Oil and Gas Investor

THE OGINTERVIEW

GROWTH THROUGH M&A

Crescent Energy CEO David Rockecharlie on Growth in the Eagle Ford and Uinta

MONTNEY MOMENTUM

US Companies Seize Opportunity in Canada

NOW, THE UINTA

Drilling Goes Vertical in the Basin

SPECIAL OGI REPORT

ELECTION 2024

How Energy May Fuel US Policy

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OCTOBER 2024

BUILDING BLOCKS OF A STRONGER OIL & GAS INDUSTRY

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

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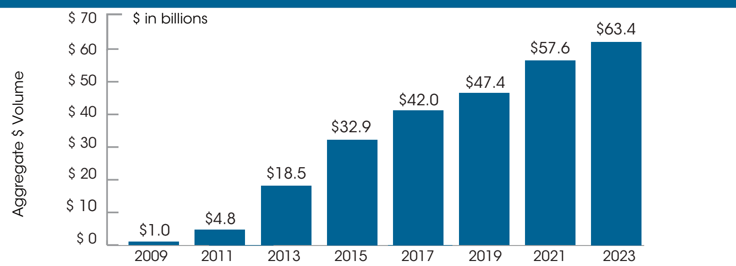
STEPHENS ENERGY GROUP KEY STATISTICS

$63+ Billion
Energy Investment Banking Transaction Volume Since 2009

~$300 Million
Average Transaction Size

222
Transactions Closed since 2009

ENERGY GROUP AGGREGATE TRANSACTION VOLUME



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Oil and Gas Investor

OCTOBER 2024/VOLUME 44/NUMBER 10

SPECIAL OGI REPORT

ELECTION 2024 ★ ENERGY ON THE BALLOT

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

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

IN MEMORIAM

COMMENTARY

FINANCE & INVESTMENT

ACQUISITIONS & DIVESTITURES

Oil and Gas Investor
by HARTENERGY

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MIDSTREAM

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ABOUT THE COVER:
A rig in the Utica Shale proudly flies the U.S. flag in this image by Advantage Video & Marketing.

Aramco is an energy and chemicals company with oil and gas production as its primary business. The solutions mentioned here are in the first stages of commercial deployment.

Coming to an Energy Conference Near You

The fall conference season begins in earnest this month, and our team is bringing the heat.

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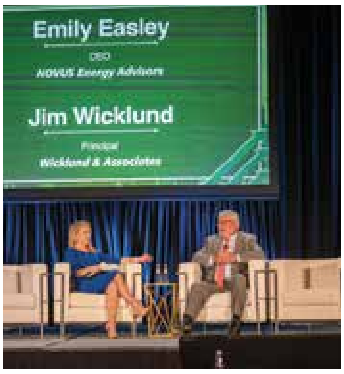

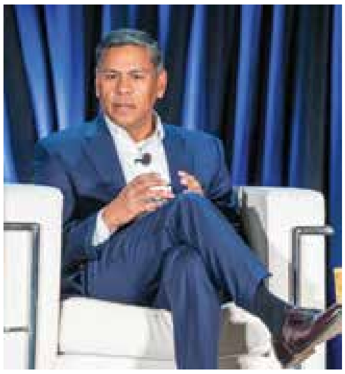

Not only is *Oil and Gas Investor* this month bringing you our routinely exclusive, comprehensive coverage of important finance trends and A&D transactions, we're bringing the news—and newsmakers—to you throughout October.

Our annual Energy Capital Conference on Oct. 3 in Dallas kicks off with Bryan Sheffield of Formentera Partners, who will walk attendees through the successful IPO process of Tamboran Resources and tee up the morning discussions on private equity.

Sessions on capital access, the secondaries market and asset-backed securitizations will follow a special keynote from legendary political strategist Karl Rove, known as "the architect" of President George W. Bush's successful 2000 and 2004 campaigns.

On Oct. 23, we'll reconvene in Dallas for our annual A&D Strategies & Opportunities Conference.

Our expert sources say the massive consolidation cycle in the upstream space is in its middle innings, suggesting a lot more A&D to come—to be followed by another wave of activity as companies weigh their pro forma portfolios and sell off what doesn't make sense to a new batch of private equity-backed ventures.

This action sets the stage for the A&D event with folks such as Crescent Energy's David Rockecharlie (see page 54), Northern Oil and Gas' Nick O'Grady, Vital Energy's Jason Pigott and Ring Energy's Paul McKinney to share their experiences and ideas on the deal-making market.

But in the meantime, you hold in your hands a wealth of information to prepare for those events, industry insights and the pivotal election ahead.

In this edition of *OGI*, our editors caught up with LNG veteran Charif Souki, talked with executives who are leading the non-op buying trend, examined Enterprise Products Partners' expansion in the Delaware Basin and produced an in-depth analysis on the Trans Mountain Pipeline System. Nissa Darbonne, our executive editor-at-large, took a trek into the wilds of the Uinta Basin to provide our readers with unprecedented insight into the surging region.

As you prepare to vote, be sure to check out our special report on the upcoming election. We've talked to energy stakeholders across the supply chain to gather voters' need-to-know intelligence.

And packaged with this issue is our annual publication, Who's Who in A&D and Capital Formation. This is an industry must-read and our editors have worked diligently to craft a product you'll refer to throughout the year. In addition to the directory, we examine how companies are allocating free cash flow, M&A prospects in basins beyond the Permian and the divestiture market.

In a special roundtable, we interviewed key industry lenders of all sizes for their outlook and expectations for the year ahead. It's crucial intelligence, especially in the current cycle.

We produce this content to keep you apprised of the oil and gas industry and welcome your feedback.

And, we can't wait to see you in Dallas this month. OGI

DEON DAUGHERTY
EDITOR-IN-CHIEF


Oil and Gas Investor
ELECTION
2024
ENERGY ON THE BALLOT

Policy at a Glance

Contrasting energy policies of Vice President Kamala Harris and former President Donald Trump, taken from statements made by the candidates and the Democratic and Republican party platforms.

HARRIS	TRUMP
QUICK TAKES	
"Clean energy boom"	"Energy dominance"
CORE PLAN	
Address climate change by supporting development of renewable energy sources and the electric vehicle industry.	Remove restrictions on drilling to increase domestic oil and gas production.
FEDERAL LANDS	
Limit offshore oil and gas leasing to the central and western Gulf of Mexico. Limit onshore leasing with more restrictions and possibly higher royalties.	Streamline permitting and expand leasing in the Gulf of Mexico and offshore Alaska. Onshore, open up the Arctic Wildlife Refuge and the National Petroleum Reserve Alaska.
ENVIRONMENT	
Prioritize enforcement of environmental regulations, push for cleaner forms of energy, cap orphan oil and gas wells.	Withdraw again from the Paris climate accords, review how the EPA interprets and enforces the Clean Air Act.
TAXES	
Tax cuts for the middle class; higher taxes for businesses and high earners.	Make tax cuts from his first term, which are set to expire, permanent and enact new cuts.

STAKEHOLDER ROUNDTABLE

On the Issues

The November election cycle has ramifications throughout the energy supply chain.

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U.S. energy production, transmission and consumption keeps the nation, as well as the global economy, moving. In this election cycle, not only is the outcome of the presidential race unclear, but down-ballot races are up for grabs and the regulatory impact of those election results will affect the oil and gas industry for years to come.

In this roundtable, Oil and Gas Investor *asked key industry players to share their perspective on issues to keep in mind as readers exercise one of their most fundamental rights.*

There are varying issues at play, including federal methane emissions rulemaking, the so-called pause on LNG permitting and the recent Supreme Court ruling striking down the Chevron deference doctrine and potentially limiting the powers of federal regulating agencies.

Q&A

Deon Daugherty: What are the top policy issues and potential regulations ahead for oil and gas operations in top U.S. producing regions?

Rob Brundrett, president, Ohio Oil and Gas Association: In Ohio, we are focused on engaging with our membership regarding the new methane rule and methane tax, particularly how their implementation and enforcement will impact all of our producers. Additionally, the permitting reform bill making its way through Congress is of great significance to our membership.

Michael Collier, partner in transaction advisory services, Weaver and Tidwell: The future of natural gas should be on every policymaker's mind. The pause in LNG export licensing, which in my opinion was driven by political rather than policy considerations, should be reversed. The U.S. should be the leading exporter of LNG because it's a clean substitute for coal-fired power generation and because a vibrant natural gas industry is vital to our national security.

Here at home, concerns about the Texas grid in light of exploding demand from data centers should also be top of mind. Policymakers need to figure out quickly how to attract investment in dispatchable power generation, and natural gas will play a prominent, if not dominant, role in this.

Ryan Keys, president and co-founder, Triple Crown Resources: I can only speak to regulations in Texas and at the federal level, as state regulations vary wildly from state to state. In Texas, it will be interesting to see how sentiment evolves regarding orphan wells, water and induced seismicity.

At the federal level, among the biggest issues is the implementation of new emissions rules from EPA 0000b/c, EPA Subpart W, and the Department of Transportation's Pipeline and Hazardous Materials Safety Administration (PHMSA). There's still a lot of uncertainty how some of these rules will play out in the real world. The Waste Emissions Charge (WEC) will be assessed through EPA Subpart W starting next year on methane emissions that exceed certain thresholds, so this is imminent. The Supreme Court's ending of the Chevron deference introduces more uncertainty in this evolving emissions regulation landscape.

Ed Longanecker, president, Texas Independent Producers & Royalty Owners Association: In July, U.S. Sens. Joe Manchin

ROB BRUNDRETT
PRESIDENT, OHIO OIL AND GAS ASSOCIATION

MICHAEL COLLIER
PARTNER/TRANSACTION ADVISORY SERVICES, WEAVER AND TIDWELL

RYAN KEYS
PRESIDENT AND CO-FOUNDER, TRIPLE CROWN RESOURCES

ED LONGANECKER
PRESIDENT, TEXAS INDEPENDENT PRODUCERS & ROYALTY OWNERS ASSOCIATION

SARAH MILLER
PRESIDENT AND CEO, GPA MIDSTREAM

DAN PICKERING
CHIEF INVESTMENT OFFICER, PICKERING ENERGY PARTNERS

STEVE PRUETT
PRESIDENT AND CEO, ELEVATION RESOURCES; BOARD CHAIRMAN, INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

(I-W.Va.) and John Barrasso (R-Wyo.) released a long-awaited bill that aims to expedite the development of domestic energy projects by streamlining the federal government's energy infrastructure permitting process. Overregulation is consistently cited as an obstacle that has stalled energy projects across the country. Electricity demand will increase rapidly in the coming years, particularly in Texas, and provisions in the Energy Permitting Reform Act of 2024 (EPRA) will help streamline processes for natural gas producers to meet that demand and provide reliable, affordable energy for years to come.

In the U.S., gaining permits to build energy infrastructure and connecting it to the electric grid is harder today than at any point in recent memory. Projects built between 2018 and 2022 face an average wait time of four years before they can connect to the grid, up from less than two years for projects built between 2000 and 2007. Unclear and overlapping mandates, poor coordination among federal agencies, and unnecessarily long timelines are just some of the many hurdles energy projects face in development.

Natural gas producers in Texas and across the country continue to prove their commitment to providing reliable and affordable energy with record-setting production. But with great production comes great responsibility; particularly, the responsibility to provide adequate transportation to keep the energy flowing. As pipelines in the Permian Basin reach capacity, future production is threatened. The approval process for building additional pipelines can be convoluted, but the introduction of the EPRA is a promising step toward simplifying that process and ensuring that we can continue to meet our state's growing energy demand.

Sarah Miller, president and CEO, GPA Midstream: The industry's top priority is establishing regulatory certainty and sensibility to enable the long-term planning and capital allocations necessary to build the infrastructure that reliably, sustainably and affordably powers our economic vitality.

We will continue to bring a spotlight on how the regulations implementing the tax on methane emissions should be drafted to achieve congressional intent. For example, Congress wrote the Inflation Reduction Act to provide exemptions that recognize good action, and it's critical that such exemptions are part of EPA's [WEC] rules. We will continue fighting for regulations that follow

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The Environmental Protection Agency headquarters in Washington, D.C. The EPA's Waste Emissions Charge rule and how it will be implemented is of particular concern to industry leaders.

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Whoever wins the White House in November will have a limited impact on long-term oil prices.

the law and promote cost-effective emission reduction.

We will also continue to advocate for methane regulations, greenhouse-gas reporting rules and leak detection and reporting requirements that are within the scope of agency authority, consistent with empirical data and aligned with other regulations.

Dan Pickering, chief investment officer, Pickering Energy Partners: Methane and ESG reporting looms large. Permitting generally–LNG export facilities, pipelines, drilling, offshore wells, CCUS sites, the list goes on. Sanctions on bad actors that happen to be big oil suppliers (Russia and Iran are two examples). Rejuvenation and enhancement of the power grid. Carbon taxes–will we ever have one?

Steve Pruett, president and CEO, Elevation Resources; board chairman, Independent Petroleum Association of America: Methane Emissions Reduction Program; the Waste Emissions Charge (methane tax); U.S. District Judge Deborah Boardman's recent decision to vacate the 2020 Gulf of Mexico Biological Opinion, a ruling that could lead to a shutdown of a "wide and substantial swath of offshore oil and gas operations and activities on Dec. 20, 2024." The IPAA stated "the shutdown is likely unless a legal, regulatory or legislative solution that prevents a gap between biological opinions is in place before then."

DD: Which down-ballot races are you watching, and how might those results impact the industry?

RB: The Ohio U.S. Senate race pitting incumbent Democrat Sherrod Brown versus Republican businessman Bernie Moreno is one of the most watched races in the country. It is one of a handful of races nationwide that will determine which party controls the U.S. Senate. Control of the Senate will go a long way in determining the future of U.S. energy policy.

In Ohio, the biggest issue we are watching is State Issue 1, the constitutional amendment to change how statehouse districts are drawn. Additionally, the outcome of the three Ohio Supreme Court races will no doubt impact what is happening in our industry as well as others.

MC: Regardless of the down-ballot winners in Texas, our Texas representatives and senators will, in my view, work to shield the oil and gas industry as best they can from the kinds of attacks we've seen lately. That said, my observation is that our energy literacy as a country is on the rise; the Democratic presidential nominee, for example, is under less pressure to criticize the oil and gas industry as was her predecessor.

Again, it's not been an issue with Texas politicians,

"The top priority of the next administration should be to unleash American natural gas and oil."

ROB BRUNDRETT, president, Ohio Oil And Gas Association

"The U.S. needs to maximize oil and gas production, for economic and national security reasons. We also need to lead the way in terms of carbon capture, geothermal, hydrogen and supplying the world with LNG."

MICHAEL COLLIER, partner/transaction advisory services, Weaver And Tidwell

An oil tanker at the De-Kastri export terminal, a hub for Russian crude exports to Asian markets. How the next president handles sanctions against countries like Russia and Venezuela will have an impact on the U.S. energy sector.

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but I see Democrats in non-oil producing regions far less vocally opposed to us as we saw in the past. The industry is doing a good job explaining their work in such areas as carbon capture, geothermal and hydrogen, which I believe has had an impact on public opinion.

RK: The direct election by popular vote of the Texas Railroad Commissioners is always a curiosity. Since the average Texan has no idea what the Texas Railroad Commission does, with added confusion from their antiquated name, the candidates often win their primaries and elections on policy positions that have nothing to do with the oil and gas industry.

I think it would be better if they were appointed by the governor and serve the same six-year staggered terms. It's such an important position for the Texas economy, and I think it would benefit everyone in the industry to keep the RRC focused on regulation that balances the interests of all stakeholders instead of being distracted by trying to appeal to people who have no idea what the RRC is.

Otherwise, there are some congressional races all over the country that I'm interested in—there's a lot of bipartisan support for American dominance in global LNG markets, and I hope that grows.

EL: Without question, there will be some tight races this election cycle. We are watching some tough fights along the Rio Grande Valley, in our key oil producing

"I think it would be better if [Texas Railroad Commissioners] were appointed by the governor and serve the same six-year staggered terms. It's such an important position for the Texas economy and I think it would benefit everyone in the industry to keep the RRC focused on regulation that balances the interests of all stakeholders instead of being distracted by trying to appeal to people who have no idea what the RRC is."

RYAN KEYS, president and co-founder, Triple Crown Resources regions and in some of the major metroplexes across the state. By and large, however, elected officials in Texas understand the importance of oil and gas. They recognize the contributions of Texas oil and gas to employment in their districts, the state's Rainy Day Fund or Economic Stabilization Fund, state infrastructure, public schools, universities, first responders and other essential services.

Texas elected officials, regardless of party, generally understand that Texas oil and gas producers live, work and raise families in the very communities that they develop mineral resources and that they have a genuine commitment to positive stewardship.

SP: Balance of power in the Senate and House is critical to our industry. There are a number of pivotal Senate races, including Ted Cruz (R-Texas) along with races in Michigan, Montana, Maryland, Nevada, Ohio, Pennsylvania, and Wisconsin.

The House is a toss-up on the majority and is critical, given the chairs of the committees affecting our industry are at stake.

In the event of a Harris-Walz victory, Republicans must control at least the House to prevent permanent damage to the energy industry, capitalism and consumers.

DD: How might the outcome of the November election improve the economics of domestic oil and gas production?

RB: Our message is the same regardless of who wins in November, and that is energy should not be a partisan issue. We will continue to advocate for common-sense rules so our members can do what they do best, which is to responsibly and efficiently produce natural gas and oil to serve the needs of American families.

Answers to this question are going to vary wildly depending on where someone operates and what kind of assets they have. We operate in Texas, don't have any federal leases and our hydrocarbons are transported to Texas markets in pipelines that don't cross state lines, so we aren't affected as much from political volatility at the federal level, at least in terms of regulation. With that said, I think everyone in the industry needs to keep an eye on policy positions on these macroeconomic and geopolitical themes:

1. Iranian sanctions. A more hawkish stance towards Iran will likely result in lower exports, which would be bullish for oil prices.

2. Conflicts in the Middle East and Ukraine. As far as we can tell, there's very little geopolitical risk premium in the current price, and there hasn't been since 2022. We see little spikes here and there (missile strikes, Houthis, etc.), but they don't last very long. If things really heat up, we'll see that risk premium return. Short term, that would benefit producers, but long term, that results in demand destruction, so it's to everyone's benefit to have a stable, peaceful world with low market volatility.

3. OPEC. The populist rhetoric for low energy prices is coming from all corners of the political spectrum, albeit with different philosophies on how to get there. The U.S. is the world's largest oil producer, but the projections calling for another 1 million bbl/d of growth in the next few years are not grounded in reality. Consolidation and lower prices have driven rig counts to levels we haven't seen since 2021, and we are drilling our inventory faster than we can replace it. So, the balance of power in global oil markets is shifting back to OPEC with its substantial spare capacity. In other words, in terms of global supply and demand balances, I don't think there's much that a Trump or Harris administration can do to affect oil prices over the long term. If OPEC wants the price at $50/bbl (and they can live with the fiscal consequences), it will go to $50/bbl. If they want the price at $100/bbl, it will go to $100/bbl. The domestic oil and gas industry has lived with this reality for most of the last 50 years, so we should be used to it.

4. The Strategic Petroleum Reserve. This is a drop in the ocean compared to OPEC, but the SPR is 300 MMbbl below where it was in 2021. It's getting refilled very slowly. I'm not sure which of Trump or Harris is more likely to support filling it back to where it was, but the precedent has been set that it can be used to temporarily suppress a spike in oil prices, but only if the reserve is there.

5. The EU border carbon tax, and more broadly, growing LNG exports. Bypassing or mitigating the border carbon tax in the European Union is a potential windfall for everyone in the American oil and gas supply

"... (N)ew administrations mean opportunity to sit down and discuss current policies, what's needed and what challenges the industry is facing to hopefully reach some solutions together, if they are willing."

ED LONGANECKER, president, Texas Independent Producers & Royalty Owners Association

"We will continue fighting for regulations that follow the law and promote cost-effective emission reduction."

SARAH MILLER, president and CEO, GPA Midstream

The U.S. Strategic Petroleum Reserve is 300 MMbbl below where it was in 2021, an issue that may need to be addressed by the next president.

U.S. DEPARTMENT OF ENERGY

chain. This will need cooperation from our entire supply chain and the federal government. There's bipartisan support for this, but it's weighted to the R side.

MC: Regardless of who wins the presidency, the pause in LNG licensing will likely be lifted because the political imperative for the pause will be behind us. Beyond that, I don't see the parties as terribly far apart on oil and gas policy as some might think, except perhaps when it comes to federal lands and the development of the Gulf of Mexico. There, too, political expediency, as opposed to thoughtful policy, was at play and, post-election, I hope to see us return to rational policy regardless of who wins.

EL: Federal policies, especially those enabling the expansion of LNG export capacity, more efficient environmental reviews for infrastructure, and continued leasing on federal lands and waters are crucial to safeguarding American energy and national security. Currently, four multibillion-dollar LNG projects in Texas are at risk from the current permitting pause. An administration that lifts the currently imposed LNG pause and recognizes the significance of American energy security is paramount.

The oil and gas industry, particularly here in Texas, where we lead the nation in producing these valuable resources, is a major job creator and contributor to economic growth in our communities. It's also critical for supplying energy across the United States and globally. Whatever the outcome in November, we need elected

"Industry profitability is solid, which allows companies to invest in R&D and technology that brings down costs and boosts productivity. Profitability, not the president, will keep these advances moving ahead."

DAN PICKERING, chief investment officer, Pickering Energy Partners

"In the event of a Harris-Walz victory, Republicans must control at least the House to prevent permanent damage to the energy industry, capitalism and consumers."

STEVE PRUETT, president and CEO, Elevation Resources; board chairman, Independent Petroleum Association Of America officials who understand what's at stake and work alongside the industry to ensure workable regulations and less uncertainty for investments. A drop in production would lead to destabilized global energy markets, supply shortages and high energy prices for not only Americans, but our strategic allies who are as dependent on strong American production as we are.

The need for regulatory certainty at the state and federal levels remains a top priority and elections can have a significant impact. Fortunately, we have that in Texas with our pro-business environment and common-sense energy policy, but the federal government has consistently made it more challenging and costly to produce domestic energy.

