire a 33.33% stake in EnCap Investments-backed Delaware Basin E&P Novo Oil & Gas for $500 million—NOG's largest deal to date. Earthstone Energy is scooping up the other 66% interest in Novo for $1 billion.

NOG closed a $167.9 million acquisition of Delaware Basin assets from Forge Energy II, another EnCap portfolio company, in late June. Vital Energy, which will operate the assets, agreed to purchase 70% of Forge's assets for $378 million, with NOG purchasing the remaining 30%.

Earlier this year in the Midland Basin, NOG boosted its non-operated stake in the Mascot Project up to a 39.958% working interest. NOG had initially acquired a 36.7% interest in the project for $320 million in October 2022.

NOG is also making strides in its ground game, completing 13 mini-transactions that are expected to add more than 16 net wells to production in the coming years, the company reported in second-quarter earnings released in August.

In an exclusive interview with Hart Energy, NOG CEO Nick O'Grady and President Adam Dirlam said the company sees a nearly endless stream of opportunities to acquire disparate non-op interests in its development areas. The company has also considered expanding its footprint into new regions—if NOG can find the right deal.

Chris Mathews: NOG has announced several deals recently—including the Novo acquisition, NOG's largest transaction to date. How has the company's M&A strategy evolved over time?

Nick O'Grady: I think some of the evolution you've seen, just from the structure of our deals, is less a function of us changing our strategy. As the business has become larger, we're capable of doing things that maybe always existed, but we did not have the capability when we were smaller, either from a risk or financial perspective.

I think I'd be very resistant to saying that we are evolving the business model into something else. I think if it's evolving, it's just that we can do three or four discreet businesses where once we did one or two.

In the life cycle of A&D, I think that, at least for the time being, we're close to a crescendo in terms of the volume of private M&A going on—meaning you've seen a lot of M&A activity in the last 12 months. A lot of sponsor companies are finally being sold. I think that you're in the tail end of that.

There's still some to go. There are still an inordinate amount of companies that need to find a permanent home at some point, but maybe not of the same scale.

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"I think we would love to grow our gas properties, especially in Appalachia. We're actively looking there."

—**Nick O'Grady,** *CEO, Northern Oil & Gas*

On the non-operated side, there are so many billions of disparate non-op interests that exist out there. I think that that's a business that will keep us very busy for a long time.

Adam Dirlam: I think the co-buying or buying down minority interests in an operated asset really is the function of our scale. We've been doing this for the past few years. It just hadn't necessarily gotten to the level that might've been press release-worthy.

We've been partnering with operators across all our respective bases, helping them out as a capital provider, but really focusing on alignment and being an equitable partner.

I think the drillcos of old left a bad taste in a lot of operators' mouths. We've talked to a number of operators, both big and small, and at the end of the day, they wanted something that was different from a structural standpoint.

And our ability, especially as an engineering-centric E&P company, to approach the underwriting in an equitable fashion, has given us a leg up to really consider both the social and the operational dynamics as you perpetuate the development of these assets.

NO: What I think Adam is getting to is that we're a permanent owner of these assets. We're willing to take risk. We're not trying to turn it into a security in which all that risk is borne by the operator, and then somehow we want to go away at some point.

That trumps the cost of capital—being a fair and equitable partner. And what we need on the other end is for it to be fair and equitable.

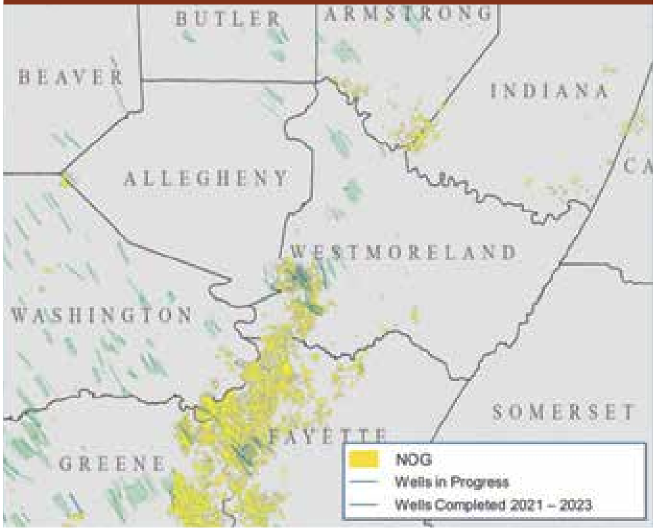
What we try very hard to do, and you'll see me talk about this in our public statements, is we really believe in a portfolio management approach. And we have a portfolio theory: keep the diversity of the business, the diversity of operators and interest and partners.

We have problems every day, but the goal is to keep those problems relatively small, not to have all your eggs in one basket. Relationships are really important to us, but I think really when it comes down to it, is that we want to be a fair transacting partner, not necessarily to be in bed with one person or another for personal reasons.

AD: That's right. We're looking at true non-op packages day in and day out. We've got our ground game strategy, which is kind of the micro-acquisitions, where you're dust-busting disparate interests.

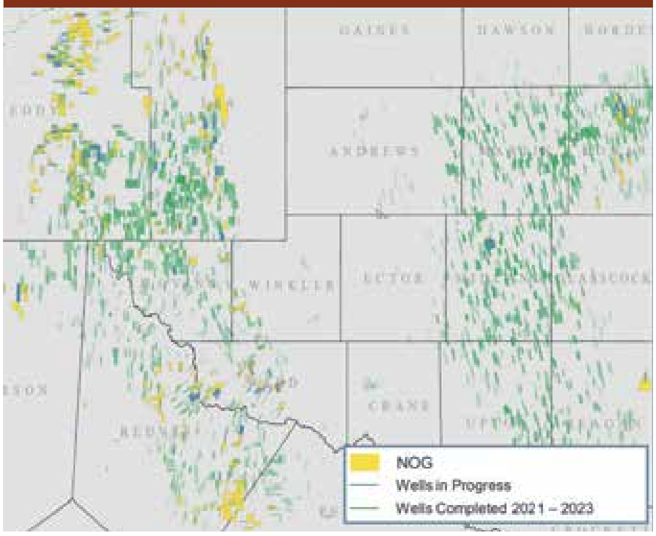
The business model lends itself to the ability to stay

Marcellus Acres: ~57,500 net acres



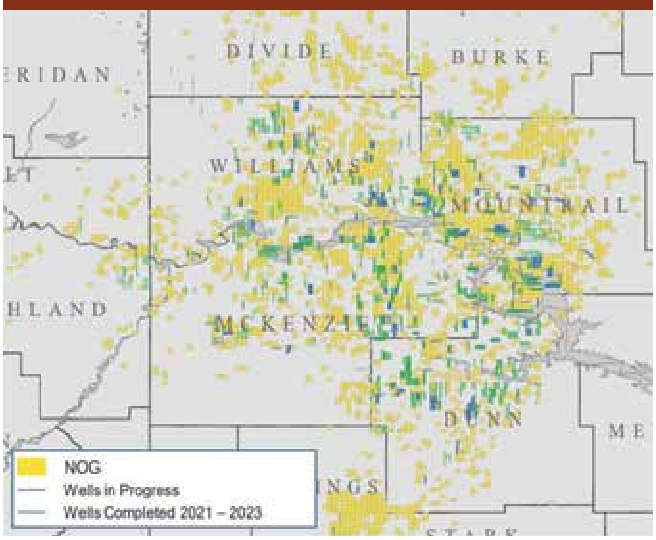
NOG's footprint in the gassy Marcellus play

Permian Basin: ~30,400 net acres



NOG's footprint in the Permian Basin

Williston Basin: ~180,400 net acres



Source: NOG

NOG's legacy footprint in the Williston Basin of North Dakota and Montana

within the core of our respective base ends, which then gives us the ability to maintain our return on capital employed. So, we don't necessarily need to scale the business by stepping out into Tier 2 and Tier 3 acreage.

We continue to see hundreds of opportunities throughout each and every quarter, and it really gives us the opportunity to be picky and keep our hurdle rates where they need to be.

CM: What are the benefits to spreading your eggs—your non-op interests—around multiple baskets, versus keeping them all in one?

NO: One thing that's notable about Forge and Novo—as well as a lot of the transactions we've done that have been more traditional non-op—is that even when we go down to the ground game level of when development is being sold, the dollars are important to what your competitive landscape is, but it's also the concentration.

Buying 10 distinct 10% interests versus one 100% interest has a big impact on that risk management. When you're a portfolio of 9,000-plus wells, we can take that 100% interest-type scenario. That's certainly not the normal case for us to take something that high, and our average is still less than 10% as a portfolio.

The point being that it's not just that it's $50 million, but $50 million concentrated in a few things can disqualify a good portion of our competitors. Because even if they had the money, they can't take a 50% interest in one well or something like that.

AD: I think the risk factors are effectively equal. But if one thing can go wrong on a large working interest with a small base, that could potentially tip over a small non-operator. What that gives us the ability to do is raise our discount rate and still get things done.

CM: Is NOG interested in expanding into new basins through M&A?

NO: I think you don't need to look far from where we already are. I think we would love to grow our gas properties, especially in Appalachia. We're actively looking there. I think that's one that we have optimism that we can do. Given the nature of the land and other issues in Pennsylvania, it really has to be very specific to certain things.

The Permian has as many rigs as the rest of the United States combined. As you can imagine, the volume of things going on, the fractional nature of the ownership across [the Permian], it creates a ton of opportunities.

And in the Williston—which is our legacy asset—we continue to surprise ourselves with significant opportunities. We're going to hit record volumes in the Williston this year, which is interesting. It's not that we have de-emphasized it in any way, it's just that other things have grown faster. But we have continued to find ways to grow the business there.

AD: And that's a testament to the active management, right? We're not just buying a piece of land and then waiting for the rigs showing up. We're actively targeting the operators in the areas that we want to be in and then getting in ahead of the drill bit.

CM: Some of your biggest deals have been in the Permian Basin. What's the state of Permian M&A? How competitive is it out there?

"We're not just buying a piece of land and then waiting for the rigs showing up. We're actively targeting the operators in the areas that we want to be in and then getting in ahead of the drill bit."

—**Adam Dirlam,** ***president, Northern Oil & Gas***

NO: I think for the first time in about 20 years in the United States, you really have sudden fears both from investors and Wall Street that shale is reaching its zenith in terms of locations; that it is a finite amount. Suddenly, inventory has become precious.

A few years ago, when it really came down to just survival, I think a lot of operators were more focused on generating cash and deleveraging, and not necessarily about replacing that inventory. Of those larger, chunkier private opportunities, there's been a bit of a feeding frenzy in some of the cases. And it's varied from deal to deal, to be candid in our view, at least from how we look at these assets.

There has been a tale of haves and have-nots, where some of the midsize public companies have been in a replacement cycle or rejuvenation cycle—that's why you've seen a slew of transactions.

In terms of the larger scale of those, at least from a sponsor perspective, they are starting to peter off. There are a number of very large private companies that could sell at a moment's notice. But in terms of sponsor-backed stuff, I think you're probably in the seventh or eighth inning of that for the time being.

There are smaller targets that aren't necessarily going to grab the attention of the larger operator, and they may get sold at some point, or may merge into other midsize entities.

The trend of the number of publics has been shrinking. I think you're likely going to see more potential mergers in the public sphere than you're going to see new IPOs, in my opinion.

While [the Permian] is still very early in its life, as it goes to full development the finiteness of that inventory has created interesting opportunities for us.

Really, we were a later entrant to the Permian—which meant on one hand, we didn't buy something and make 10x on it. But on the other hand, we didn't buy something and get a donut. It meant that we had a lot more well control and surety and data to make sure we weren't going to do something inordinately stupid.

We really focused on New Mexico. It has benefits from a land perspective in terms of forced pooling that are good for a non-operator. It has the consistency that we see in the Williston and in the Midland Basin but with the higher pressures and returns that you typically see in the Delaware. It is more expensive to drill and more variable, say, than the Midland.

But what that has meant is finding the right operating partners to attack inventory is critical: whether it be Vital and their path for Forge, which was critical, or Novo. We both had a ton of existing land around the Novo acreage, as did Earthstone.

So, we felt that both were the logical party. Earthstone in particular should have some synergistic effects on cost given their existing operations in the area.

CM: You mentioned gas properties—what's the appetite like to acquire more gas-weighted assets?

NO: The things that concern us about gas … the contango in the strip has the industry not reacting to a pretty hard down move than it should, in our opinion, which could potentially mean that it drags on a period of lower prices longer.

I think people are, very rightfully so, excited about a material uptick in export capacity for global gas demand for the United States, and I think those are valid points. I think what concerns me personally is that if the U.S. supply is not reacting to current pricing at all, are you effectively building that inventory of gas in advance of that? It's been very hot this summer, which I think has kind of softened the blow of what you might have otherwise seen.

But I have not seen producers react, and they're drilling through it to some degree. That gives me a little bit of pause medium term versus people's expectations. It's like everybody is pivoting for something that may not come because they're all pivoting towards it.

Longer term, I think that gas has a very bright future. It's a lot easier for Adam and I to evaluate gas properties in a more normalized environment than it was last year when it was $6 or $8, the highest prices in a decade. It's very hard to want to buy things during that period.

I think that there is still long-life inventory in gas. I think the Haynesville is a phenomenal play at a certain price. It is also one of the older gas shale plays, relative to its overall physical size. So, I think the inventory—it's maybe not in the eighth inning, but it's not in the third inning anymore, that's for sure.

The challenge there is that, effectively, anything you work to develop or do in the short- to medium term is likely a money-losing proposition. Really, it would be a target towards the longer term.

Appalachia, I would say some of the core areas have largely been developed at this time, but it is a massive land footprint. We own one of the less developed areas, and I think we've got 20 years of inventory on our own asset. I think we bought the asset for that option.

AD: When you saw $7, $9 gas, you had a massive bid-ask spread. Now, you've kind of slipped that on its head and you still have a bid-ask spread that you could drive a truck through. So, I think we'll continue to stay disciplined and opportunistic.

To your question about looking out of basins, we continue to keep our ear to the ground with the Haynesville, the Eagle Ford and a number of other different basins.

But those are generally going to be higher-bar areas for us to expand in, especially if you look at it from a relative perspective with the opportunities that we see within the Permian, within the Williston, within the Marcellus. We can continue to bolt-on properties there—and we will, if there's an opportunity that we can't pass up because of the return thresholds.

In an outside basin, that's definitely something we'll also take a hard look at. OGI

THE OGI INTERVIEW

Watch the video interview here:

Southwestern's NEW DIRECTIONS

CEO Bill Way has shifted Southwestern Energy's course from Fayetteville founder to dual-basin natural gas powerhouse. Now, the E&P aims to be the LNG sector's top supplier.

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The Arkansas Western Gas Co. was founded in 1929 as a subsidiary of a larger Dallas gas player.

Fast forward 94 years, and the renamed Southwestern Energy Co., which was renowned for discovering the Fayetteville Shale natural gas play in Arkansas, is no longer even active in "The Natural State."

Instead, Southwestern last year transformed itself into the largest dual-basin gas producer in the country, focusing its attention on Appalachia and, most recently, the Haynesville shale gas plays with headquarters just north of Houston.

Southwestern, often pronounced in shorthand as "Swin" for the "SWN" stock ticker, aims to capitalize on the growing global LNG market now that it has established its Haynesville position and has the capacity to move its Appalachia gas to Louisiana via pipelines, and then to rapidly growing LNG hubs along the U.S. Gulf Coast.

In August, SWN reported second-quarter production of 4.65 Bcfe/d, down slightly from 4.81 Bcfe/d during the same time period last year. Likewise, profits fell from a whopping $1.2 billion in second-quarter 2022 to $231 million this year.

It's a dramatic difference, but there were extenuating circumstances. Henry Hub spot prices for natural gas in August 2022 reached a sky-high average of $8.81/MMBtu; the price was hovering near $2.70/MMBtu in mid-August, according to the U.S. Energy Information Administration (EIA).

The bottom line is that SWN is keeping costs down, reducing activity slightly and remaining profitable while awaiting the next wave of global LNG demand as new U.S. export facilities come online and prices respond correspondingly.

Southwestern President and CEO Bill Way has overseen much of the recent transformation. A Houston native, Texas A&M University Aggie and the ninth of 12 children, Way made his bones working around the world with gas and LNG for ConocoPhillips and the BG Group before joining SWN in 2011 as the COO and taking over the CEO role in 2016.

SWN was growing a sizable Appalachia footprint during this time, having made big buys from Chesapeake Energy and others. But then the deal-making under Way took off.

First, in 2018, SWN sold its legacy Fayetteville position for nearly $2 billion, deciding to focus on the East Coast. And just as Southwestern was struggling with a stock price under $2 per share in 2019 and during the height of the pandemic in 2020, SWN bought bigger into the Appalachia with the purchase of Montage Resources for about $850 million.

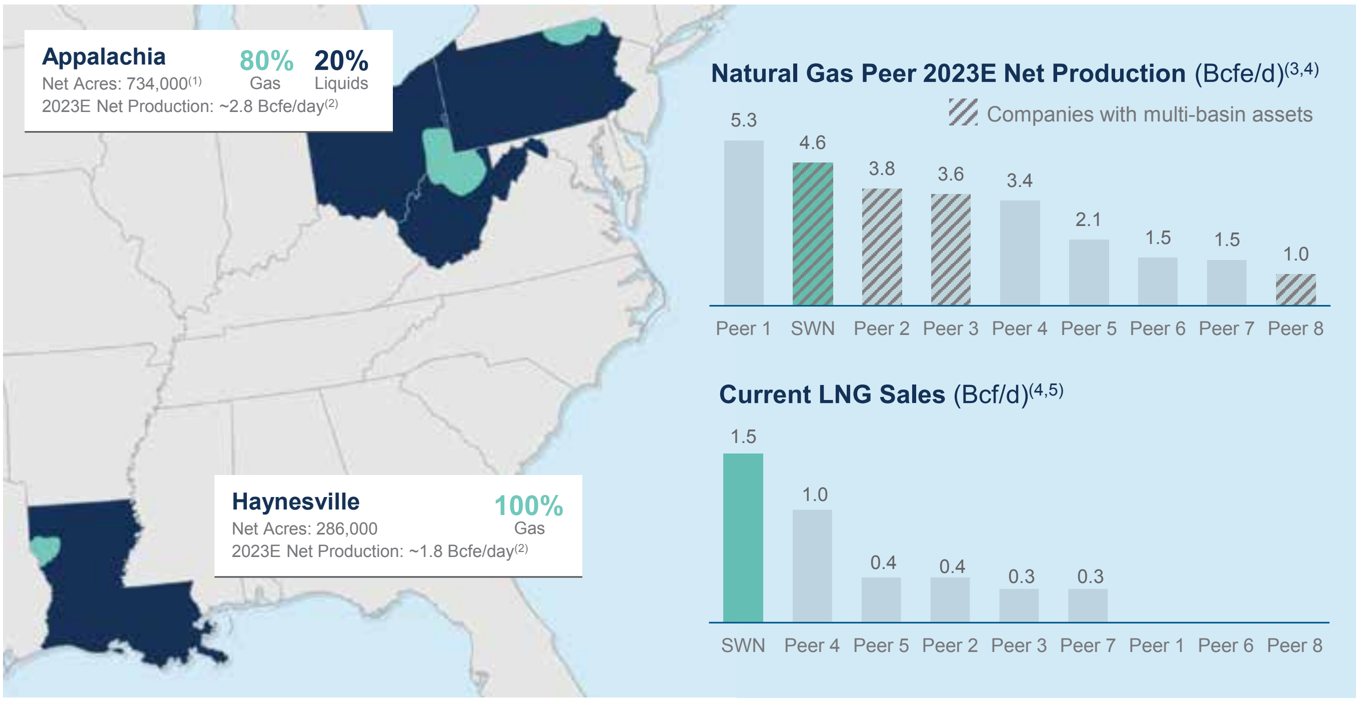
Then the bolder and bigger, rapid-fire buys into the Haynesville unfolded in 2021 and 2022. First came Indigo Natural Resources for $2.7 billion and then, just five months later, GeoSouthern Energy's GEP Haynesville for $1.85 billion. Quite abruptly, SWN was the largest Haynesville producer and the biggest dual-basin gas player.

With a rising market capitalization value above $7 billion as of mid-August, SWN holds more than four times the investment value it did from lows just prior to the pandemic.

Way sat down with Hart Energy to discuss the growth, challenges and the promising future.

Jon Shapley

Largest dual basin natural gas producer



Source: SWN

1) Pro forma for Pennsylvania Utica asset sale in June 2023
2) Based on midpoint of guidance
3) Based on midpoint of company provided guidance and most recent SEC filings
4) Peers include AR, CHK, CNX, CRK, CTRA, EQT, GPOR and RRC
5) Based on publicly available materials and SWN estimates

Jordan Blum: You came from BG before it was acquired by Shell in 2015, so that turned out to be pretty good timing on a number of fronts, right?

Bill Way: When I was at BG, we bought half of Exco [Resources] so that we could learn how to do shale. So, I had an early entry into the Haynesville. Doing that at a major company is quite challenging because of the cost and the agility and the flexibility you need. But it was perfect having experienced that level of tension between a major global leader and 'how do you get the economics and the margins to make shale work?' And so it felt like a very natural fit to take what I had experienced at BG, where I had accountability for their shale development along with operations. Then I come here and keep us from growing into this cost-centered behemoth of a company like so many tried to do. You look back in the old days of shale, and the ability to drive margins up and costs down eluded a lot of large companies.

JB: Bigger picture, can you to talk about the transformation of Southwestern from a small Arkansas gas company so long ago to unlocking the Fayetteville Shale to no longer being in the Fayetteville, but having all this big Appalachia and Haynesville footprint now?

BW: The genesis of that came from better understanding margins. In the commodity business, margin is everything. Cost management is important, and you've got to invest in the properties that you own, or you have to ask yourself, why do you have them? I come here and am a part of the discussion of shifting our investment from Fayetteville, which we discovered. We had drilled thousands of wells. We had quite a mature business on our hands, and the economics for the Northeast were significantly ahead of the Fayetteville economics. So, we made a case for change and went to the board [of directors] and got approval to basically exit the Fayetteville, the foundational asset of the modern company, and to shift that capital to Appalachia and begin to accelerate the growth.

So, we began expanding our [Appalachia] footprint both from acquisitions of land all the way through drilling and completions and growing that spot.

Now, in the Haynesville we have a core mandate, which is, you will have firm transportation from field to market of choice, or you will not acquire, or you'll not develop a major piece of the business. Doing that enabled us to assure ourselves that we're going to get the returns that we wanted because of the gas reaching the market.

Part of this was the pre-2019-2020 era of low share price, low gas price, COVID and all these other things that were going on. We examined our state of play, and while we had grown in the Appalachia to a degree, we were unable to continue to grow at the rate that one needs to build the scale to differentiate yourself in the pack. And so, during all of the things that were going on with COVID and everything else, we shifted our focus on how we build a growth strategy, and what do we want that to look like.

We had been a dual-basin supplier when we had Fayetteville and Appalachia. So, that wasn't an issue for us. It was a question by a number of investors: Are you sure you want to go through a dual-basin kind of thing? And we said, 'Well, we're a gas company first and always, and if we're a leading gas company, we ought to be in the two leading basins in the country.' And so it was natural and logical for us to make that shift.

We picked the most prolific, the highest-return companies that we wanted, and we went after them in a very disciplined, very focused, very methodical way, so that we were making the right choice at the right time with the right economics. The process was transparent enough that our board could

"We're in the hottest, highest-pressure area in the basin, and we can drill and complete wells at a reasonable, but not reasonable enough, cost. We're continuing to drive that down."