Despite this reality, we see some candidates taking credit for record levels of production, when their policy decisions reflect the opposite. Increased domestic production is the result of growing global demand, a recovery from the COVID-19 pandemic, production cuts by OPEC and efficiencies gained by U.S. operators during extreme periods of market volatility, not the policy actions taken in recent years that are considered anti-oil and natural gas. It's not the first time we've seen this during an election cycle, nor will it be the last, but we are producing more oil and natural gas despite current federal policy, not as a result of it. It's our hope that the focus on energy policy by various candidates, including "banning" hydraulic fracturing, will help to educate more Americans on how critical our industry is in every aspect of their lives.

Some of the more impactful federal regulations facing our industry that could be bolstered or reversed depending on the outcome of the elections are in the methane emissions category, including: the [WEC], which is the natural fee or tax in the Inflation Reduction Act; revisions to Subpart W reporting that will be used to determine the amount of methane that will be subject to the [WEC]; and New Source Performance Standards OOOO B&C. The latter, and most impactful, directly regulates the oil and gas industry through setting emission standards for both new and existing sites.

SM: Our country has an opportunity to enhance its domestic energy production and support allies who need energy security. The United States produces the cleanest natural gas in the world and our international partners, especially in Europe, need a reliable energy partner. We're hopeful that either presidential candidate will execute energy policy that realizes the potential for stability and economic prosperity for the United States and our international partners.

DP: To state the obvious, this clearly depends on which candidate wins. Harris is likely to make it tougher on oil and gas business, with potentially more restrictive regulations, taxes, access, etc., while supporting and encouraging clean energy (and thus shortening the ultimate runway of the conventional energy industry). However, these actions could result in lower/tighter oil and gas supply and potentially higher prices, boosting profitability.

Trump is more likely to be a friend to the conventional energy industry with less restrictive regulations, taxes, access, etc. He'll also likely hammer the clean energy business (removing incentives), thus lengthening the oil and gas runway. While business conditions would be more favorable, Trump's "drill, baby, drill" mentality could result in higher supply and lower commodity prices.

SP: A Harris-Walz victory and one or more houses of Congress with a Democratic majority will raise the cost of doing business in energy, damage markets for our products, increase cycle time for projects (permitting), and severely reduce access to developing and producing on federal lands, which is already in place under Biden-Harris. A Trump-Vance administration with one or more houses of Congress will reverse the Biden-Harris punitive regulatory policies by replacing the progressive heads of the regulatory agencies affecting the energy industry, along with imposing stronger sanctions on Iranian and Russian oil exports. Post the Supreme Court's reversal of the Chevron deference case, federal agencies need to be reined in and follow legislative and judicial directives.

DD: What opportunities and challenges may result from the election outcome?

RB: Those involved in the natural gas and oil industry are authentic entrepreneurs whose focus will continue to be turning challenges into opportunities and will always find ways to operate and innovate. Politics sometimes slows things down but, regardless of who wins in November, we have a responsibility to find, lift and process the natural gas and oil that will continue to power the global economy.

MC: There is no question Democrats will be less vocal in support of oil and gas than Republicans; but I believe sentiment within the Democratic Party is not as profoundly anti-oil and gas as it once was. Nor do I believe a Democratic victory will pose a threat to our industry. I often remind my friends that oil and gas production, even under a Democratic president, is at an all-time high.

RK: Presidents get too much credit when things go well, and too much blame when they don't. For most, macroeconomic trends and state/local regulations have a greater impact. With that said, smaller operators and those with federal leases and/or insufficient pipeline egress will likely face more challenges with Harris in the White House.

EL: There is only one thing that is certain from whatever the outcome in November might be—change is on the horizon, and with it, a multitude of challenges and opportunities for our industry. As with any election where a new president is guaranteed, we'll be navigating a period of uncertainty as the new administration settles in and establishes what its regulatory priorities will be.

Whether there will be a continuation or expansion of current policies or a reversal of them is unknown at this

The election could meaningfully impact the pace of clean energy technology development and rollout, such as hydrogen technology and alternative energy sources.

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point. What we do know is that new administrations mean opportunity to sit down and discuss current policies, what's needed and what challenges the industry is facing to hopefully reach some solutions together, if they are willing.

SM: Election cycles have repeatedly caused stop-start regulatory challenges in recent decades, complicating and interrupting development of the infrastructure necessary to satisfy energy demand, which is increasing due to AI data centers, new technologies, population growth, rising living standards and industrialization. That stop-start cycle needs to end. Regardless of the election outcome, we look forward to working with the new administration to enact a realistic, real-world regulatory framework that supports the goal of reliable, affordable and cleaner energy.

DP: One unknown regards the geopolitical actions the new president will take. Will they push for a conclusion to the Russia/Ukraine conflict and the Israel/Gaza turmoil? Will they sanction countries like Iran and Venezuela? Will they be a friend or foe to OPEC+ and Saudi Arabia?

SP: The oil and gas industry just needs a pragmatic, stable regulatory environment to continue producing and processing clean, affordable natural gas and petroleum products for our citizens and our allies across the globe. For challenges, a Harris-Walz administration will permanently threaten the existence of the small operator in the United States, impacting almost 1 MMboe/d of production and countless jobs and tax revenue to localities.

The other threat to independents and royalty owners is the Democrats' plans to eliminate Intangible Drilling Cost Deductions and percentage depletion, along with raising corporate and individual tax rates. These changes leave less funds available to reinvest in the upstream industry, but in all forms of manufacturing and thus destroy jobs and our economy.

DD: How will the election affect innovation and technological advances in the industry?

RB: Over the next several years, as we continue to explore opportunities within the hydrogen space, we expect to see additional advances in technology that very well may be applicable to other sectors within the industry. We are hopeful that industry innovation will continue to outpace political roadblocks.

MC: There is always the possibility that IRA subsidies will be rolled back, depending on who wins. But I think the possibility is remote. As long as IRA money doesn't prevent investment in oil and gas, opposition to subsidies will be muted at best. Deficit hawks will form the most vocal opposition to continued IRA subsidies, but politicians stopped listening to deficit hawks (sadly) many years ago.

Controlling methane leaks may be one area where the election could make a difference. The majors are already working on this, but some smaller operators aren't. If

Democrats take over completely, we could see much more stringent rules; but from a macro perspective, I don't think stricter rules will have a profound impact on the whole industry, just smaller players.

RK: A good idea that lowers the cost of supply is going to be successful regardless of who is in the White House.

EL: Innovation and technological advancement are at the heart of the U.S. oil and gas industry. We're continuously researching and studying to find ways to improve efficiency, reduce our environmental footprint, and continue to supply the energy that fuels the world. That won't change with a shift in administration.

Depending on the outcome, we could see increased incentives, R&D funding through the Department of Energy and related policy to support one form of energy over another, but it's irrefutable that oil and natural gas will continue to play a dominant role in meeting growing energy demand. Policy and any federal-oriented funding should reflect that reality.

To be clear, the Texas oil and natural gas industry is not asking for more incentives at the federal level. We are asking for a level playing field that does not pick winners and losers to the detriment of American consumers.

SM: The shale revolution brought about an energy reality previously unfathomable to energy economists and experts across the globe. That revolution reflected the ingenuity, expertise and intellect of the oil and gas industry, which has a proven record for solving problems. Any new administration will best benefit our country by listening to oil and gas industry leaders and partnering with them as problem-solving experts who can nurture the next innovations that will facilitate our nation meeting its challenges. Top-down mandates built on assumptions untethered from practical realities will fail to achieve our shared goal for reliable, affordable and sustainable energy.

DP: It feels like the election is a relatively small influence on innovation and technological advances in the oil and gas portion of the energy sector. Industry profitability is solid, which allows companies to invest in R&D and technology that brings down costs and boosts productivity. Profitability, not the president, will keep these advances moving ahead.

Turning to clean energy, the election could meaningfully impact the pace of technology development and rollout. If the loans, grants, tax credits and subsidies associated with the IRA are halted or reversed, technology-dependent clean energy will take a hit.

DD: What should top the priorities of those officials who take the oath of office in January?

RB: The top priority of the next administration should be to unleash American natural gas and oil. We have seen firsthand the growth and positive change that comes directly to communities when our members invest in the people and infrastructure it takes to grow our industry.

MC: In my opinion, the U.S. needs to maximize oil and gas production, for economic and national security reasons. We also need to lead the way in terms of carbon capture, geothermal, hydrogen and supplying the world with LNG. These imperatives complement each other, and it has been good for the general public to see this. Irrational critiques of the oil and gas industry need to stop, and this goes a long way.

RK: Affordable, abundant energy from all sources–an "all of the above" approach that relies on market solutions and avoids perverse incentives. Oil, gas, nuclear, wind, solar, batteries, coal, biofuels. All of it. If a company produces affordable energy profitably in a way that balances the needs of society, then it deserves a seat at the table.

EL: Producers in the Lone Star State look to state and federal officials for common-sense legislation, like the Energy Permitting Reform Act, that supports responsible production and meeting energy demand. Over the last 12 years, natural gas demand has increased 45% within the United States, yet pipeline capacity has only expanded 28% in that same time period. The industry is dedicated to helping meet this demand, and we urge lawmakers to do their part in ensuring the industry has the critical infrastructure to deliver energy when and where it's needed.

SM: From midstream's perspective, the top priority should be designing energy policy that reflects the need to facilitate a diversity of energy sources to satisfy increasing energy demand. We take for granted the growing quantity of energy required to maintain the lifestyle we enjoy in this country today. Government policies should reflect the challenges faced in all sectors of the energy industry when setting goals and targets. Policies should reflect an understanding of the practical realities affecting the delivery of reliable, affordable and sustainable energy.

DP: Top energy priorities should be making sure the U.S. oil and gas industry maintains its status as the world's biggest energy producer. Domestic energy stability and "independence" gives the United States so much strategic flexibility. The U.S. is no longer beholden to foreign oil producers for oil or gasoline. This must be maintained. Another priority is to thread the needle on the cost/benefit of new energy technologies and renewables. Balancing fiscal responsibility and speed of decarbonization will move the U.S. forward without inefficient spending or unnecessary declines in standard of living.

SP: Securing the border, reforming welfare and other federal programs that are bankrupting the country, eliminate subsidies on energy and carbon projects that do not improve the quality of life for our citizens, and get out of the way of the business that is focused on providing energy of all forms to its citizens.

DD: How do you view the energy policies of Kamala

Harris and Donald Trump? Whose leadership would advantage the oil and gas industry, including its ability to address growing local, national and global demand for energy?

RB: Energy in general and oil and gas specifically will continue to be debated during the remaining weeks of this election cycle and both candidates and their campaigns will refine their messages. Our hope is that both see the value that the industry brings to the country and the economy. American energy is vital to the growing global economy as well as the mission to reduce carbon emissions. Demand is expected to surge, and we can meet that growing need today and into the future.

MC: I believe a Trump administration will be more singularly focused on oil and gas than a Harris administration. But the broader focus of a Harris administration, i.e., an "all of the above" approach embracing new sources of energy and innovative technologies to manage carbon, need not be harmful to oil and gas interests. A Harris administration is not likely to feel anywhere near the pressure to vilify the oil and gas industry as the current president felt at the start of his term. If the oil industry continues to lead in such areas as carbon capture, geothermal, hydrogen and reducing methane emission, we may find an ally in Harris if she wins the presidency. That, in my opinion, should be the industry's objective.

EL: Both Harris and Trump have acknowledged the importance of domestic energy production and are committed to not banning fracking. Trump has a strong record of supporting realistic regulation and providing opportunities for increased oil and gas production. The Biden-Harris administration has issued a long list of policies that are considered anti-oil and natural gas, like the pauses on LNG permits and leasing on federal lands that have created uncertainty for U.S. investment. Not to say elected officials can't change course, but we generally know what to expect in both scenarios and will work with either administration to craft an energy platform that reflects our needs from an energy security, economic and environmental standpoint.

SM: The need for energy—at home and abroad—won't change based on who's in office. Regardless of the outcome in November, our task is to build bipartisan support for real-world solutions to our energy needs. That means working with lawmakers and regulators so we can build the infrastructure necessary for America to remain the world leader in producing clean, reliable and affordable energy. OGI

CAMPAIGN FINANCE

Capitol Expenditures

Influencing policy in Washington requires substantial investment in campaign donations and lobbying. But the ROI is substantial, as well.

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Former President Donald Trump met with a cadre of top oil and gas CEOs in April and reportedly proposed a deal: provide $1 billion for his campaign and he would fast-track federal permitting for energy projects, including drilling and LNG export terminals.

"Scandal!" the environmentalists shrieked. "It's a quid pro quo!"

Not so. Unless he promised to advance specific projects in exchange for donations, there was no violation of campaign finance laws. It was a campaign promise, and not exactly a secret.

As the 2024 Republican Party platform states: "Republicans will increase Energy Production across the board, streamline permitting, and end market-distorting restrictions on Oil, Natural Gas, and Coal."

What Trump said, in effect, was that he needed funds to run his campaign, and if donors were to provide those funds, he would be in a better position to win and do what he already said he was going to do. Or, what every politician says while running for office, more or less.

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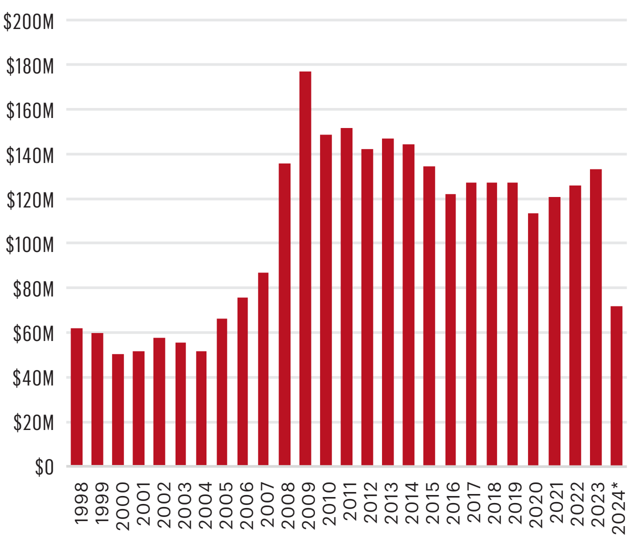
Gathering executives for a fundraising pitch at his Mar-a-Lago home in Palm Beach, Fla., gives former President Donald Trump a home-field advantage.

What is omitted from the telling of this pearl-clutching episode is the underlying purpose of campaign contributions for the donor: access.

Want to share a chopped steak dinner at Mar-a-Lago with the former and possibly

Annual Oil and Gas Lobbying Totals

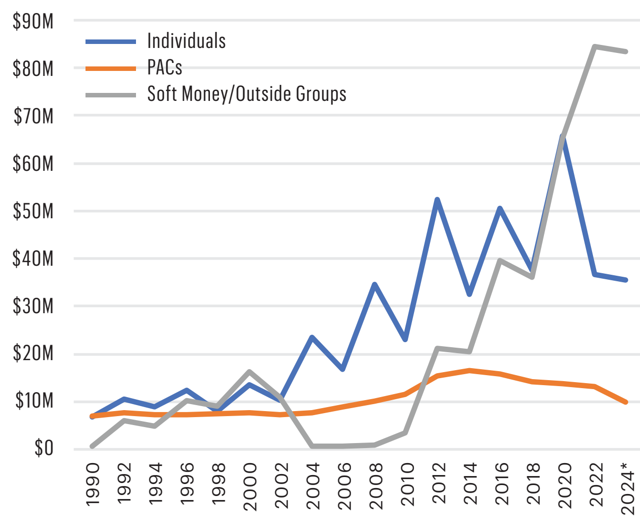


SOURCE: OPENSECRETS

2024 ASTERISK: AS OF JULY 29

Contribution Trends by Source, 1990-2024

Growth in political donations from the oil and gas sector.



2024 ASTERISK: AS OF JULY 29

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future president of the United States? It'll cost in political contributions. A lot.

But is the spending on political donations and lobbying to gain access to Washington's powerful people in the executive branch and in Congress a worthwhile investment? Oh, heck yeah, and it can be quantified.

"The average returns from lobbying expenditures are estimated to be over 130%," wrote economist Karam Kang in an article about policy influence, specifically concerning the energy sector.

In her peer-reviewed paper, Kang, now at the University of Wisconsin, analyzed how lobbying on behalf of the energy industry influenced energy policy that resulted in financial benefit to the industry.

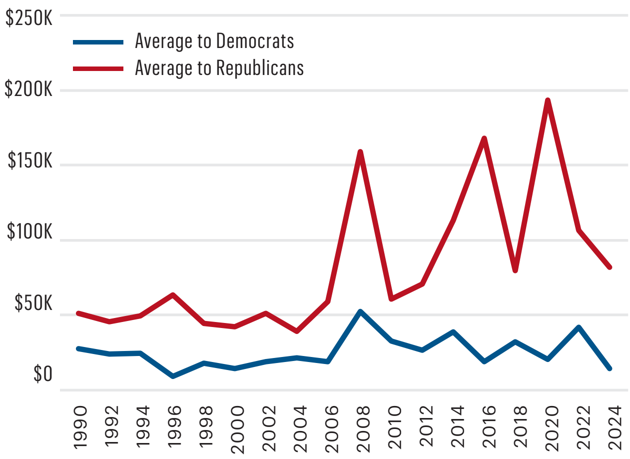
Jack Belcher, principal at Cornerstone Government Affairs, was not surprised.

"Money makes a difference," he told *Oil and Gas Investor*. "It makes a difference in getting your voice heard."

Belcher's job is to influence lawmakers, and he finds it a lot easier if his clients are willing to engage in the political process and make campaign donations, particularly through corporate political action committees (PACs), where the sky is the limit in terms of

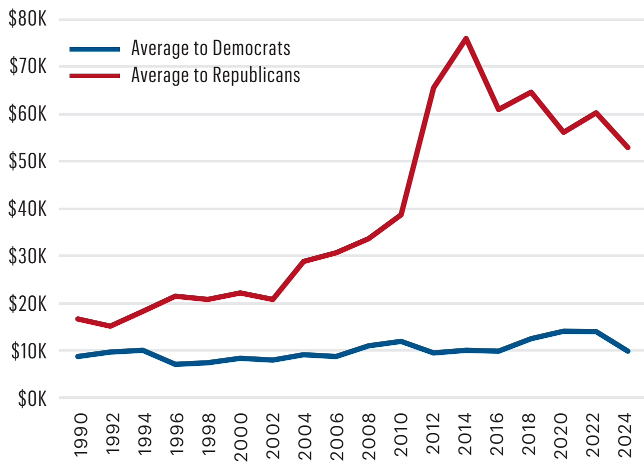
Average Contributions to Members of the Senate, 1990-2024

These charts display average contributions to all members of the U.S. Senate from the oil and gas sector, including the campaign committees of sitting members who run for president.



Average Contributions to Members of the House, 1990-2024

These charts display average contributions to all members of the U.S. House of Representatives from the oil and gas sector, including the campaign committees of sitting members who run for president.



how much can be spent.

"That's not to say you're not going to get your voice heard if you don't spend money," he said. "I've got clients that don't. We still get what we need done. But it helps."

How it Works

To be heard, it's not necessary for a special interest group like oil and gas to carpet bomb Capitol Hill with cash. A little selectivity can go a long way.

As a sector, energy and natural resources trails most in political donations, according to OpenSecrets, a nonpartisan research group that tracks money in U.S. politics. As of the end of July, the finance/insurance/real estate, health, communications/electronics, and lawyer and lobbyist sectors spent more.

The industry, with donations totaling $182 million as of July 29 in the 2023-2024 election cycle, ranked ahead of the labor, transportation, agribusiness, construction and defense sectors.

What a company or industry group needs to decide, Belcher said, is what it wants to accomplish. Is it gaining tax breaks? Fending off regulations? Disposing of the Jones Act? Lobbyists can help determine who to target and how to target them.

An E&P, for example, benefits most from influencing lawmakers who sit on the Natural Resources Committees of both the House of Representatives and the Senate, along with the House Energy and Commerce Committee and Senate Environment and Public Works Committee.

A company that operates globally will pay attention to members of House Foreign Affairs and Senate Foreign Relations. If taxes are the concern, then it might be necessary to seek out a champion on House Ways and Means or Senate Finance.

But influencing legislation is not the only goal of political spending. Issues pop up that are not even anticipated during election campaigns.

One example was the Biden administration's freeze on approvals for LNG export applications, which took effect in January. Oil and gas lobbyists immediately reached out to the powers that be on Capitol Hill, and the powers that be took their calls. Again, money equals access.

In April, a subcommittee of the House Oversight and Accountability Committee held a hearing to examine the political nature of the permitting pause. It may not have accomplished much more than putting a Department of Energy official on the hot seat, but it demonstrated that allies in the House were responsive to industry concerns.

In fact, the pause was reversed in July by a federal judge's ruling in a lawsuit brought by 16 state attorneys general. The reversal turned out to be an example of influence at the state level, rather than the federal.

Not Left Out

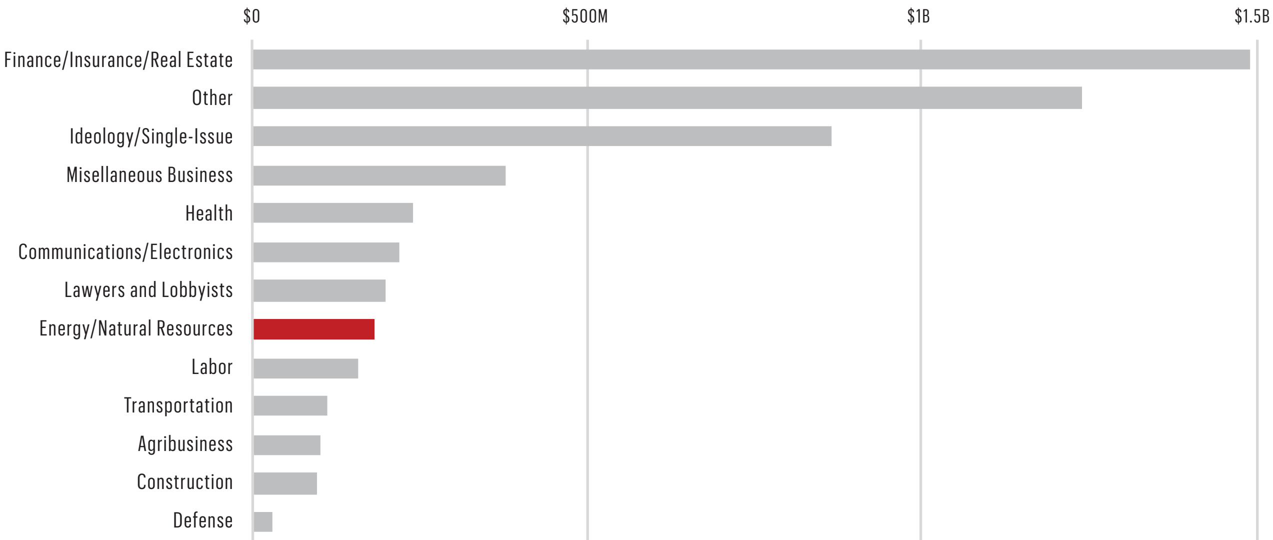
Decisionmakers in the oil and gas industry are well known for favoring Republican lawmakers in Washington. As of the end of August, 75% of energy industry donations went to Republicans, according to OpenSecrets. But sticking with one party over the other isn't the best strategy, Belcher said.