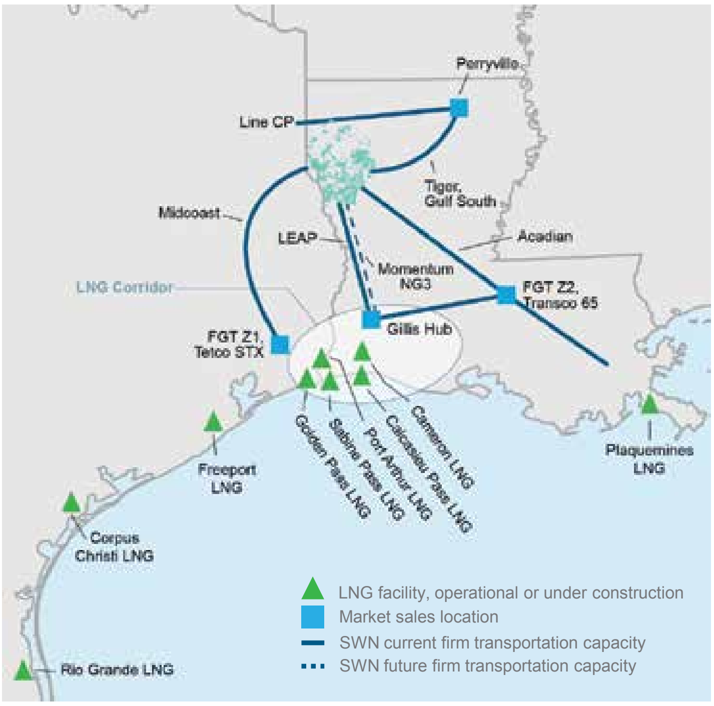
—**Bill Way,** *CEO, SWN*

Jon Shapley

Optimizing access to premium Gulf Coast markets

SWN Gulf Coast Transportation Portfolio[1]

LNG Corridor	2023E	2024E
LEAP [2]	1.2 Bcf/d	1.5 Bcf/d
Momentum NG3	–	0.3 Bcf/d
Acadian	0.2 Bcf/d	0.2 Bcf/d
Midcoast	0.2 Bcf/d	0.1 Bcf/d
Other [3]	0.2 Bcf/d	0.2 Bcf/d
LNG Corridor	**~1.8 Bcf/d**	**~2.3 Bcf/d**
Greater Gulf Coast	**2023E**	**2024E**
Gulf South	0.3 Bcf/d	0.3 Bcf/d
ETC Tiger	0.3 Bcf/d	0.3 Bcf/d
Enable CP	0.3 Bcf/d	0.3 Bcf/d
Rover	0.3 Bcf/d	0.3 Bcf/d
MXP / GXP	0.2 Bcf/d	0.2 Bcf/d
Greater Gulf Coast	**~1.4 Bcf/d**	**~1.4 Bcf/d**
Total	**~3.2 Bcf/d**	**~3.7 Bcf/d**



Source: SWN

1) Company will optimize future transportation and may not elect to extend all transport
2) LEAP capacity increases to 1.15 Bcf/d in the second half of 2023
3) Columbia Gulf Delivered and TGP 500L

opine and approve, and our shareholders could vote for it, and they understood how we put it all together. Our entry into the Haynesville then jettisoned us from a meaty or robust player in Appalachia into a dual-basin, significantly larger enterprise with cost economies and access to markets we didn't have. We're the largest supplier of natural gas to the LNG sector today in the U.S.

JB: Are you looking now at doing more direct LNG contracts?
BW: As we look forward in time and study whether we're going to be in the international LNG price market or whatever, we have a deep understanding from inside, and we're spending time with current companies, including some of the major ones we supply, to learn more and more about the market should we could choose to get in.

We don't feel pressured. We have plenty of time, and we have plenty of volume and reserves co-located, so we're advantaged—no matter what—when we get there. We have the ability to now get Appalachian gas to Louisiana, and Louisiana gas to the Gillis Hub, which was set in place and signed agreements before we closed.

We're, as a company, right there with existing contracts in hand. They're all Henry Hub-based for now. But, if we're going to do internationally priced [contracts], it's probably to some of the people that we're already supplying.

JB: So, it seems like there's an interest there?
BW: There's interest there. We have an interest in understanding it. We would never build an LNG global price business off of a pricing peak. So, it's getting past that and understanding what the real market looks like.

JB: Despite the lower gas prices now, you seem quite bullish overall?
BW: I do, and the reason I believe that is LNG is the defining moment for the gas supply industry in this country. The bulk of the facilities are all on the Gulf Coast in two of the friendliest states to our industry. So, we have all of that production. The interstate pipelines to bring our Appalachia gas down to the Gulf Coast, they're already built. So we have assured flow from production to the market of choice for us.

We want a business that can generate free cash flow sustainably and get this debt down, and we see a path to get there as LNG picks up. The strategy made logical sense to us as long as we weren't just trying to grow for the sake of growth. We're excited about how we position the company when the real ramp of LNG occurs.

One of the things we needed to do was to educate our investors more deeply in the Haynesville. It's LNG and it's the technology advancements that have occurred over the years that have enabled us there. We're in the hottest, highest-pressure area in the basin, and we can drill and complete wells at a reasonable, but not reasonable enough, cost. We're continuing to drive that down. It represents a significant opportunity to supply because we can repeat, highly repeat it to supply these very large numbers for LNG. In the very near term, I think this will continue to accelerate.

JB: Would you take me behind the scenes? How tricky was it to line up those back-to-back Haynesville deals with Indigo and GeoSouthern, not just timing wise, but in the heart of the pandemic as well?
BW: I'll back up a little bit. During the heart of the pandemic, … we were also coming out of or right at the very lowest share price we had in a long time. But all of that was, quite frankly, really dwarfed by the loss of our CFO right in the middle of COVID and the acquisitions. Julian Bott's passing [in January 2021] was very, very difficult on the team and very difficult on me. He's a dear, dear friend. But it was a really, really strong testament to the leadership team. We couldn't go and pay respects because of COVID, but we managed through it. We

dug in and, in his honor and his spirit, we drove through low gas prices, low share price. We shifted and focused our strategy a bit more around making sure that we were controlling what we could control.

Thank goodness we had done Montage first. The Montage acquisition built credibility on how we do acquisitions with the discipline and the rigor. We jettisoned the parts of those acquisitions that we didn't want right up front, so we never had to touch them. And it gave the board confidence, after they went through their analysis, to support the acquisitions.

I think the root of these two acquisitions began with relationships. I got to know [Indigo founder and Chair] Bill [Pritchard] very well, and I got to know [GeoSouthern President and CEO] Meg [Molleston] very well. We spent time with their entire teams and our entire teams, making sure that they knew who we were and what we stood for, and how we were going to go about it. I can tell you, in both cases, that their view of those pieces of the puzzle were instrumental in helping us win those. We weren't in a competitive process, but there were competitors all around us. And we knew they were sitting there waiting to interlope if they could.

Meg is still one of our major shareholders today. And we worked through each piece. We understood the integrity of the data, and we understood what fair price would be. We have our own drilling rigs and frac fleets, so we could bring employees to Louisiana to learn from the same way they learned in Appalachia from Fayetteville, and learn deeply so that we could begin to drill these wells and have the performance that we built into the models and expected. And that happened.

JB: You touched on how tough things were in the pandemic, but 2019 was a really difficult, tough year too. Can you compare and contrast just how and why things were so tough pre-pandemic, and how things have transformed since then?

BW: I think that certainly gas markets have a role to play. It's the effectiveness of your hedging program or whether you have a [cold] winter or not. LNG's big demand pool hadn't happened yet in a material way. So, what do you do to deal with that? Well, we amped up our hedging program. We understood the importance of not overdoing it, but certainly providing that base of support for the business.

The fact that we kept driving forward on the acquisitions was critically important. We needed the scale; we needed to be able to manage the costs and grow the margins by owning those businesses. We were just undeterred. We spent a lot of time with our board helping them understand what we were trying to do. They understood from the days of exiting the Fayetteville that the advantages of well-executed scale increases would come to the company. We really never paused to say, 'Is this the right thing?' If you're going to be a serious gas champion, you've got to have scale and why not have complimentary basins where you have incredible flexibility and agility built into your company.

And we're now focusing on debt reduction. When we set out last year and this year, our capital allocation strategy is focused primarily on debt reduction. Whether there's high gas price[s] or low gas price[s], carrying this level of debt is not competitive. We got a lot of questions about returning the money to the shareholders. And, we changed their minds, and they came back solidly in support of maintenance-capital level investment to keep production relatively flat. All of the available free cash flow after that goes to pay down debt. We've done one or two non-core small deals, and last year we paid down $1 billion of debt.

JB: On the macro side of things, can you elaborate on how gas has transformed from more of a domestic product to the growing global LNG demand with exports and all of the geopolitical conflicts?

BW: The advent of the shale boom showed the industry and the world that we had the depth of inventory and reserves to be able to participate from a supply standpoint in the growing LNG demand in the world. And you began to see the shift of massive growth in that sector that was going to really kind of reset demand.

I think the U.S. is the supplier of choice from a security of supply political position. In a very fast-growing LNG market, you're expecting significant growth overseas. There's a supply-demand gap. In Australia, they're struggling with domestic gas, and Qatar and a number of other countries [have issues]. Then you have the U.S., that has ample reserves, ample ability in building these facilities.

The U.S. supply over the next several years will tend to outpace local demand. Having an outlet for that gas supply as LNG brings economics back to fields, brings economics back to companies. And it's sort of a symbiotic relationship because the LNG industry needs the U.S. reserves, and the U.S. production companies need a ready market that is bigger than here. So, thus, you have additional LNG facilities ready to be sanctioned and started up over the next handful of years.

JB: With lower gas prices now impacting drilling and completions and maintenance-level capex, is it tough scaling back a little bit?

BW: To ensure this year that we invested within cash flow, we put together a program in the beginning of the year that would adjust downward if prices fell further. For us, we added, 'what else can we do to generate cash flow?' And it was an all-out assault on inflation. So, we were able to cut capital costs materially and not cut production because the unit cost to do things had come back down. We're looking at a 5% to 10% inflation impact going forward instead of 15% to 20%.

The other piece is what we call the productive capacity of the company. Think of a flywheel and you have an investment decline, which will slow your flywheel down and maybe make it go backwards if it's a big enough decline. We did that in 2016, the day after I became CEO, in a pretty big leadership moment. We said we're going to tell the industry we're going to stop. The problems of then don't exist today, but the impact was a great learning opportunity. When we stopped, the flywheel started turning backwards and it took $500 million of investment to arrest the backwards and get it going back forward. What's the big deal about that? Well we believe in a constructive view of the gas markets going forward. There's going to have to be a price that will incentivize, at some point in the future, drilling and completion of wells to fill all of this LNG demand. Call it the 2024, '25, '26 time period.

We'll watch that because better economics from higher prices also can mean paying down debt faster. If it works out the way we hope, you can end up with higher prices in the near term that can provide additional cash flow. Then, the ability to quickly ramp up–remember we own seven of the rigs that we actually use–we can move them at will, start them up, stop them at will. And so our spot time can be quite, quite quick. We estimate probably a $4/MMBtu gas price to incent enough activity to get the supply needed.

"We believe in a constructive view of the gas markets going forward. There's going to have to be a price that will incentivize, at some point in the future, drilling and completion of wells to fill all of this LNG demand. Call it the 2024, '25, '26 time period."

—**Bill Way**, *CEO, SWN*

JB: So a lot of the plan now is positioning to be able to flip that switch quickly?

BW: I would call it that. We'll have a little decline this year, and we do not plan on growing production next year. I think the fact that we've gotten inflation out and gotten more effective, we can lower our previously projected capital and not cut activity so much that we're in the reverse flywheel kind of thing, which means we can come back fairly quickly.

JB: In the meantime, you haven't scaled back much in the Haynesville, but you're leaning a bit more on the liquids portions of the Appalachia, right?

BW: In the beginning of the year, we put an extra rig in our NGL-laden gas in West Virginia, and we've kept that there. Our overall allocation, 55:45, still favors Haynesville. But since we've owned Haynesville, everywhere we own, we're doing some level of drilling, whether it's Ohio or Pennsylvania or West Virginia. A well in Pennsylvania is a lot cheaper because you can drill 24,000-foot horizontals that are 6,000 feet deep. So, you're talking about a 30,000-foot well. And we can do those highly repeatable to drive cost out. You can't do that in Haynesville. It's too high pressure, high temperature, even the units are not that long. But there are other ways to optimize. Haynesville is advantaged with very, very low differentials because you're right there in the marketplace.

JB: Does the LNG focus play a big role in SWN's investments in RSG (responsibly sourced gas) and methane emissions to satiate potential global buyers?

BW: I think that those are enablers. I've changed my view on this, and it's probably based off of being deeply involved in understanding around our culture here. We focused on the components of ESG as core values that support our culture before that ESG acronym was cool. We built and designed our modern company to reflect the tenets of an RSG requirement. We use Project Canary for 100% certified gas, and we will be 100% monitored. We are the only producer in the country that replaces all the freshwater that we use. That's, for us, a social aspect, not even environmental. We've basically put 16 billion gallons of freshwater back into the aquifers where we've removed them. We have low methane intensity, and we have GHG goals and 50% reduction targets.

My point is that we've been doing all of this because that's how we operate and because it is the right thing to do. OGI

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▸ DRILLING

(Jack) Up, Up and Away!

The market for both jackups and floaters is in a global resurgence with day rates and utilization continuing to climb.

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After up-and-down years spurred by the pandemic, the rig market seems to have officially exited its low point with a mass resurgence.

Rig supply for both jackups and floaters remains tight, and day rates are on the rise and expected to continue trending up. The tight market has also created opportunities for lower spec floating rigs and jackups to be reintroduced to the global fleet, as well as create discounts for long-term work in the market.

"There's a steady pipeline of [jackup rigs] purchased over the past year that will extend its working count as they finish preparations and crewing and begin their assignments," Cinnamon Edralin, Esgian's head of rig market research, said in July. "This situation has led to a tight market in particular for premium jack ups."

Currently, the Middle East is dominating the jackup market with about 145 units currently under contract. Due to the tightness of the market, there has been an increase in interest for some of the older and lower spec rigs, as most of the higher spec rigs are concentrated in the Middle East. Because of the difficulty in securing newer rigs outside of the Middle East, day rates are increasing worldwide.

Utilization for marketed jackups is at a very high 96%. In the past year, the total supply for jackups only decreased by four. During that same time frame, the competitive supply increased by 12, while the contracted count grew to 19. These numbers indicate demand is growing faster than supply has decreased; previously stacked units are making a comeback—and not just on speculation, but with contracts in hand.

"This was the highest jackup contracting level the market has seen in many years…But before that, the market had already been in a downturn for several years and contracting levels had been much lower," said Edralin.

In the first half of 2023, the average day rate for jackups grew by almost $30,000 since June of 2022, increasing from $83,000 to $112,000. Jackups rated for water depths of 400 ft and 449 ft—which constituted 44% of all awarded contracts in the first half of this year—had day rates ranging from $110,000 to $175,000.

Jackup rigs aren't the only units doing well, as the market for floaters is also strong.

"Similar to the jack up segment, the marketed floater utilization rate is quite high at 87%, with certain categories, such as the seventh-generation drill ships and the sixth-generation harsh environment semisubmersibles nearly fully booked for the rest of this year and at least partway into next year," Edralin said.

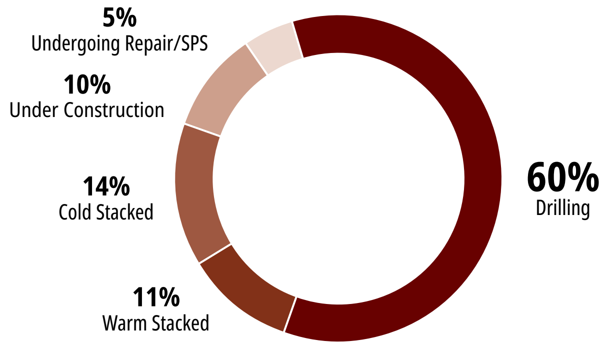
Around 60% of the 209 drillships and semisubmersibles in the global fleet are currently under contract. While there are 11 units undergoing repairs or reactivations, only one is uncommitted, but it is understood to be targeting some likely work, Edralin said. South America continues to lead the way with 31 floaters under contract—Brazil accounts for 25 of them—and is poised to continue its growth. Drillships are primed for a strong second half of 2023.

According to Esgian's forecasted numbers, both jackups and drillships are expected to continue their upward trends well into 2026. Even with some older rigs aging out of the fleet, the market is expected to continue to grow. Newbuilds for rigs on the market have been in high demand due to high utilization and market tightness.

"While demand remains high, there are some aging units that are likely to exit the competitive jackup fleet over the next several years. Those will largely be replaced by newbuilds entering the fleet and reactivated units," said Matthew Donovan, senior market analyst at Esgian. OGI

Floaters at a glance

Total supply = 209

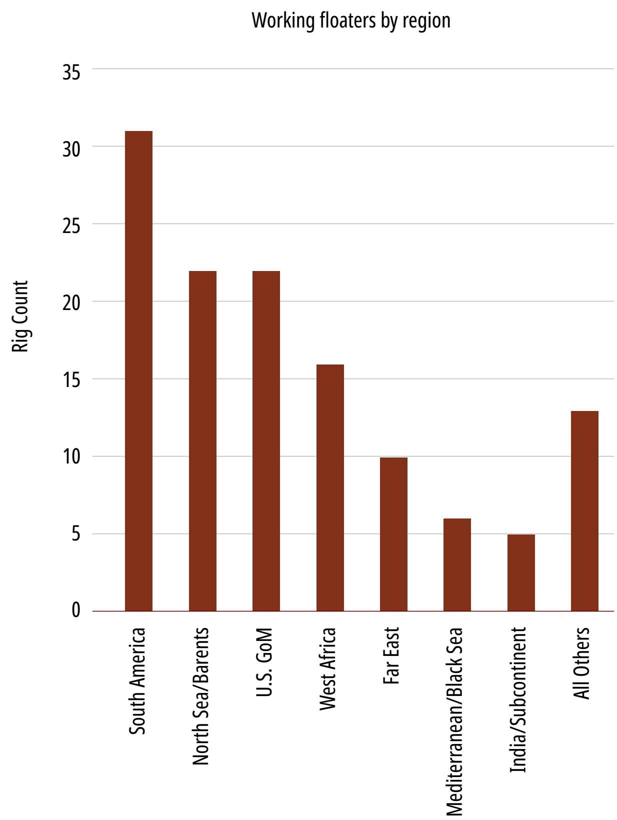


Select H1 2023 fixtures

Rig Name	Type	Operator	County	Fixture Date	Duration (days)	Dayrate (est.)
Noble Valiant	7th gen DS*	Murphy	U.S. GOM	May 2023	40	$450,000
Noble Voyager	7th gen DS*	Shell	Mauritania	May 2023	60	$465,000
Noble Faye Kozack	7th gen DS*	Petrobras	Brazil	May 2023	919	$475,000
Transocean Equinox	6th gen HE SS**	Multiple operators	Australia	July 2023	380	$484,200
Valaris DPS-5	6th gen SS*	Occidental	U.S. GOM	July 2023	60	$367,000

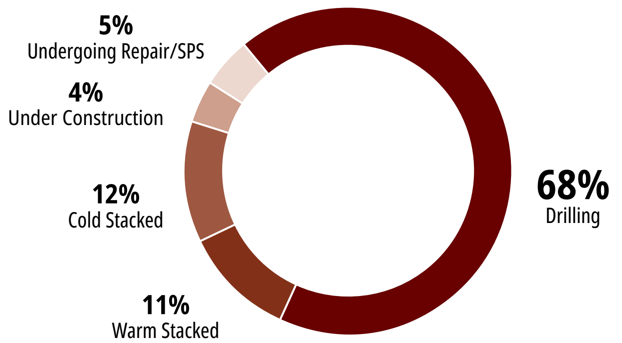
* Drillship ** Harsh environment semi-submersible *** Semisubmersible

South America count is led by Brazil



Jackups at a glance

Total supply = 500

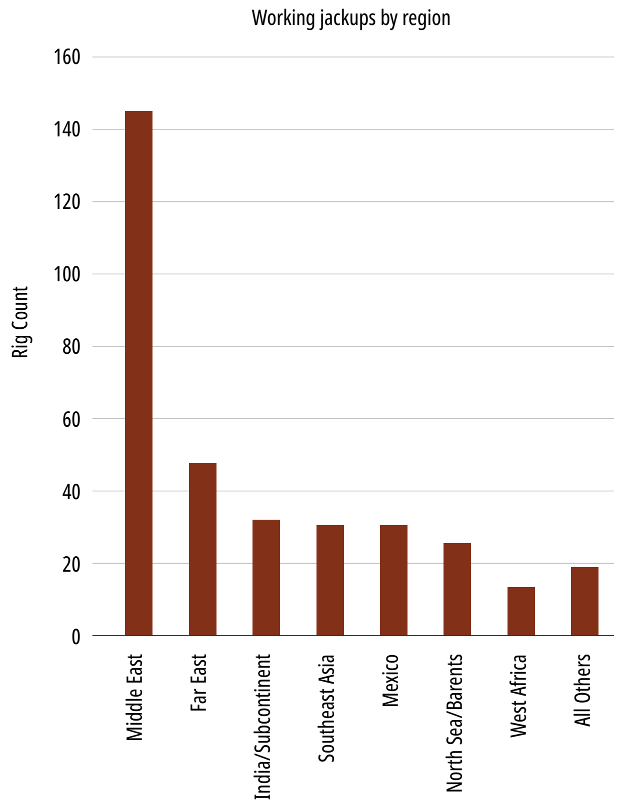


Select H1 2023 fixtures

Rig Name	Operator	County	Fixture Date	Duration (days)	Dayrate (est.)
Noble Lloyd Noble	Equinor	Norway	April 2023	270	$225,925
Valaris 92	Harbour Energy	UK	May 2023	730	$95,000
Noble Tom Prosser	Shell	Malaysia	May 2023	365	$127,000
Valaris 247	INPEX	Australia	July 2023	100	$180,000
Valaris 101	Santos	Australia	July 2023	180	$150,000

Source: Esgian AS

Middle East dominates working units



Oxy Reaches for the Cloud

The operator is working with Amazon Web Services on its digital transformation, seeking to reduce capex and gain access to software-defined technology.

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Going all-in on the cloud will speed up how quickly Occidental Petroleum can experiment with new technologies and potentially improve operations.

As the company moves through its digital transformation, Occidental expects to see a reduction in capex associated with migrating away from on-premises data centers. Occidental also expects significant results through access to innovative software-defined technology that can be deployed via Amazon Web Services (AWS).

AWS announced in July that Occidental had chosen the company to provide cloud services under a multiyear agreement underpinning the operator's digital transformation.

Under the agreement, Occidental will migrate its core production applications and on-premises information technology (IT) infrastructure to the AWS cloud to improve operational efficiencies, eliminate upfront capex and support the company's development of systems that will remove CO_2 from the atmosphere, including at the large-scale direct air capture (DAC) plants at Occidental's 1PointFive subsidiary.

Yanni Charalambous, chief information officer at Occidental, told Hart Energy that the move will give the company access to technology that's not available outside the cloud environment, while helping Occidental better manage its resources. Using the cloud will minimize capex on hardware and software for data centers, along with space and energy needed for the data center.

Uwem Ukpong, vice president of global services at AWS, told Hart Energy that companies often choose to migrate to the cloud because it frees them from the constraints associated with building, maintaining and expanding their own data centers.