"If you're an oil and gas company, you're trying to find those Democrats that are somewhat reasonable on oil and gas," he said. "You try to find the candidates that are good on their issues; you want to have a go-to in both parties."

That's not always easy for oil and gas lobbyists. Ideally, he said, there would be more of a balance in donations to lawmakers of the two major parties, but

How the Sectors Compare

Political contributions from corporate sectors in the 2023-2024 election cycle as of July 29.



SOURCE: OPENSECRETS

many Democrats have refused contributions from fossil fuel companies.

"They don't even want to take the money, or they're just not going to be supportive of your position," Belcher said. In that case, he sometimes recommends sending money to certain members of Congress anyway, just to remind them that people employed in the industry live in their districts.

Not all Democratic representatives are averse to industry funds. Among those who have accepted donations from industry PACs in the past are Texas Reps. Henry Cuellar, Lizzie Fletcher and the late Sheila Jackson Lee, and South Carolina Rep. James Clyburn, the former House majority whip.

The political polarization of the country is to blame. In this with-us-or-against-us era, it has become untenable for many Democrats to be in contact with the oil and gas industry lest factions in their party disown them. Same for Republicans with the renewable energy sector. Critical issues like energy security and climate change have become so politically charged that progress on solutions is agonizing at best.

The Value of Speaking Up

But even if money talks, it's no substitute for the donor actually saying the words. There are those who choose not to speak, in which case, their voices are rarely heard in the corridors of power.

"Companies are really weird this way," Belcher said. "Some companies have a cultural aversion to all of this, especially European companies."

And then there's Harold Hamm.

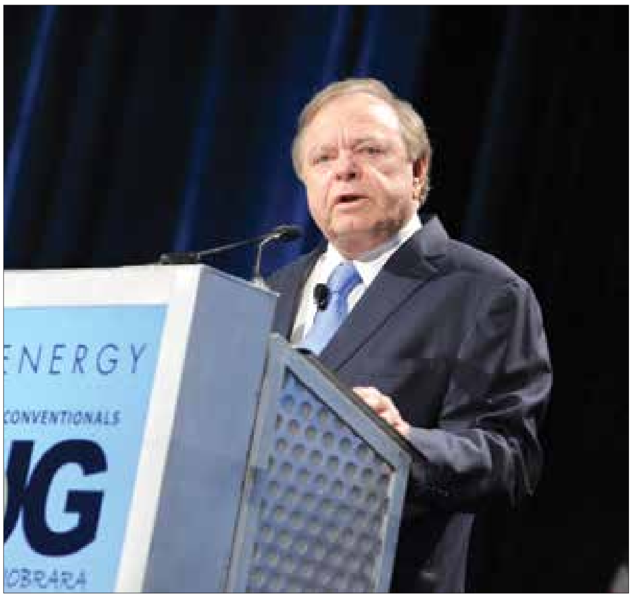
"You'll have companies that are … willing to take a lead on an issue that maybe is a lot bigger than themselves," he said, referring to the executive chairman of Continental Resources. "You see that happen a lot."

Hamm, who heads the nation's top-producing private E&P, was among those who lobbied ferociously to lift the crude oil export ban, an effort that resulted in its repeal as part of the Consolidated Appropriations Act that was signed into law by President Barack Obama in December 2015. But Belcher witnessed Hamm's political savvy firsthand during his time at IPAA, when he would escort Hamm around Capitol Hill. In that period, the Continental portfolio included operations on federal land.

"We'd go office to office and office, and [Hamm was] tireless out there," Belcher said. "They loved him. You've got people like that [who] just get passionate about things and play this kind of role."

Like oil and gas, politics is a relationship business. Most politicians are, by their nature, extroverts. They need money and votes to keep their jobs, but they thrive on interpersonal connections and attention, too, especially with those who are also in positions of power. When captains of industry come to town, they perk up.

Trump could have just as easily made his fundraising pitch via Zoom. By gathering the executives for dinner, he made it personal (not to mention giving himself the homefield advantage). The executives benefit from the connection, as well.



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"We'd go office to office and office, and [Harold Hamm was] tireless out there," Belcher said. "They loved him. You've got people like that [who] just get passionate about things and play this kind of role."

JACK BELCHER, principal, Cornerstone Government Affairs

"When I think about all of these big, consequential pieces of legislation that get passed, it isn't just the organizations," Belcher said. "It's the individuals that actually go out there and champion something and help make it happen."

Few industries are regulated to the degree experienced by the oil and gas industry. Not engaging in the political process via campaign donations and lobbying can deny companies and executives access to those who make impactful decisions, and it can limit input when legislation is proposed and debated.

It's not just the return on investment due to the results of particular legislation.

"The total amount of lobbying expenditures is relatively small when compared to the value of the government policies they are intended to influence," the economist Kang wrote in her paper, noting that "the content of a bill can and often does change throughout the entirety of the legislative process."

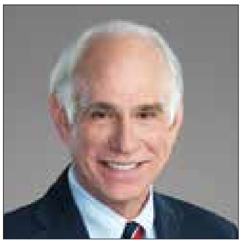
That's why influencing policy is more important than trying to alter the direction of a particular bill. It comes down to making a call to a powerful person in Washington and having that person pick up.

That kind of access costs. But it's worth it. OGI

POLICY & REGULATIONS

Trump vs. Harris—Policy Promises vs. Economics

The presidential debate did not shed much light on policy initiatives. Are there substantive differences?



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Energy

Former President Donald Trump's energy platform is "drill baby drill," with some rhetoric about reversing the green and renewable initiatives instituted by the Biden administration.

The reality is that Trump would have little ability to increase oil production from already historic highs. If the past is any guide, during his previous term in office, he cut a deal with Saudi Arabia to increase oil production and drive down oil prices in exchange for a pass on the murder of Jamal Khashoggi.

Vice President Kamala Harris now says she is pro-fracking, reflecting a boom in U.S. natural gas and oil production during the Biden-Harris administration that led to a sharp drop in carbon emissions as inexpensive natural gas has chased coal power plants off the grid.

A Harris administration may raise the cost of production, but the higher oil prices that are typical under Democratic administrations would offset the increased costs. U.S. oil production with fracking has soared from less than 5 MMbbl/d to more than 13 MMbbl/d, with a net gain to U.S. gross domestic product of more than $200 billion.

Both candidates pay lip service to making U.S. electric grids more resilient. Prior to the growth of solar, wind and batteries, the nation was facing more than $2 trillion in required investment to update the old grid.

The new grid, soon to be dominated by wind and solar resources, will require a larger buildout of transmission facilities

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and relative overspending on batteries to the extent that these replace coal, natural gas and nuclear power plants. Regardless of who sits in the White House, there is no way to avoid higher electricity bills for America.

Energy is, however, deep on the second page of voters' concerns. The economy ranks higher, so what of the candidates' economic policies?

Taxes, Deficits, Trade and Tariffs

President Ronald Reagan took office with an old-fashioned Keynesian economic stimulus package driven by increased government spending (enough to force an end to the Cold War) and tax cuts. Later, Reagan increased taxes and fees for government services.

President George H.W. Bush's tax increases set the stage for balanced budgets during the Clinton administration. In succeeding administrations, Republicans and Democrats have raced to deplete the nation's credit line.

Trump has proposed additional tax cuts and renewing those enacted during his first administration that currently are set to expire. Estimates are that his proposals will add up to $5 trillion to the nation's debt.

Harris has also proposed targeted tax cuts—taking some cues from Trump—but would let the Trump tax cuts expire to address the increasing and extreme concentration of wealth among very few taxpayers.

The middle class was hammered by the Trump tax cuts, and the growing disparity of wealth is increasingly a red flag for the 98%. Change is coming sooner or later. Harris's proposals are projected to add less than $500 billion to the nation's debt.

Both candidates suggest tariffs to provide more revenue and encourage domestic industry. Simplistic assumptions that our trading partners will absorb the tariffs without increasing U.S. inflation is not borne out by experience. The brutal Smoot-Hawley tariffs of 1930 sparked a global trade war that brought on the Great Depression, and that is the risk for a broad-spectrum tariff policy.

Education

Both candidates say they would reinvigorate domestic industry with innovation, technology and capital, but both have ignored the related need for reinvigoration of U.S. higher education, a modern-day reboot of the efforts following the Soviets' launch of Sputnik in 1957.

For decades, many nations have sent their best and brightest to U.S. colleges and universities. These international students pay more in tuition than U.S. students, making them profit centers for cash-strapped U.S. research universities.

But domestic student enrollment in the sciences hasn't kept up, leading to concerns about how the U.S. will maintain its technological edge over competitors. A key concern? If our nation's top minds can make more as hedge fund managers or clever tax attorneys, why would they instead choose careers as researchers to solve the pressing science and technology problems of the day?

Assuming that the market will solve our problems is a failure of neoclassical economic thought and bears thinking about as voters prepare to head to the polls. Executive leadership is needed if we expect long-term results and a positive return on investment.

That's true in politics, just as it is in business. That means the choice for voters is clear—pick the candidate who is focused on the future, that shining "City on the Hill," or pick the candidate who is focused on expediency. OGJ

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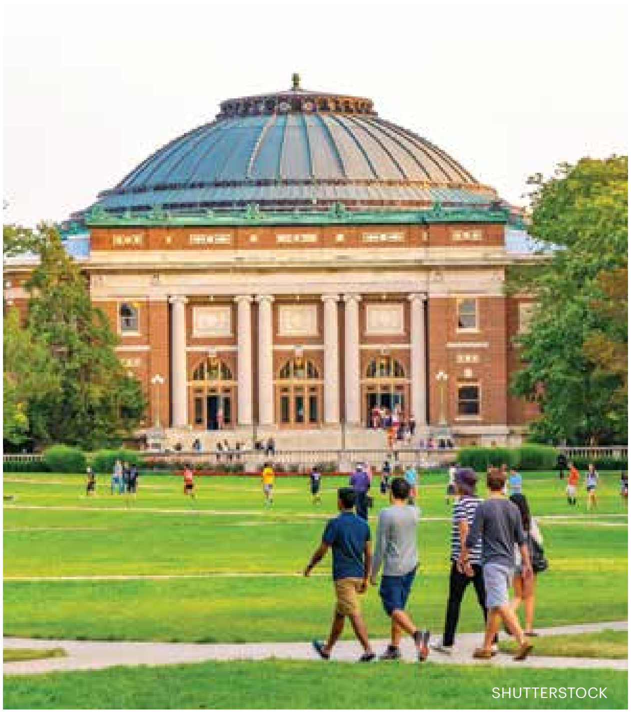

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POLICY & REGULATIONS

Belcher: Election Outcomes and Their Impacts on Future US Policy

Trump would back 'energy dominance,' while Harris would pursue a climate change agenda.

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With Election Day 2024 quickly approaching, former President Donald Trump and Vice President Kamala Harris have been quite vocal regarding their position on energy and climate change.

Trump is vowing to bring back "Energy Dominance" by supporting greater production of traditional energy forms and by reducing the regulatory burden the industry is facing.

Harris is pledging to do more to address climate change and continue the current administration's support for renewable energy and electric vehicles, focusing on distributing much of the funding generated through the Inflation Reduction Act and the Infrastructure Investment and Jobs Act.

A key area where the campaigns have very different policies on oil and gas development is on federal lands. A Harris administration would likely continue some of the policy initiatives put forth under the Biden administration that restricted and slowed federal oil and gas leasing. In January 2021, President Biden placed a "pause" on oil and gas leasing in order to issue more restrictive policies for activities on federal lands.

Harris can be expected to continue policies on offshore programs that limit leasing activities to the central and western Gulf of Mexico, and favoring offshore wind. A Harris administration would likely continue existing plans to hold Gulf of Mexico oil and gas lease sales in 2025, 2027 and 2029 to ensure compliance with Inflation Reduction Act requirements that condition new offshore wind lease sales on recent offshore oil and gas lease sales.

A Trump administration would likely be very supportive of expanded oil and gas leasing through more accommodative fiscal terms, like lower royalties and rents, and through expanded lease sales, returning to a policy of two annual regionwide Gulf of Mexico lease sales. It would also seek to expand federal leasing to areas offshore Alaska. Trump has limited his ability to expand leasing to the Southeast coast and eastern Gulf of Mexico through 2032 by his own executive order.

Onshore Agenda

Onshore, a Harris administration could continue the current administration's climate and conservation agenda on federal lands, issuing few oil and gas leases with more restrictions and higher royalties. We would expect oil and gas leasing to continue in order to meet requirements under the Inflation Reduction Act that solar and wind rights-of-way on federal land only get issued if sufficient oil and gas leasing occurs.

When serving as a U.S. senator, Harris vowed to ban hydraulic fracturing. As a presidential candidate, she has reversed that position, stating that she would not ban fracking.

Under a Trump administration, we would expect more vigorous federal onshore oil and gas leasing and permitting. This would include regular robust quarterly lease sales and more generous fiscal terms. It would also attempt to reverse policies, such as critical habitat designations and endangered species listings (dunes sagebrush lizard) that are deemed harmful to industry.

We would also fully expect a Trump administration to reverse actions by the Biden administration to halt leasing activity in the Arctic Wildlife Refuge and restrict leasing in the National Petroleum Reserve Alaska.

In terms of environmental policy regarding methane, Trump is vowing to overturn recent methane emissions regulations, including the EPA Methane Rule and the Methane Fee on emissions. Harris remains fully supportive of those policies.

It is important to note that under the Biden-Harris administration, the U.S. has experienced record levels of oil and natural gas production and exports. This is partially due to the fact that so much additional production has come from shale plays that are predominantly located on state and private

A pump station for TC Energy's Keystone Pipeline in Steele City, Neb. The Biden administration ended hopes for construction of the Keystone XL Pipeline in early 2021 that would have expanded Keystone and significantly added to the flow of Canadian crude to the U.S.

HART ENERGY

lands and are thus less susceptible to impacts from federal policies.

Midstream and Climate

The Biden-Harris administration began with the executive order halting the Keystone XL Pipeline, which set an anti-fossil energy tone for the administration. The permitting process for pipelines has become highly contentious and politicized and will likely remain that way for years to come. It took the passage of a bill to raise the debt limit with language included approving all permits and authorizations to get the Mountain Valley Pipeline built.

Under a Harris administration, pipelines likely would be judged on a case-by-case basis, weighing the political pros and cons of each project. Harris might appoint FERC commissioners who will give greater consideration to the climate change impacts of future projects. A Harris administration would be expected to sign the Pipeline Safety/PHMSA Reauthorization into law.

A Trump administration could be more aggressive with regard to approving and permitting future pipeline projects. It is likely that a Trump administration would pursue permitting reform that would benefit pipelines and other types of energy infrastructure.

Both candidates are generally supportive of LNG exports, which have been a major foreign policy tool for Biden in light of the reduction in Russian natural gas imports to Europe following the Russian invasion of Ukraine and the sabotage of the Nord Stream 2 Pipeline.

Earlier this year, Biden announced a "pause" in the issuance of LNG export licenses to non-free trade agreement countries until a study is performed on the purported impacts of LNG exports on climate, the economy and national security. This was done to placate environmental groups that have opposed increased U.S. exports of LNG, citing their climate impacts.

This announcement was not well-received by the U.S. oil and gas industry, LNG exporters and importing countries, many of whom are allies. The pause has negatively impacted projects and the U.S.' reputation as a reliable exporter. Despite these impacts, the U.S. is on track to double LNG export capacity, reaching 24.4 Bcf/d the next three years, according to the U.S. Energy Information Administration.

While the problem will most likely go away before a Harris presidency would commence, it is indicative of a bigger issue—a need to satisfy the environmental base. Such commitments in the future could thwart our ability to grow our energy industry and infrastructure.

Trump has been very supportive of LNG exports, as well as crude oil and products exports, examples of what he deems to be U.S. energy dominance. His position on tariffs of imports like Chinese steel could make U.S. LNG activity more challenging.

Another important factor to consider in terms of future energy policy is the range of outcomes in the U.S. House and Senate elections. Should either candidate's party fail to win both the House and Senate, they will have a difficult time moving favored legislation through Congress.

Under a split Congress, which many currently see as the most likely scenario, the president would have to rely on regulations and executive orders to achieve goals, with the opposition party using oversight and appropriations to try to limit the policy success of the administration. Should either Trump or Harris have control of both houses of Congress as president, implementing an agenda could be a much smoother task. OGI

POLICY

Bracewell: How Trump and Harris Differ (or Don't) on Energy Policy

Presidential impact on energy prices is largely about perception.

SCOTT SEGAL
BRACEWELL

Scott Segal is co-chair of the Bracewell law firm's policy resolution group. He is based in Washington DC.

Before either Vice President Kamala Harris or former President Donald Trump can make good on their campaign promises, they must get elected. And getting elected during a time of economic uncertainty, including high inflation, necessitates a degree of pragmatism on pocketbook issues.

Of course, one of the most important such issues is energy—its price, supply and availability. One recent poll showed that at least nine out of 10 battleground-state voters are at least somewhat concerned about inflation, and they perceive a role for oil and gas production in assisting consumers and small business.

Whether an election really impacts energy prices is hardly material since almost half of Americans believe that a presidential election has more impact on energy prices (including fuel prices) than the actual market forces at play. In reality, presidents have very little direct power to affect energy prices, no matter how restrictive or encouraging their policy choices may be.

Policy at Play

The political dynamics of energy may push both candidates into slightly less familiar postures.

Let's take Harris' previous positions. In 2019 as a senator, Harris expressed her support for a ban on hydraulic fracturing. Now, after a term in office as vice president, Harris recently told CNN that, "What I have seen is that we can grow, and we can increase a clean energy economy without banning fracking."

While the passage of the Inflation Reduction Act (IRA) did mark support for a carrot-based clean energy strategy in place of command-and-control limits, it also seems likely that macroeconomic concerns about energy prices and employment in oil and gas played roles, as well. But having cast the tie-breaking vote passing IRA, Harris's emphasis on the statute is understandable.

With Trump, support for oil and gas production is familiar terrain for the former president's campaign with references to "drill, baby drill" and "liquid gold under our feet" punctuating his acceptance speech at the Republican National Convention.

However, while Trump has made it clear that he doesn't support clean energy programs like the IRA, he has been confronted by a growing chorus of support from some Republican legislators in support of clean-energy incentives, particularly because these investments land disproportionately in the pro-construction, wide-open spaces that tend to characterize more politically conservative areas. In a Bloomberg survey, while some $42 billion of IRA money is going to projects in Democratic House districts, almost four times that amount is slated for Republican districts.

What's Ahead?

Despite obvious policy differences on a range of issues, when it comes to energy policy, both campaigns face pressures to balance some clean-energy investments and some support for traditional oil and gas production. That said, once the election is over, we can expect a different approach to governance on issues of importance to oil and gas investors. Here are some examples:

- **Production incentives:** A Trump administration would likely press for expedited permitting of oil and gas infrastructure, increased drilling on public lands and offshore, favorable tax policy for production, and a deregulatory impulse that could slow the pace of decarbonization of the power sector. While a Harris administration might disagree on some or all of these priorities, the overturning of the Chevron deference and lingering macroeconomic concerns would likely stay regulatory overreaction.

- **LNG:** The Biden administration announced a pause on consideration of new LNG export terminals. While Harris has not indicated a reversal of this policy, on July 1, a federal district court in Louisiana ordered that pause to be “stayed in its entirety, effective immediately.” And of course, existing terminals or those already underway allow for significant exports already. So, while the importance of climate considerations as part of any public interest analysis will differ depending on the election outcome, it is not clear how effective (or legal) a policy the LNG pause was in the first instance. The first new export terminal approval was announced on Sept. 3.

- **Global climate accords:** In 2017, Trump withdrew the U.S. from the Paris Climate Agreement. In 2021, President Joe Biden placed the nation back in the accord. Trump has committed to taking the U.S. back out of Paris, perhaps even the underlying framework convention, whereas Harris has called the agreement crucial to addressing climate change and protect “our children’s future.” This is an area of clear difference in governance on climate change, although the real-world significance on domestic energy policy is debatable.

- **Environmental enforcement:** One of the most significant powers of an incoming administration as it relates to energy production is the ability to set priorities for the strength of environmental enforcement. Harris began her career as prosecutor and established one of the first environmental justice units, and that experience likely colors her approach to regulation. By contrast, Trump advisers have suggested a number of reforms, paring back enforcement authorities and reorganizing the U.S. Environmental Protection Agency. This profound difference in approach could change the predictability and cost structure for oil and gas investments, even as both administrations would seem likely to support some permitting reform in support of energy investments.