Ukpong recounted a recent conversation with a customer that typically built data centers for the maximum amount of computer power they anticipated in the future—even if they wouldn't reach that level for three years or more. They put that money down up front so they wouldn't have trouble expanding when the need arose.

With on-premises data centers, "if they needed to expand capacity, they needed to go through a rigorous process with the finance (department) and the supply chain to go buy and acquire hardware," he said.

Migrating to the cloud provides pay-as-you-go elasticity, allowing a company to quickly ramp up on computer power to accommodate a project and scale back when the workload eases, he said. Companies are also able to repurpose IT staff to handle different projects, such as building applications, he said. It's a shift in thinking from the traditional route companies travel with on-premises data centers.

"The beauty here with 1PointFive is that a lot of the applications that they are going to be developing to really improve the way this DAC plant is working are going to be built with the cloud mindset—fast and optimized."

—Uwem Ukpong, ***vice president of global services, AWS***

Charalambous said, "We are sharing now on the cloud with other companies that same infrastructure that AWS provides. That allows us to save money, mostly on the capital side, as well as on the operations side of that environment."

And while that's important, he's most excited about the agility of the cloud environment when it comes to innovating.

"That will allow us to try out things faster, fail where things are not working out and be successful faster," he said.

Charalambous believes the innovative benefit will materialize soonest in the DAC facilities, where the company is focused on developing and using software-defined plants. If Occidental found a way to reduce the energy necessary to capture CO_2 out of the atmosphere through a digital twin of the DAC plant, the company could validate the model and deploy it without a turnaround, he said.

When Amazon identifies an opportunity to improve the way it operates, he said, the company doesn't take its whole data center down to make the change.

"They don't do a turnaround. They actually inject that new technology or capability right into the environment, while that environment is still running. So, we're looking to do the exact same thing with the direct air capture plants," Charalambous said.

> *"We are sharing now on the cloud with other companies that same infrastructure that AWS provides. That allows us to save money, mostly on the capital side, as well as on the operations side of that environment."*
>
> —Yanni Charalambous, *chief information officer, Occidental*

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Using AWS infrastructure, Occidental subsidiary 1PointFive can analyze real-time direct air capture performance data to optimize processes and equipment performance for peak efficiency, and also apply learnings for future plants.

He said Occidental has worked with various cloud vendors over the years and ultimately chose AWS as its digital transformation partner because of the technology AWS can deploy while being price competitive.

"The agility is very encouraging and progressive," he said.

Migrating to the cloud

Digital transformation is a major undertaking, and it starts with migrating on-premises systems to the cloud. But it's not so simple as a "lift and shift" of data, Charalambous said. That would prevent Occidental from taking full advantage of the capabilities that the cloud offers. First, the data has to be optimized for the cloud before it's migrated.

Occidental expects to spend up to 18 months migrating data from its thousands of servers and systems in its main data centers in Houston and Dallas, as well as smaller locations around the world. The migration is already underway.

The company sees the cloud as something of a fresh start, Charalambous said.

"We're starting from a blank piece of paper here to redesign how we manage our data in that environment. It gives us an opportunity to review how we're doing data management and analytics today, and how we can further improve it by using the technologies that AWS provides for that," he said.

Ukpong said content from the on-premises data centers includes simulation data, seismic data, financial data, SAP data, facilities data and applications

"With all their technical data moving onto the cloud—seismic simulation data, geology data, et cetera—your ability to then access that information and leverage the additional computing power you have on the cloud is what's going to help Oxy run even faster in the way they prospect for oil and gas or simulate the behavior of their reservoirs," he said.

Once the migration is complete, applications that have been migrated will be modernized, or enhanced, as well as building new applications in the cloud, he said. Modernizing is important because data may not optimally interact with apps, slowing down performance and computations, he said.

"When we migrate a large bank, for example, all of that data is migrated. But the way that data interacts with your app may not be optimized for the cloud. So, we need to go back and rebuild and reconstruct the data and the application so that when you log into your bank (account) on the app, it's much faster and you can do more computations of comparison between different financial products, loan rates, et cetera," he said.

Innovation can take place in parallel with modernization and may include the use of artificial intelligence (AI), generative AI or machine learning. After modernization, innovation kicks into high gear.

AWS and Occidental will sit down with partners who could bring technology solutions that could optimize the company's performance.

"Let's look at aspects of your business that relate to production optimization, for example, or seismic interpretation, for example, and say, 'What are the new things we want to introduce here that are going to double productivity and drive efficiency in what you do?'" Ukpong said.

And, he said, those things will likely be in the area of predictive maintenance for the DAC plants because equipment reliability is critical to operations.

"Being able to connect all of their sensors and relaying all of that sensor information in real time back onto the cloud—and to be able to start predictive maintenance or forecasting when failures will occur—is going to be one of the big things we're going to do with them," he said. "The beauty here with 1PointFive is that a lot of the applications that they are going to be developing to really improve the way this DAC plant is working are going to be built with the cloud mindset—fast and optimized." OGI

▸ EARNINGS

Robust International Results Lift Oilfield Services Companies

SLB, Baker Hughes and Halliburton reap the benefits of offshore and non-U.S. operations.

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Oilfield service companies continue to expand in international and offshore markets as the North American market softens, top executives said during second quarter earnings calls over the last week.

And that's fine with Olivier Le Peuch, CEO of SLB, whose company is positioned for it.

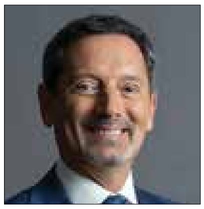
"This is playing to the strengths of our business, as international revenue represents nearly 80% of our global portfolio, and offshore comprises nearly half of that," he told analysts.

The investment momentum is accelerating internationally, Le Peuch said. SLB anticipates more than $500 billion in global final investment decisions (FIDs) between 2022 and 2025, with more than $200 billion of that total in the deepwater sector.

But even in the short term, SLB benefits from deriving 78% of its revenue outside of North America.

"About half of SLB's international markets posted year-over-year growth exceeding 30%, led by the Middle East and Asia," Morningstar analyst Katherine Olexa wrote in a research note. "We expect SLB will continue to benefit from elevated demand and favorable operating dynamics through at least year-end."

SLB's second-quarter revenues of $8.1 billion beat its first quarter by 5% and second quarter 2022 by 20%. Quarterly net income of $1.03 billion was up 11% sequentially and 8% year-over-year. Its stock price was up 15.6% for the year by mid-August, similar to the S&P Oil & Gas Exploration & Production Select Industry Index flat for 2023.



"This is playing to the strengths of our business, as international revenue represents nearly 80% of our global portfolio, and offshore comprises nearly half of that."

—**Olivier Le Peuch,** ***CEO, SLB***

Oil price rebound

Baker Hughes, reliant on international work for 73% of its revenues, saw its second quarter revenue rise 10% sequentially to $6.3 billion, which was a 25% increase year-over-year. Net income fell 29% sequentially to $410 million, but that total was much improved over the $839 million loss in second-quarter 2022.

International revenue in the quarter rose 23% year-over-year, compared to 13% for North America. Sequentially, it was up 10%, compared to 5% for North America.

"Despite lower oil prices over the first-half of the

Oilfield service companies SLB, Baker Hughes and Halliburton reported solid Q2 results from offshore and international operations.

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"Market softness in North America is expected to be more than offset by strength in international and offshore markets."

—**Lorenzo Simonelli,** ***chairman and CEO, Baker Hughes***

"Equally important, in addition to strong growth in the Middle East and Latin America, we see steady growth in activity across the globe."

—**Jeff Miller,** ***president and CEO, Halliburton***

year, we maintain a constructive outlook for global upstream spending in 2023," Lorenzo Simonelli, Baker Hughes's chairman and CEO, said during the call. "Market softness in North America is expected to be more than offset by strength in international and offshore markets."

The company's stock price was up 25.6% for the year by mid-August and had jumped 14.2% since the start of July. Wells Fargo raised its price target to $37/share from $32/share in a July 19 research note and noted that it was "fairly bullish" on an oil price recovery in 2024.

Steady growth

By contrast, international revenues only account for 54% of Halliburton's total. Total revenues rose 2.1% sequentially in the quarter, despite a 2.5% dip in North America. International earnings were up 6.5%.

Wells Fargo noted that shares fell following the earnings announcement and a lukewarm outlook in North America for the rest of the year. The stock price was up 7.4% for the year by mid-August.

Net income slipped 6% to $616 million from the first quarter, but was far above the $117 million recorded in second-quarter 2022.

The quarterly picture brightens in the year-over-year comparison. Total revenue of $5.8 billion was up 14% year-over-year. International revenue was up 17%, with North America rising 11%. The company expects international spending to increase between 15% and 20% for 2023, with North American growth about 10%.

"Equally important, in addition to strong growth in the Middle East and Latin America, we see steady growth in activity across the globe," said Jeff Miller, Halliburton's chairman, president and CEO.

Wells Fargo was optimistic on the company's outlook.

"Macro fundamentals remain robust for HAL, particularly in international and offshore markets," analysts said in a July 19 report. "Global service capacity remains tight, which should allow for greater pricing power and further revenue/margin improvements." OGI

TotalEnergies Plans to Ride Second US LNG Wave

CEO Patrick Pouyanné said the French company has committed to expanding its LNG business and its growing U.S. position is key to that strategy.

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TotalEnergies is committed to growing its LNG business and its growing U.S. position is a major piece, CEO Patrick Pouyanné said during the French company's second-quarter earnings call with analysts.

"A very major example of the strategy in motion is our new LNG project in the U.S., the Rio Grande LNG project, which we have announced in June," Pouyanné said during the call.

TotalEnergies entered into a joint venture on Rio Grande LNG (RGLNG) in June, when NextDecade announced an $18.4 billion final investment decision (FID) for the first phase of the project. The first three trains will have capacity to export 17.6 mtpa. RGLNG is part of a second wave of U.S. LNG projects, of which three have taken an FID so far this year.

"We are very committed to LNG, we think demand [will] grow and … the U.S. position is very important because we have the lowest cost, a very low-cost source of gas there," Pouyanné said. "And I would say this project is attractive because it's one of the most competitive LNG plants with a $850 per ton [cost]."

Pouyanné said TotalEnergies is moving to integrate its LNG projects in the Americas from North America to Mexico by becoming an equity holder or shareholder as well as its position as an off-taker.

"We've done that because, in fact, we are leveraging this integration in order to have access to the most competitive pricing for U.S. LNG, and which will give us a clear competitive advantage on the market," he said.

The integration affords TotalEnergies the capacity to negotiate better prices than competitors, Pouyanné said. "We might also enhance the value of the project by further integrating the upstream in order to protect our gas feedstock costs in the future."

"Considering the cost of the feedstock, [it's] a smart way in order to control the full integration value—and so it's part of, I would say, our strategic agenda and integration in the U.S.," Pouyanné said in response to an analyst question about TotalEnergies' exposure to U.S. feedstock.

Paris-based TotalEnergies is focused on a two-pillar strategy for hydrocarbons and electricity. The former pillar aims to grow its portfolio with an eye on low-cost and low emissions, and is mainly driven by LNG, which is currently the company's cash engine. The latter pillar aims to develop a profitable and integrated power business, key to generating future cash, Pouyanné said.

Weaker commodities weigh on results

Despite upstream operational improvements in the quarter, financial results were heavily weighed

NextDecade announced an $18.4 billion FID for the first phase of its Rio Grande LNG project in June.

NextDecade

TotalEnergies is committed to growing its LNG business and its growing U.S. position is a major piece, CEO Patrick Pouyanné said during the French company's ssecond-quarter 2023 earnings call with analysts.

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down by lower commodity prices.

"The commodity environment softened in the second quarter but still [remained] at high levels," TotalEnergies CFO Jean-Pierre Sbraire said during the conference call.

TotalEnergies reported adjusted net income of $5 billion in the second quarter of 2023, down 49% compared to $9.8 billion in second-quarter 2022. Cash flow from operations came in at $9.9 billion, down 39% compared to $16.3 billion for second-quarter 2022.

Hydrocarbon production averaged 2.47 MMboe/d in the second quarter, up 2% compared to 2.41 MMboe/d in second-quarter 2022, excluding Novatek. Positive results related to start-ups and ramp-ups including Ikike in Nigeria, Mero 1 (Brazil), Johan Sverdrup Phase 2 (Norway) and Block 10 (Oman). Other factors included better security conditions in Nigeria and Libya as well as price effects, which were offset by declines from exiting Termokarstovoye (Russia) as well as natural field declines.

In the third quarter, TotalEnergies expects hydrocarbon average production of 2.5 MMboe/d driven by the start of the Absheron Field in Azerbaijan. The company expects utilization rates at its refineries to stay above 80%.

LNG sales were 11 million tonnes (MMtonne) in the second quarter, down 6% compared to second-quarter 2022 sales of 11.7 MMtonne. The company said lower demand in Europe due to mild weather and high inventories had sapped demand, but was stable compared to the first quarter, when Freeport LNG restarted operations on the Texas Gulf Coast, Sbraire said.

Financially, the downturn in commodity prices made a noticeable impact on TotalEnergies' income statement during the second quarter compared to second-quarter 2022. Brent oil prices settled at $78.10/bbl, down 31% compared to the same

"We are very committed to LNG, we think demand [will] grow and ... the U.S. position is very important because we have the lowest cost, a very low-cost source of gas there"

—**Patrick Pouyanné**, *CEO, TotalEnergies*

year-ago quarter while Henry Hub was $2.30/MMBtu (down 69%), and the JKM benchmark LNG price in Asia was $10.90/MMBtu (down 60%).

"European natural gas prices are currently around $10/MMBtu due to high inventories in Europe," TotalEnergies said in the press release. "Demand recovery in Asia and tension on supply capacities in Europe support forward prices above $15/MMBtu for the winter of 2023-2024."

TotalEnergies expects its average LNG selling prices to be between $9/MMBtu and $10/MMBtu in the third quarter.

TotalEnergies' integrated power business generated much lower income than its upstream and LNG business segments but continued to build its track record as an integrated and profitable player in the electricity markets with a return on average capital employed ratio of 10.1%, the company said. OGI

▸ ANALYSIS

Venezuela Flares More Gas Than Freeport LNG Exports

OPEC's Venezuela continues to flare over half its natural gas production and burn off more than the output from Houston-based Freeport LNG's three-train, 15-mtpa export facility, which is about 2.2 Bcf/d.

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CARACAS, Venezuela—Venezuela continues to flare over half its natural gas production, mainly due to infrastructure limitations, and burns off more than 2.2 Bcf/d—greater than the output from Houston-based Freeport LNG's three-train, 15-million tonnes per annum export facility.

The OPEC country continues to flare, vent and lose gas production volumes through leakage. The lost volumes are due to a combination of historically low crude oil production and low gas injections to maintain reservoir pressures, coupled with a lack of infrastructure to capture and monetize those gas volumes, experts from consulting firm Gas Energy Latin America, Antero Alvarado, Luis Marin and Aidemiro Valera, said during a July company presentation in Caracas.

Gas Energy expects Venezuela's gas production to average around 4 Bcf/d in 2023, while volumes estimated to be flared, vented or lost through leakage are expected to amount to 53% of total production, the experts concurred during the event co-hosted by the Venezuela-German Chamber of Commerce and Industry (CAVENAL) and the Friedrich Ebert Stiftung Venezuela Foundation's Latin American Institute of Social Investigations.

This compares to Venezuelan gas production of 4.4 Bcf/d in 2022 (2.6 Bcf/d or 59% flared, vented and lost), 4.4 Bcf/d in 2021 (65%), 4.5 Bcf/d in 2020 (68%) and 6.9 Bcf/d in 2010 (29%), according to Gas Energy. While Venezuela has gained a reputation over the years as an oil producer, the country produces a lot of associated gas.

Historically in better economic times, the country and its state-owned company Petróleos de Venezuela (PDVSA) would reinject significant gas volumes to maintain reservoir pressures. However, those better times are behind the country and company due to years of oil rents mismanagement, widespread corruption and a lack of foreign direct investment from international oil companies.

Today, amid an epic collapse in oil production at just below the 800,000 bbl/d mark and down from an average of around 3 million bbl/d over much of the last two decades, reinjections have become a thing of the past, especially in Venezuela's Maturín state in the east of the country and in areas such as Furrial and Punta de Mata.

In 2022 in eastern Venezuela alone, an average 1.5 Bcf/d was either flared, vented or

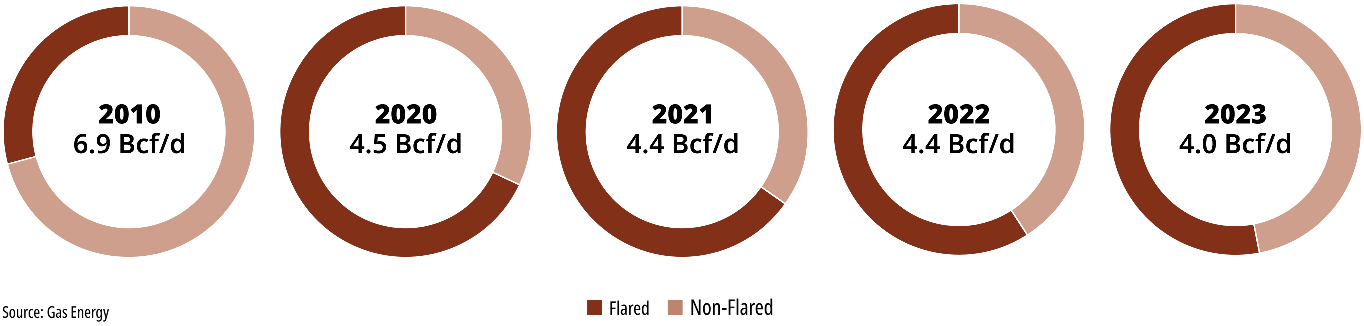
Pietro D. Pitts/Hart Energy

Conasa's building in Los Palos Grandes in Caracas, Venezuela.

Flaring at Venezuela's Punta de Mata field.

Venezuela's vexing problem: lower gas production, higher rate of loss

As the country's oil production dropped sharply from 2010 to 2020, so did its output of associated natural gas. Now, most of that gas is lost as a result of infrastructure and investment constraints.



Source: Gas Energy

lost, which emitted around 2.5 million tons of CO_2 per month into the atmosphere, according to Gas Energy estimates. The flaring, in addition to generating direct environmental and health problems, also generates constant loud noises in the surrounding communities.

Wasted supply

Venezuela is home to the world's largest oil reserves at 304 Bbbl and the world's seventh-largest gas reserves at 221 Tcf, according to BP's Statistical Review of Energy. The country's high reserves, coupled with low production, means it has enough oil to last easily over 500 years and enough gas for around 334 years.

Venezuela's wasted gas volumes could be captured and used to supply the domestic market as well as for export to international markets likes Europe, Asia or to neighboring Trinidad and Tobago, the Gas Energy experts said.

Moscow's invasion of Ukraine last year boosted demand in Europe for LNG to replace lost Russian piped-gas volumes. Bulge-bracket LNG exporters ranging from Australia to the U.S. to Qatar continue to dominate the market, and the latter two plan to bring to market significant new volumes over the short term. But with expected LNG demand growth anticipated to outstrip supply, potential new suppliers are scrambling to seek financing to build out liquefaction capacity.

In the case of Trinidad, the Caribbean country is currently short of gas to feed its LNG, methanol and ammonia plants. Trinidad's four-train 14.8 mtpa Atlantic LNG export facility continues to operate with three trains due to the severity of gas scarcity that continues to impact the small twin-island gas-dependent economy.

But getting those wasted Venezuelan gas volumes to markets far across the Atlantic or Pacific—or even next door—where it can be monetized remains the biggest headwind for potential clients, as well as for the Venezuelan government of Nicolás Maduro.

While investors' hesitancy to make investments in Venezuela's oil and gas sector will see the country strand massive reserves, their unwillingness to take a bet on infrastructure to capture flared gas will see the South American country continue to lose massive revenue potential from its remaining oil production. OGI

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Gas Energy Latin America's Aidemiro Valera (left), Antero Alvarado (center) and Luis Marin (right) during their presentation on Venezuela's gas sector from the Conasa building in Los Palos Grandes in Caracas, Venezuela.

▸ GLOBAL ENERGY

Can Machado Save Venezuela?

The leading opposition presidential candidate is barred from public office, but her plan to end the state's energy monopoly and shift the oil sector to private ownership may be just what the country needs.

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CARACAS, Venezuela—Venezuela's leading opposition candidate María Corina Machado says she would privatize the upstream and downstream sectors of the Caribbean country if elected president in 2024.

"Our plan will open Venezuela's energy sector to attract investors by ending the state monopoly and transitioning the oil sector to private ownership," Machado said in July. "My plan is to privatize all hydrocarbon extraction and downstream activities that can safely be assumed by the international and national private sector and transform Venezuela."

While admirable, the plan would be a massive undertaking by any government, given Venezuela's epic collapse in the last 10 years. In Machado's case in particular, the largest headwind she faces is her recent restriction from holding public office for 15 years by the Venezuelan government of Nicolás Maduro due to her radical tone, which includes backing U.S. sanctions.

Venezuela has been under so-called "socialist" rule since 1999 when the late Hugo Chávez first won the presidency. After his death in 2013, his predecessor Maduro took the reins and has been in charge since.

Machado, a 55-year-old industrial engineer and former lawmaker, stressed that more domestic and foreign assistance was necessary to achieve "free and fair" presidential elections in late 2024.

After nearly a quarter-century, it seems that a miracle is the only thing that could save Machado—and Venezuela.

For Machado, the journey toward a transition government requires addressing several crucial and concurrent crises: security; sovereignty and state territorial control; public services; and economic and humanitarian troubles.

The most recent crisis has seen over 7 million citizens flee Venezuela, including many from the oil sector, due to low wages and dangerous work environments, resulting in a massive brain drain of talent. Many citizens who have fled the Caribbean country will likely not return due to ongoing uncertainties, even if an opposition leader were to win the presidency.

Additionally, widespread corruption across Venezuela's oil sector continues to deter investors, while years of oil rent mismanagement and a lack of regular maintenance in upstream, downstream and midstream infrastructure will require years—if not decades—to return to an operating state even at a shadow of the sector's former peaks.

Geopolitically, Caracas and Washington still don't see eye to eye, and U.S. sanctions have only worsened the divide, thus making the push for "free and fair" elections much more difficult.

Venezuela's economy and petroleum sector have already touched bottom, and the country's return to its former glory might never happen, especially under current leadership. If that is the case, Venezuela could remain in a Cuba-like existence with one ruling party and widespread poverty, with the one advantage of its oil exports generating income for government coffers. And that, too, might only be for another two to four decades with the energy transition picking up speed.

Still, Machado reiterated that Venezuela had significant hydrocarbon and renewable energy potential to become a global oil powerhouse. But she admitted that considerable private investment and cutting-edge technology was needed to take advantage of the resources.

"We will set a competitive, an attractive framework of legal, fiscal, commercial and financial conditions, including the reform of the hydrocarbons law to assure a predictable regime for royalties and taxes," Machado said in a video call from Venezuela to New York for an event hosted by the Americas Society/Council of the Americas (AS/COA).

Initiatives proposed by Machado look to establish rule of law and judiciary system independence while ensuring respect for private property, fostering open markets, stabilizing public service and addressing social needs.

Energy hub of the Americas

Machado—who ran for the presidency in 2012 only to lose the opposition primary to Henrique Capriles—said her plans to rebuild Venezuela and achieve long-term economic growth would be based on four fundamental pillars, of which three depended on rescuing the country's hydrocarbon sector.