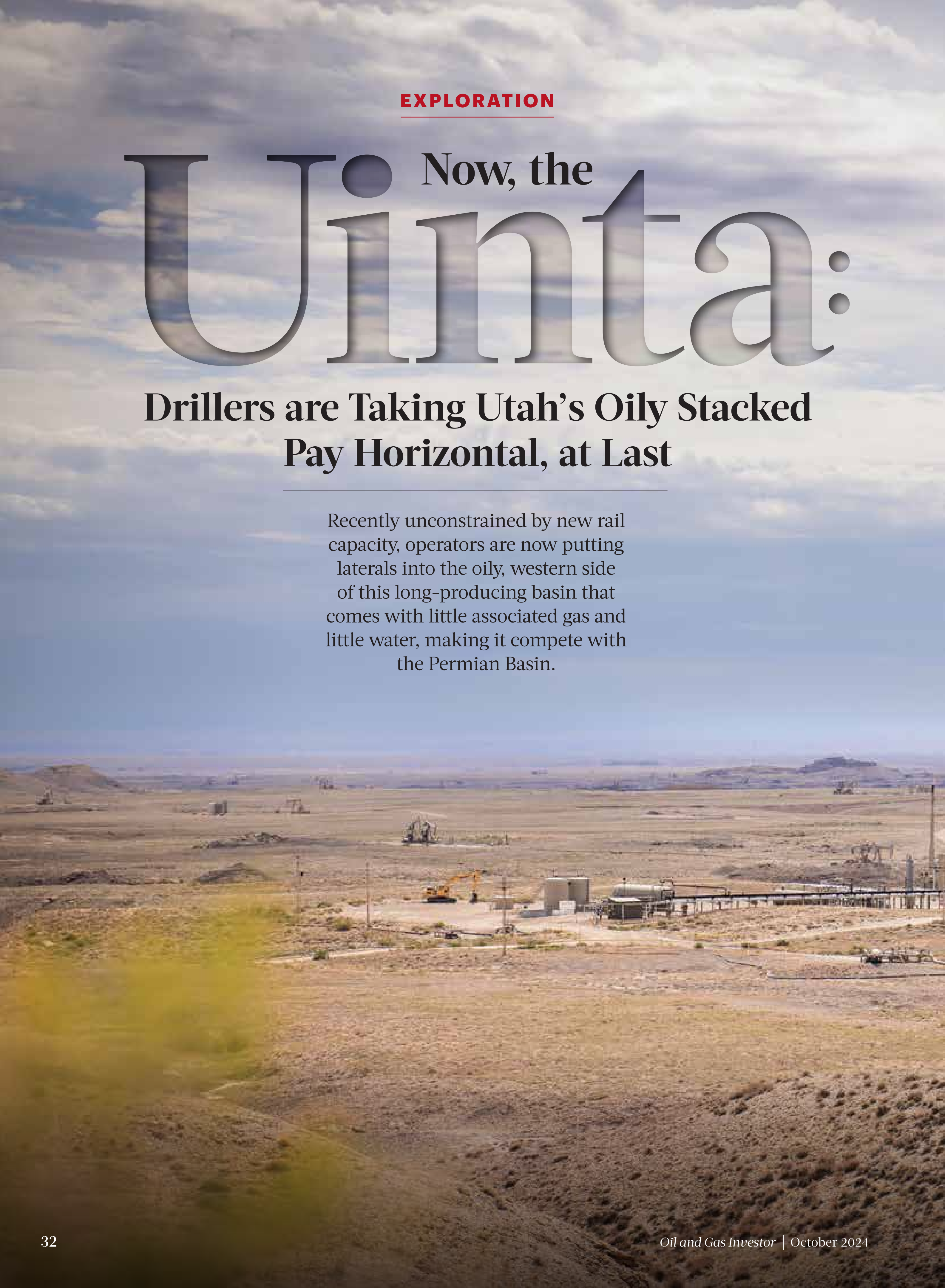
Presidents can only do what the law allows them to do.

Beyond that, they need the support of a Congress that is often unable to overcome partisan divides on energy topics. While it is tempting to stress the rhetorical differences in approach between the two candidates, real-world considerations like energy prices, investment patterns, and energy security may make the actual outcomes closer than you might think. OGI

EXPLORATION

Now, the Uinta: Drillers are Taking Utah's Oily Stacked Pay Horizontal, at Last

Recently unconstrained by new rail capacity, operators are now putting laterals into the oily, western side of this long-producing basin that comes with little associated gas and little water, making it compete with the Permian Basin.



The Uinta Basin's history is steeped in names that have come and gone, often departing for oil prizes unconstrained by the Uinta's takeaway issues of the past.

An A&D broker could run a standalone shop just on trading basin property and marketing farm-ins and farmouts, drill-to-earns, joint ventures and other deals.

But today, the two-decade-old stimulated horizontal revolution has discovered this corner of Utah as market constraint has been unlocked for the basin's valuable, but complicated, waxy crude. While 1.1 Bbbl of oil have already been produced, the Uinta was late to wildcatting from its start–drilling didn't begin until the 1940s.

At first, operators were tapping deep Paleozoic Era deposits.

Quickly, though, they turned to the younger Cretaceous and Tertiary formations that were laid during the Laramide orogeny–particularly during the Tertiary's Eocene and Paleocene epochs–that lifted the Uinta Mountains.

In the foreground during those millions of years, the land subsided and an ancient lake covered the structural depression, laying down thick, organic-rich lacustrine beds that the weight of more recent sedimentary deposits cooked into oil.

Drillers' primary targets then and now are the Wasatch layer and, in particular, the Green River.

Among the latter's members, the lowermost and most popular is the Uteland Butte, while perforations were also made in Castle Peak that is separated by a black shale source rock, Long Point, from the younger Douglas Creek and Garden Gulch.

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As some producers today are still making only vertical holes, the new Uinta is horizontal–also a bit late to the fractured lateral era. That's because, until a few years ago, the Uinta's waxy oil was virtually capped at about 100,000 bbl/d.

New rail capacities upended this. Oil production this past June averaged 176,000 bbl/d, according to state files. That's up from 104,000 bbl/d in June 2019 and 114,000 bbl/d in June 2014. In June 2004, the basin's operators produced only 39,000 bbl/d.

'Pleasantly Surprised'

A Permian and Eagle Ford operator, SM Energy surprised the market in June, announcing it planned to add the Uinta to its portfolio with a deal to buy XCL Resources.

Herb Vogel, SM president and CEO, said the Uinta was as surprising to SM as the news had been to peers and securities analysts.

"Pleasantly surprised," he added.

Takeaway costs–hauling the oil to refineries in Salt Lake City or to rail south of the basin–do eat into the margin, he told investors in a post-announcement call.

But the high oil content per boe produced, along with the higher market price for the Uinta's waxy crude, "winds up being better than the Permian," he said.

SM had begun looking at the XCL property this spring and signed a deal within three months. He told investors that he was initially doubtful, as well.

"When I first looked at this, I thought 'How can that be?'" he said. But "you look at the numbers and it's really that the high oil percentage drives that really great per-boe number

Pads, tank batteries, pumpjacks, pipe and other oilfield iconography dot Monument Butte Field in the southwestern Uinta Basin where operators are landing laterals today in stacked oil pay.

BROOKE HADLOCK PHOTOGRAPHY

and lower costs."

SM estimates the breakeven is between $43/bbl and $57/bbl.

There are five oil refineries in Salt Lake City and several rail options to ship crude to other markets. "We don't see an issue on the takeaway side at all," Vogel said.

In the latter option, XCL has a contract for a large portion of Energy Transfer's 75,000 bbl/d Price River Terminal in Wellington, Utah, about 80 miles south of XCL's property.

"So, there's capacity," Vogel said. Expanding the terminal doesn't take much time, particularly when "compared to running a long-haul pipeline through Appalachia or something like that, right?"

Uinta?

Investors and onlookers were startled by SM's news of expanding outside of Texas. Tim Rezvan, a securities analyst for KeyBanc Capital Markets, took a look at the basin, reporting his findings in early July.

"As the initial shock of learning SM Energy expanded back outside Texas subsides for investors, we believe it is important for them to realize that SM is not buying a science project or an exploratory acreage position," he wrote.

"It is buying a high-quality asset in the early innings of full-field development with consistently strong and oily results across three intervals."

In a quarterly earnings call with investors in August, SM didn't receive any questions about the Uinta. Vogel took the mic back as the operator was closing the call.

"Is it sufficient in terms of takeaway and can we grow production?" he said investors have asked him. Out there, he said, are "perceptions about takeaway or complications related to rail that are actually quite outdated now."

Capacity to market waxy crude "was limited in the 80,000 bbl/d range for the [Uinta] industry and was all delivered to Salt Lake City refineries."

But, since mid-2021, refineries south on the Gulf Coast and east in Oklahoma and Wyoming are able to add the oil to their refining slates, Vogel said.

It goes like this: As natural gas has overcome coal as the U.S.' No. 1 power generation feedstock, western U.S. railways "are generally underutilized in the region because there's less coal being moved," Vogel said.

Now there is room for oil trains. "There are no rail constraints for current production or for expanding production," Vogel said.

For the small amount of gas XCL's northern Uinta property produces and gas from elsewhere in the basin, the MountainWest pipeline expansion this summer added 80 MMcf/d of capacity and Kinder Morgan has one underway to take 150 MMcf/d.

The Deals

SM is paying $2.04 billion for XCL and separately selling 20% interest to nonoperator Northern Oil and Gas for $510 million.

Gabe Daoud, an analyst for TD Cowen, said the price is $35,000 per boe for XCL's 44,000 boe/d and $1.25 million per each of 465 estimated net future-well locations.

In addition to EnCap Investments, XCL is backed by Rice Investment Group, the family office of the Marcellus-focused Rice Energy's founders. (Rice Energy was sold to EQT Corp.)

XCL's 46,500 net acres (37,000 net to SM) are in the overpressured oil window on the basin's northwestern rim, 99% operated, producing 56,000 boe/d (43,000 boe/d net to SM), 88% oil with an API gravity of between 36 and 43 degrees.

The oil doesn't contain sulfur and has a low metals content. Its waxy content sells in the higher-priced lubricants market.

Produced water is less than in SM's and others' operations in the Midland Basin, Vogel said. Drilling and completion (D&C) costs are the same as in West Texas and in SM's Austin Chalk play at less than $850 per lateral foot.

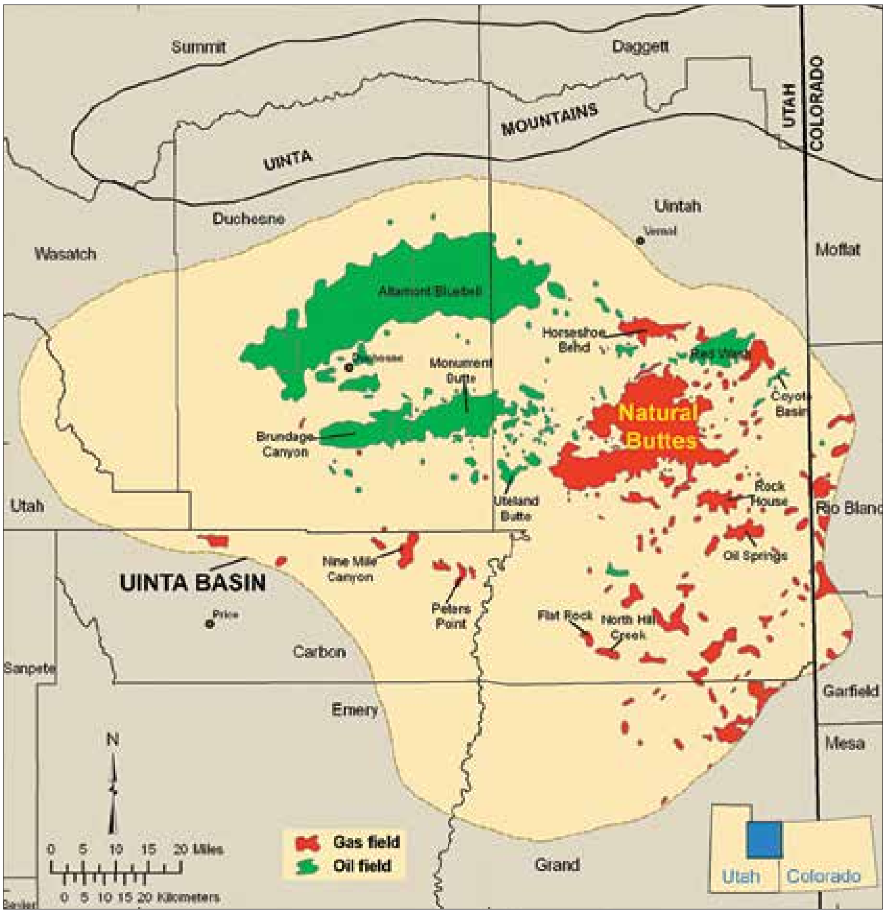
The leasehold is less developed, Vogel said in June. "There's quite a bit of acreage, but not much in production."

In another deal, SM is buying 80% of XCL neighbor Altamont Energy for $70 million; Northern is buying 20%.

All in the Altamont-Bluebell Field, the Altamont property was bought from Linn Energy for $132 million in 2018. The property was 36,000 net acres, 27,000 net undeveloped, at the time, producing 1,500 boe/d from 116 wells.

J.P. Morgan Securities analyst Arun Jayaram wrote in July that Altamont

Uinta Basin Oil and Gas Fields



SOURCE: UTAH GEOLOGICAL SURVEY

The Uinta Basin's oil fields are concentrated on the western side of the basin, while gas fields dominate the east side towards the Colorado border.

"What stands out immediately is simply how much oil is in place relative to other top basins."

HERB VOGEL,
president and CEO,
SM Energy

Helmerich & Payne's FlexRig walking rig #522 drilling a two-well pad in August for Wasatch Energy Management (WEM) on Scout Energy Partners property in Monument Butte Field southeast of Duchesne, Utah.

BROOKE HADLOCK PHOTOGRAPHY

brought only eight wells online in 2023. Its production in 2023 was
3,200 bbl/d versus 84 bbl/d in 2022.

Its volume this year through May averaged 2,200 bbl/d, Jayaram reported.

17 Benches

From XCL's and other data, SM sees 17 layers of pay in the property in a 4,000-foot hydrocarbon column, "which ranks among the largest overpressured hydrocarbon columns in U.S. producing basins," Vogel said.

Nearly 1 Bbbl of oil has been produced from just the Wasatch and Green River formations in the basin to date in nearly 9,000 wells.

"What stands out immediately is simply how much oil is in place relative to other top basins," Vogel said.

Of the acres SM is buying, 10 benches have at least one test well and six of those have more than 10 tests each,
Vogel said.

"It is quite de-risked when you look at it," Vogel said. "And that's only on the XCL acreage. If you go off to neighboring acreage, there's even more.

"So, the amount of de-risking that's been done and the continuity of the play with the rock that we're talking about here really shows what a high-quality basin this is."

J.P. Morgan's Jayaram wrote, "SM believes that its technical expertise at stacked-pay development is applicable to other basins across U.S. shale, which the company will now get the chance to prove to the market with the Uinta asset."

About That Wax

Uinta wax ranges from yellow (north) to black (south) depending on deposition. Both are valuable, but the paraffin content makes Uinta oil more costly to get to market, said Juan Nevarez, executive vice president of Uinta operator Scout Energy Partners.

"You're having to truck it and, in some cases, [both] truck and rail it because it has to remain heated," he told Hart Energy in August.

The wax will solidify otherwise. "That's what makes Uinta oil a little more challenged than in the Delaware Basin."

The new rail option for the basin's oil has allowed Uinta production to grow. But to continue to grow, "you're going to have to have more rail capacity," he added.

The oil is heated in the tank battery at the pad. The truck trailers and rail cars are insulated.

In-field heating is low-cost, though, he said: Operators use some of the associated gas they produce.

▸ CLOSER LOOK

THE CAERUS PROPERTY

In another Uinta deal this year, two Quantum Capital Group-backed E&Ps bought Caerus Oil and Gas' property that straddles the Utah-Colorado border.

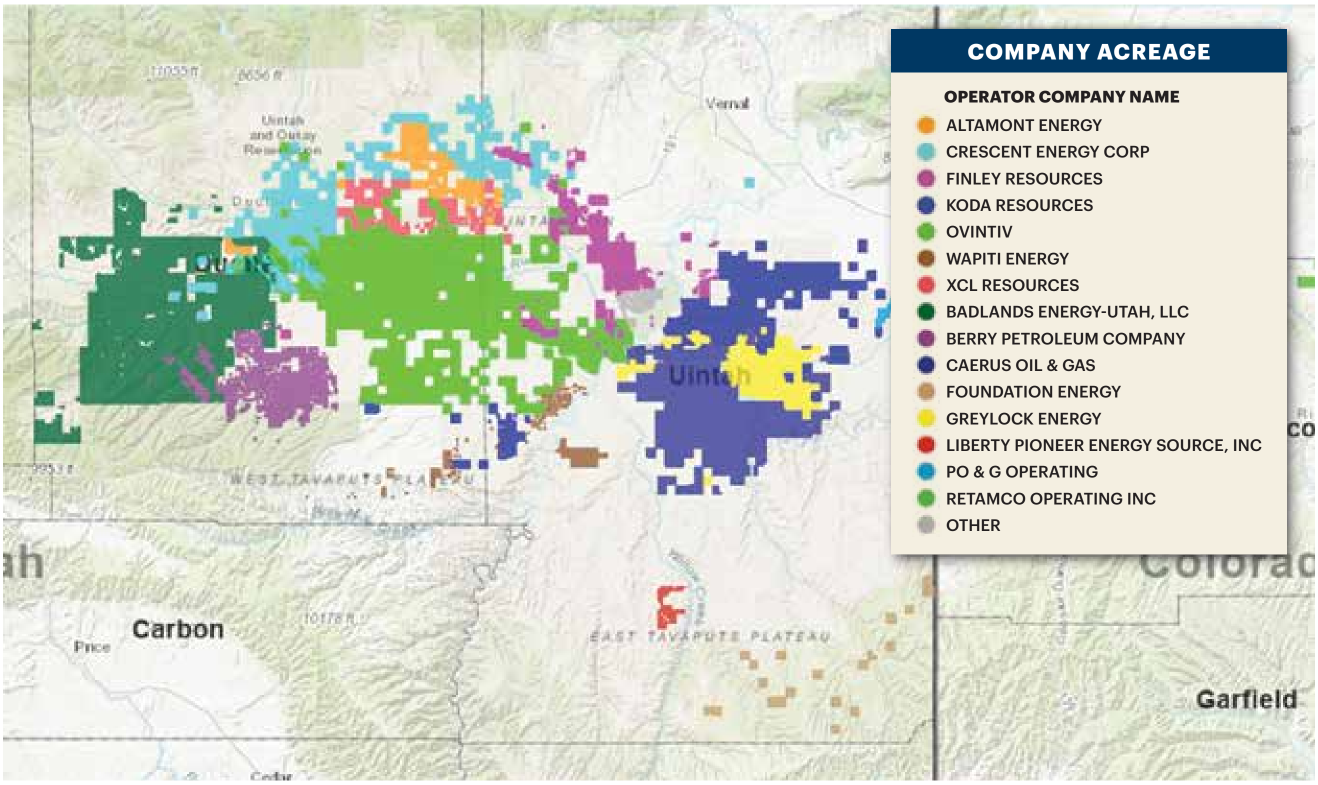
Some of the leasehold is in the eastern, gassy Uinta in Utah, while most is in the gassy Piceance Basin in Colorado on the other side of the Douglas Creek Arch.

The combined deal value is $1.8 billion.

Caerus is owned by Oaktree Capital Management, Anschutz Exploration and Old Ironsides Energy.

The property on the Uinta side—160,000 acres—went to Koda Resources, led by Osman Apaydin, president and CEO, and Kurt Doerr, executive chairman.

Uinta Basin Operators



SOURCE: T.D. COWEN, CITING ENVERUS

About a half-dozen operators have wrapped up most of the leasehold on the Uinta Basin's oily western side.

“Two years ago, there was no indication that [the Uinta] would compete, on a rock-quality basis, with some of the best basins in the United States. But it does.”

JUAN NEVAREZ,
executive vice president,
Scout Energy Partners

Shale and sandstone churned up along the perimeter of a Wasatch Energy Management pad in Monument Butte Field while forming a safety moat around operations.

BROOKE HADLOCK PHOTOGRAPHY

And there is relatively little associated gas to process and ship. In Scout's operations, "you're typically getting about one Mcf for every barrel of oil.

"It's far less gassy than anything that you're dealing with in the Permian."

What gas is leftover–and what's produced from the gassy eastern side of the basin–flows to California on the Kern River pipeline.

The basin is producing some 180,000 bbl/d now. Nevarez said, "I think 300,000 is possible. But you have to continue to have a good price environment."

Scout's Position

Dallas-headquartered Scout entered the Uinta in mid-2022 when it saw an opportunity to pick up a property from Ovintiv.

Formed in 2011, the institutional fund manager buys mature assets–"property that still has opportunity to be optimized and to put some capital in them to either grow production or maintain flat production," Nevarez said.

The entry asset was a waterflood in the basin's oily southside in Monument Butte Field, southeast of Duchesne. "Ovintiv wanted to focus north where they saw more opportunity to develop horizontally."

The property came with some 3,000 gross vertical wells, virtually all in the Green River formation, and 90,000 net acres.

Scout's position today is 110,000 gross acres, 85,000 net, all HBP and all on federal, state and private, non-tribe land.

While it continues to work the vertical waterflood, "we knew there was opportunity to exploit the horizontal portion of the field," he said.

In 2023, it brought in Wasatch Energy Management (WEM) in a horizontal drill-to-earn deal. Upon a well's completion, Scout takes over as operator, while WEM retains a significant working interest.

"They de-risk the area, putting their own capital to work," Nevarez said. "It allows us to prove up that acreage and, after an assessment period, say, 'OK, this is a good area' and have the ability to put some of our own capital to work."

WEM Partner

Provo, Utah-headquartered WEM got its break in the Uinta in 2018. The team had been looking for where it could build an E&P company–but at a five-figures-per-acre entry cost rather than the tens of thousands the Permian and other high-profile oil plays command.

Its drill-to-earn and other deals now number five, spanning the Uinta's oily western side, with XCL Resources, Uinta Wax, Ovintiv, Scout and Altamont, said Danny Gunnell, WEM's CEO.

The E&P plans to double its current net production of 15,500 boe/d from some 28,000-plus net acres in nonop positions and joint ventures, along with an operated position in the southwestern corner of the basin.

Its primary target is Uteland Butte with four wells in a drilling spacing unit with secondary targets in the underlying Wasatch (two) and the overlying Black Shale/Long Point (four) and Douglas Creek (four).

"The Uinta Basin has some of the best wells in America," Gunnell said. "Well results are predictable, consistent and compete toe-to-toe with Permian Basin wells."

Tight Reservoir

The Green River Formation is at about 5,000 feet in Monument Butte Field.