Venezuela, a founding OPEC member, is home to the world's largest oil reserves at around 304 Bbbl and the world's seventh-largest gas reserves, according to BP's Statistical Review of Energy. Earlier in the century, the country was one of the largest oil producers and exporters in the Latin America and Caribbean region. The lion's share of Venezuela's reserves are found in its Orinoco heavy oil belt, or Faja, with its massive heavy and extra-heavy reserves, though the oil does have a high sulfur content.

Amos Global Energy President Ali Moshiri, Chevron Corp.'s former head over Venezuela, reiterated during the event that the world

Americas Society/Council of the Americas

needed Venezuela's heavy oil.

Venezuela also has sizable steel resources and other minerals, including gold.

"In general, we will leverage our vast hydrocarbon and clean energy resources alongside our prime coastal location at the heart of the western hemisphere to turn Venezuela into [a] superior investment opportunity within the global energy transition process and provide reliable, safe and clean energy to the rest of the world," Machado said during her participation in the call.

Machado's energy sector plan aims to convert Venezuela into the energy hub of the Americas and consists of six key points:

First, Venezuela needs to boost oil production to over 3 MMbbl/d in seven or eight years, compared to just below the 800,000 bbl/d currently being produced, while also significantly reducing the country's carbon footprint.

Second, Venezuela's 221 Tcf of proven gas reserves must be developed and production boosted to around 12 Bcf/d within eight years to export gas to the rest of the world. Within five years, Venezuela could export around 5 Bcf/d to Trinidad and Tobago, Colombia and Brazil, according to Machado, citing details from her economic and petroleum team. The exports could increase as Venezuela's internal electricity crisis is resolved, she said.

Third, Venezuela's 32,000 megawatts (MW) of combined thermal, hydro and renewable energy generation capacity need to be recovered and expanded by more than 20,000 MW.

Fourth, Venezuela must develop its potential to produce green steel and aluminum and competitively produce blue hydrogen, ammonia and methanol by capturing CO_2 emissions within depleted oil fields.

Fifth, Venezuela needs to guarantee a consistent, stable, high-quality electricity supply across the country to drastically improve the welfare of Venezuelan families and drive economic development.

And sixth, implement a comprehensive plan to connect households, commercial entities and industries to the national gas grid. Currently, a lot of households and even small businesses are still reliant on LPG for cooking needs.

Machado said Venezuela has other advantages to help revive its once-thriving energy sector, including a highly skilled energy workforce; one of the world's largest refining complexes, which with necessary repairs and upgrades, could have the potential to boost exports of refined products across the Americas and beyond; close proximity to major refiners on the U.S. Gulf Coast; and sufficient gas reserves for the energy transition.

Machado also said Citgo Petroleum, the U.S. subsidiary of state-owned Petróleos de Venezuela S.A. (PDVSA), held strategic value and needed to be kept intact until her government was formed.

Evanan Romero, a member of Machado's economic and petroleum teams, assured investors that her government would welcome companies from all over the world, including China and Russia, which still have a presence in Venezuela. Chevron is the lone U.S.-based company operating in Venezuela, while Italy's Eni SpA and Spain's Repsol have also retained a minimal presence.

For its part, China originally lent Venezuela around $65 billion in loan-for-oil deals. To date, around $12 billion is still outstanding, Romero said.

Energy-rich Russia's presence in Venezuela has always been more militarily and politically driven. Moscow has always been keen to provide small arms, tanks, military training and political consultancy—in line with political coaching provided to Caracas by Venezuela's long-time Caribbean ally Cuba.

Three pillars

The other three pillars of Machado's plan for Venezuela relate to the economy and the country's external debt.

Under the economic stabilization pillar, the plan for the economy is based on fiscal, monetary and currency exchange policies—aiming to halt high inflation, financial chaos and currency devaluations. Machado said she would privatize government-owned corporations, which she said

María Corina Machado in a file photo from 2014. Machado has promised to make sweeping reform to the way Venezuela conducts energy sector business if elected in 2024.

Venezuelan immigrants in Colombia. The last crisis has seen over 7 million citizens flee Venezuela, resulting in a massive brain drain of talent.

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Shantytown along the hillsides of Caracas. Machado's plan includes extensive privatization programs across all sectors—priority sectors being energy, water, gas, telecommunications and roads—while addressing the humanitarian crisis in the short term.

were all making losses, reduce the fiscal deficit and reinstate independence at Venezuela's Central Bank, or BCV by its Spanish acronym.

Under the economic expansion pillar, the plan aims to get Venezuela back to high and sustainable long-term economic growth through an extensive privatization program across all sectors—priority sectors being energy, water, gas, telecommunications and roads—while addressing the humanitarian crisis in the short term.

Machado said additional measures would be taken to strengthen a market-oriented economy, promote growth and increase economic productivity and would entail digitizing and simplifying bureaucratic procedures and generating wealth to drastically reduce poverty.

Finally, Machado said restructuring Venezuela's debt would allow it to recover financial sustainability over the medium- to long term as a necessary condition for high and sustainable economic growth.

"However, we must address the enormous public external debt overhang which has been in a situation of total default for seven years [while] lawsuits in the U.S. and Europe need to be addressed," Machado said.

Machado said her government would recognize all liabilities and debts before engaging in any debt restructuring, while also looking to restore relations with international financial entities like the International Monetary Fund and the World Bank, as well as others like the International Centre for Settlement of Investment Disputes.

"Our government will seek an agreement to restructure external debt through a bond swap process that is financially sustainable [and] offers flexible options so that all creditors receive the same financial treatment," she said. OGI

▸ **GLOBAL** ENERGY

Pitts: Venezuela's Burning Through Gas and Cash

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Venezuela's natural gas flaring problem is one small part of a larger problem the OPEC member country has monetizing its massive gas reserves both onshore and offshore.

A lack of infrastructure is arguably state-owned Petróleos de Venezuela's (PDVSA) biggest headwind, which ties into others from financial to human capital.

Around 80% of Venezuela's gas production is associated with the production of crude oil, and the country is expected to flare an average 2.1 Bcf/d in 2023, according to Gas Energy Latin America, down from 2.6 Bcf/d in 2022.

As a result, the Caribbean country is on track this year to lose around 53% of its gas production through flaring. Importantly, the flaring figure includes venting and leakages—which includes methane—but is, in essence, predominantly related to flaring. When the 2023 data is compiled with data from 2020-2022, Venezuela's four-year average flaring rate is around 61%, according to data from Gas Energy.

Venezuela's flaring problem in its most basic form has negative financial, economic, environmental and health impacts—in no particular order of importance.

Financially for PDVSA and economically for Venezuela, the flaring problem represents a massive lost opportunity to capture gas for use in the domestic market. Maybe more importantly, it's a lost chance to export and monetize the gas internationally.

But Venezuela's flaring problem hits deeper on the environmental and health side of the equation.

Natural gas contains different compounds, but the largest is methane, which is released during venting and leakages. And methane rightfully has a bad rap as a greenhouse gas (GHG) as it's 25 times more potent than CO_2 in trapping heat in the atmosphere, according to the EPA.

Flaring produces CO_2, carbon monoxide, sulfur dioxide, nitrogen oxides and other compounds, which are still bad for the environment but less harmful than methane over the near-term, according to the U.S. Energy Information Administration (EIA).

Environmentally, it's a mess not only for Venezuela because GHGs don't tend to respect borders. And in terms of health issues, the flaring problem is just as worrying or more so. Local communities across Venezuela are impacted daily by the country's flaring problem, which are not limited to the release of GHGs but also the constant light and noise that is associated with flaring.

Venezuela's flaring problem could be resolved, but that would require massive investments from a cash-strapped PDVSA. International oil companies (IOCs) could step in but many continue to keep a distance from Venezuela owing to U.S. sanctions imposed in 2019. Prior to that, IOCs had to contend with asset expropriations as well as economic and political uncertainties, of which many of the latter two still exist today.

Venezuela has a population of some 29 million, according to Worldometer. As a result, the country's domestic gas market is relatively small compared to the country's estimated proved gas reserves of 221 Tcf, according to BP's Statistical Review of Energy.

While Venezuela's domestic market could arguably be the first to benefit from reducing flaring activities, the country's gas pipeline infrastructure is still lacking. Many households and small businesses remain disconnected from Venezuela's gas grid and rely heavily on LPG.

Gas Energy estimates that only 7% of Venezuelan consumers have direct residential gas access. This compares to around 70% in neighboring Colombia.

Direct gas hook-ups would also help to reduce further GHG emissions caused by citizens who have to revert to cooking with coal or wood when LPG containers are not available due to logistical distribution issues or an inability to afford them.

Venezuela's flaring problem, if resolved, could also help to boost the supply of CNG and help displace the need and use of internal combustion vehicles, although that has an associated conversion cost. In Venezuela, CNG is basically free, considering that its users usually offer foodstuffs to service station attendants who fill up their compressors. So, the increased availability of CNG would reduce pressures on PDVSA to produce more gasoline and diesel, which at times are not easy to find, especially in interior regions outside the capital city of Caracas.

The biggest economic impact to come from resolution of Venezuela's flaring problem relates to potential exports to neighboring Trinidad and Tobago, or beyond to Europe and Asia. That option requires IOCs willing to take a bet on a Venezuela sanctioned by Washington. Look no further than the U.S.-Mexico border to see negative impacts from U.S. sanctions on Venezuela.

Venezuela's flaring problem is just that. Capturing that gas could go a long way toward solving a number of problems, but moving from problem recognition to problem solving in theory and then in practice is another story. OGI

Could US LNG be 'Stuck at Sea?'

Exporters could see cargos back up as European storage nears capacity and Asian demand lags, a Bernstein report says.

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A supply glut of LNG could result in a queue of floating cargos riding the waves as European storage fills and Asian demand lags, Bernstein analysts said recently.

"In the worst case, this would lead to a backup of LNG/gas to the U.S.," Bernstein analyst Jean Ann Salisbury wrote in the report, "Will LNG be Stuck at Sea?"

"There has been significant interest and concern in whether there is a one-to-three-month 'chaotic period' in gas this summer due to [first] European storage filling well before the normal October period and [second] Asian demand being unable to redirect and absorb more gas that quickly," Salisbury said.

At the same time, U.S. natural gas production reportedly reached a record 103 Bcf in June, though Goldman Sachs said the increase was driven by a sharp rise in Permian Basin volumes that analyst Samantha Dart suggested could be revised lower.

In June, Morgan Stanley warned that U.S. LNG exporters could see cargo cancellations in the second half of 2023 amid strong European gas injections.

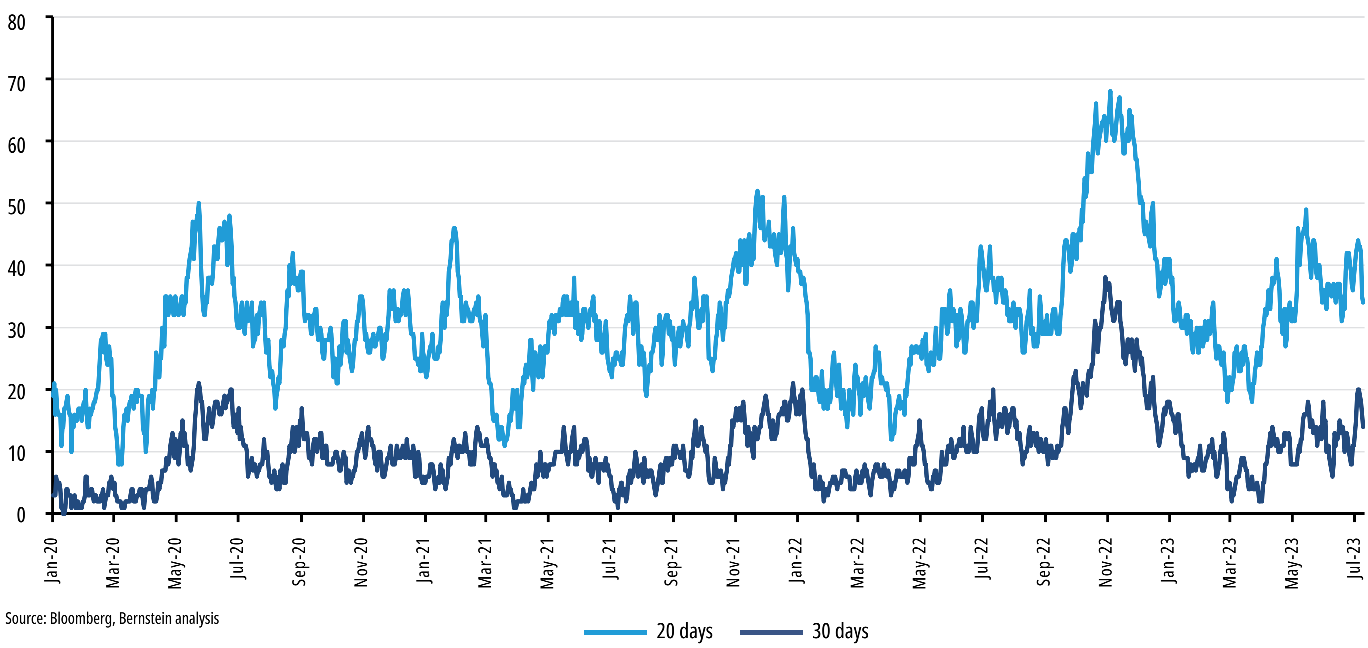
Approximately 35 LNG ships have been sitting on the water for more than 20 or 30 days. This compares to a peak of 68 ships in October 2022, Salisbury said, but she added that even with this record number of ships, there was no back-up to the U.S.

"To see vessels wait for a month, we need the inter-month price difference to exceed the value of shipping another cargo to Asia for 1 month, (it takes 2 months to go to Asia and back, so half the arb can be achieved in 1 month), which is ~$6/Mcf going into winter," according to the Bernstein report.

Such a rise in the number of ships on the water functioning as storage wouldn't be good for U.S. gas prices, Salisbury said.

"Normally, we assume $2/MMBtu as a sustained floor for Henry Hub, which has held for one month [plus] periods in the past, and is driven by the high lifting cost of old verticals," Salisbury wrote. "But given the already high storage levels and the speed at which this would unfold, we think U.S. gas could go into the mid $1s for a month or two (lowest one-month price in recent memory was $1.6/Mcf)."

Global LNG on water for more than 20 and 30 days



Source: Bloomberg, Bernstein analysis

The peak of global LNG vessels on the water >20 days (one measure of ships functioning as storage) was 68 ships in Oct 2022 versus 35 today.

PFLNG SATU off the coast of Sarawak in Malaysia

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Two main drivers to watch

Bernstein sees two main drivers to watch for this year: storage levels, especially in Europe, and Asia's appetite to absorb more LNG cargos.

In Europe last year, prices skyrocketed amid Russia's invasion of Ukraine. European markets were willing to pay high prices to secure LNG cargo amid wartime supply disruptions. More than a year after the war began, European gas inventories are near the five-year high and on track to fill up soon following a warm winter globally and weak year-to-date industrial demand.

Likewise, storage levels in the U.S., Japan and Korea are also well above the five-year averages for the same reasons, Bernstein said.

The second relates to "the waiting arb," as Bernstein calls it.

The waiting arb, or arbitrage, depends on the month-to-month uptick in prices required to make waiting on the water for a month worthwhile, in contrast to delivering and returning to reload. That price is now around $6/MMbtu (in one month). Currently, the October to November arbitrage is only $3/MMbtu, Bernstein said.

"So, said another way, if Asia cannot pivot quickly enough to absorb more gas (our base case is still that they can), we would expect to see September/October TTF [Dutch Title Transfer Facility] fall to $10/Mcf and November to remain at $16/Mcf (i.e. the $6/MMbtu one-month waiting fee). This is more or less what happened last year on a smaller scale," Salisbury wrote.

U.S. LNG supply, Permian revisions

Rystad Energy views U.S. LNG supply as robust but foresees some export declines emerging due to possible issues at Cheniere Energy's Sabine Pass Train 3, the company said in a July. In Asia, LNG spot prices for August delivery are around $11/MMbtu.

"This has incentivized some players with U.S. free-on-board LNG cargoes to direct their LNG towards Asia rather than Europe," Rystad said. "However, finding Asian importers may be difficult as some countries still face high inventory, subject to demand fluctuation during summer."

U.S. gas production recently reached 103 Bcf for a few days in June, according to Wood Mackenzie, owing to rising Permian production after maintenance-related declines in late June, Goldman Sachs said in a July report.

Goldman's Dart said Permian production could be revised lower due to pipeline take-away capacity issues and limited room for additional exports to Mexico.

"We recently argued that, although the June rally in U.S. gas prices reduced the incentive for coal-to-gas substitution, the resulting negative impact on gas demand wasn't visible in the June data, and would likely unfold in subsequent weeks," Goldman reported.

Goldman said the lag between a large price move and a visible demand response often happens because utilities opting to switch fuels "might want to wait a bit to test whether the shift in price is persistent."

And they "typically rely on bid week towards the end of each month to change their gas nominations for the following month." OGI

BCG: Net-Zero Investments Short by $18 Trillion

A Boston Consulting Group study says a shortfall between now and 2030 could mean 2050 climate goals won't be met.

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Drone footage of oil storage silos and solar panels in the Eemshaven port in the Netherlands.

An investment gap of roughly $18 trillion could jeopardize a global push to achieve net-zero carbon emissions by 2050, according to a study by the Washington, D.C.-based Boston Consulting Group (BCG).

The International Energy Agency estimates $37 trillion is needed between now and 2030 to achieve net zero by 2050, BCG partner Rebecca Fitz said in a July press release. However, a BCG survey of around 300 large energy companies revealed investment plans of $19 trillion, which would leave a large investment gap.

The study revealed investments are lacking in several key areas: development of fossil and low-carbon fuels; infrastructure developments such as power grids and the expansion of electricity power generation; and decarbonization at the end-use category. End-use categories are broad and include everything from industrial supplies and capital goods to automotive vehicles and consumer goods.

"Our analysis found that the largest gap—about 50% of the total—was in the end-use category," said Fitz, also the associate director of BCG's Center for Energy Impact.

"This highlights that end-users—industrial goods companies such as steel, cement, and aluminum manufacturers—have critical roles to play," Fitz said. "They need to increase investments not only in energy efficiency, but also in fuel switching (for example, to biofuels) and on-premises renewables and carbon capture, utilization, and storage."

Fitz said the investment gap problem stemmed from a change in the energy ecosystem.

"Traditionally, energy has been an extractive resource. You extract and sell it. And that was a high risk, but high return, business. As we move to net zero, that premise changes," Fitz said. "Energy becomes less of an extractive resource and more of a developed and manufactured resource with lower risk and returns."

Given the high capital requirements that are still needed in the energy sector—including those related to wind and solar projects—the need for joint investments with customers is important.

"That changes the relationship between buyer and seller. You need a much bigger ecosystem where the energy providers and users are investing jointly to see projects through," Fitz said.

Large industrial energy users have a role to play as well in closing the energy transition investment gap. They can boost spending on energy transition initiatives, create new ecosystems between suppliers and users, capitalize on government support and subsidies and push business models and technological innovations, Fitz said.

Assistance is also needed from investors to close the investment gap.

"Investors need to fully integrate carbon risk into their portfolios—something that isn't happening today," Fitz said. OGI

Around the World

LATIN AMERICA

Argentina's Energy Secretary

Argentina's Economy Minister Sergio Massa (left) and the country's Energy Secretary Flavia Royón (right) during an event related to the completion of the President Néstor Kirchner Gas Pipeline (GPNK)

Argentina's LNG Project to Require $51 Billion Over 15 Years

About $51 billion in investments will be required over 15 years if Argentina is to join the global LNG exporting club, according to state-owned YPF SA.

Plans revealed by YPF and its Malaysian counterpart Petronas call for a 25 million tonnes per annum (mtpa) liquefaction facility with Atlantic Ocean access. Natural gas would be sourced from Argentina's prolific Vaca Muerta shale formation. YPF will hold a controlling 51% interest in the project and Petronas will hold the remaining 49%.

Commercialization of the shale resources could convert Argentina into the second-largest LNG exporter in the Latin America and Caribbean region, behind Mexico, bringing to market around 32 mtpa if it executes its actual, approved and planned liquefaction plants.

The lion's share of the investments, some $31 billion, will build out liquefaction capacity and construct pipelines to transport the Vaca Muerta gas in the Neuquén Province to a port at Bahía Blanca in the Buenos Aires province, YPF said in a June corporate presentation.

The first stage of the project will require $5 billion to construct a 5 mtpa floating liquefaction facility, while $2 billion will go to pipeline developments. YPF aims to make a final investment decision (FID) on the first stage by year-end 2024, it confirmed in the presentation.

The second stage of the project will require $10 billion for construction of a 10-mtpa onshore liquefaction facility and $2 billion for pipeline developments.

The third and final stage of the project will require $10 billion for construction of another 10-mtpa onshore liquefaction facility, with $2 billion for pipeline development.

Over 15 years, $20 billion will be needed to develop Vaca Muerta gas blocks, according to YPF.

Argentina's plans to move forward with the large-scale LNG exporting project will have varying impacts across the economy and primarily boost foreign investment, allow for the industrialization and development of infrastructure, and improve the country's trade balance through increased exports.

Argentina's Neuquén Province Gas Production Nears Record Highs

June natural gas production from Argentina's Neuquén Province, home to the Vaca Muerta shale formation, almost surpassed a record high obtained just last winter.

"Undoubtedly, the full commissioning of the Néstor Kirchner Gas Pipeline (GPNK) in the coming days will have an exponential impact on gas production in our province," Omar Gutiérrez, Neuquén Province governor, said in a July press release.

Gas production in Neuquén in June was 91.03 MMcm/d or about 3.21 Bcf/d, up 3.33% compared to May and up 0.93% compared to June of 2022, according to the province's energy ministry.

Provincial production in June rose mainly due to higher volumes in the Fortín de Piedra, Aguada Pichana Oeste, Rincón del Mangrullo, El Orejano and Sierra Chata areas, but came in just shy of August 2022's record high gas production of 91.5 MMcm/d, or 3.23 Bcf/d.

Pemex's Flaring Problem Not Going Away

A study by the Center on Global Energy Policy at Columbia University's School of International and Public Affairs confirmed in July that the state-owned Petróleos Mexicanos (Pemex) remains one of the world's largest sources of flared natural gas.

According to data from the World Bank, Mexico flared the world's seventh-largest gas volumes in 2022, and data from the Paris-based International Energy Agency (IEA) ranked the country as the 10th-largest methane emitter in 2021.

Despite the negative economic and environmental impacts of flaring, Pemex continues with the practice due to a political mandate from president Andrés Manuel López Obrador favoring production and refining to help Mexico achieve energy self-sufficiency. The country also suffers from a lack of economic incentives and lax regulatory policies.

The country's 2024 presidential election means reforms are unlikely or that Pemex will change direction on flaring this year or next.

OCEANIA

IGU: Australia Retains Top LNG Exporter Spot

The Aussies edged out the Americans to keep their crown as the world's largest exporter of LNG in 2022, according to the International Gas Union (IGU).

Australia exported 80.9 million tonnes (MMmt) in 2022, up from the 79 MMmt the country exported in 2021.

INEOS

Australia edged out the U.S. to maintain its position as the world's largest exporter of LNG in 2022, according to the International Gas Union. The top three exporters were: Australia, the U.S. and Qatar. Russia ranked fourth, despite western sanctions.

Similarly, the U.S. exported 80.5 MMmt in 2022 compared to the 70 MMmt the country exported in 2021—overtaking Qatar, which exported 80.1 MMmt in 2022 and exceeding its 77.1 mtpa of nameplate capacity, the IGU said in its "2023 World LNG Report" published in July.