Vertical drillers wouldn't perforate the Uteland Butte in the past because the carbonate was too tight to give up much oil, Nevarez said. Putting a frac on it will create flow, but a vertical hole doesn't expose the well to enough rock beyond just what's near the hole.

"Most of the horizontal wells that are being drilled in the Uinta Basin are going into the Uteland Butte now," Nevarez said.

Operators are also testing Castle Peak that overlies Uteland Butte and the underlying Wasatch with stimulated laterals. At times, drillers are landing in the yet shallower Douglas Creek.

While Scout thought in 2022 the Uinta would lend itself to horizontal development, what operators have proven in just two years has exceeded its expectations.

"Two years ago, there was no indication that it would compete,

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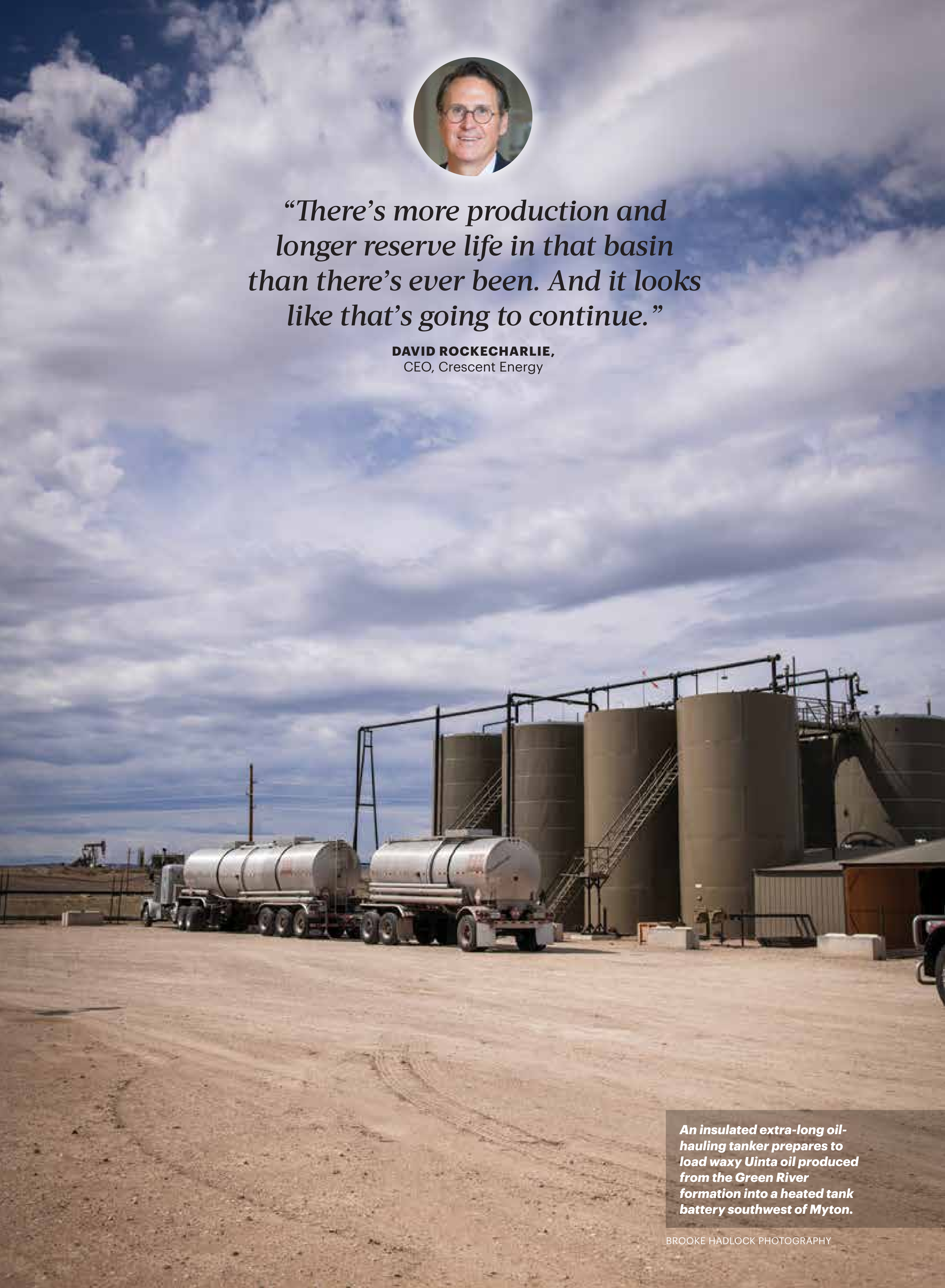
A fracwater pond in Monument Butte Field, southeast of Duchesne.

“There’s more production and longer reserve life in that basin than there’s ever been. And it looks like that’s going to continue.”

DAVID ROCKECHARLIE,
CEO, Crescent Energy



An insulated extra-long oil-hauling tanker prepares to load waxy Uinta oil produced from the Green River formation into a heated tank battery southwest of Myton.

BROOKE HADLOCK PHOTOGRAPHY

on a rock-quality basis, with some of the best basins in the United States," Nevarez said. "But it does."

SM is entering the basin and Nevarez sees other companies showing interest. "I think the basin has proven that it can provide a good return for your capital."

But the growth isn't just because the oil is there, he added–Utah is a pro-business state. In addition, residents support the industry and many work in the business.

"There's some farming in the basin, but there aren't many other jobs there. They really appreciate the oil and gas industry."

9-Gallon Bucket

Before that Monument Butte Field waterflood came eventually into Scout's hands, it was in the hands, so to speak, of Dave Donegan.

Park City, Utah-based Donegan retired in 2023 from Sinclair Oil & Gas Co., where he was president, and this summer from a six-year term on Utah's Trust Lands Administration (TLA) board, lastly as chairman.

The TLA is similar to Texas' University Lands in that it manages state land with proceeds benefiting the state's public schools and select institutions. Created in 1994, the Permanent School Fund has grown from $50 million to more than $3.2 billion.

Its portfolio consists of 3.3 million acres of surface and mineral acres and 1.2 million acres of minerals-only property.

In the late 1990s, Donegan was operations manager and director of business development for Uinta-focused Inland Resources, which owned the waterflood program in the Green River Formation that Ovintiv bought and Scout now owns.

At the time, Uinta operators produced deep oil from Wasatch on the northern rim of the basin and shallow oil from the Green River on the southern rim.

"Historically, all of the crude went to Salt Lake City," Donegan said. "Refining capacity is roughly 150,000 bbl/d, but they're short of cracking capacity. The cracking capacity is about 90,000 bbl/d."

Uinta oil is almost all waxy. "Those are long hydrocarbon chains that have to be cracked," Donegan said. "As long as you have cracking capacity, waxy crude is the perfect crude. It's worth WTI-Cushing."

When the basin exceeded that 90,000 bbl/d cap in the past, the extra oil's economics collapsed.

"It's worth a significant discount to WTI," Donegan said. "So historically, that always provided a cap to how much production came out of the basin."

Extra oil is like pouring 10 gallons into a 9-gallon bucket. The 10th gallon "has no value at all."

Fort Worth-based Uinta operator Jim Finley changed this, though. "He put a lot of money into building rail-takeaway capacity."

To rail a Uinta barrel out of Utah costs more. Uinta operators who don't have all of their capacity contracted to Salt Lake City refiners will need a higher breakeven on the extra oil.

For this reason, the Uinta "has historically been a sort of Tier 2 basin–not for its geology, but for its commercial aspects."

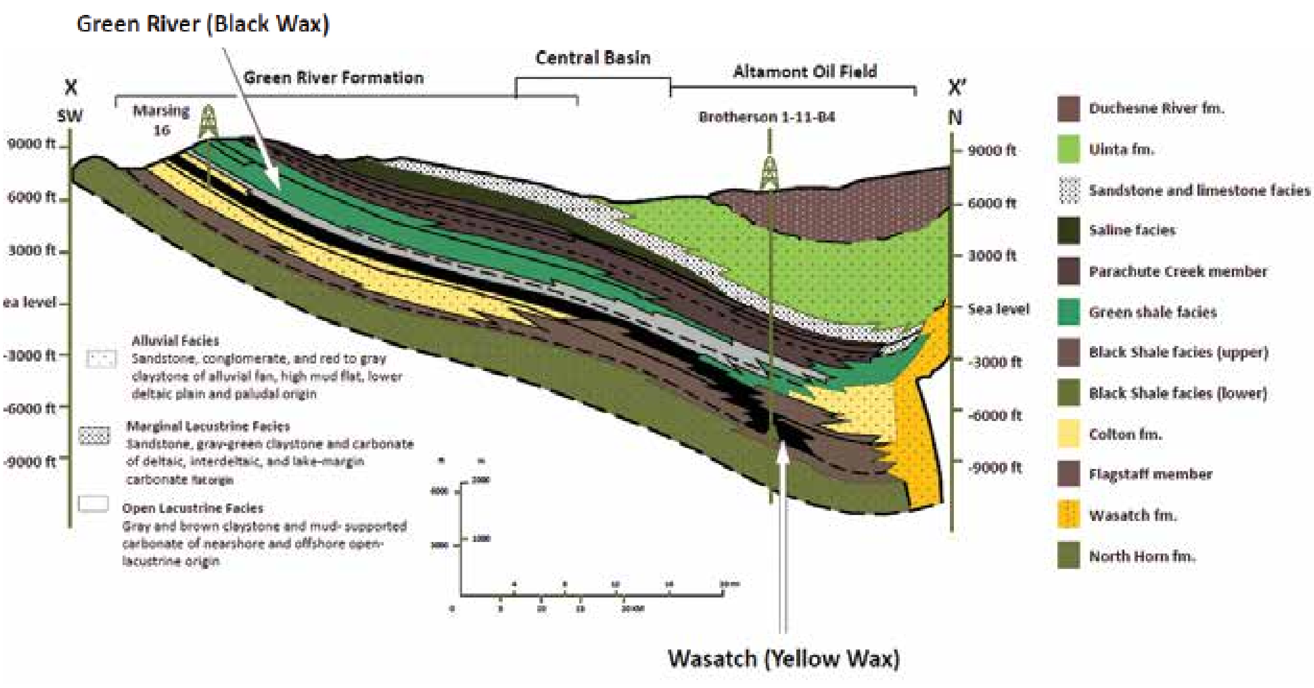
'Goldilocks Area'

The northern rim of the Uinta, including the Altamont-Bluebell Field, is deep at between 8,000 and 12,000 feet, Donegan said. It originally produced from the Wasatch.

"The target reservoir is overpressured, steeply dipping with a lot of porosity," he said.

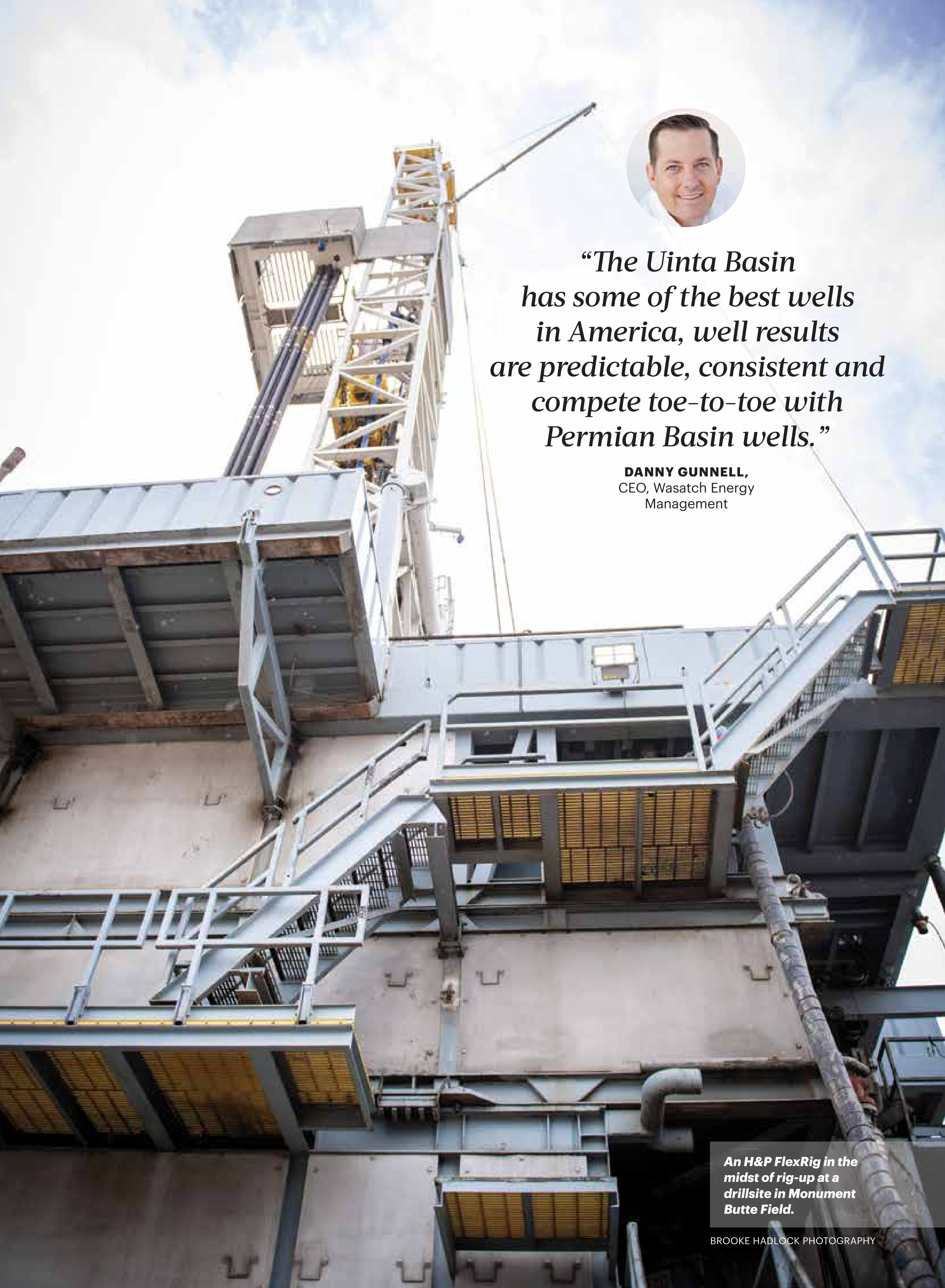
The south side is a less steeply dipping flank that primarily

Uinta Basin Stratigraphic Complex



SOURCE: SEC FILING, FORMER UINTA BASIN OPERATOR VEREN INC., FKA CRESCENT POINT ENERGY

Oil targets at the Uinta Basin's southwestern end are at a shallower depth and wells are primarily in the black wax Green River Formation, while the north side is deeper and the primary target is the yellow wax Wasatch.



"The Uinta Basin has some of the best wells in America, well results are predictable, consistent and compete toe-to-toe with Permian Basin wells."

DANNY GUNNELL,
CEO, Wasatch Energy Management

An H&P FlexRig in the midst of rig-up at a drillsite in Monument Butte Field.

BROOKE HADLOCK PHOTOGRAPHY

produces from the Green River Formation at between 4,000 and 6,000 feet with many thin sand lenses at a normal pressure and little fracture porosity.

Meanwhile, the central part of the basin is the “Goldilocks area.” There, the target reservoirs range from moderately deep to deep and overpressured in a gently dipping structure.

“You have the ability to drill long laterals within multiple individual benches and recover substantial reserves per lateral,” Donegan said. “This is the part of the basin that SM [is buying] and is the play that has dramatically grown the production from the basin.”

There, recovery per well “is comparable to be the best horizontal crude plays in the Lower 48 today, including the Bakken, Eagle Ford and Midland Basin’s Wolfcamp/Spraberry.”

The Learning Curve

KeyBanc’s Rezvan’s look at the Uinta this summer was similar to many others’ Uinta experience in 2024: “Quickly climbing the Uinta Basin learning curve,” he wrote.

While much of the basin is geologically quiet, so was news attention to drilling and dealmaking over the years.

Rezvan found that, of the 530 horizontals 11 operators put in the basin since 2016, the layers targeted most often are the Uteland Butte, Wasatch and Castle Peak.

He called it “a prolific, stacked-pay oil play” and was “impressed by the overall rock quality.”

Of those 11 operators that landed laterals, six are still active in the basin, he added.

Among the Uteland Butte wells, first-12-month production averaged 227,000 boe, 85% oil. From the Wasatch, it was 202,000 boe, also 85% oil. From Castle Peak, production was less, coming in with 141,000 boe, but 87% oil.

XCL had 121 horizontals in the three formations by this summer with at least six months of production history. Among these, 58 were landed in Wasatch, 35 in Uteland Butte and 28 in Castle Peak.

It also put five horizontals in other formations. The average lateral length of all 126 was 2 miles.

The first-six-month performance from Uteland Butte horizontals was 18,937 boe per 1,000 feet; from Wasatch, 15,165 boe per 1,000; and Castle Peak, 12,015. The five laterals in other formations averaged 9,252 per 1,000 lateral feet.

Meanwhile, 110 laterals landed by Ovintiv made between 15,000 and 27,000 boe per 1,000 feet in their first six months.

Crescent Energy’s 104 horizontals averaged between 12,000 and 17,000 boe per 1,000 feet. The wells also brought more solution gas, averaging 78% oil while the XCL and Ovintiv wells averaged 87% oil.

And the 131 made by Uinta Wax averaged between 10,000 and 17,000 boe per 1,000 feet, 89% oil.

New Neighbor

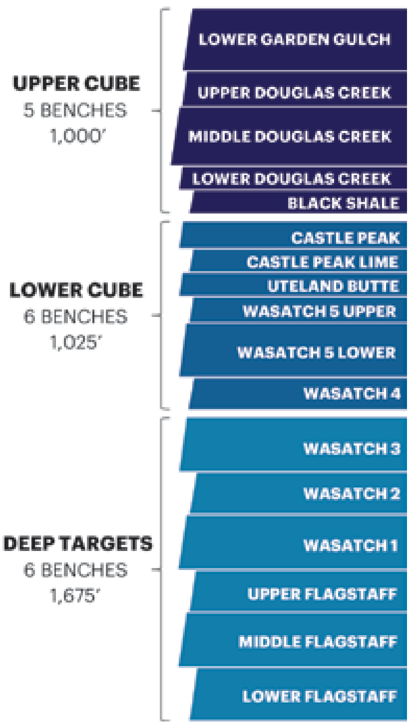
The increased M&A interest in the Uinta–and the potential entry now of a third public operator, SM, adding to public comment on the results in addition to Ovintiv’s–is helpful to the basin, said David Rockecharlie, Crescent CEO.

“We’re very pleased to have another–what I’ll call resource-oriented public company–in the basin helping develop it,” he told *Oil and Gas Investor* in September.

Publicly traded Crescent began sharing results earlier this year of testing larger proppant loads in its horizontal Uinta wells.

The operator was formed in 2021 from the merger of publicly traded Contango Oil & Gas and privately held Independence Energy under the management of investment

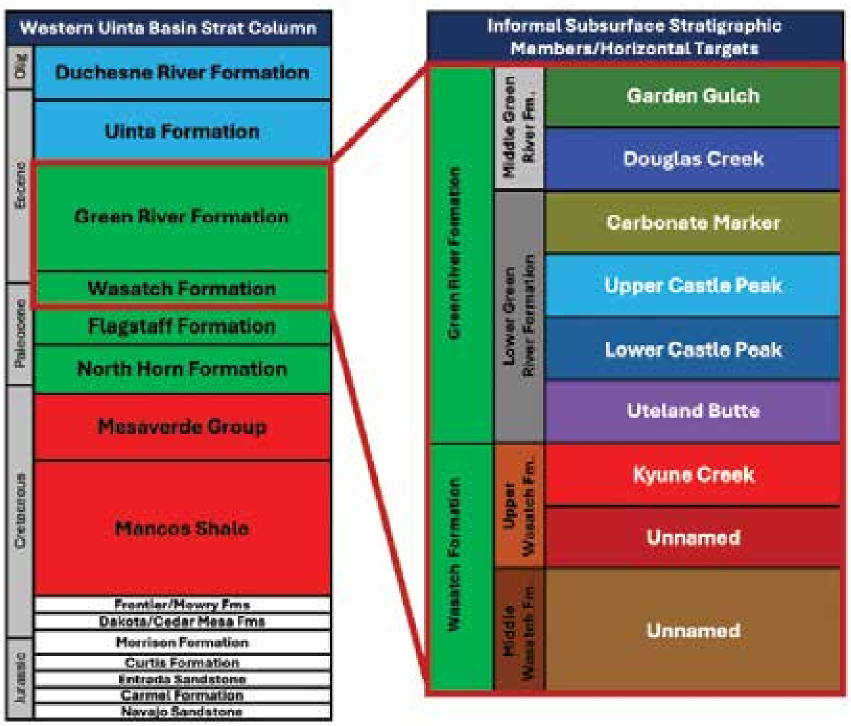
SM Energy’s 17 Targets



SOURCE: SM ENERGY

SM Energy sees 17 potential targets for horizontals in XCL Resources’ property.

Layers of Traditional Uinta Basin Pay



SOURCE: SCOUT ENERGY PARTNERS

Wasatch and Green River are the primary targets in the oily western side of the Uinta Basin.

Safety checks before drilling commences at a Monument Butte Field pad.

BROOKE HADLOCK PHOTOGRAPHY

firm KKR's real estate team.

Crescent picked up its Uinta property in early 2022 from EP Energy for $690 million after the Federal Trade Commission (FTC) refused XCL's attempt to bolt the EP property onto its own.

In the deal, Crescent acquired 30,000 boe/d, 65% oil, from more than 400 active vertical and horizontal wells with 145,000 contiguous net acres and 83% average working interest.

Before rail capacity was added in the past few years, "a lot of the challenges came from companies trying to grow too fast" in the basin, Rockecharlie said. "I think this latest stage of growth has been more methodical."

Bigger Fracs

Crescent's new Uinta Basin completions are showing 60% greater production from new-design wells, based on first-150-day results, it reported in May.

And the extra oil has been with only minimal increases in D&C cost, Rockecharlie told investors in an August call.

"When we acquired this position [in 2022], the only horizontal development on the assets utilized a legacy, smaller completion design with roughly 1,500 pounds of proppant per foot," Rockecharlie said in a May call.

The new completions are with twice the proppant—3,000 pounds per foot (lb/ft).