The top three exporters—Australia, the U.S. and Qatar—were collectively responsible for 60% of global LNG output in 2022.

Russia, despite its invasion of Ukraine in early 2022, retained its position as the fourth-largest LNG exporter, transporting 33 MMmt in 2022, followed by Malaysia with 27.3 MMmt in 2022.

"Global LNG trade grew by 6.8% between 2021 and 2022 to about 401.5 [MMmt]," the IGU said.

The U.S. was the prime contributor to the rise in LNG exports in 2022. U.S. exports rose by 10.5 MMmt, or 15%, following the start of Sabine Pass Train 6 and Calcasieu Pass projects.

Africa's Mozambique joined the LNG exporters' club in 2022, sending out its first cargo from Coral South FLNG in November.

Energy market volatility, spanning from the start of the COVID-19 pandemic in 2020 to Russia's invasion of Ukraine in early 2022, forced world leaders to rethink and prioritize energy security—delaying decarbonization goals in some cases. The heightened uncertainty has benefited LNG exporters and boosted interest in building liquefaction and regasification facilities worldwide.

NORTH AMERICA

NextDecade Takes FID on $18.4B Rio Grande LNG Phase 1

NextDecade Corp.'s $18.4 billion Rio Grande LNG (RGLNG) export facility is a go, the company said in a July press release.

The company reached FID on the first three trains for the 17.6 mtpa Phase 1 of its liquefaction facility in Brownsville, Texas.

NextDecade said the planned 27 mtpa RGLNG facility to be built in two phases is the largest greenfield energy project financing in U.S. history and "underscores the critical role that LNG and natural gas will continue to play in the global energy transition."

U.S. LNG exporters gained greater importance in 2022, especially in Europe after Russia's invasion of Ukraine and Moscow's decision to reduce gas exports to the European Union. Demand for LNG is expected to remain robust in Europe and Asia for decades, according to many analysts.

The FID comes as NextDecade executed and closed a joint venture (JV) agreement for Phase 1 which included approximately $5.9 billion of financial commitments from Global Infrastructure Partners (GIP), GIC, Mubadala Investment (collectively the Financial Investors) and TotalEnergies.

Under the JV agreement executed, NextDecade will hold equity interests that entitles the company to receive up to 20.8% of the cash flows generated by Phase 1 during operations. Financial Investors will hold equity interests that entitle them to a minimum of 62.5% of the cash flows generated by Phase 1 during operations and TotalEnergies will be entitled to 16.7%.

NextDecade also said it had committed to invest approximately $283 million in Phase 1, including $125 million of pre-FID capital investments. The company also closed senior secured non-recourse bank credit facilities of $11.6 billion as well as a $700 million senior secured non-recourse private placement notes offering.

Of Phase 1's nameplate liquefaction capacity of 17.6 mtpa, NextDecade said it had long-term binding LNG sale and purchase agreements for 16.2 mtpa with TotalEnergies, Shell, ENN LNG, Engie, Exxon Mobil, Guangdong Energy Group, China Gas Hongda Energy Trading, Galp Trading and Itochu Corp.

NextDecade Corp.'s FID to Fuel Second Wave of US Exporting Power

NextDecade Corp.'s recent $18.4 billion FID for Phase 1 of its Rio Grande LNG (RGLNG) project is a key to U.S. efforts to boost LNG exports to markets in Europe and Asia, an analyst with ICIS told Hart Energy.

"NextDecade's FID is the third U.S. LNG FID of 2023 alongside Venture Global at Plaquemines and Sempra at Port Arthur," ICIS global LNG market specialist Ed Cox told Hart Energy. "Put together, these three projects will supply more than 50 mtpa of LNG in the next wave of U.S. LNG exports."

The start of the Russia-Ukraine war in 2022 and the resulting gas shortage in Europe shone a spotlight on the importance of U.S. LNG exports. Numerous U.S. LNG projects under construction or nearing completion will allow the U.S. to continue to boost LNG supply over the near-term, to the delight (or relief) of gas-hungry regions such as Europe and Asia.

Global LNG trade set a record high in 2022, averaging 51.7 Bcf/d, up 5% compared to 2021, according to CEDIGAZ data.

Europe's growing demand for LNG, coupled with major Chinese commitments to the next wave of U.S. LNG projects, will be beneficial for domestic exporters.

"[This] means that projects that were previously struggling to progress have had much greater commercial momentum over the past two years," Cox said, adding that commercial discussions remain challenging due to ballooning contractor costs.

The U.S. is set to become the largest LNG exporter globally in 2023, according to ICIS. Overall North American LNG exports are expected to hit a record high of 90.2 million tonnes (11.8 Bcf/d) in 2023 and rise to 93.2 million tonnes (12.2 Bcf/d) in 2024. OGI


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CEO: Exxon Mobil Can Produce Lithium at 'Much Lower Cost'

The supermajor is investing $17 billion in low-carbon businesses but is also considering lithium production, Darren Woods says.

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Daniel Ortiz/Hart Energy

CEO Darren Woods says Exxon Mobil is considering lithium production.

Exxon Mobil plans to invest billions of dollars in low-carbon segments like carbon capture, biofuels and hydrogen. But the U.S. supermajor is also evaluating opportunities in lithium production, CEO Darren Woods said.

Exxon Mobil plans to plans to invest $17 billion into low-carbon initiatives in the coming years, but it has reportedly also been making a quick—and quiet—entrance into the lithium space.

Exxon Mobil acquired drilling rights for over 100,000 gross acres in southern Arkansas from which it plans to produce lithium, a key mineral used in electric vehicle batteries, The Wall Street Journal reported in May.

This summer, a subsidiary, Saltwerx LLC, signed a memorandum of understanding (MOU) with services company Tetra Technologies to develop about 6,138 acres in Arkansas' Smackover formation for potential lithium brine production, Reuters reported.

Exxon Mobil declined to comment.

The company continues to focus its low-carbon efforts on the so-called "molecule side of the equation" of the energy transition, Woods said during the second-quarter earnings call with analysts.

In contrast to the electron side of the transition—developing wind, solar or battery storage projects—Exxon Mobil sees growing opportunity in carbon capture, utilization and storage (CCUS), low-carbon hydrogen and fuels made from renewable feedstocks.

Lithium production from brine water is an extension of the company's current upstream capabilities, Woods said.

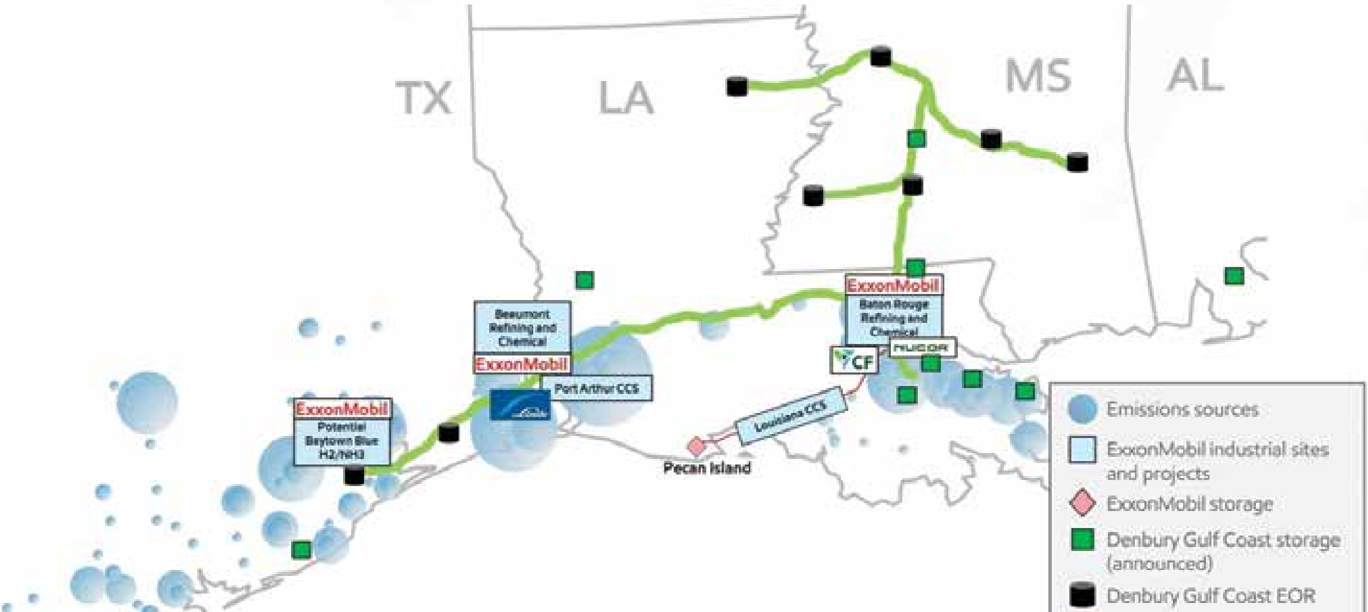
"It requires a good understanding of the subsurface, it requires a good understanding of reservoir management, it requires drilling and injections," Woods said on the call. "I think the below-surface things are very much in line with the skills and capabilities that we've built out over the decades in our upstream business."

Woods also noted that processing brine water to extract lithium is similar to operations Exxon already performs at its refineries and chemical plants.

With global lithium demand forecast to double over the next five years, Exxon can leverage its scale and existing advantages to bring lithium to market "at a much lower cost," Woods said.

"And I think, importantly, with much less environmental impact versus, say, the open

Exxon goes big on CO_2 transport, storage



Exxon's acquisition of Denbury includes a 1,300-mile CO_2 pipeline, 70% of which runs through Gulf Coast states with high industrial emissions.

Source: Exxon Mobil

mining that they're doing in other parts of the world," he said.

However, Exxon is still early in evaluating its lithium opportunities, Woods said.

Carbon capture

While Exxon is still in the early innings on lithium, the company is making major investments into carbon capture and sequestration (CCS).

Exxon's $4.9 billion bid to acquire Denbury Inc., announced in July, will deliver a key component to the company's emerging CCS business: the nation's largest network of CO_2 pipelines and access to 10 onshore sites for permanent CO_2 sequestration.

Plano, Texas-based Denbury uses its 1,300-mile CO_2 pipeline network, somewhat paradoxically, as part of a process to produce barrels of oil. The company's main business is EOR, where CO_2 is injected under pressure into oil-bearing reservoirs to maximize oil recovery from a field.

EOR is Denbury's core business today and has facilitated the development of the company's existing infrastructure, Woods said. But Denbury's EOR production wasn't a key driver for Exxon's multibillion-dollar acquisition.

"If you think about the broader opportunity, it's really around carbon capture storage, sequestration and keeping the carbon under the ground," Woods said. "That's the longer-term play for us."

But as Exxon Mobil works through regulatory and permitting constraints to start permanently sequestering CO_2 in subsurface formations, Denbury's EOR business gives the supermajor options to choose from.

The company has already secured several major CO_2 offtake agreements with third-party customers, like industrial gas company Linde, steelmaker Nucor and fertilizer maker CF Industries. Exxon Mobil's offtake arrangement with Linde—a deal to transport and store up to 2.2 million metric tons of

"I think the below-surface things are very much in line with the skills and capabilities that we've built out over the decades in our upstream business."

—**Darren Woods, *CEO, Exxon Mobil***

CO_2 per year from Linde's blue hydrogen production plant in Beaumont, Texas—is slated to begin in 2025.

If Exxon doesn't have its ducks lined up on the sequestration side when it starts capturing CO_2 from third-party customers, EOR gives the company an option to facilitate the offtake agreements and not fall off schedule, Woods said.

Adding Denbury's EOR assets is expected to provide immediate cash flow of around $600 million annually.

Exxon Mobil and fellow supermajor Chevron both reported a drop in second-quarter earnings as the companies faced volatile natural gas and refining markets.

Exxon booked earnings of $7.88 billion during the quarter, down 31% from $11.43 billion last quarter. Chevron's second-quarter haul of $6.01 billion was down 8% from the California-based company's first-quarter earnings of $6.57 billion.

Both companies said that lower upstream realizations and declines in refining margins negatively impacted profitability for the quarter. OGI

DAC Projects Capture $1.2 Billion in Funding

Demonstration projects by Oxy and Battelle aim to kickstart the first two U.S. commercial-scale facilities.

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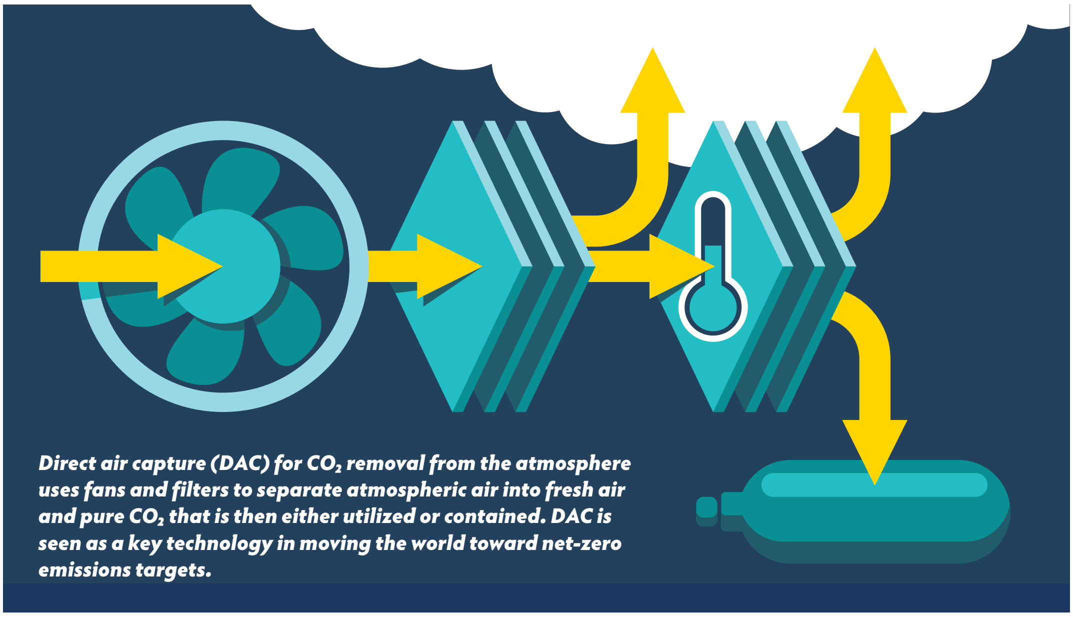

Direct air capture (DAC) for CO_2 removal from the atmosphere uses fans and filters to separate atmospheric air into fresh air and pure CO_2 that is then either utilized or contained. DAC is seen as a key technology in moving the world toward net-zero emissions targets.

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Two direct air capture (DAC) projects—one led by Occidental subsidiary 1PointFive in Texas and the other by Battelle in Louisiana—have landed up to $1.2 billion in funding from the U.S. Department of Energy (DOE), becoming the world's largest investment in engineered carbon removal, the Biden administration said in August.

As the first two recipients of the Bipartisan Infrastructure Law-funded Regional Direct Air Capture Hubs program, the demonstration projects aim to kickstart and advance development of the nation's first two commercial-scale DAC facilities. Described as a giant vacuum that sucks CO_2 directly from the atmosphere, DAC is seen as a key technology in moving the world toward net-zero emissions targets.

"Once we harness that pollution, we can trap it permanently deep underground, or we can turn it into building materials, or we can turn it into agricultural products or even clean fuels," Energy Secretary Jennifer Granholm told the media prior to public announcement.

"If we deploy this at scale, this technology can help us make serious headway toward our net-zero emissions goals, while we are still focused on deploying, deploying, deploying more clean energy at the same time."

Between 400 million and 1.8 billion metric tons of CO_2 must be removed from the atmosphere and captured annually by 2050 to meet the Biden administration's net-zero emissions target, by DOE's estimates.

Together, Louisiana's Project Cypress and South Texas' DAC Hub are expected to remove more than 2 million metric tons of CO_2 from the atmosphere annually. That's equivalent to taking nearly half a million gas-powered cars off the road, Granholm said. The projects will form regional DAC hubs to "link everything from capture to processing to deep underground storage, all in one seamless process" and help the U.S. "prove out the potential of this game-changing technology so that others can follow in their footsteps."

Working with Climeworks and Heirloom Carbon Technologies, Battelle is managing the project in Calcasieu Parish where plans are to capture more than 1 million metric tons of existing CO_2. The captured carbon will be stored underground by geologic storage company Gulf Coast Sequestration.

"We've had a long-term, proven record of managing large, complex projects that bring the latest technology systems together at scale, with the goal of making the world safer, healthier and more sustainable," said Battelle CEO Lou Von Thaer.

"And this is a perfect example," he said, citing the partnerships with the federal government, including seven national labs.

Filling the gap

At the South Texas DAC Hub in Kleberg County, 1PointFive partnered with Carbon Engineering and Worley on a DAC facility designed to remove and store up to 1 million metric tons of CO_2 annually. Oxy announced in mid-August that it would purchase Carbon Engineering for $1.1 billion.

Oxy CEO Vicki Hollub said the DOE's selection of the project "validates our readiness, technical maturity and our ability to use Oxy's expertise in large projects and carbon management to move this technology forward so it can reach its full potential."

The facility is located on 106,000 acres of surface land leased from King Ranch, a privately-held agricultural company. Oxy has said the site is large enough to support up to 30 DAC plants.

The project will be powered by solar energy, Hollub said.

FEED work for the South Texas hub's first DAC plant and preparations to drill test wells needed to gather data for a Class VI well permit are underway, 1PointFive said in a news release in August. The plant's design is adapted from Stratos, 1PointFive's first commercial-scale DAC plant under construction in the Texas Permian Basin.

Stratos is expected to start up in 2025.

Neither project will use CO_2 for enhanced oil recovery, said Kelly Cummins, deputy director of the Office of Clean Energy Demonstrations. She added that the projects are focused on making sure the technology can scale commercially with revenue streams that support uptake of the technology.

"I will also say that the nonfederal funding is at least 50% of the contribution to these projects," Cummins said. "So, we want to make sure that these companies and these projects are financially viable in the long term, so we're not restricting revenue sources."

Today's primary market is voluntary with significant commitments from a handful of corporate leaders, added Noah Deich, deputy assistant secretary for the DOE's Office of Carbon Management.

"There's greater demand than supply, and these projects will be really critical for helping to fill that gap once they do start to come online," Deich said.

The potential awards should help de-risk capital deployment in the medium term, analysts with Tudor, Pickering, Holt & Co. said in an August note.

"We suspect investors currently ascribe little value to the DAC business given its nascent stage, but awards like these (and potential third-party funding) will help to de-risk capital deployed into the development of the 1PointFive business over the coming years," TPH said in the note.

Meanwhile, eyes are on Stratos "to better understand construction costs, timelines, and viability of expanding."

Funding for two more potential DAC hubs is expected in the coming years, as the Bipartisan Infrastructure Law allocates $3.5 billion to create four hubs.

Along with the Louisiana and Texas projects, the DOE said it has selected 19 more projects (14 feasibility studies and five FEED studies) for award negotiations to support early-stage project development as it assesses the viability of future DAC Hub demonstrations. OGJ

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▸ **ENERGY** TRANSITION

Ørsted Optimistic, Despite Rough Summer

The Danish offshore wind developer is one of many that have faced supply chain issues, inflationary pressure and rising cost of capital.

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As Danish offshore wind developer Ørsted gears up to expand its pipeline of projects in the U.S. and abroad, CEO Mads Nipper sees more challenges ahead for the sector.

Speaking to analysts during Ørsted's second-quarter earnings call in August, Nipper described the summer as eventful as some of the offshore wind industry's projects were rejected or fell apart.

The company's joint bid with Eversource for the Revolution Wind 2 project was rejected by Rhode Island Energy, which said the project didn't meet all requirements in the Affordable Clean Energy Security Act. Regulators in Sweden shot down Swedish utility Vattenfall's request to construct the Stora Middelgrund wind farm with about 50 turbines, citing potential negative impacts on shipping and sensitive natural values.

Though the push toward lower carbon energy sources has led to higher demand for clean energy such as wind, the sector has faced supply chain issues, inflationary pressure and rising cost of capital as it works to scale the global offshore market.

Citing high capex and finance costs, SouthCoast Wind—the 50:50 joint venture between Shell New Energies and Ocean Winds North America—began talks with Massachusetts to terminate and rebid its existing power purchase agreements. Ørsted was among those in June that requested inflation adjustments on existing contracts for projects offshore New York.

Also, during the summer, price concerns—specifically record high concession prices and their potential to raise consumer prices—prompted Ørsted to exit Germany's offshore wind auction.

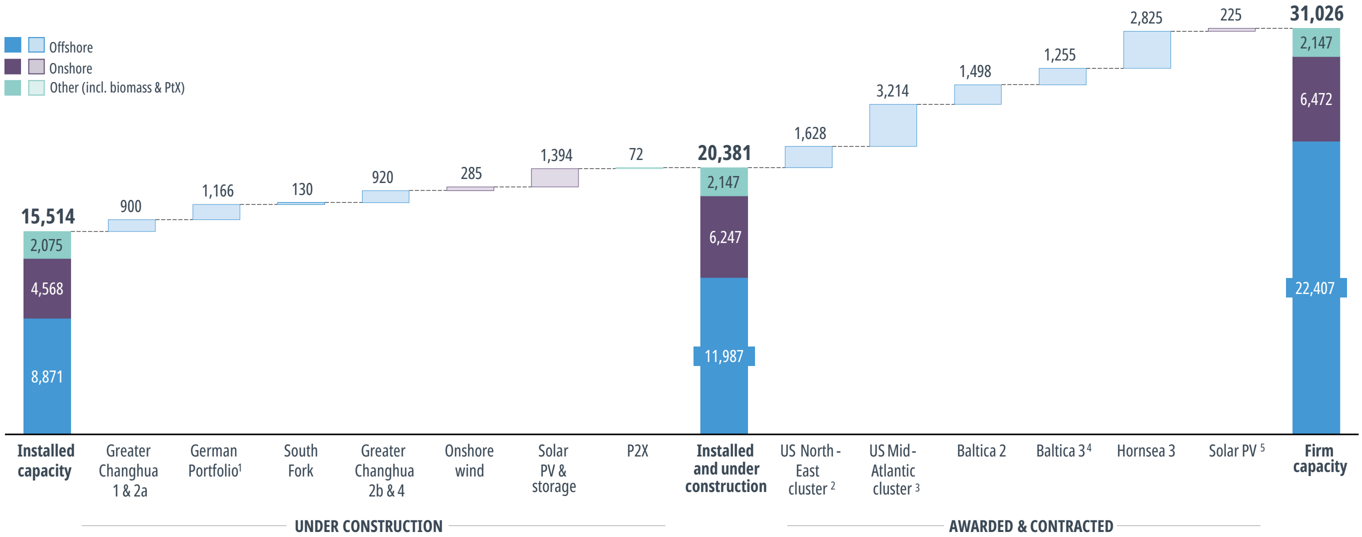
Still, Nipper said Ørsted remains confident in the offshore market's scalability, adding the industry and regulators must overcome challenges.

"We think it is good that the industry is showing financial discipline like, for example,

Ørsted construction program and pipeline

Gross renewable capacity

MW



Source: Ørsted

1.German Portfolio: Gode Wind 3 (253 MW) and Borkum Riffgrund 3 (913 MW), 2.US North-East cluster: Revolution Wind (704 MW) and Sunrise Wind (924 MW), 3.US Mid-Atlantic cluster: Skipjack 1 (120 MW), Skipjack 2 (846 MW/), Ocean Wind 1 (1,100 MW/) and Ocean Wind 2 (1,148 MW/), 4. Includes both Baltica 3 (1,045 MW) and the awarded lease capacity for Baltica 2+ (210 MW/), 5. Ballinrea Solar Farm (65 MW) and Gareenleen Solar Farm (160 MW/) Onshore firm capacity (6,472 MW) consist of 3,785 MW wind, 2,347 MW solar PV, and 340 MW storage

… pulling a project because that is a very stark reminder, for example, in this case the U.K. authorities, that prices need to be different and the auction frameworks need to change," Nipper said. "But we are generally confident that there will be a move that will advance offshore."

Seeing value, despite challenges

Analysts on the call questioned whether the decision in Rhode Island, a lawsuit by New Jersey residents opposing a tax break that the state granted Ørsted for a wind farm and other concerns in U.S. offshore wind, could lead the company to rethink some financial investment decisions in the U.S.

Nipper pointed out the good potential for value creation.

"We have gotten the record of decision for Ocean Wind 1, so the permitting is moving along," he said.

The 1.1-gigawatt (GW) Ocean Wind 1 offshore New Jersey was approved in July by the Bureau of Ocean Energy Management, and New Jersey passed legislation for the project to access and retain all federal tax credit.

"And we continue to have good dialogues about the adjustment in New York for our Sunrise 1 project as well.… We are achieving some milestones," he added. "We are still working towards the FID [final investment decision] as mentioned on Hornsea [in the North Sea]. So, given where we are, especially on the U.S. projects and the rest of our portfolio, we see no positive value creation impact by walking away from projects and pursuing new" ones.

Ørsted aims to install nearly 30 GW of offshore wind capacity by 2030. During second-quarter 2023, it added 3 GW to its pipeline. That included 2 GW in the U.S. via an acquisition from Eversource.

Advancing projects

Progress is being made on projects in the U.S. and other parts of the world.

At the Greater Changhua 1 and 2a wind farms in Taiwan, all export cables, array cables and jacket foundations have been installed. More than 80 turbines are producing energy with 14 more remaining to be installed. "We aim to commission the project in the second half of this year," Nipper said.

The 130-megawatt South Fork Wind offshore New York is expected to start operations this year.

"The team has reached a huge milestone by successfully installing the first-ever American built offshore wind substation as well as all foundations for the project," Nipper said. "These fantastic achievements mean that the 130-megawatt project is on track to become the first completed utility-scale offshore wind farm in the U.S. with expected commissioning by the end of 2023."

Ørsted is looking to win some of the up to 50 GW of offshore wind capacity expected to be auctioned in 2023 and 2024. The company submitted a proposal for development rights offshore New York, which intends to announce awards in fourth-quarter 2023.

Other upcoming auctions and tenders are set for offshore New Jersey, Norway and the U.K. this year, with more expected next year offshore Denmark, Germany, Ireland, the Netherlands, Taiwan and the U.S.

The tenders illustrate the "huge growth potential of the offshore wind industry," Nipper said.

"Ørsted has an industry leading renewables pipeline of more than 100 gigawatts, and we will stay disciplined in our bidding approach for new tenders and select the most value creating opportunities." OGI

▸ **ENERGY** TRANSITION

Linde Primed for Growth in Hydrogen Market

Even as E&Ps move in, CEO Sanjiv Lamba says his company can scale up.

Linde

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As the number of hydrogen players expands due to big oil companies entering the game, Linde sees opportunity—not threat—for demand of the multinational company's services and assets.

"It's a bread and butter part of our business. We know it well. We manage those processes well," Linde CEO Sanjiv Lamba said in late July of hydrogen production. "In a large refinery or a chemical complex, those assets sit by themselves and really do not get optimized. So, there is a value that gets unlocked by bringing a very competent operator like Linde into the mix."

During Linde's second-quarter 2023 earnings call, the chemicals company's executives fielded questions from analysts seeking insight on how the U.S. Inflation Reduction Act (IRA) could impact Linde's businesses and more details on $50 billion worth of global investment opportunities over the next decade.

Global demand for hydrogen, which has near-zero greenhouse gas emissions, is forecast to surpass 150 million tonnes (MMtonne) by 2030, up from 95 MMtonne in 2022, according to the International Energy Agency. About 30% of the demand is expected to come from new applications, including the shipping sector. Linde is eyeing growth in the hydrogen fuel market among other areas. "Even a small slice of the pie makes it very interesting from a Linde perspective," he said.

Positioned for growth

Boasting 200 hydrogen fueling stations, more than 1,000 km of hydrogen pipeline and transport and production facilities, "Linde has the ability to scale that up and provide hydrogen to refiners in addition to ensuring that surplus hydrogen is put into that pipeline network, providing a significant advantage and obviously getting us economic return," Lamba said.

Along the U.S. Gulf Coast, for example, multiple assets are already hooked into the network, reducing operational risks that may come with a single large site or plant. He agreed that the IRA is making hydrogen financially attractive to traditional oil companies and hydrogen producers alike.

"But in many of those cases, people might own assets and often they need to either incorporate that into our network and/or operate and manage it, as well," Lamba said. "Again, providing greater opportunity for us. You put that together, I think that's essentially what the hydrogen of the future is going to look like from a U.S. Gulf Coast perspective, replicated in many other parts of the world."

Signed into law in 2022, the IRA includes nearly $370 billion in incentives for clean energy and climate-related spending. Hydrogen incentives in the IRA include a 10-year production tax credit with a maximum value of $3/kg for hydrogen produced with nearly no emissions.

The law also provides incentives for carbon sequestration, which is used for blue hydrogen. Provisions include a tax credit of $85/ton for sequestering CO_2 produced

(Left) Linde hydrogen refinery in Texas; (above) Linde's hydrogen center in Unterschleissheim, Germany.

Linde

by industrial activity, up from $50/ton. It also adds a tax credit of $180/ton for direct air capture.

Quarterly results

While the forecast looks bright, Linde saw its second-quarter sales dip by 3% to about $8.2 billion compared to a year earlier. The drop was attributed to base volume declines due to some temporary outages on the U.S. Gulf Coast and a decline in Europe.

In a Reuters article, Baader Helvea bank analyst Markus Mayer pointed out the cyclical nature of the segment.

"Late cyclicality of the industrial gas business has started to be felt and should accelerate over the coming quarters," Mayer wrote in a note, adding this confirmed the bank's cautious view on the stock.

"Despite the lower year-over-year volumes, operating profit of $2.3 billion increased 15% and resulted in an operating margin of 27.9%," CFO Matt White said. "We anticipate sequential volume growth into Q3."

Reported second-quarter 2023 net income was about $1.8 billion.

Linde's CEO said the company managed inflation by contractually passing through energy costs.

"On top of this, we continuously optimize costs through robust productivity initiatives. Ultimately, it's the spread between price and cost, which adds compound value. Add to that a backlog that fuels growth," Lamba said.

More to come

In the past 12 months, the company started 22 projects valued at $2.1 billion, while winning 38 new projects valued at nearly $3 billion. "Looking ahead, investors can rest assured we will win projects that add value commensurate with risk," Lamba said. "With this in mind, we continue to make good progress on the $50 billion of clean energy opportunities, of

"[Hydrogen is] a bread and butter part of our business. We know it well. We manage those processes well."

—**Sanjiv Lamba,** ***CEO, Linde***

which I expect $9 [billion] to $10 billion to be decided in the next few years."

Linde's order backlog ended the quarter at $7.8 billion as green energy investment rose.

The company sees $30 billion in potential investment over the next decade for the U.S., which accounts for about 60% of Linde's decarbonization plans.

Projects could also be on the horizon in the Europe/Middle East and Asia-Pacific regions. Areas include mobility such as hydrogen refueling stations (10%), industrial applications such as blue and green hydrogen projects (60%); and hydrogen as an energy carrier, which Lamba said may involve green ammonia and methanol.

Linde is working with SLB on a carbon capture and sequestration (CCS) project in Saudi Arabia. FEED is underway with a final investment decision expected in early 2024.

"We're looking at a very large scope of carbon capture. In fact, the first phase we're currently working on is 11 million tonnes of CO_2 a year," Lamba said, noting the three-phase CCS project could become the world's largest, "adding up to 54 million tonnes per annum of CO_2 being sequestered." OGI

Transition in Focus

BIOFUELS/RNG

SoCalGas Submits Application for Large RNG Pilot Project

Southern California Gas Co. (SoCalGas) plans to turn agricultural waste into renewable natural gas (RNG) as part of what could become California's largest RNG pilot project.

The project, which would be developed by San Joaquin Renewables in McFarland, Calif., would produce up to 4.5 Bcf of RNG annually from 400,000 to 500,000 tons of agricultural waste, if the project is approved. SoCalGas submitted its application for the project to the California Public Utilities Commission (CPUC).

As part of ongoing clean energy efforts to reduce emissions, the CPUC requires utilities to hit biomethane procurement targets and replace a certain percentage of traditional gas with RNG by 2030.

SunGas Renewables Forms Beaver Lake to Build $2B Green Methanol Facility

Houston-based GTI Energy spinout SunGas Renewables has formed a subsidiary that will build a $2 billion green methanol facility in Louisiana, transforming a former International Paper Co. facility in Rapides Parish.

Wood fiber will be used to make the green methanol, the company said.

The investment comes as demand for green fuels rises. The subsidiary, called Beaver Lake Renewable Energy, plans to produce nearly 400,000 metric tons of green methanol per year for marine fuel, SunGas said in a news release. It will be used to power A.P. Moller-Maersk's fleet of vessels. Construction of the facility is set to begin in late 2024, with operations starting in 2027.

Vision RNG's Gas Project Starts Operations

Business Wire

Vision RNG's Landfill Gas to RNG project at Meridian Waste's Eagle Ridge Landfill in Missouri produces 375,000 MMBtu of RNG annually.

Vision RNG's Landfill Gas (LFG) to RNG project at Meridian Waste's Eagle Ridge Landfill in Bowling Green, Mo., has begun operations. The project uses 1,500 scf/min of LFG and produces 375,000 MMBtu of RNG annually, enough RNG to heat about 8,800 homes per year.

"This is the first of several LFG to RNG projects VRNG will be bringing online, including projects in Kentucky, Alabama, South Carolina and Oklahoma," VRNG Bill Johnson said in a press release.

The Missouri Clean Energy Project is the first of three that Meridian Waste has partnered with Vision RNG. RNG production is seen as a carbon-neutral energy solution that lowers methane emissions while utilizing current natural gas infrastructure.

ENERGY STORAGE

RWE Brings Texas Battery Storage Online Amid Heat Wave

RWE

RWE's Texas Wave II battery storage facility is located in Scurry County, Texas.

RWE has brought its 30-megawatt (MW) Texas Waves II co-located battery storage facility online in Texas, the company said.

Located at the Pyron Wind Farm in Scurry, Texas, southeast of Lubbock, the facility features a 1-hour lithium-ion battery and provides ancillary services to the energy market and grid operator Electric Reliability Council of Texas.

The project follows Texas Waves I, two 9.9-MW short duration energy storage projects that went online in 2017 at the RWE Pyron and Inadale wind farms in West Texas.

Battery energy storage systems store energy from various sources and discharge it when needed such as when demand exceeds supply. RWE said it has about 2.5 gigawatt-hours (GWh) of battery storage projects underway in the U.S.

Arizona Lithium Raises $10M to Advance Prairie Lithium Project

Arizona Lithium has received firm commitments of $10 million to move its Prairie lithium project forward in the Williston Basin of Saskatchewan, Canada.

The commitments were made through share placement to institutional and professional investors at $0.025 per share with one free attaching option per one new share, the company said in a news release.

Funds will also be used to complete construction of a lithium

Advance Prairie lithium project locations

1. Lightning Dock Geothermal Plant
2. Tesla Gigafactory
3. Nikola Coolidge Manufacturing Facility
4. Proposed Kore Power "Koreplex" Facility
5. Lucid Motors AMP Facility
6. Lithium Research Centre

Source: Arizona Lithium

research center, which Arizona Lithium said will enable treatment of bulk samples from the Big Sandy Lithium project in Arizona. The center, located in Tempe, Ariz. will serve as a technology incubator.

Considered a critical mineral in short supply, the U.S. has been working to increase domestic production and processing of lithium, which is used to make batteries for electric vehicles (EV). Lithium demand is expected to grow 43 times by 2040 amid rising demand for EVs, according to the International Energy Agency.

HYDROGEN

Cummins, Chevron Sign Hydrogen, Gas MOU

Cummins Inc. and Chevron will work together to leverage complimentary positioning in hydrogen, natural gas and other lower carbon fuel value chains.

The companies each have contributed to the research, development and deployment of alternative fuel systems and technologies. They will work together to enable the commercial development at scale of alternative fuels production, transportation and delivery systems for industrial and commercial markets, with target consumption by transportation vehicles of the type manufactured by Cummins.

The new collaboration focuses on hydrogen, natural gas and other alternative lower-carbon intensity fuels such as renewable gasoline blend, biodiesel, renewable diesel, compressed natural gas and other liquid renewables to expand commercial adoption.

SOLAR

First Solar, Maxeon to Build Separate $1B Manufacturing Facilities

The U.S. Inflation Reduction Act (IRA) and the nation's ambitions to reduce emissions continue to boost the solar sector with two companies announcing plans for $1 billion-plus solar panel manufacturing facilities.

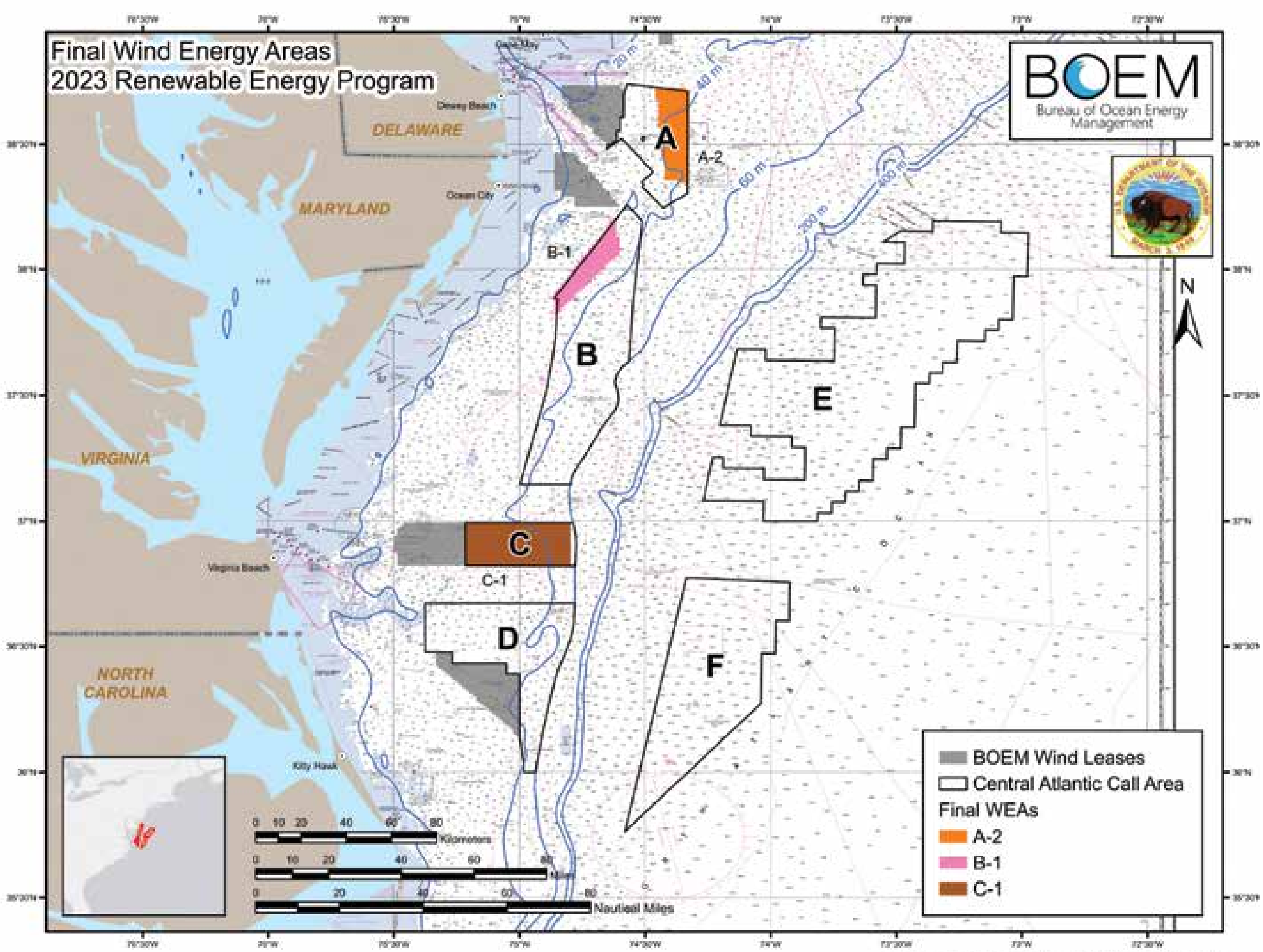
Maxeon

A rendering on Maxeon's new manufacturing site in New Mexico

Louisiana's Iberia Parish will become home to First Solar's fifth manufacturing facility in the U.S. The 3.5-gigawatt (GW) facility represents a $1.1 billion investment for the Arizona-headquartered company and is expected to create more than 700 new direct manufacturing jobs in the state. The facility, which will produce First Solar's Series 7 modules, is expected to be complete in the first half of 2026 and boost the company's U.S. nameplate manufacturing capacity to about 14 GW. The facility will be located at the Acadiana Regional Airport.

Singapore-headquartered Maxeon Solar Technologies said it will build a 3-GW photovoltaic (PV) cell and panel manufacturing facility in Albuquerque, N.M., marking an investment of more than $1 billion—subject to securing a loan from the U.S. Department of Energy.

Maxeon said its facility will produce Tunnel Oxide Passivated Contact (TOPCon) PV-silicon solar cells and shingled-cell Performance Line solar modules. Construction is scheduled to begin in first-quarter 2024. The facility will open in 2025. Given it will sit on a 160-acre site with sufficient infrastructure and customer demand, Maxeon said it might increase the nameplate capacity of the facility to 4.5 GW.



Source: BOEM

Forecast Shows Utilities Adding 35.2 GW of Capacity to Power Grids

Solar developers are expected to lead the way toward another 35.2 GW of total new utility-scale capacity additions in the U.S. in the second half of 2023, according to the U.S. Energy Information Administration (EIA).

Planned capacity for solar could reach 19.3 GW later this year, accounting for 55% of the total 2H23 capacity additions, the EIA said. About 7.8 GW of battery storage capacity additions are expected and 4.9 GW of wind.

The forecast, released as part of the EIA's latest inventory of electric generators, was delivered as renewable energy companies pursue more new projects and startup others that had been delayed, utilizing incentives made available in the Inflation Reduction Act.

The growth also comes as operators retire or gear up to retire some 15.3 GW of electric generating capacity from coal-fired and natural gas power plants amid the transition to lower carbon energy sources.

Canadian Solar Lands EDF Renewables Solar Module Order

EDF Renewables North America has tapped Canadian Solar to supply up to 7 GW of solar modules, the renewable energy company said.

The N-type TOPCon solar modules will be produced at Canadian Solar's new factory in Mesquite, Texas, the Ontario-based company's first U.S. manufacturing facility.

The agreement was reached as EDF Renewables aims to increase its global renewable capacity to 50 GW, up from 28 GW, by 2030 and Canadian Solar boosts its supply of solar modules to meet growing clean energy needs. It also comes as the IRA incentivizes growth.

Canadian Solar said its Mesquite facility will have an annual output of 5 GW when it is fully ramped up. Production is scheduled to start in fourth-quarter 2023.

WIND

US Finalizes Additional Areas for Wind Development

With ambitions to deploy 30 GW of offshore wind energy capacity by 2030, the U.S. has finalized three more wind energy areas off the East Coast.

Combined, the three areas spanning 356,550 acres offshore Delaware, Maryland and Virginia have the potential to support up to 8 GW of renewable energy, according to the U.S. Bureau of Ocean Energy Management (BOEM).

The areas were developed following feedback from the public, including states, tribes, local residents, ocean users and federal government partners, BOEM said. If it decides to proceed with a lease sale in any of the areas, additional public comment will be sought. OGI

Matador Expands Permian Capacity in Delaware Basin

The E&P plans to boost its natural gas processing capacity to serve third-party demand and its own development plans.

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Matador Resources is expanding its gas processing capacity in the Delaware Basin to service third-party demand and the E&P's own development plans as it integrates assets acquired earlier this year for $1.6 billion.

Dallas-based Matador Resources plans to make investments this year to boost the flow assurance of the company's natural gas production in the Delaware, Joseph Wm. Foran, Matador founder, chairman and CEO, said in the company's second-quarter earnings report.

Matador acquired Delaware Basin midstream assets in a transaction with Summit Midstream Partners last summer.

The Summit assets—later rebranded as Pronto Midstream—included 45 miles of gas gathering pipelines in Lea and Eddy counties, N.M.; a cryogenic gas processing plant with an inlet capacity of 60 MMcf/d; and three compressor stations, according to Securities and Exchange Commission filings.

The Pronto system assures additional flow capacity for Matador's acreage in the northern Delaware, Foran said. The assets also deliver flow capacity for the incremental production Matador scooped up through its acquisition of Advance Energy Partners earlier this year.

Matador has connected more than 15 of its wells in Lea County to the Pronto system to date, and the E&P expects to connect the Advance assets into the system later this year or in early 2024.

As the company begins to develop the newly acquired Advance acreage, and as third-party demand for gas gathering and processing in the Delaware grows, Matador now plans to expand the Pronto system.

Matador is looking to add a larger cryogenic gas processing plant with an inlet capacity of 200 MMcf/d to the Pronto system.

"We are currently evaluating whether to include a partner in building the processing plant," Foran said.

In a July research report, Siebert Williams Shank & Co. Managing Director Gabriele Sorbara said the new processing plant could cost in the range of $180 million to $220 million over an 18- to 24-month period.

"With our estimated maintenance capex plus a majority owned new gas plant on the Pronto assets, we model total midstream spending at $200 million for 2024," Sorbara said.

Matador also owns operational control of the San Mateo midstream assets in the Delaware, per regulatory filings.

Service costs soften

Matador, like other oil and gas E&Ps, reported seeing some relief on high drilling and completion costs during the second quarter.

The company incurred drilling, completion and equipping capital expenses of $310 million during the quarter—14% below Matador's previous budget forecast of $358 million.

Matador expects to see decreased drilling, completion and equipping costs for the rest of this year and into 2024.

"Our long-term relationships with our vendors have been beneficial as we have begun to see service costs peaking across the board," Foran said.

"Combining these overall peaking service costs with our capital and operational efficiencies, which include faster drilling and completion times, dual-fuel fracturing fleets, simultaneous and remote fracturing operations and the use of existing facilities, should position us well to

Matador's strategic bolt-on acquisition of Advance Energy

18,500	$300 to $350M	99%	$475 to $525M	203 (85% operated)
Net acres	2023E "D/C/E" CapEx	Held by production (%)	Forward 1-year adj. EBITDA	Net locations

Source: Matador Resources

Matador Resources plans to expand the gas processing capacity for its Pronto Midstream system to serve third-party demand and output from the E&P's own acreage.

Shutterstock

increase production while still reducing costs," he said.

The company anticipates that service cost deflation and other capital and operation efficiencies should bring in well-cost savings of between $25 million and $30 million this year, compared to Matador's prior outlook.