Crescent operates as Javelin Energy Partners and was Utah's No. 3 oil producer in January, putting some 21,000 bbl/d into trucks and trains, according to state data.

One of its laterals, Robinson 5-19-20-C4-6H in Altamont-Bluebell Field, came on in November with 21,000 bbl of oil in 31 days in its first full month of production, according to state data.

The adjacent Robinson #4H made 21,000 bbl and the neighboring Robinson 4-19-20-C4-2H produced 46,000 bbl.

"There's more production and longer reserve life in that basin than there's ever been," Rockecharlie said. "And it looks like that's going to continue."

Neighbors are more active than Crescent right now, he added, and "others' growth will outpace ours because of a different business philosophy and strategy."

The FTC Problem

Scout's Nevarez expects the FTC will become untroubled by Uinta dealmaking going forward as production and rail capacity grow and while Salt Lake City refineries continue to be supplied.

Of the 10 rigs drilling in the basin in August, three were making hole for XCL.

Built and soon to be flipped to SM in just a half-dozen years, Denver-based XCL was producing 53,000 bbl/d of oil, gross, this spring from the Uinta.

Quickly, it overtook Ovintiv, which was pushed to the No. 2 position at 34,000 bbl/d.

When XCL's deal to add the Altamont property in 2022 was blocked by the FTC and went to Crescent instead, "we just went full in focus on our asset only," Blake McKenna, XCL president and COO, told Hart Energy in a May interview.

XCL didn't get quiet; instead, it got bigger—entirely from the property it already held.

What it already had was producing less than 10,000 bbl/d. "We just focused all of our efforts on that asset," McKenna said.

It was comfortable with the risk because it had planned ahead, he added. The team went to work to "make sure we have the

NISSA DARBONNE/HART ENERGY

1.The Duchesne River behind the Duchesne County welcome center on U.S. Highway 40 at U.S. 191. 2. Starvation Reservoir in Starvation State Park on the western rim of the Uinta Basin. 3. An American flag atop an outcrop in Roosevelt. 4. The Northern Ute Veterans Memorial on Ute Reservation grounds in Fort Duchesne honoring native Americans who have served in branches of the U.S. military.

Ovintiv's four-lateral Bruce pad west of Roosevelt, Utah, with the Uinta Mountains at the basin's northern rim in the background. The wells, as well as four nearby, are landed in Castle Peak, according to Utah state files.

NISSA DARBONNE/HART ENERGY

refineries to sell to in Oklahoma, Wyoming, the Gulf Coast and all of our takeaway points."

On the D&C side, it tested small and went big and bigger.

"We're big believers in bookends," McKenna said. "Let's test it small; let's test it huge. And we'll go to both sides [of the leasehold] and see where we should end up."

Frac sizes ranged from 1,800 lb/ft to 3,000 lb/ft, finding the volume at which "a frac is so big it's not worth the extra money," he said.

"That helped us settle more in the middle–2,200 to 2,500."

Neighbors have done completions of 1,000-1,500 lb/ft. They're moving into the 2,000- and 2,500-lb/ft range now as well, McKenna said.

Spacing

Lateral length is typically 2 miles, but XCL has been landing 3-milers in some of its northernmost leasehold–depending on the formation–for spacing reasons.

While it has two years of data now on its bigger wells, XCL gained a clear look just six months in at what the modern frac jobs will get out of Uinta rock–and what is the appropriate spacing.

It came quickly because of the highly overpressured nature of XCL's end of the basin.

"When we operated in the Bakken in a previous life, it would take you 12 to 18 months to really understand how those wells were interacting," McKenna said. "But in the Uinta, because the pressure profile is so great, you understand where you are in six to nine months.

"It's helped us make that evolution faster here in the Uinta because we can update spacing and change frac design quickly."

Berry Looking Lateral

Operating in the Uinta since 2003, Berry Corp. has 100,000 net acres in the basin, producing from roughly 1,200 verticals primarily perforated in Uteland Butte.

By its count, roughly half of all Uinta operators' new wells in the past seven years were drilled in just the past two.

And it's excited about what neighbors' work has brought to its already-paid-for, nearly 100% HBP leasehold, it told investors.

Berry's business model is onshore, low geologic risk, low decline, long-lived–entirely focused in California and Utah.

The company was bought in 2013 for $4.3 billion by Linn Energy, a PDP-focused MLP. But Linn succumbed to bankruptcy in 2016, imploding under the weight of its M&A-heavy model that had deals priced at when oil prices were on their way up.

Berry spun out in 2017 as a standalone company and carried on.

Earlier this year, having watched neighbors' horizontal results for some time and as lateral development was moving toward its leasehold, it wanted to take a look.

In April, it bought a 21% interest for $10 million in a neighbor's plan to make four 10,000- to 15,000-foot laterals in the Uteland Butte on Berry's property, which is tucked into the Uinta's southwestern corner.

By August, the initial results indicated better wells than Berry's pre-drill estimate, CEO Fernando Araujo told investors in a call.

The wells IP'ed 1,100 boe/d each, 90% oil. "But also remember that we are at the shallow end of the basin with lower reservoir pressures," Araujo said.

"So, our IPs are slightly lower compared to some of the IPs in the northern end in the deep basin. We have to be mindful of that."

Berry's current Uinta profile isn't much different than at year-end 2012 when it reported 7,600 boe/d from the property, all from verticals in the Green River and Wasatch.

Its leasehold at the time was 122,000 net, excluding 49,000 undeveloped net acres that were part of a drill-to-earn deal. Proved reserves were 36.8 MMboe with 20.6 MMboe of these PUD.

Ovintiv's Uinta for Sale?

Ovintiv entered the Uinta in 2004 with a $575 million acquisition of Inland by a predecessor, Newfield Exploration, gaining 110,000 acres in Monument Butte Field with an 80% average working interest.

The deal came with 326 Bcfe of proved reserves, 85% oil, and 70% proved undeveloped. Net production at the time was approximately 7,000 boe/d and Newfield expected to increase that to 14,000 boe/d in 2006 with three rigs.

But Ovintiv hasn't aimed to increase its Uinta output since then. More than 80% of its 137,000 net acres are undeveloped. Most recently, it was making 28,000 bbl/d of oil.

Its capex is in output-maintenance mode.

"We have the ability to grow [the Uinta] if we choose," Brendan McCracken, president and CEO, told investors in July. The property is "competitive with the Permian" in market access, well productivity and cost.

"But, if we're not growing the total company production, there's not a motive to be growing the Uinta at the expense of any of [our] other assets. So, I would expect it to stay pretty stable as we head through the back of this year and into 2025."

Reports circulating in late August citing unidentified sources had Ovintiv putting its Uinta property for sale for $2 billion.

TD Cowen's Daoud wrote after the news, "While we've liked the well productivity and improved margin profile of the Uinta, it'll likely never amount to a material play for Ovintiv."

Ovintiv improving its debt profile by selling the Uinta property and focusing on its Permian property instead "likely makes the most sense and would be most preferred amongst investors," Daoud added.

Using the SM deal metrics for the XCL property, he assessed the PDP value of the Ovintiv property at $1.1 billion and the undeveloped property at $1.6 billion, based on 1,248 potential additional well locations.

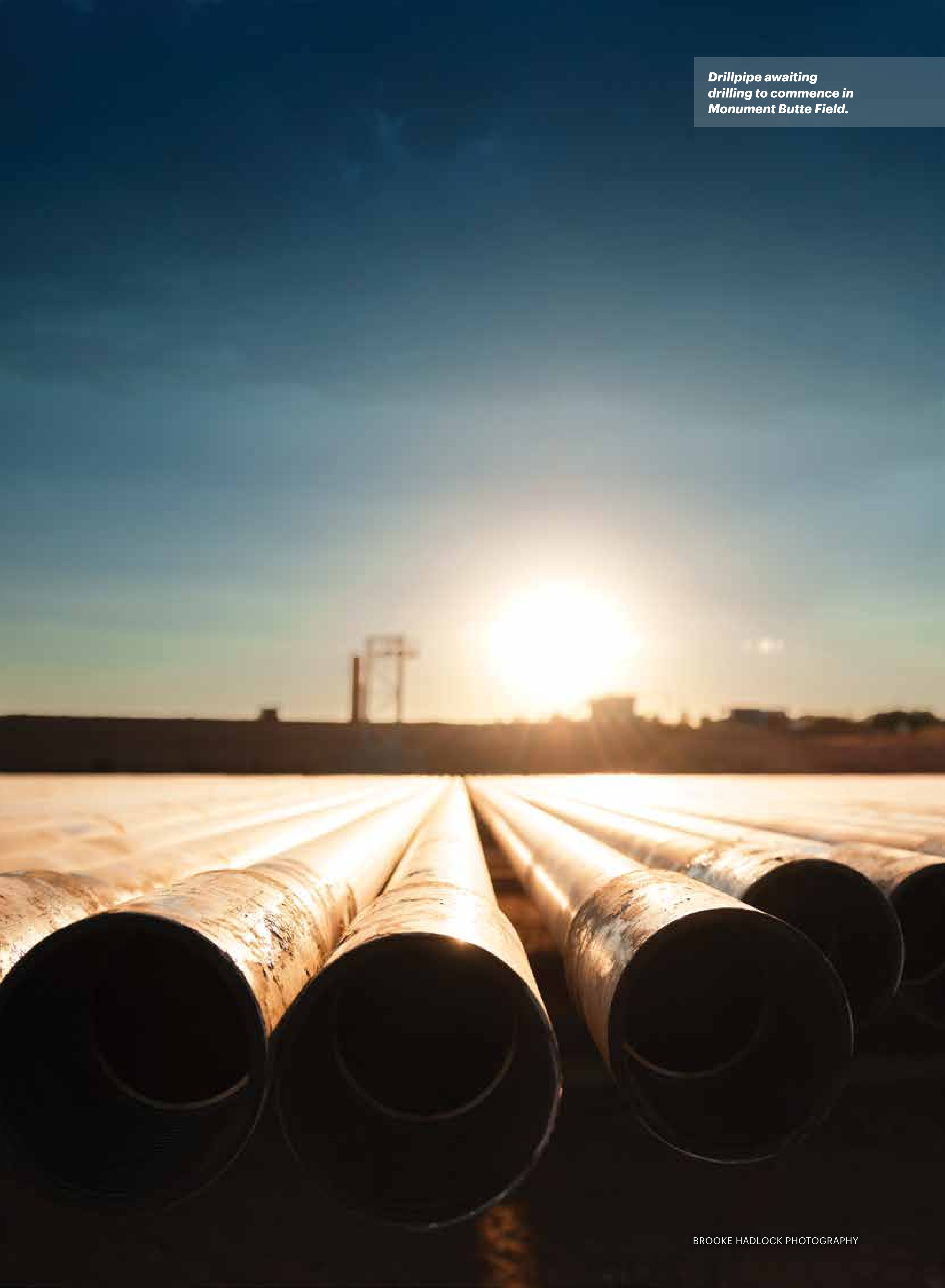
"Thus, all-in, we believe Ovintiv could attract greater than the [news article's stated] $2 billion," Daoud wrote.

But, he noted, "our inventory estimate could be overstated and a buyer may be unwilling to pay up entirely for undeveloped value."

While the FTC remains on the loose, identifying the buyer could be difficult to guess.

"Crescent would be an obvious candidate," he wrote. But it had just bought Eagle Ford operator SilverBow Resources. Since the Ovintiv rumor, Crescent made a second Eagle Ford deal.

SM "would logically make sense as well," Daoud wrote, but since SM just arrived in the basin with some $2.1 billion for 80% of XCL and Altamont, "that also feels unlikely." OGI



Drillpipe awaiting drilling to commence in Monument Butte Field.

BROOKE HADLOCK PHOTOGRAPHY

Helmerich & Payne's walking FlexRig #522 is readying to drill a two-lateral pad in Monument Butte Field in the southwestern Uinta Basin in August for Wasatch Energy Management.

124%

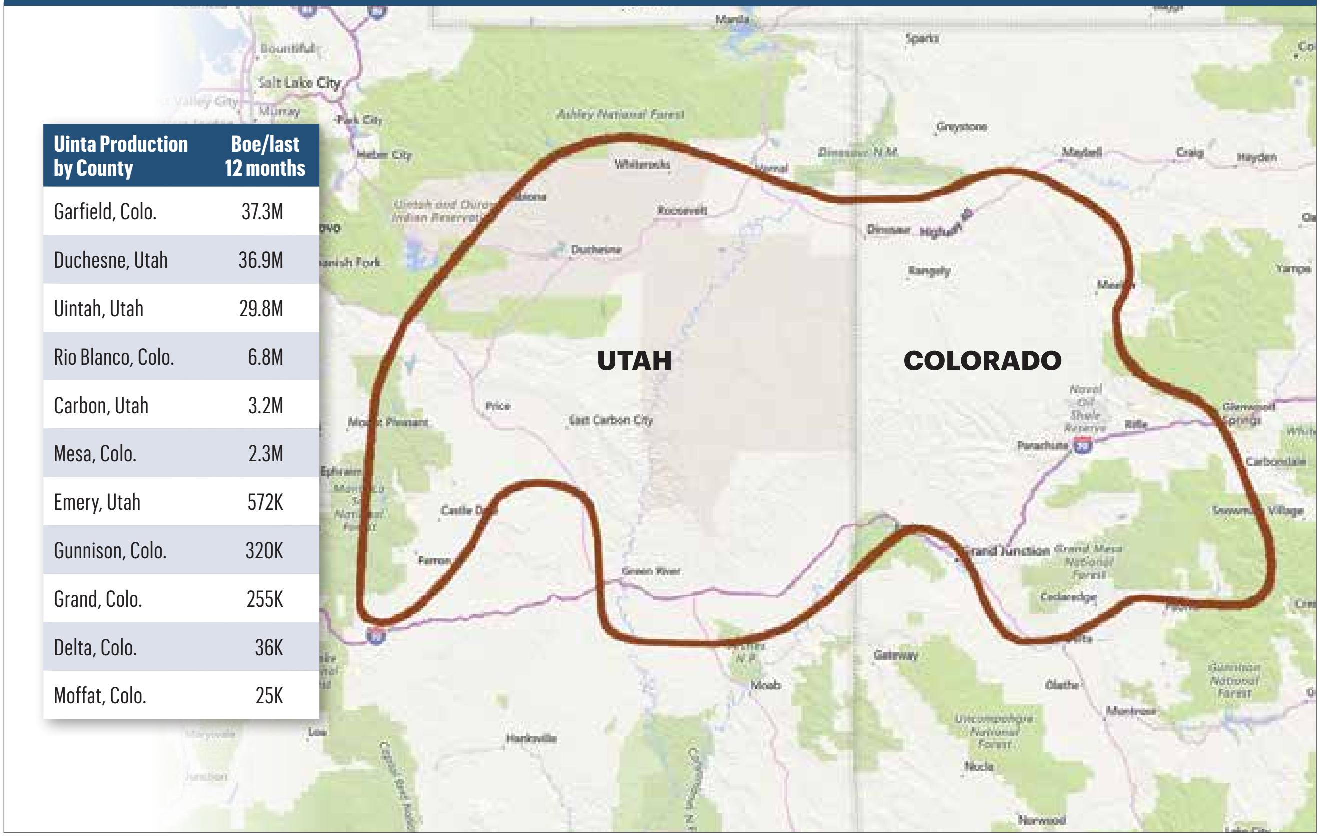
Increase in oil production in the Uinta / Piceance Basin since 2020.

BROOKE HADLOCK PHOTOGRAPHY

BASIN FOCUS: UINTA / PICEANCE BASIN

Garfield County on the Piceance side and Duchesne County on Uinta side lead oil production in the basin.

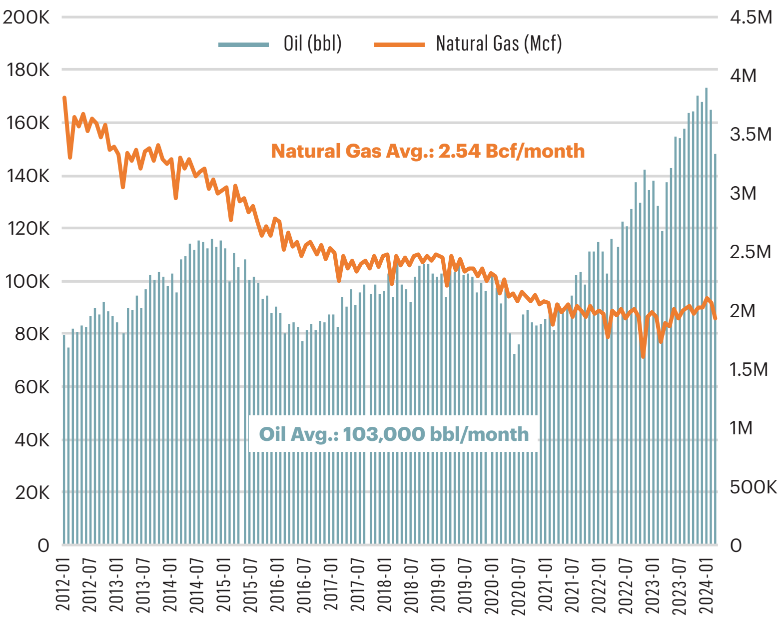
Uinta / Piceance Basin Production by County



Uinta Production by County	Boe/last 12 months
Garfield, Colo.	37.3M
Duchesne, Utah	36.9M
Uintah, Utah	29.8M
Rio Blanco, Colo.	6.8M
Carbon, Utah	3.2M
Mesa, Colo.	2.3M
Emery, Utah	572K
Gunnison, Colo.	320K
Grand, Colo.	255K
Delta, Colo.	36K
Moffat, Colo.	25K

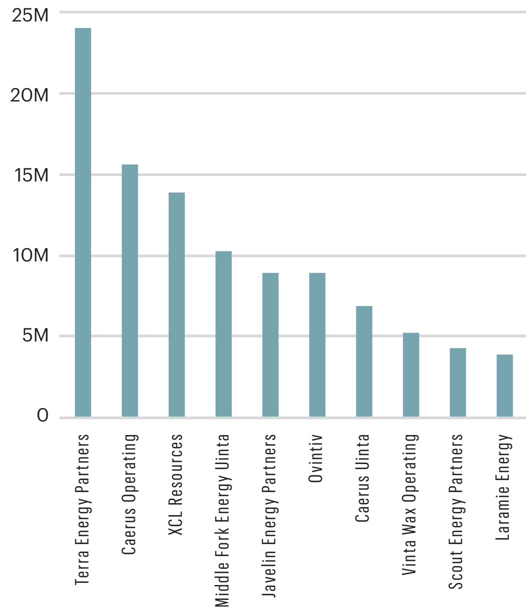
Oil and Gas Production

monthly, 2012-2024



Top Operators

boe/last 12 months



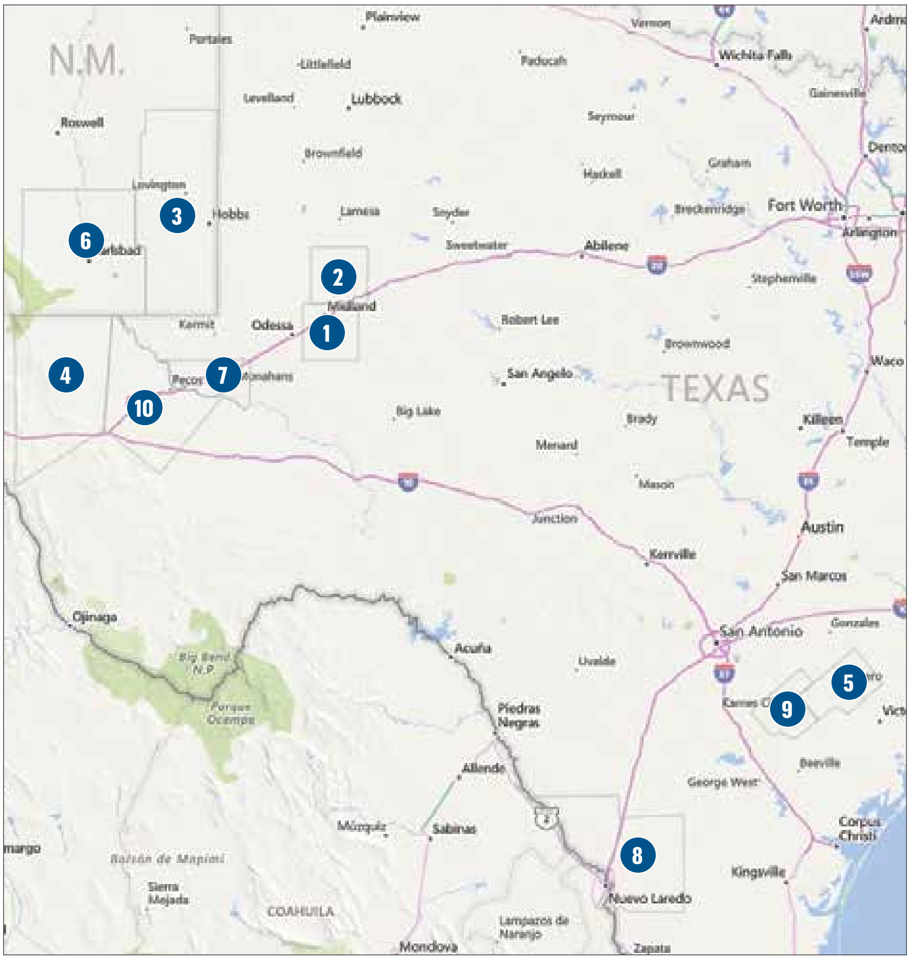
SOURCE FOR CHARTS AND MAPS: REXTAG.COM

PERMITS

The Permian Basin dominates in well permit approvals.