Matador production outlook

Matador brought in strong second-quarter financial results and scored beats on key metrics including free cash flow, EBITDA and capital spending, Sorbara said.

But second-quarter oil production came in light compared to Siebert Williams Shank & Co.'s expectations, he said. And, Matador lowered its oil and gas production guidance for the second half of 2023 as the company works to bring more wells to sales.

Matador's operated wells turning to sales in the third quarter are expected to be back-half weighted and won't fully contribute to production until the fourth quarter, the company said in an investor presentation.

Matador estimates that its total third-quarter production will come in between 129,000 boe/d and 131,500 boe/d—down from the company's original guidance of between 133,000 boe/d and 135,000 boe/d.

Average daily oil production is anticipated to be between 75,500 bbl/d and 76,500 bbl/d, down about 6% from a previous guidance range of 80,500 bbl/d to 81,500 bbl/d.

But Matador expects fourth-quarter oil production to come in at between 85,500 bbl/d to 86,500 bbl/d, down only 1.7% from its previous outlook of 87,500 bbl/d to 88,000 bbl/d.

Analysts at Capital One Securities anticipated that bearish investors would point to Matador's decision to cut oil production guidance for the third and fourth quarters.

"[Management] has a well-known track record of setting the bar low when it comes to production guidance, so this should be taken into context," Capital One Securities wrote in a July report. OGI

$1.92B
PV-10 at strip pricing

24,500 to 25,500 BOE/d (74% oil)
Q1 2023E production

9,400 ft
Avg. operated lateral length

106 MMBOE (73% oil)
YE 2022 proved reserves

$45,600 BOE per day
Production value

Plains All American Seeks More Bolt-Ons

The pipeline company's purchase of Diamondback's pipeline strengthens its Permian footprint.

FRANK NIETO
CONTRIBUTING EDITOR

Plains All American Pipeline (PAA) reported strong second-quarter results highlighted by improved operations and a $225 million bolt-on acquisition in the Permian Basin.

In late July, Plains All American closed on its Permian bolt-on deal to acquire Diamondback Energy's 43% share in the OMOG JV LLC pipeline. The acquisition "further improves our premier Permian footprint in an efficient disciplined manner," Willie Chiang, Plains All American chairman and CEO, said during the company's August earnings conference call.

Assets acquired in the deal include roughly 400 miles of crude oil gathering and regional transport pipeline, along with 350,000 bbl of crude oil storage. Excess free cash flow was used to fund the acquisition. Chiang noted the acquisition was consistent in maintaining capital discipline while also complementing the company's existing footprint.

Jeremy Goebel, executive vice president and chief commercial officer at Plains, said the deal strengthens the company's relationship with Diamondback Energy by making a clear delineation between the roles of both companies.

"[This deal] further aligns us with Diamondback. They want to drill wells and feel very comfortable with us as operators. It made sense for us to acquire this position," Goebel said on the call.

The company's asset base in the Permian enables Plains to extract synergies in the region. Executives said the company will remain financially disciplined with A&D opportunities by focusing on further bolt-ons in the play.

Earnings up, expansion continues

PAA's diversified asset base helped the company to post strong results for the quarter, with Chiang noting Plains' revised outlook anticipates lower-than-expected production from the play. Volumes dipped because of lower commodity prices and excessive heat in the area that resulted in incomplete wells this summer, he said.

"We ended up with some weather problems in June and July. There were also some gas plant issues and producers have been very disciplined not to flare. There hasn't been as much incentive to try to produce," Chiang said.

For the quarter, PAA's net income rose 39% to $349 million from $251 million in the previous year's quarter. This led company officials to increase adjusted EBITDA guidance for 2023 to the high end of the spectrum in the range of about $2.45 billion to $2.55 billion.

He added it's likely estimates will change due to improving oil prices, which he expects to be further strengthened by the decision by OPEC+ to maintain its oil production levels for the rest of the summer.

Besides the Permian bolt-on acquisition, Plains also announced it sanctioned the 30,000 bbl/d Fort Saskatchewan Train 1 debottleneck and expansion project.

"We added connectivity projects to both our Co-Ed Y-grade gathering pipeline and our Fort [Saskatchewan] fractionation complex, which further integrates and expands our NGL system," Chiang said. The investments fit within the company's previously communicated expectations for total average annual capital spend of $300 million to $400 million a year.

The Train 1 debottleneck and expansion project will help the company offset the expiration of a third-party liquids supply agreement contract at year-end 2024. This contract expiration will also help Plains reduce its overall frac spread exposed volumes by about 15,000 bbl/d. This expiration will be EBITDA neutral in 2025 and beyond in a $0.55/gallon (gal) to $0.60/gal frac spread environment.

While the Train 1 project is moving forward, the Train 2 expansion project at Fort Saskatchewan is not, since it failed to meet the company's required return thresholds.

Instead, the company identified some lower-cost brownfield opportunities around the Train 1 system, including utilizing existing capacity in Sarnia.

The company anticipates going from strength to strength by continuing to de-risk its positions.

"Macro uncertainty continues to drive volatility in both the crude and NGL markets," Chiang said. "However, we previously took steps to proactively mitigate this risk by entering into a combination of short-term crude contracts and hedges in the long-haul crude business, along with our substantial hedge position in our NGL business. Over the long term, Plains remains well-positioned as North American supply will continue to be critical to meeting growing global demand." OGI

Howard: Midstream Goes Back to School

HINDS HOWARD
CRBE INVESTMENT MANAGEMENT

Hinds Howard is a portfolio manager at CRBE Investment Management, where he evaluates listed infrastructure and transportation companies in North America and coordinates research of listed transportation companies globally. He is based in Wayne, Pa.

Growing up, I watched a lot of TV, especially in the summer. Scanning the movie channels, multiple times I came across and watched the film "Back to School." The film's premise: an old, wealthy businessman who likes to party, played by Rodney Dangerfield, decides to return to college with his son and hijinks ensue. Robert Downey Jr. had a small role as the best friend of the son, and "Karate Kid" bad guy Billy Zabka played the "heavy." The climax of the movie involved a diving competition where Dangerfield's character Thornton Mellon performs his signature dive, the "Triple Lindy." Silly, but fun movie.

Anyway, those of you in Texas are Back to School already, and here in the Northeast we'll be starting soon enough. So, below I try to catch you up on what's been going on in the publicly traded stock side of the midstream space in recent months.

Valuation data points

The asset sale market has recently offered multiple data points that suggest historical valuations could be coming down, even for the highest quality pipeline assets. The idea that you can slap a 12x-14x multiple on a high-quality natural gas pipeline asset with long-term contracts doesn't seem to be the case anymore.

Data points:

- In May, Spire acquired the MoGas interstate gas pipeline for an estimated 10x EBITDA multiple;
- In July, Berkshire Hathaway announced the acquisition of 50% of Cove Point LNG from Dominion for around 10.5x EBITDA; and
- Later in July, TC Energy announced the sale of 40% of Columbia Gas to GIP for a 10.5x EBITDA multiple.

These assets are all natural gas infrastructure assets, either regulated or heavily contracted. Each circumstance was unique and there are reasons each should have been sold for lower valuations than you'd expect. Higher interest rates, terminal value concerns and a limited buyer pool for big pipeline packages are all factors in these deals.

Even so, this smattering of transactions bunched so closely together are worth noting when assessing valuation for other assets held within midstream companies like Energy Transfer, Kinder Morgan, The Williams Cos. and the rest of TC Energy.

Mixed tolerance for growth capex creep

Big capex increases are still met with skepticism by the market, given the trade-off between capex and free cash flow. However, modest increases for needed infrastructure are being accepted by the market. Capital discipline balance is critical; publicly traded midstream companies seem to be aware of this balance and they are putting forward only their highest quality projects.

So, there is a bit of nuance playing through with the stocks, where the market is willing to evaluate capex increases on a case-by-case basis. Modest increases to capex plans were announced by Targa Resources (TRGP), Energy Transfer (ET) and DT Midstream (DTM). The market was more receptive to TRGP's increase than the others. Generally speaking, if there's a need for infrastructure, it is backed by customer contracts and doesn't thwart previous leverage targets or capital return expectations, then the market tends be OK with it.

Equity capital markets thawing

Over the last five to seven years, MLP equity capital markets have been largely closed. There has been basically no activity on the primary side. There have been exceptions, notably HESM, which has executed several offerings of shares held by sponsor entity Global Infrastructure Partners (including another one in August). But primary equity issuance of new common equity from a midstream company has been basically nil. We have had at least one data point this summer that might signal a thawing of the capital markets.

See below for a list of recent capital markets activity.

- Aug. 9: NuStar Energy (NS) sold $200 million worth of units in upsized equity offering to fund redemption of preferred units.
- June 28: IPO of Kodiak Gas Services (KGS) raised $256 million.
- Kimbell Royalty Partners (KRP) sold $102 million worth of units in upsized equity offering to partially fund acquisition.
- June 14: Canadian midstream company Gibson Energy sold C$403 million worth of subscription receipts to partially fund large acquisition of port assets in Corpus Christi, Texas.

A functioning equity capital market gives midstream companies another option when it comes to managing growth, leverage and liquidity for sponsor holdings. Not many midstream companies need equity at the moment, in fact, many have plans to buy back stock rather than issue more, but knowing equity capital is an option could change the calculus for M&A going forward.

In summary, valuations for high quality assets are under pressure, growth capex is creeping, and equity capital markets are back open. Companies that are not desperate to sell assets into a buyer's market should be well-positioned to thrive in the current environment. OGI

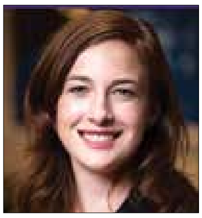
▸ PERSPECTIVES

Voices

Say what you will about the energy transition, but plenty is being said about it.

Setting greenhouse gas emission targets would help "demonstrate to the world that this industry is able to lower emissions."

—**Patrick Pouyanné**, *CEO, TotalEnergies*



"As we move to net zero, ... energy becomes less of an extractive resource and more of a developed and manufactured resource with lower risk and returns."

—**Rebecca Fitz**, *partner, Boston Consulting Group*

"The [EPA's] near-singular focus on EVs ignores other fuel and vehicle-based options that could better achieve the administration's goal of reducing emissions in the transportation sector."

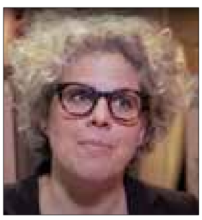
—**Will Hupman**, *vice president, API's downstream policy initiative*

"Clean energy's growing dominance is especially clear when it comes to solar power. In 2023, for the first time, investment in solar energy is expected to beat out investment in oil production."

—*MIT Technology Review*

"The clean energy economy is rapidly taking shape, but even faster progress is needed in most areas to meet international energy and climate goals."

—**Fatih Birol**, *executive director, International Energy Agency*



"What we are currently witnessing is a power transition rather than an energy transition, as most policies and regulations have mainly focused on developing renewables in the power sector."

—**Rana Adib**, *executive director, REN21*

Blending Digital Innovation and Teamwork

Baker Hughes and Corva execs detail their companies' recent collaboration.

JENNIFER PALLANICH
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Companies often point to collaboration and partnerships as ingretients for success. They make possible a future that one business alone could not accomplish.

Blending strengths and domain knowledge of different organizations opens the way to innovations the oil and gas industry needs to streamline operations, increase production and generate better shareholder value.

In an interview with Hart Energy *Senior Technology Editor Jennifer Pallanich, Matthias Gatzen, executive director of digital well construction business at Baker Hughes, and Courtney Diezi, COO at Corva, discuss how their companies are collaborating to solve problems and innovate.*

Editor's Note: The following interview originally published in July and has been edited for length and clarity. Visit HartEnergy.com for the full-length version.

Jennifer Pallanich: What if the future of well construction lies in the perfect blend of digital innovation and teamwork?
Matthias Gatzen: It's really about taking Baker Hughes' longstanding industry experience and Corva's superior digital platform, and bringing those together, and driving performance and efficiencies for our global customers.
Courtney Diezi: We have over 100 completions, drilling and geoscience apps that can be used in different ways to solve problems in real time and using historical data. And then, we also have something called Dev Center, and it allows our customers and our partner companies to be able to deploy apps on top of our platform very quickly.

JP: What does Baker Hughes bring to this collaboration?
MG: We bring over 100 years of industry experience, and if you think about it, a lot of the digital offerings that we have, we've been running internally for our day-to-day operations. And we can actually take those applications now and make them available to our customers and actually every single Corva customer. Secondly, we can take Corva now and offer it to our global customers. We have an incremental sales channel. And thirdly, the opportunity that we have is that we can run Corva internally, and we are actually rolling that out right now to drive efficiency performance in day-to-day operations.

JP: Speaking of efficiencies, what kind of operations efficiencies might we be seeing on rigs as a result of this partnership?
CD: Corva's deployed originally on unconventional drilling. That's really where we got our feet on the ground six years ago. And there, we were driving things like tripping speed, improving ROP, getting best-in-class performance across the platform. We also do some things that help prevent hazards so that we can use that historical data, understand what's coming up and mitigate. We have a lot of track record on the unconventionals. We started moving offshore a couple of years ago, and so we have the same sorts of metrics as well as those engineering apps that help prevent the hazards.

JP: I understand that during this partnership, Baker Hughes has started populating the Corva app store with apps. Tell me about some of those.
MG: If you take a look at the app store, it's a fantastic opportunity to take any application that you have and bring it onto the app store, make it available for your operations running Corva or any operations globally. We're taking some of our long-term experience in driving efficiency performance like i-Trak—drilling automation—and putting that on the Corva platform. And so, the first one we're actually building right now is an ROP-based application. We're taking our i-Trak automation platform and taking the best of those applications and one after the other changing the industry, and really bringing them onto the Corva platform. The first one we're building right now, and it's shortly to be released, is an ROP-based application. It's very exciting. It's a vibration-based model that's really geared at driving efficiency and performance, and it takes your downhole data, and the Corva platform brings that together and drives efficiencies.

JP: You announced this collaboration back in January at the Baker Hughes annual meeting. What have you guys

"We have a lot of track record on the unconventionals. We started moving offshore a couple of years ago."

—**Courtney Diezi,** ***COO, Corva***

"We're taking our i-Trak automation platform and taking the best of those applications and one after the other changing the industry."

—**Matthias Gatzen,** ***executive director of digital well construction business, Baker Hughes***

accomplished since then?

MG: We have multiple pillars we're focused on. Firstly, we're rolling out Corva into our global operations and driving performance and efficiencies in the Baker Hughes operations, and really our customers are appreciating that. Secondly, we're also a sales channel for Corva, and so we're in multiple discussions globally and rolling out Corva with our customers for their day-to-day operations across their entire fleets. And thirdly, as we just talked about, we're taking applications and making those available on the Corva platform, either Baker Hughes applications or also our customers' applications that they want to run on Corva.

CD: The other thing that we've both been working really hard on is deploying our first on-premises instance of Corva along with the Baker Hughes team. That's gone very well, and we're looking forward to doing more and more of those.

JP: That sounds exciting. Sometimes a customer or a country will have restrictions on data. How do you deal with those?

CD: We've been working on that, actually, for a couple of years leading up to this partnership. We have been able to take Corva, which is a cloud-hosted environment, and we've been able to package it up so that we can deploy it fully on-premises within a customer's architecture if needed, but we can also deploy it on any cloud within any country. With these different scenarios, we're actually able to accommodate whatever in-country data restrictions the customer may have. All operators have really realized that digitalization plays a big part in their future strategy, and so having a proven digital platform like Corva partnering with the wide breadth of experience of Baker Hughes means that we can deploy so many solutions very quickly for the industry or for a specific customer's needs.

MG: Yeah, I mean, I could just say I think we're changing the industry one app at a time, right?

CD: I think so. OGI

▸ TECHNOLOGY

Clear as Mud: Tech Enables Reuse of Drilling Fluids

R3 Environmental Systems' process recovers drilling fluid and water from waste generated during drilling operations for use as a direct substitute for virgin drilling fluid in new drilling mud products.

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A company taking "waste not, want not" to heart has developed a vacuum-assisted oil recovery process that makes it possible to reuse drilling mud.

The technology, which emerged from the construction industry, recovers used drilling fluid and water and generates fuel pellets. Nova Scotia, Canada-based R3 Environmental Systems, a subsidiary of Municipal Group of Companies, started developing the process in 2017, and in 2022, the Vacuum Assisted Pure Oil Recovery process received OTC Spotlight on New Technology recognition.

R3's process heats used drilling fluid under a vacuum to evaporate out the oil and water fractions before condensing them and separating them into hydrocarbon and water products. Circulating the used fluid under heat and 20 mm to 40 mm of mercury lowers the boiling point—speeding up the distillation process and reducing the energy required to boil off the oil, said Patrick Rooney, director of manufacturing for Municipal Group of Companies.

Normally, he said, the recovered fluids would boil off at temperatures as high as 350 C.

"We're boiling it off at 170 degrees Celsius, so therefore we're not cracking" or degrading the oil, he said. "We're pulling off just the virgin oil."

He said the process makes it possible to use one part of recovered oil to heat the system while leaving two parts of recovered oil available for resale or further reuse.

"We're actually burning the oil in our industrial heaters," Rooney said.

The recovered distilled water contains no chlorides, he added.

"The water could go back for a new formulation because, being distilled water, there's no more chlorides in it. They could actually use that again to reformulate drill mud or use it in the process somewhere else. And in lots of places where water is scarce, it's very valuable to get the water back," he said.

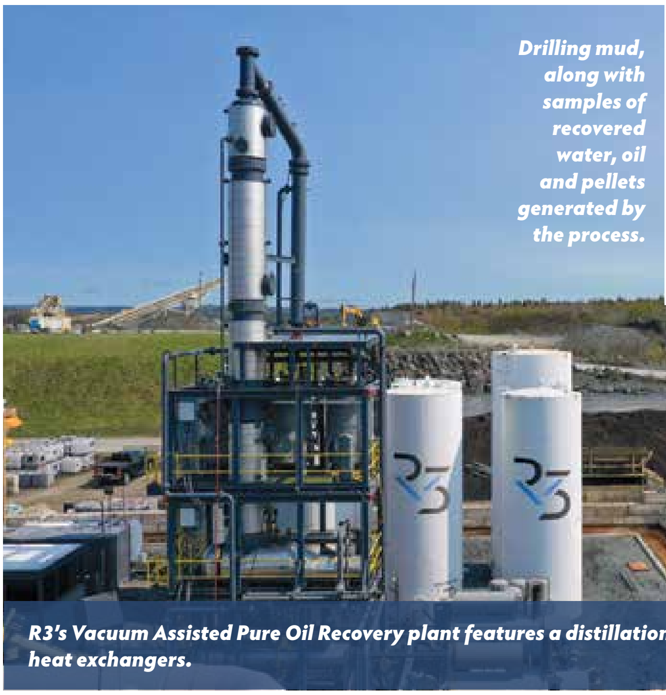
'200 mistakes ahead'

Jerry Scott, general manager for R3, said the amount of water in the mud affects the speed of the process.

"It takes a lot of energy to burn off the water. So if there's a lot of water," the process takes longer, he said.

Drilling mud, along with samples of recovered water, oil and pellets generated by the process.

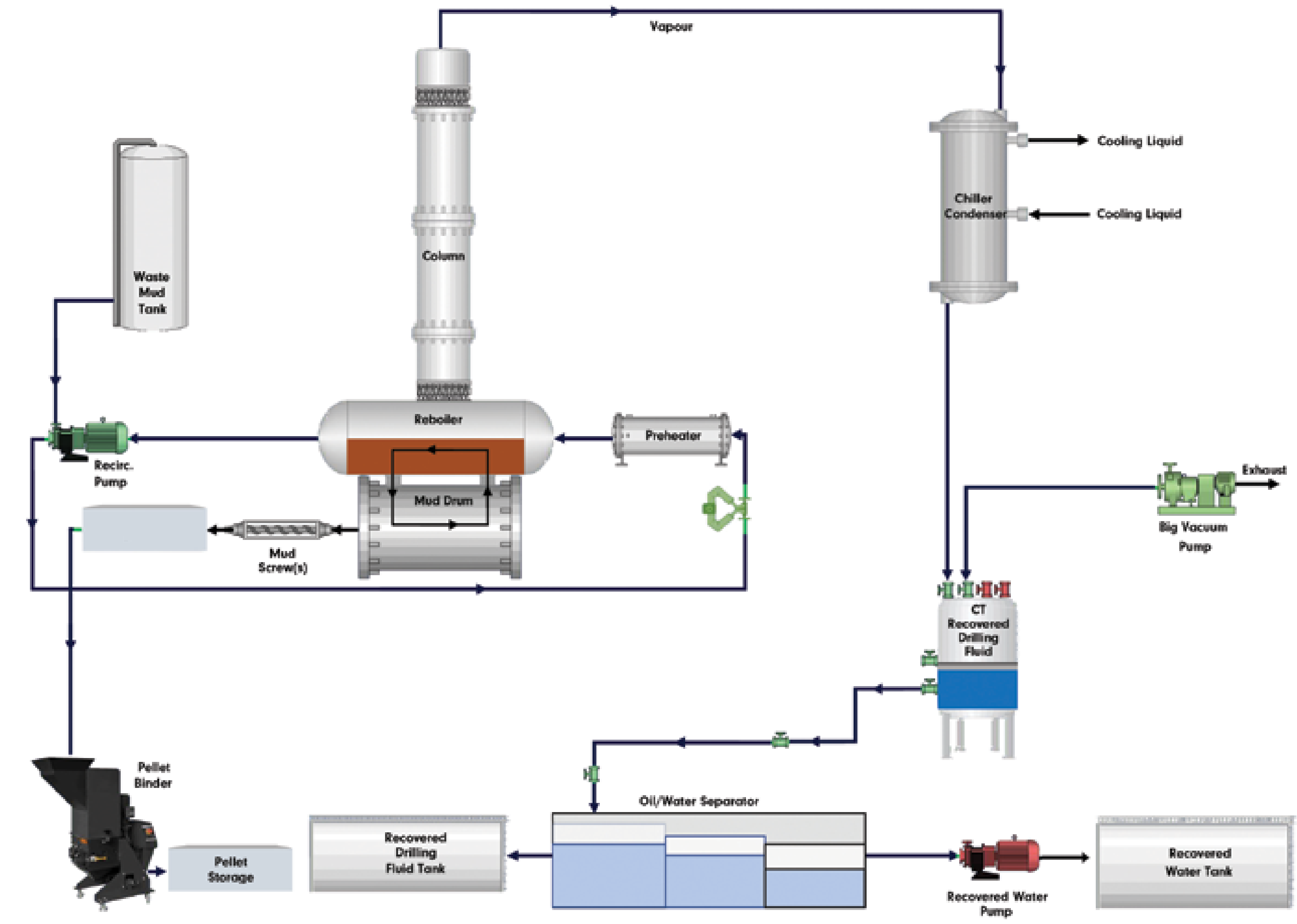
Hart Energy



R3's Vacuum Assisted Pure Oil Recovery plant features a distillation tower, distillation tower pumps and heat exchangers.

R3 Environmental Systems

Flow diagram for R3's Vacuum Assisted Pure Oil Recovery process



Source: R3 Environmental Systems

On average, the system can treat about two tons of used drilling fluid per hour.

Scott said the company started looking for a way to extract oil from drilling mud without cracking some years back. There are, he said, other technologies that can extract the oil, but rather than returning virgin quality oil, it's degraded.

Rooney said the company investigated a number of technologies before choosing a path to pursue.

"Dyson never invented the cyclone. He's just the first one to put it in a vacuum," Rooney said. "We looked at these different technologies and one of the ones that fascinated us was distillation."