Permitted Wells by County

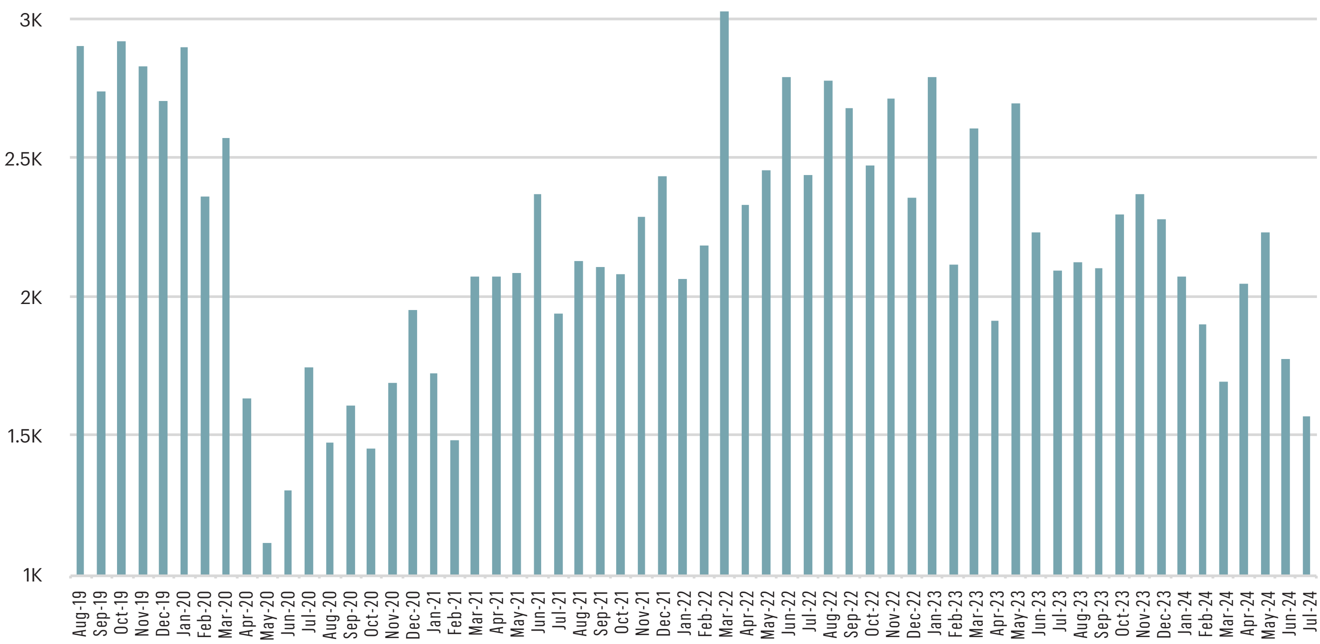
Rank	County	Well Count
1	Midland, Texas	113
2	Martin, Texas	67
3	Lea, N.M.	62
4	Culberson, Texas	34
5	DeWitt, Texas	31
6	Eddy, N.M.	29
7	Ward, Texas	28
8	Webb, Texas	27
9	Karnes, Texas	25
10	Reeves, Texas	24



Permitted Wells by State

State	Well Count
Texas	737
Colorado	149
New Mexico	91
North Dakota	36
Louisiana	10

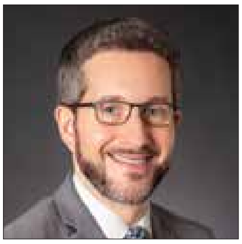
Permitted Wells



SOURCE FOR CHARTS AND MAPS: REXTAG.COM

Growth through M&A: The Making of an Eagle Ford and Uinta Giant

Crescent Energy CEO discusses the expanding gravitational pull of Crescent after acquiring SilverBow and others



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The hottest soap opera to follow in 2024 energy M&A involved Kimmeridge's takeover bid of SilverBow Resources and the resulting war of words between the two.

But the emerging upstream power Crescent Energy had quietly lurked behind the scenes since October 2022, when CEO David Rockecharlie first struck up a conversation with Eagle Ford Shale player SilverBow.

Kimmeridge, a major SilverBow investor, aimed to combine its Kimmeridge Texas Gas assets and may ultimately have forced SilverBow into making a deal. But "a" deal is key, because SilverBow ultimately chose the more secretive Crescent bid, which temporarily turned Crescent into the second-largest producer in the Eagle Ford behind EOG Resources.

Crescent's first offer came in January at a 10% premium of $29.94 per share, and the final, $2.1 billion deal reached at a nearly 17% premium of $38 per share, including up to $400 million in cash, which ended up upon closing at about $358 million.

The acquisition, which closed at the end of July, was the third-largest energy deal announced in the first half of 2024, behind ConocoPhillips' massive acquisition of Marathon Oil and just narrowly behind SM Energy scooping up XCL Resources. When and if the Marathon deal closes, Conoco would push Crescent back down as the third-ranked Eagle Ford producer.

As with SM after the XCL deal, Crescent also is a major player in the emerging Uinta Basin in Utah, having acquired in 2022 the EnCap Investments-backed Verdun Oil assets, which had previously been held by EP Energy.

An additional smaller, bolt-on Eagle Ford deal came in September with the acquisition of Cheyenne Petroleum assets. The seller was not identified, but Oil and Gas Investor *identified Cheyenne through Hart Energy's Rextag mapping and data services.*

The Crescent name emerged in late 2021 when Rockecharlie and KKR-backed Independence Energy acquired the publicly traded, John Goff-led Contango Oil & Gas in a reverse merger. The Verdun deal and a series of modest deals ensued, positioning Crescent strongly in the Eagle Ford and Uinta plays.

Rockecharlie sat down with Hart Energy Editorial Director Jordan Blum to discuss the SilverBow and Cheyenne deals, the Eagle Ford and Uinta Basin, and the future of Crescent and the energy sector.

Jordan Blum: The SilverBow deal is obviously the biggest news. So, please tell me why the deal made a lot of sense, and what you make of the combined position in the Eagle Ford now that the deal is closed?

David Rockecharlie: The acquisition is consistent with our strategy. The company was founded with a differentiated vision and discipline—the growth through M&A strategy. I think this is a great example of what we've been doing for the last 10-plus years as a company. First, it met all of our financial and operational targets. We typically describe our investment and financial targets

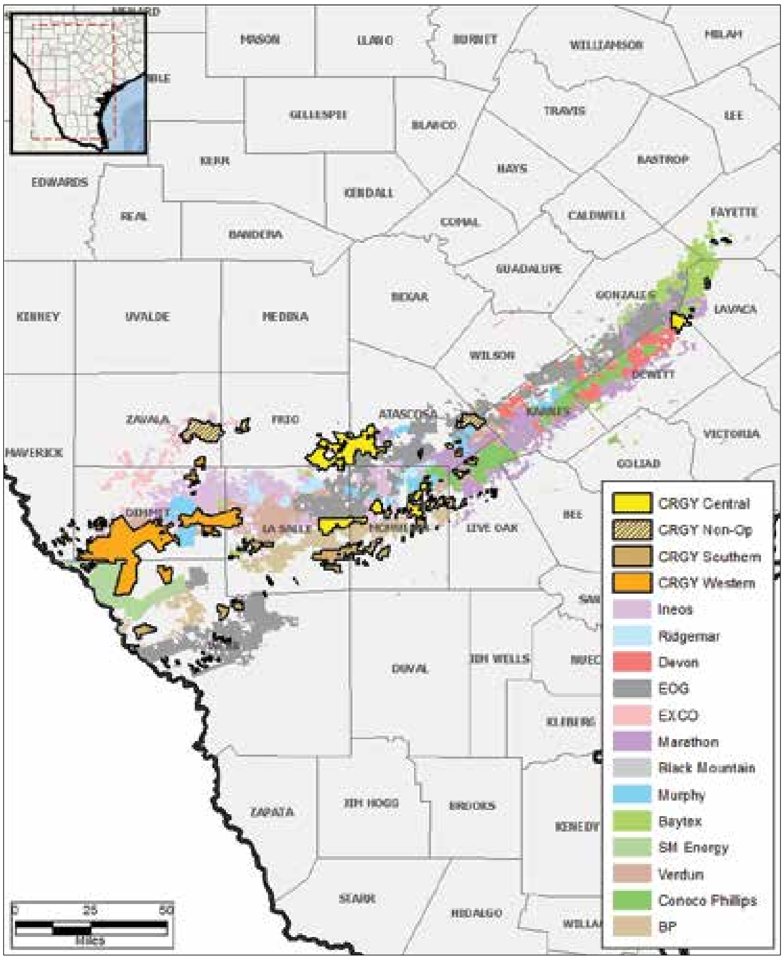
> *The No. 1 thing about this company is we know where we're headed, and we've had a consistent strategy from the founding."*

DAVID ROCKECHARLIE,
CEO, Crescent Energy

DANIEL ORTIZ

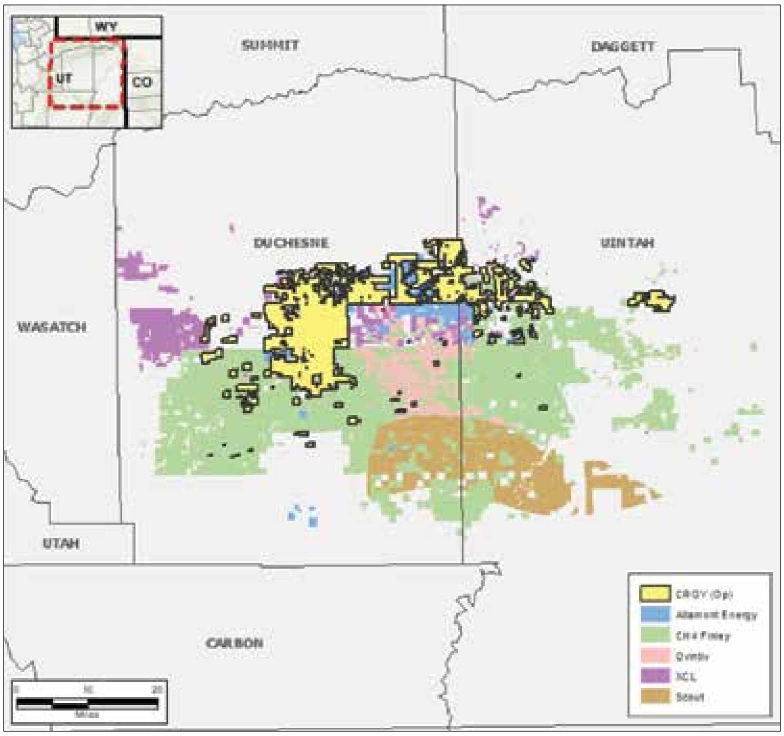
Eagle Ford Asset Overview

Premier position with attractive commodity diversification.



Uinta Asset Overview

Proven oil resource with multi-year development inventory.



SOURCE: CRESCENT ENERGY, ENVERUS

in terms of returns on capital, multiple of money, we expect to make two times our money or better. We think we'll get paid back on that acquisition in five years or less. Operationally, we want to do things that are consistent with our core areas, and also our areas of expertise. The Eagle Ford has been a core area of the company from our founding. This is really strong overlap with the business that we already had in a number of places.

We've got adjacent lease positions, so we see significant synergy opportunities, operational efficiencies. But, overall, this is just consistent with our long-term strategy and makes the company bigger and better. The other important thing is we feel like we've been doing the same thing for a long time, but this particular transaction also has put all the hard work of our employees a little bit more on notice to the market. I don't think we did anything different, but it is definitely the biggest acquisition we've done.

JB: And what about how the acreage fits together and the importance of focusing so much on the Eagle Ford?

DR: I think it's great. Our position over time at Crescent, prior to the acquisition, had been built in two areas. In particular, we've had an oil-focused area in what we call the central Eagle Ford, and then across the oil, gas, and condensate window in what we call the western Eagle Ford. SilverBow, over the last three years, had made a number of acquisitions. We also had done so. When you look at the two companies coming together today, both had really strong central and western positions. So, in our two core areas within the Eagle Ford, SilverBow had strong overlap.

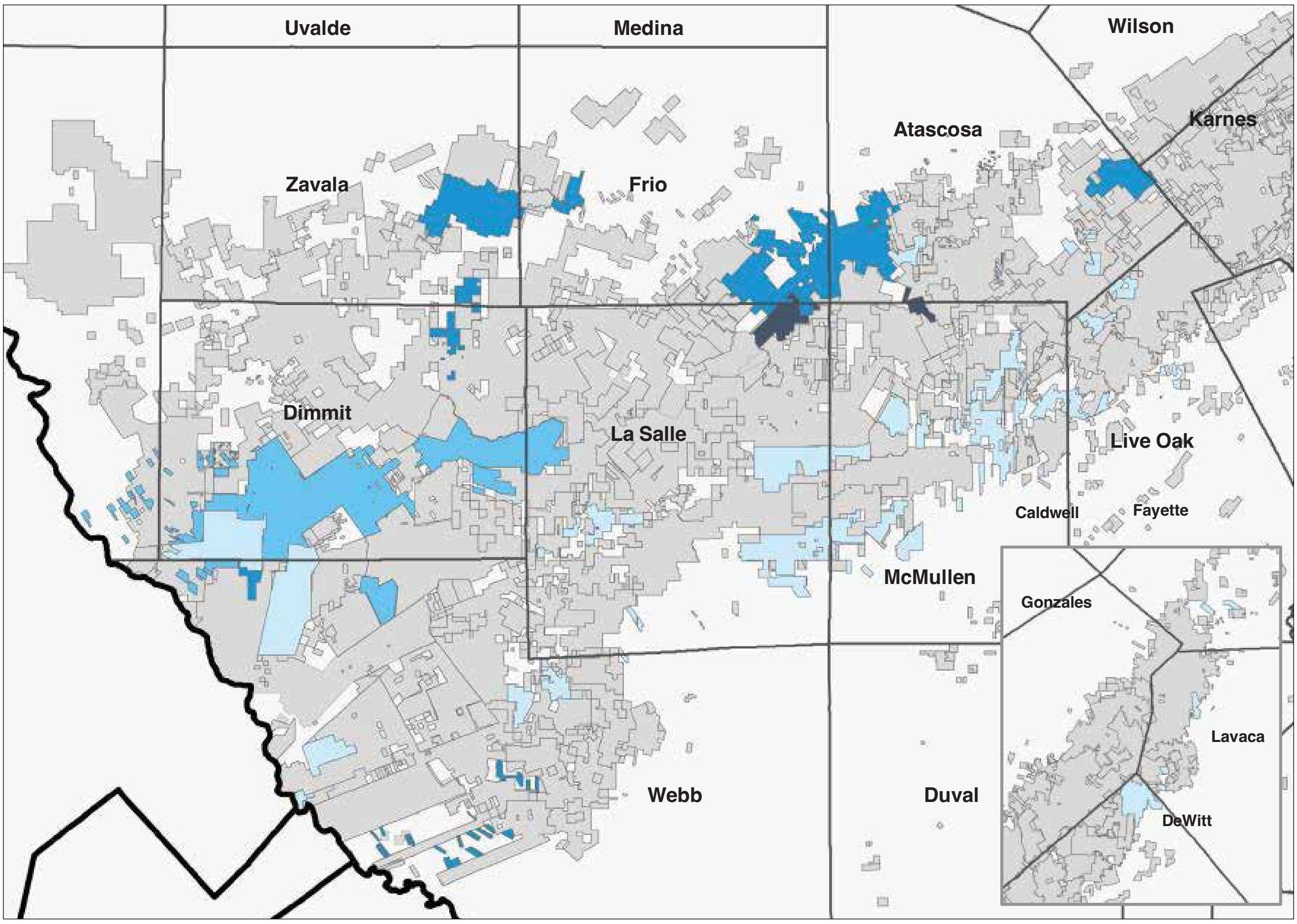
When we looked at the two companies separately, we had some things we were doing better. In particular, time and efficiency on drilling and completions that we now think we can apply to their program. But they were also doing some things that were interesting and different. They had started some refrac programs, and they had been doing different things with their facilities. When you're able to put two companies together that have really strong positions in the same area, you can take the best of both. They were two really strong companies beforehand, but they also had some strengths that were different.

JB: Can you take me through how all of this came about? Obviously, it was very public with Kimmeridge's hostile approach. But I thought it was interesting that we now know you started talking to SilverBow back in October 2022 and how it played out from there.

DR: We really try to look at everything going on in the industry. So, it's no surprise that

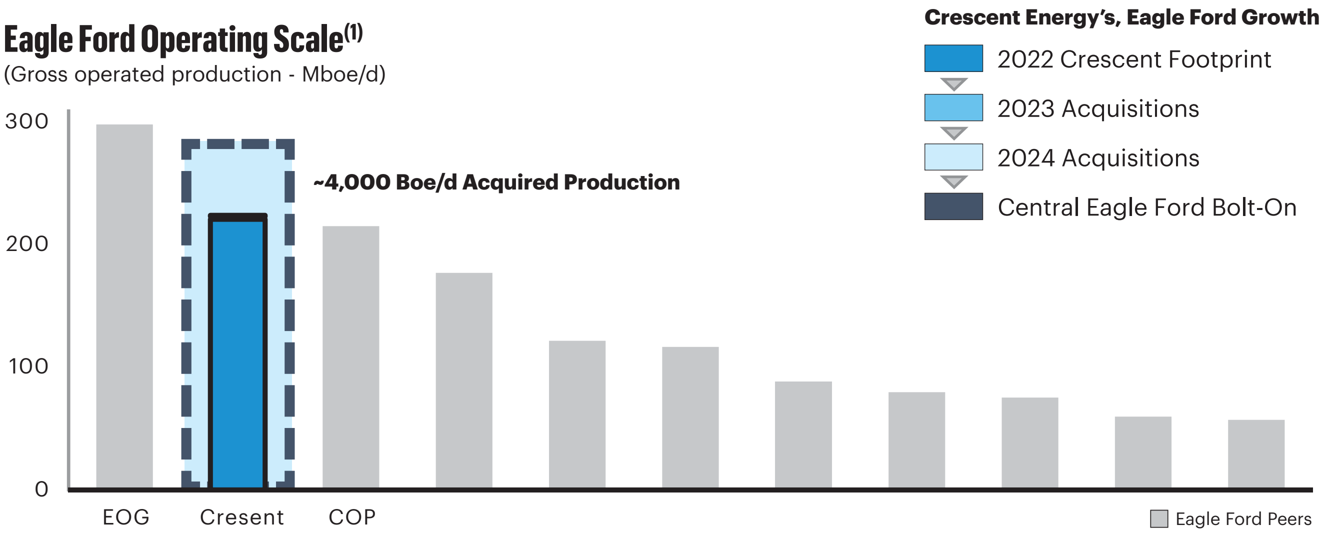
Leading Eagle Ford Position

More than doubled net acres, production and inventory over the last two years.



Eagle Ford Operating Scale[1]

(Gross operated production - Mboe/d)



SOURCE: CRESCENT ENERGY, ENVERUS

(1) BASED ON YTD ACTUAL PRODUCTION FOR MONTHS WITH COMPLETE DATA. INCLUDES LARGEST 10 OPERATORS BESIDES PRO FORMA CRGY. PEERS INCLUDE BP, BTE, COP, DVN, EOG, INEOS, MGY, MRO, SM AND VERDUN.

we would have conversations with our peers and, in particular, with folks who are in our operating areas. To your point, I think there's a lot of things in the acquisition business that are out of your control. We tend to focus on what is in our control, which is knowing where we're good, paying attention to the areas where we think we can grow—both because we're strong operators, but also because there's activity—and what we would consider fragmentation and consolidation opportunity. The Eagle Ford has clearly been an area of fragmentation, but also consolidation.

Really, we just maintained a strong relationship with the company. A lot of it was just as good industry partners, which we do with as many folks as we can. I would say it was opportunistic that SilverBow decided that they were open at that point in time to have conversations with multiple potential partners. Consistent with our strategy, we didn't know when that opportunity might come available, but we were prepared to engage and react when it did. So, yes, we were at it for a long time and then it kind of felt like it came together pretty quickly, but I'd say we were prepared for it. It's just another good example of how the company thinks about and prepares for things to come.

JB: Was it advantageous to be kind of quietly bidding as opposed to, let's say, Kimmeridge's slightly different approach?

DR: (smiling) I only comment on Crescent. I think we are, in particular, very focused on doing what we can control, doing the right thing. We want people to recognize Crescent for doing what we say we're going to do. So, we tend to be very transparent about what our objectives are. We're a growth-through-M&A company. We want to operate in areas where we have expertise, but we typically don't talk about success until we've actually completed it. We're not really talking about things until we get them done. Flying below the radar is more of our style.

JB: In reading the background, it looked like you and John Goff at times, and maybe I'm misreading, kind of took turns taking the lead on negotiations, and I'm sure in a very concerted way. I wanted to get your take on how that dynamic works with you and the chairman working together.

DR: I think it's a great question and a good observation. We met John Goff really as peers in the industry. One of, obviously, the results of that is the predecessor to Crescent ultimately went public through a reverse merger with the company that John was chairman of. We felt very aligned with his strategy, which was focused on cash flow and risk management and return on capital. John is a big supporter of the company. He's a large shareholder. He has not sold any stock since he was part of the merger with us. He's very involved and he's also well connected in the industry. I wouldn't say that we necessarily handed things off back and forth. I think it's really just a team effort. That, maybe, is a small example of how the whole company works. This is really a team-oriented business and everything we have achieved and will achieve will be because we have good alignment.

JB: Now that the deal is closed, how is the integration going?

DR: It's going great. No surprises. If anything, we're seeing more opportunity in bringing the best of both [companies] together than we could see from the outside. Prior to closing, you're really just allowed to plan and do things at a high level. We closed on July 30, and we were ready for that date. The integration starts on what we referred to as day one following closing. We're still in the integration phase, but it's going really well. It all starts with the people. I think we've brought together a great team from both sides, and everybody's really motivated and excited about the challenge of bringing the business together.

> *"I think we've been able to invest in the company in ways that you wouldn't if you had a shorter-term mindset just to make sure that we've got stability. We plan to be a much bigger company than we are today."*
>
> **DAVID ROCKECHARLIE,**
> CEO, Crescent Energy

JB: In September, you did a bolt-on deal to add more adjacent acreage in the Eagle Ford. Why is that a good deal and fit, and should we expect to see similar deals in the future?

DR: It's literally adjacent to our acreage. We've been familiar with this company for many, many years similar to our interactions with SilverBow. Everything we do on the acquisition side is opportunistic. The company is in great shape, we're delivering free cash flow, we're making operational improvement, and we don't have to do anything [in M&A]. With the people and the asset base we have, it allows us to be disciplined and patient. But, with that, when assets come up for sale that we like at attractive value, we're also going to be prepared to do it.