But pumping sludges under a vacuum posed some problems.

"Sludges are hard to pump in the first place. They're abrasive," he said.

Scott said pump vendors were not receptive to the concept.

"We had a lot of pump vendors even refusing to quote us once we told them the operating conditions," he said.

Through a series of test projects, R3 was able to test different types of pumps and refine the system to include a combination of peristaltic pumps with high heat hoses and lobe pumps.

"We're better than the competition right now because we're 200 mistakes ahead of them," Rooney said.

Offshore Technology Conference

Patrick Rooney, left, and Jerry Scott celebrate Spotlight on New Technology recognition for Vacuum Assisted Pure Oil Recovery during Offshore Technology Conference 2022.

The process has been used offshore Newfoundland and Labrador for a year.

"We have good recovery rates for the oil in the water," Rooney said. "That's gone very well with multiple different types of mud."

And while the process returns virgin oil and reusable water, it also creates fuel pellets, which can be used in cement kilns or industrial furnaces.

"Ideally, we'd like to make a fuel pellet that someone can use," Scott said.

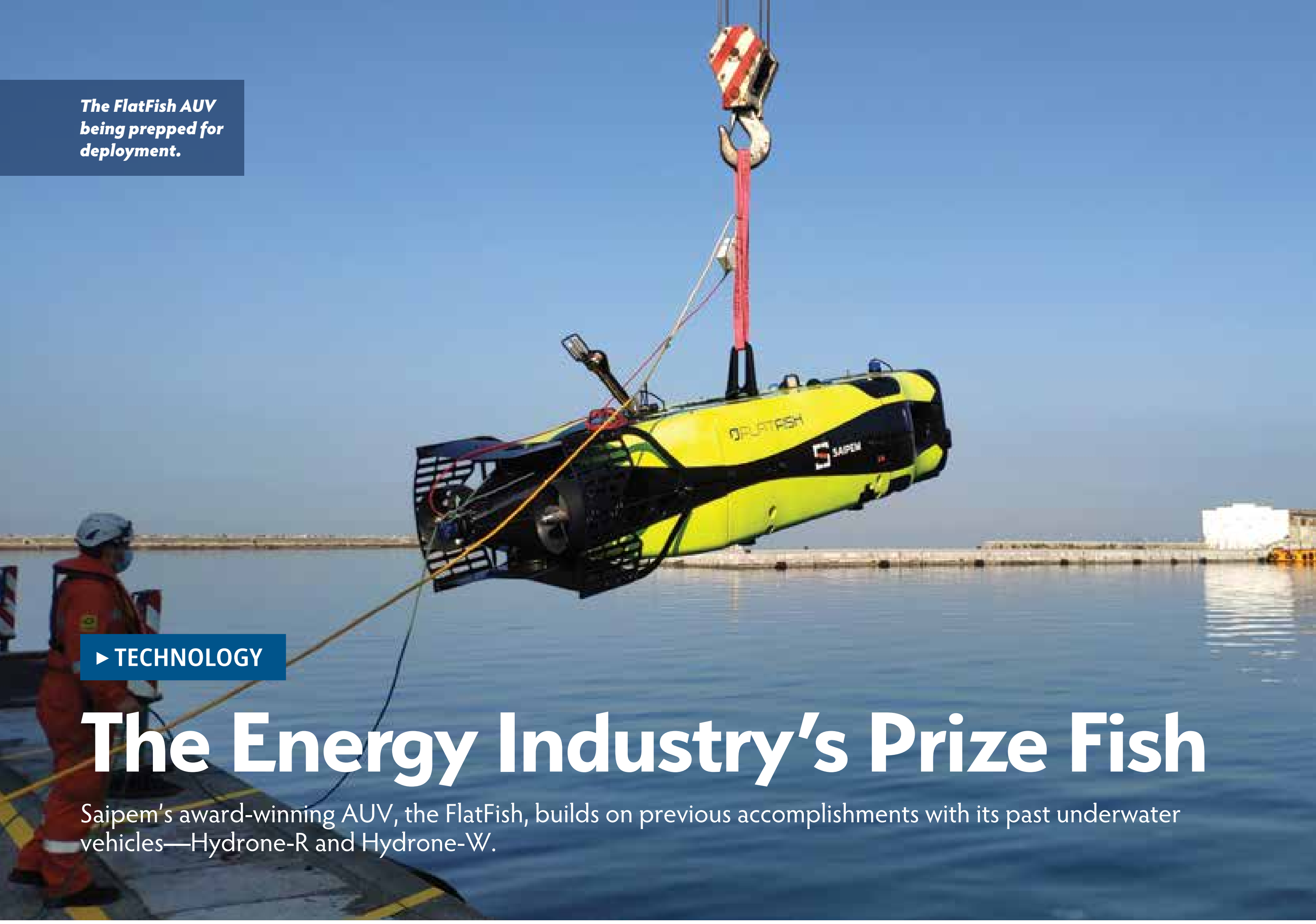
However, Rooney said, not all regions or operations are set up to use the resulting pellets.

He said the company is now working to make the process "highly mobile" to allow it to be used in remote locations where supply of drilling fluids is more difficult and recovered oil would be useful.

"The oil could be reused over and over and over again. So, as long as it comes back to us as waste, we could reproduce the same base oil that could be [used] over and over because we're not degrading it," he said.

The whole process, Scott said, reduces the carbon footprint of operations.

"Typically, to drill one well, we can save them about 400 tons of CO_2 emissions," he said. "It's a start." OGI



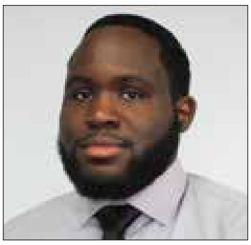
The FlatFish AUV being prepped for deployment.

▸ TECHNOLOGY

The Energy Industry's Prize Fish

Saipem's award-winning AUV, the FlatFish, builds on previous accomplishments with its past underwater vehicles—Hydrone-R and Hydrone-W.

Saipem



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Despite various subsea technologies employed by robotics companies, the ocean is still full of mystery with what is said to be more than 70% remaining undiscovered. However, one oil and gas company looks to shift that paradigm with its new species of fish floating around subsea: the Saipem FlatFish.

While not technically alive, the FlatFish resembles something like an actual fish with its square nose and propeller tail.

The fleet of FlatFish subsea drones are engineered, developed, commercialized and operated by Sonsub, Saipem's center of excellence for underwater technologies and digital automation. The drone handles high complexity inspections of pipelines and subsea structures and can reach water depths of 3,000 m. The groundbreaking technology won the 2023 Spotlight on New Technology Award at the Offshore Technology Conference earlier this year.

"We are at the forefront of technologies…we think that there is nobody else in the competition that is able to execute what we can underwater, which is the monitoring of risers by moving on a three-dimensional path," Matteo Marchiori, head of Sonsub Robotics, told Hart Energy.

The FlatFish, along with the Hydrone-R and Hydrone-W, are part of Saipem's Hydrone family. Each Hydrone is an underwater vehicle designed to operate subsea, with the FlatFish—also known as the Hydrone-S—being used strictly for inspection. The Hydrone-R is used for both inspection and intervention, while the Hydrone-W is used for work. The Hydrone-W requires an umbilical as it is the largest of the family and can stay subsea up to 12 months. The Hydrone-R is fully electric and can operate with or without a tether.

As an option, a Tether Management System can be fitted on the stern of Hydrone-R in order to pay-in or pay-out a fiber optic tether for control and real-time video streaming. The autonomous FlatFish does not require a tether and can be permanently docked subsea, unlike the other Hydrones.

Despite the differences in the Hydrone family, there is a commonality between the sensors, software, coding, architecture and other equipment in order to maximize cost efficiency and enable easier sharing of data between the vehicles.

Networking

While there are many other AUVs on the market, what sets the FlatFish apart is its internet of things (IoT) data harvesting ability.

"We are basically offering, along with an interoperable adaptive wireless node combined with drones, an array and network of communication that can be used for harbor protection, pipeline protection and protection of the critical facilities offshore," Marchiori said. "The program that we are currently executing, in connection with creating an underwater network of subsea IoT, is mirroring what is happening on earth when you're using your smartphone and you are connecting to a hotspot."

This phenomenon creates an underwater Wi-Fi network of sorts, creating links between structures that are able to communicate with the drones located subsea and harvest data in a wireless configuration.

The FlatFish, which was tested in 1,800 m of water in a live Brazilian asset in 2018, is also part of Italy's Oil Spill Response Ltd. (OSRL) assets. According to a dedicated agreement, FlatFish can be operated for environmental monitoring and inspection of asset integrity. Its other tasks in Italy included surveying, leakage detection through water column plume and dispersant concentration monitoring, environmental assessment and patrolling. Saipem also entered into contracts with Equinor in Norway for the use of Hydrone-R, Shell and Petrobras in Brazil for the use of FlatFish, and there are dialogues underway for the deployment of their drones in the Middle East.

Although the number of contracts for the FlatFish are starting to increase, Marchiori still sees a fundamental criticality regarding its adoption, as well as that of other AUVs.

"We encourage clients to be more open to…give the industry a chance to demonstrate that we are moving into a new era for subsea robotics, and such transition calls for deployment, which is a fundamental step," he said.

"We encourage clients to be more open… to give the industry a chance to demonstrate that we are moving into a new era for subsea robotics."

—**Matteo Marchiori,** ***head of Sonsub Robotics, Saipem***

While Marchiori said the commercialization of the FlatFish and other subsea drones has been limited, he still sees huge potential. Once clients begin to trust these technologies, he said, subsea drones will see a boom in the market.

To further advance the FlatFish and its related technologies, Saipem is focusing on not just adding a manipulator so that the vehicle can be used for intervention as well as inspection, but on increasing endurance of the drone.

"Endurance is vital. The more we can get away from launching point, the better," Marchiori said. "Of course, we can have more than one vehicle serving a field, but if the same vehicle is able to run for 200 kilometers, there is no longer need for a second vehicle to be deployed."

▸ TECHNOLOGY

Tech Bytes

BiSN

Sasol deploying the BiSN tool in Mozambique.

Sasol Qualifies Rigless P&A Technology

BiSN has partnered with Sasol in Mozambique to qualify the effectiveness of Wel-lok technology for rigless plug and abandonment (P&A) and intervention operations, the company announced in July.

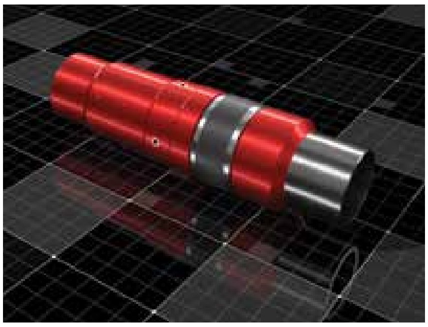
The collaboration aimed to establish the viability of using BiSN alloy via perforations to achieve rock-to-rock sealing and improve abandonment integrity.

"Upon setting, it far exceeded our expectations and we will continue to use BiSN technology in Sasol campaigns," Sandy Ferrari, well engineering consultant at Sasol, said in a press release.

Sasol Mozambique faced the challenge of establishing a 62 m rock-to-rock seal in thin cap rocks, making it challenging to ensure complete sealing using traditional cement. To overcome the challenge, Sasol elected to work with BiSN and a major service provider to deploy BiSN alloy via perforations in 9 5/8-in casing. The objective was to isolate formation activity from a gas-bearing silt layer and create a suitable regional seal within a 10 m-thick shale interval.

The operation began with the displacement of the 9 5/8-in casing to solids-free brine, followed by casing scraping and perforating gun run on wireline. A cast iron bridge plug was set to provide a mechanical base for the molten alloy, and a 33 ft Wel-lok plug was deployed and activated via a timer and hydrostatic switch. The alloy expanded, forming an effective 360-degree circumferential bismuth barrier within the annulus.

Halliburton Launches New Packer



Halliburton

The new Obex EcoLock packer

Halliburton Co. introduced in July its Obex EcoLock compression-set packer, which the service company said helps prevent sustained casing pressure.

The Obex EcoLock packer is a mechanical barrier to mitigate low-pressure gas or fluid migration and provide isolation assurance.

The packer is built on the gas-tight, V0-rated Obex GasLock packer design. The Obex EcoLock packer provides V6-rated isolation and can support multiple-stage cementing with optional integral cementing ports and an internal closing sleeve. It is available for 7-in and 9 5/8-in casing designs with additional sizes expected in the future.

GoM's New Surface Dispersant Monitoring Program

HWCG LLC

The surface dispersant monitoring launch and recovery system

HWCG LLC, a consortium of deepwater operators in the Gulf of Mexico, is leading the development of a surface dispersant monitoring (SDM) program to enhance monitoring capabilities and comply with new regulations, the group announced in August.

HWCG collaborated with CSA Ocean Sciences in the development of the SDM equipment program. CSA is a marine environmental consulting firm and key response provider for HWCG's deepwater containment organization. The SDM is expected to be available in December.

CSA's scientists and operations specialists selected equipment for the SDM program to meet regulatory requirements for the use of dispersants when responding to oil discharges. When proposing the use of surface dispersants for more than 96 hours—or in response to a discharge of more than 100,000 gallons in 24 hours—regulations require collection of water samples and data near the ocean surface.

HWCG's operating members can now deploy simultaneous deepwater monitoring and surface monitoring at different locations to effectively use dispersants as a response tool, to optimize response time and to comply with current regulations.

CGG, PGS, TGS Launch Tiers for Versal Ecosystem

CGG, PGS and TGS jointly announced in August the launch of new tiered offerings for Versal, the multi-client data ecosystem. The update gives the industry free access to multi-client data coverage in one centralized location.

The latest updates to the Versal platform are designed to offer scalability for exploration and production, data management and procurement team members through the introduction of Versal Pro and Premium tiers. Versal users will have unlimited access to the essential data from CGG, PGS and TGS—representing the majority of the world's marine multi-client data available within a single platform. The companies said the consolidation eliminates the need to visit multiple vendor websites, streamlining workflows and saving valuable time.

With the free Versal version, users can view data coverage, download coverage shapefiles and import their map layers and shapefiles. Versal Pro users can view entitlements, access vendor contracts and download acquisition and processing documents. Versal Premium users gain access to enhanced data management capabilities such as seismic visualization and downloading entitled traces.

DeepOcean Chartering Newbuild USV for Subsea Ops

Solstad Offshore

DeepOcean will charter the newbuild USV, which is expected to be delivered near year-end 2024.

DeepOcean said in August it has entered into a long-term charter agreement for a newbuild unmanned surface vessel (USV) for subsea inspection, maintenance, repair and survey work in the offshore renewables and oil and gas industries.

DeepOcean is chartering the vessel from USV AS—a joint venture company established by Solstad Offshore, Østensjø and DeepOcean with the main purpose of investing in and owning USVs.

The USV will be equipped with a work ROV that is capable of operating at depths to 1,500 m along with a tool package for subsea operations. The USV will be capable of handling most subsea inspection and survey work and a portion of subsea intervention tasks.

The USV will be remotely controlled from shore but will have many autonomous features to ensure safety and integrity of the spread. During operations, both the USV vessel crew and ROV operators will be located in the same remote operating center. The USV will be equipped with a hybrid diesel-electric propulsion system and a battery package that allows the unmanned vessel to operate offshore for up to 30 days without charging or refueling.

The USV will be 24 m long and 7.5 m wide. USV AS has contracted Astilleros Gondán shipyard to build the USV with delivery expected by year-end 2024. Following offshore testing, the USV will be ready for operations in 2025, when it will go on charter for DeepOcean. OGI

DAVIS GRAHAM & STUBBS

Energy M&A and Financing Forum

Wednesday, October 4, 2023

Four Seasons Hotel Denver

Registration | 1:00 - 1:30PM **Program | 1:30 - 4:30PM** **Reception | 4:30 - 6:00PM**

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Events Calendar

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

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EVENT	DATE	CITY	VENUE	CONTACT
2023				
SPE Offshore Europe Conference & Exhibition	Sept. 5-8	Aberdeen, Scotland	P&J Live	offshore-europe.co.uk
Solar Power International	Sept. 11-14	Las Vegas	The Venetian Conv. & Expo Ctr.	re-plus.com
GPA Midstream Convention	Sept. 17-20	San Antonio	Marriott Rivercenter & Riverwalk	gpamidstreamconvention.org
World Petroleum Conference	Sept. 17-21	Calgary, Canada	BMO Centre, Stampede Park	24wpc.com
America's Natural Gas Conference	**Sept. 27**	**Houston**	**Westin Galleria**	**hartenergy.com/events**
SPE Electric Submersible Pump Symposium	Oct. 2-6	The Woodlands, Texas	Woodlands Waterway Merriott	spegcs.org
Energy Capital Conference	**Oct. 2**	**Dallas**	**Statler Hotel**	**hartenergy.com/events**
A&D Strategies & Opportunities	**Oct. 3**	**Dallas**	**Statler Hotel**	**hartenergy.com/events**
Offshore WINDPOWER 2023	Oct. 3-4	Boston	Hynes Convention Center	cleanpower.org
Clean Energy Technology	**Oct. 23-24**	**San Antonio**	**Marriott Rivercenter & Riverwalk**	**hartenergy.com/events**
OTC Brasil	Oct. 24-26	Rio de Janeiro	Expo Mag Convention Center	otcbrasil.org
WEA Wildcatter of the Year	Nov. 4	Denver	Sheraton Denver Downtown	westernenergyalliance.org
40th USAEE/IAEE North American Conference	Nov. 6-8	Chicago	Fairmont Chicago Millennium Park Hotel	usaee.org
IPAA Annual Meeting	Nov. 6-8	San Antonio	JW Marriott San Antonio Hill Country	ipaa.org
Energy Transition North America 2023	Nov. 7-8	Houston	TBD	reutersevents.com
Rice Energy Finance Summit	Nov. 10	Houston	McNair Hall, Rice University	business.rice.edu
OK Petroleum Alliance Fall Conference	Nov. 15-16	Oklahoma City	The National Hotel	thepetroleumalliance.com
Executive Oil Conference & Exhibition	**Nov. 15-16**	**Midland, Texas**	**Midland County Horseshoe Arena**	**hartenergy.com/events**
DUG Appalachia	**Nov. 29-30**	**Pittsburgh**	**David L. Lawrence Convention Center**	**hartenergy.com/events**
URTeC Latin America	Dec. 4-6	Buenos Aires, Argentine	Hilton Buenos Aires	urtec.org/latinamerica/2023
2024				
IPAA Private Capital Conference	Jan. 17	Houston	The Post Oak	ipaa.org
Mexico Infrastructure Projects Forum	Jan. 24-25	Monterrey, Mexico	Camino Real San Pedro	mexicoinfrastructure.com
Floating Wind Solutions	Feb. 5-7	Houston	Hilton Americas-Houston	floatingwindsolutions.com
NAPE Summit	Feb. 7-9	Houston	George R. Brown Conv. Ctr.	napeexpo.com
Louisiana Oil & Gas Association Annual Meeting	Feb. 26	Lake Charles, La.	Golden Nugget Casino	loga.la
25 Influential Women in Energy Luncheon	**March 8**	**Houston**	**Hilton Americas-Houston**	**hartenergy.com/events**
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.
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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.

It's 'On:' The New Ohio Utica Oil Play

The oil-weighted hydrocarbon phase through the middle of the Utica fairway in Ohio is gaining renewed attention—and results.

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Privately held, longtime Ohio operators Ascent Resources Utica and Encino Energy's EAP Ohio are reporting stunning wells in their oil-weighted footprints.

Leading the state's new oil well results, former Chesapeake Energy executive vice president of production Jeff Fisher's Ascent made a two-well Lavada RCH GR pad in Guernsey County that produced a combined 2,691 bbl/d during its first 166 days online through March 31.

The Lavada #2H averaged 1,448 bbl/d, while the Lavada #4H averaged 1,243 bbl/d, according to Ohio's Department of Natural Resources data.

Solution gas averaged 4.5 MMcf/d per well during that time frame.

On another pad—the Jackalope WSG GR—Ascent made three wells, bringing in an average of 4,405 bbl/d during the wells' first 83 days online. The #6H averaged 1,532 bbl/d; the #4H, 1,483 bbl/d; and the #2H, 1,381 bbl/d.

Solution gas from Jackalope, which is also in Guernsey County, averaged 9.8 MMcf/d or 3.27 MMcf/d per well.

Meanwhile, former Range Resources Chairman and CEO John Pinkerton's Encino/EAP Ohio added four wells in the Utica-trapped oil play—the Point Pleasant—in its previously one-well Williams CR MON pad in Carroll County.

The new wells produced an average of 1,118 bbl/d each in their first 182 days online. Solution gas averaged 4.9 MMcf/d per well.

Pinkerton, who is Encino/EAP's executive chairman, led Range Resources in its discovery of the Marcellus shale play in 2007. Ray Walker, Encino COO, was part of that Marcellus-discovery team. Hardy Murchison, president and CEO, managed First Reserve oil and gas investments.

Encino's investors include the Canada Pension Plan Investment Board (CPPIB).

Ascent, which is in First Reserve's current portfolio, is the No. 1 privately held Appalachian oil and gas producer, making 424,000 boe/d, 96% gas, at year-end 2022, according to Enverus data.

Encino is No. 2, producing 192,000 boe/d, 86% gas. Among all privately held U.S. gas producers, Ascent is No. 2; Encino, No. 8.

Ascent and Encino operate the Top 50 oil wells in first-quarter 2023 production in Ohio, according to state data, except for three wells by INR Ohio and one by EOG Resources.

All in Carroll County, the three INR wells made 60,176 bbl in 86 days, averaging 700 bbl/d; 54,170 bbl in 90 days, averaging 602 bbl/d; and 52,523 bbl in 75 days, averaging 700 bbl/d.

The EOG well, Brookfield NBK15 #3A in Noble County, made 50,694 bbl in 90 days, averaging 563 bbl/d. The well had been brought online in the fourth quarter with 88,420 bbl during its first 77 days, averaging 1,148 bbl/d.

The Business Journal in Youngstown, Ohio, found four Encino horizontals in Columbiana County made 228,058 bbl/d in their first 90 days and were responsible for nearly all the county's 233,390 bbl/d in that period. All four wells are from the same pad, it added.

"Traditionally, wells in Columbiana County have not produced much oil, as this portion of the shale play is instead known as a major source of natural gas and natural gas liquids," Managing Editor Dan O'Brien wrote in June.

"During the fourth quarter of 2022, for example, the entire county produced just 5,084 barrels of oil."

Encino holds more than 900,000 net acres in Ohio, across the phase windows: black oil, volatile oil, wet gas and dry gas. It bought Chesapeake's Ohio Utica property in October 2018 for $2 billion. In addition to being Ohio's largest oil producer, it is its second-largest gas producer. Nearly all its leasehold is HBP and none is on federal land, it reported.

Meanwhile, EOG is working on making a new play for itself in Ohio's oil fairway. Bob Brackett, analyst for Bernstein Research, told EOG chairman and CEO Ezra Yacob this summer, "The thesis on the Utica was 'Here was a play early in the shale oil revolution that came and went quickly. We haven't drilled a decent well there, or a modern-technology well, in a dozen years.'"

His question: "Why would the Utica not work?"

Yacob said, "It's funny, right? When you take the blinders off and you come with a different perspective from different basins, it's amazing the things that you can uncover….

"I'll be honest: It's not the first time that we've looked at the Utica. We've been in and out of looking at the Utica and the liquids-rich window for a number of years.

"But … as you're learning things [in other plays] that are less pressured, you start to apply these understandings to different basins and that's when you start to unlock newfound value." OGI