We've gotten confidence from integrating a number of Eagle Ford assets over the years. We can come back to it. We had really strong execution on integration of our western Eagle Ford acquisition last year. The planning and beginning stages of the SilverBow acquisition have gone great. So, when this opportunity came up, we felt very confident both in the value and the operational fit, but also in our ability to take it on. It is a smaller acquisition, but we treat them all the same.

JB: As more consolidation occurs in the Eagle Ford and good acreage gets scarcer, how do you see dealmaking continuing to play out?

DR: It's still one of the least-consolidated basins. When we compare it to the Permian and look at what I'll call scaled positions, the amount of acreage and production that is held by public companies with a market capitalization greater than $5 billion, over 80% of the Permian is held in larger-cap, public companies. In the Eagle Ford, that statistic would be closer to 30%. There are a few large operators in the Eagle Ford, namely EOG and ConocoPhillips. We're obviously in the top three. But the rest of the play is really wide open, both publicly and privately. There are a number of other public operators, but they're really not of what would be considered large scale. In some cases, they may not even be core assets of those companies.

I think we have a really interesting and exciting opportunity over the next three to five years as there continues to be consolidation across the sector. We see that for sure continuing in the Eagle Ford as well. And there are private operators and public operators that are maybe subscale, and then there's individual lease and trade opportunities as well. We're focused in the central and western, and I think those areas line up pretty well for us to continue to add on to.

JB: And maybe ramp up activity on the western side as natural gas prices recover?

DR: Rather than ramp up, I would say allocate capital in a way that's highest returning. The reason I say that is we do

DANIEL ORTIZ

think we have a very differentiated strategy. We founded the company at the time when the industry was really pursuing shale exploration through leasing of land and drill bit growth.

We've always been focused on free cash flow. We really manage the company for low-to-moderate growth through the drill bit, and we try to deliver all of our growth through disciplined profitable acquisition. We do get asked a lot as cash flow increases and prices rise, will you ramp drilling? We want to be viewed as steady and efficient and profitable with our base business. I'd say the allocation of capital could be different, but I wouldn't expect us to be "ramping." So that's a long answer to one vocabulary word that is important to us to clarify.

JB: Obviously, the Eagle Ford is a bit more mature than some other basins, and this is cliché, but how much can refracs and recompletions change the game in the Eagle Ford and add more life?

DR: I would put refracs in what I'll call a long list of really significant future economic productive opportunities. The Eagle Ford has a lot of attributes that would lead an investor to call it mature. It was one of the early shale basins to be developed. But, while it has been drilled over a wide range of the basin, a lot of it was done early. A lot of it was done by large companies testing things. Our position came together through numerous acquisitions, but some of the larger companies that we've acquired from include Anadarko [Petroleum] and Cabot [Oil & Gas] and Chesapeake [Energy], which are larger-cap companies with a disciplined approach to exploration.

A lot of the things that were done early on didn't have the benefit of what we've now learned over the last decade-plus. We bring best practices to assets that may have been developed in a different way early on. One of the things you've seen us do on the drilling completion side is bring better, more efficient, faster techniques. We've, for example, used the latest managed pressure drilling techniques, which really were not used significantly onshore a decade ago. Simul-frac operations, which is something that certainly had been pioneered a number of years ago, but it's still not widespread onshore. We've brought that to our operations, and it's allowed us to be much more efficient. Refracs are another great opportunity, and I put that also with incremental in-field development, and recognition that spacing of wells may need to be different today with the different completion designs we're using, and better understanding of the reservoirs.

When you think about all those things, refracs is just one opportunity, but it is a big one. Some of the largest-cap companies are pursuing successful programs. SilverBow had just gotten started. We at Crescent had not done any refracs yet. That's actually part of our strategy. We tend to watch others in the industry that are doing leading things, and then go apply them. The asset base we own lends itself to that type of redevelopment or expanded development. It's held by production, and we can afford to take our time to do it. I think refracs, incremental development and different production techniques will all be part of our ability to expand and make more profitable our existing asset base. It's also something that we look at new acquisitions to try to identify whether those opportunities may be available there. With the most recent acquisition, we see significant improvement opportunity on those assets really by applying the best practices we've developed.

JB: Taking just a bit of a step back, I wanted to see if you would discuss your journey in the industry from KKR and leading the Independence-Contango merger, and how it is working in both the PE and public producer worlds?

DR: I really like building things, and I like working on teams. That's been a part of my career, also part of my upbringing. I grew up in Houston in the '70s and '80s, so I've seen what volatility looks like on the ground. I've been a part of both financial firms and operating companies. My background is in math and economics, and I got started in the industry at a financial firm, Donaldson, Lufkin & Jenrette, that was really helping other high-growth companies in the energy sector. My first operating company job was at El Paso Corp. So, I've seen significant volatility in large and small companies, and I think one of the key things that we really wanted to make sure we built into Crescent was that ability to anticipate change and really be prepared for opportunities. I think that background of being both on the financial side of things and on the operating side of things has allowed me to really be part of and contribute to a team that really has a lot of different skills and experiences in this company to make us successful.

JB: In that vein, how do you see the direction of the industry right now and how Crescent fits together with it?

DR: I see the direction of the industry today in consolidation and in a stronger focus on financial discipline and, in particular, free cash flow and investor returns. And, also, a stronger focus on operational excellence as we've come out of a high-growth phase.

Everything used to be about leasing, exploration, significant growth through the drill bit. Today, things have become much more operationally and manufacturing oriented, and focused on profitability. We started Crescent over 10 years ago wanting to operate in this way. It was differentiated at the time to focus on free cash flow and risk management and investor returns. It's still differentiated today in our view.

We want to continue to grow. We want to continue to attract new investors at the same time as we retain our existing investors. Sticking to that strategy and being opportunistic and well prepared will allow us to participate in that consolidation and grow profitably and deliver really strong value to our investors.

We've always had a disciplined financial strategy. The leverage metric we use debt-to-EBITDA. We've operated with an average leverage of 1.2x. And that's over the history of the company. We tend to say we target about 1.0x, and we've operated in the 1.0x-1.5x range, which is where we still are today. Our reinvestment rate–and our capital discipline–has been between 40% and 50% of EBITDA over the history at a time when many in the sector were outspending cash flow.

> *"We're a growth-through-M&A company. We want to operate in areas where we have expertise, but we typically don't talk about success until we've actually completed it. We're not really talking about things until we get them done. Being quiet about things is maybe our style."*
>
> **DAVID ROCKECHARLIE,**
> CEO, Crescent Energy

We like the assets we have. We bought them. But they've allowed us to execute the strategy. One of the things we highlight and have maintained is a much lower decline rate of current production than the rest of the industry. We target a 25% corporate decline or less over the next 12 months of our asset base. It just allows us to have a much lower risk, lower operationally intensive strategy, still grow profitably, and then be prepared really for whatever the cycle may bring to us because we want to be proactive when things come our way, not reactive. We've made dozens of acquisitions over the years and, obviously, since going public people have a brighter light and ability to see what we've done.

We've tripled the company since we went public. Our vision for the next five years is, I think, we can double it again. If we do that, we'll be an investment-grade company. We use that term because it really signals that we have a strong belief we can grow, and we'll grow in a disciplined and profitable way. The other thing we talk about internally is we want to grow again when we see the opportunity, not just to grow. We want to be proud of what we've built.

JB: I'm assuming you see Crescent as undervalued right now. I wanted to just see if I could get you to elaborate a bit more on the overall stock, debt and dividend strategies?

DR: We've got a really strong balance sheet. Our capital allocation strategy, which we describe as 1A and 1B, is investor first. The 1A is take care of the balance sheet, and 1B is pay a dividend. We've paid a dividend consistently over the life of the company. When we went public, we did not change our financial strategy or capital-allocation approach. The only thing I would highlight we've done in the public markets that was different than privately is we did announce earlier this year that we simplified our dividend strategy to just make it a fixed dividend.

We're now paying 12 cents per share per quarter. But that is consistent with how we've paid dividends over the life of the company. That is 1A, 1B. No. 2 would be looking for attractive investment opportunities. We don't have

DANIEL ORTIZ

to do anything; we've got a really strong, deep inventory of drilling locations focused both in the Eagle Ford and the Uinta basins. We typically reinvest about 50% of our EBITDA every year. The other thing we announced earlier this year that just strengthened our commitment to investor returns is we do have a publicly announced share-buyback authorization that's available for us to use opportunistically.

JB: With the acquisitive strategy, you're not really built to flip. What are your thoughts on that and your forward-looking, long-term plans?

DR: The business was set up to be a long-term strategy, and I think one of the core commitments of everyone here is, we're building for the long term. I think we've been able to invest in the company in ways that you wouldn't if you had a shorter-term mindset just to make sure that we've got stability. We plan to be a much bigger company than we are today.

One of the things I say a lot is, "You get what you think about." If you expect that your company is going to be twice the size five years from now than it is today, you can plan for that and you can plan the right way. I do think you do things differently when you believe and are committed to operating for the long term. When we make acquisitions, there are things you know can improve on day one, and then there are other things that may take longer either to study or assess or even implement. We're still evaluating production that we acquired within the last year, and now we've brought a really significant amount of production in with SilverBow. They were in the process of evaluating things that they had bought. I see tremendous potential from our teams operating in the field and evaluating production techniques and opportunities across our asset base over the next three to five years that may not show up tomorrow.

JB: When Independence and Contango came together, you also had positions in the Permian, Midcontinent and Denver-Julesburg. So how did you end up focusing specifically on the Eagle Ford and Uinta?

DR: We described the company as focused on Texas and the Rockies. In Texas, that's the Eagle Ford. One of the fun things for me about the SilverBow acquisition is, I think the market has a lot more clear understanding of what we meant when we said we were going to be a growth-through-acquisition company focused in the Eagle Ford. I think we've done a lot now. We were confident that we would be able to achieve those goals, but it's nice to have added significantly to that track record. You've seen us make a number of acquisitions. I think we're probably We've announced six transactions since going public, and they've all been in the Eagle Ford or the Rocky Mountain region. That's just allowed us to take core areas and make them an even greater part of the company.

We are in the acquisition and divestiture business, and so you've seen us also sell some sub-scale positions over time. We had some assets in the Permian Basin. It was not an area that we thought we could grow, and we've divested a few things there. Over the last 18 months, we've sold approximately $150 million of non-core assets. While we are a growth company, we also really are focused on being efficient and focused in our core areas. We are a multi-basin company, and we intend to be. It's allowed us to balance our business and grow successfully and manage through the cycles.

JB: Please tell me about your bullishness for the Uinta Basin, especially now that there's more takeaway capacity there. And do you see more M&A with the Federal Trade Commission concerns?

DR: It is an absolutely great resource basin with multiple formations that are proven productive. We're really excited about the way we got into that position, which was really through an acquisition of production, but we hold a tremendous amount of resource there. So, we see a very significant opportunity for us to continue to develop the resource base there.

There has been a lot more attention on that basin. I think that is for a couple of reasons. One, the basin is generally smaller geographically, and so there aren't as many operators in the area. There are, largely, four operating companies there that have significant amounts of rigs running. So, over the last number of years since our acquisition, there's been a lot more public company commentary about it. Obviously, we're a public company and are talking about the Uinta. Ovintiv has made a significant investment and progress on developing additional resource in the basin. And now with SM entering (SM Energy acquiring Uinta-focused XCL Resources), we're very pleased to have another, what I'll call resource-oriented public company in the basin helping develop it. I think that is all positive from our perspective.

The other thing I would highlight is that, because the basin was generally smaller geographically and had a fewer number of operators, the horizontal drilling and completion techniques came later to the basin. So, we're still seeing significant improvement in well performance and completion design and drilling techniques there. I think that'll continue to attract attention in the basin. But, again, similar to our strategy, we don't expect to have a significant rig ramp there. We expect to be steady and methodical. We've got contracted capacity in the local Salt Lake City refinery complex. We're able to move our oil and gas to market in a relatively consistent way. Really, over my whole career [since] that basin's been discussed publicly, a lot of the challenges came from companies trying to grow too fast. I think this latest stage of growth has been more methodical and learned a lot from other shale basins in doing that. Today, the export capacity from the basin has grown significantly, and we're really excited.

No comment on the FTC situation, but I would say we're in a consolidating industry and there are lots of transactions getting done. So, I think that's exciting.

JB: And any interest since Ovintiv might be looking to sell there?

DR: (laughs) Yeah, I can only tell you what we know, and we're really excited about our position there. I can tell you that.

JB: What are you seeing in the potential for the different formations/benches in the Uinta, as well as the technical strategies?

DR: I think what's most notable is that the development techniques in the Uinta Basin are very similar to what's happened in all the other shale basins. We were able to bring a lot of the expertise we had from the Eagle Ford. I would also highlight that the other operators there have been very strong and have advanced the development techniques, and we've been able to learn from that. I would expect to see more of the same, which is just more efficiency, more advanced designs, and learning from experience as more completions and well performance happens. There has been a significant ramp in production over the last three or four years, and so there's a lot to learn.

When we acquired the assets, what we really got was a strong production base. It was at a time in the market when the resource potential was really option value for us. The Uteland Butte Formation has been the primary formation that was under development. But now, some of the other public operators have listed many formations that we agree are productive. In particular, the Wasatch and the Castle Peak and the Douglas Creek are areas that we're seeing significant development and more well performance come out. The production performance and economics from those formations have been very positive. And so, I would say we see multiple formations that we hold and have significant future development value and opportunity.

I'll also bring that back to the Eagle Ford. We got into the Eagle Ford many years ago, and most of our acquisitions have been based around just developing the Lower Eagle Ford Formation. But we're starting to see, across large areas of our position, the ability to go back differently in the Lower Eagle Ford, but also into the Upper Eagle Ford and even potentially multiple zones within the Austin Chalk Formation, depending on where you are in the play. We definitely have productive and economic acreage within our portfolio across all of those benches, both in the Uinta and in the Eagle Ford-Austin Chalk.

JB: What else might you want to highlight?

DR: The No. 1 thing about this company is we know where we're headed, and we've had a consistent strategy from the founding. I don't think we're going to surprise anybody with the actions we take, but I do expect us to continue to grow the business opportunistically.

This company is the best-kept secret in Houston, and I think investors will get to know this company better. We believe this is going to be a mid-cap, must-own business, and we want the investors who come in and join us today to look back five years from now and say, "We're proud that we were part of this company. We're proud of what we built." I'm really excited. In a lot of ways, we've been at this a long time, but we have that beginner's mindset and excitement of a growth-oriented company. We're just getting started. We feel like people are just starting to notice what we're doing. And I think that's exciting. OGI

Jay Precourt
(1937–2024)

Legendary wildcatter leaves behind a legacy of philanthropy in Colorado and at Stanford University.

OIL AND GAS INVESTOR

Legendary oil and gas wildcatter Jay Anthony Precourt died on Sept. 16, 2024, in Vail, Colo. He was 87.

Growing up in Chicago, Precourt developed a romantic notion of becoming an oil and gas wildcatter. It was a vision he "never doubted," he told Hart Energy in 2014.

Precourt earned bachelor's and master's degrees in petroleum engineering from Stanford University, and his MBA from Harvard University. While a student, he spent summers working in the oil industry: at refineries, a petroleum research lab, in marketing, on or around drilling rigs and at Standard Oil in New York. These experiences helped him understand the business from the wellhead to the trading floor.


JAY PRECOURT

During his career, Precourt founded five energy companies, including a New York Stock Exchange company that sold for 21 times the initial investment after only 12 years, and another for 24 times the investment after only five years, according to the Colorado Business Hall of Fame, which inducted him in 2023.

He also served on the boards of several top public companies, including Hamilton Oil, Timken Co., Apache Corp., Baroid Industrial Drilling Products, Dresser Industries, Halliburton and Tejas Gas, as well as several large private industrial corporations and nonprofits.

In addition to his business and economic endeavors, Precourt was a prolific community contributor and philanthropist. He served on Vail Health Hospital's board of directors; as president of Eagle Valley Land Trust; and on the boards of Denver Art Museum Foundation, Children's Hospital Colorado, Historic Denver foundation and Alley Theater in Houston.

Precourt's most lasting legacy may be in education. He founded the Precourt Institute for Energy at Stanford in 2009. It was integrated into Stanford's Doerr School of Sustainability when the program opened in 2022.

Precourt stepped down from the co-chairman role on the institute's advisory council in May.

"When it comes to the Precourt Institute, there's really only one father, and that's Jay Precourt," Arun Majumdar, dean of the Stanford Doerr School of Sustainability and a former director of the institute, said when the university released the news. "Jay has always been there to provide us with support. He cares about our success, and cheers for us when we achieve it." OGI

Souki's Saga: How 'The Pause' Enabled Tellurian to Escape Ruin

With its export permit for Driftwood LNG suddenly more valuable, Tellurian could make a $1.2 billion deal while its co-founder, however, lost his stock, ranch and yacht in a foreclosure.

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Tellurian's eight-year journey from startup to exit is steeped in Netflix-worthy tales.

There is an eye-popping under-sight, global plague, epic run of canceled contracts, war, demand notices, political windfall and a foreclosure on the executive chairman's ranch, yacht, home and his children's homes, too.

The executive chairman, Tellurian's co-founder Charif Souki, was dismissed from the post on Dec. 8 after an investigation into undisclosed personal dealmaking with a Tellurian lender.

The CEO quit and the CFO resigned.

There was a surprise $250 million employee bonus package.

And the company was on the cusp of selling its land, while it had little cash on hand most days to fend off its creditors and pay its 168 employees.

Then the Biden administration suspended permit approvals for new U.S. LNG projects, throwing a lifeline to the flailing corporation.

In an instant, the Jan. 26 announcement made Tellurian's fledgling plans for an LNG export plant more valuable: It had an existing, active permit.

Putting its Haynesville Shale E&P portfolio on the market would buy enough time to keep the company going until summer, even while it was going broke. But it would net little cash: The proceeds were obligated already to pay off a debt that was secured by the E&P property.

Tellurian's stock price tumbled as Souki lost 25 million shares in a foreclosure on a personal loan and the lender dumped the stock into the market.

The company was running out of time to pursue solvency options other than to sell the rest of its property–an LNG export permit and the plant property.

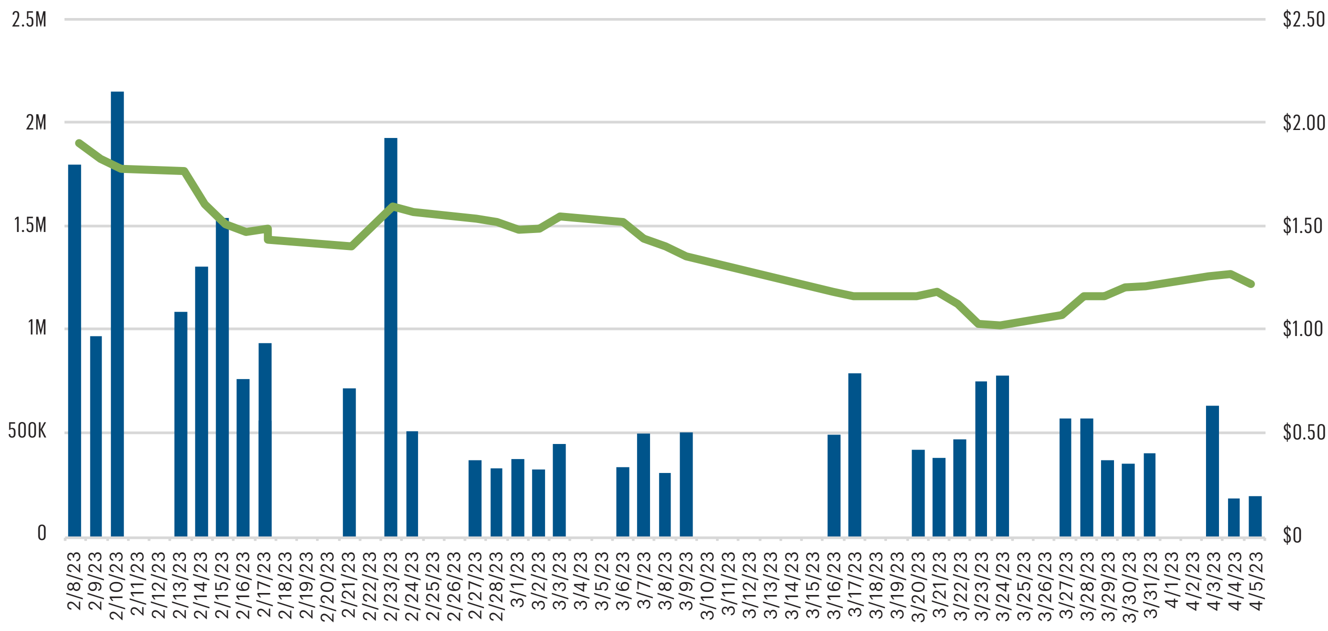
In July, it had one firm bid: $1 a share.

Sold.

Souki told Hart Energy in early September

The Selloff of Charif Souki Shares

shares sold and price • Feb. 8-April 5, 2024



SOURCE: SECURITIES & EXCHANGE COMMISSION FILINGS, HART ENERGY

After a lender seized 25 million Tellurian shares from the company's co-founder, Charif Souki, it began selling them off even as the price began to drop.

The Driftwood LNG project, south of Lake Charles, La., was estimated to cost $25 billion to build.

TELLURIAN

that he is now building a position in Woodside Energy stock, totaling at least six figures to date and on a path to seven figures.

He said he couldn't comment on his dismissal and the Tellurian board's decision to sell due to a non-compete in effect through year-end.

But "I did read the proxy statement, so I know what they say," he added.

"I don't agree with them, but I can understand how people can disagree in good faith."

The Review

Tellurian unpacked it for shareholders in its Aug. 27 proxy statement, explaining the background on the plan to exit to Australia's Woodside, a 35-year LNG exporter, in a deal for $900 million in cash for the stock.

With assumption of debt and other liabilities, the total deal value is $1.2 billion, according to Woodside.

Hart Energy reviewed more than 150 documents, including prior Tellurian filings with the Securities and Exchange Commission (SEC), filings involved in Souki's federal civil court and bankruptcy cases, and other public records.

Jacob Frenkel, a former senior counsel in the SEC's Division of Enforcement and a former federal criminal prosecutor of securities violations, reviewed a Hart Energy summary of the details.

"SEC statutes and regulations are a robust disclosure regime that requires, among many things, reporting–accurately–related-party transactions and prohibiting providing material non-public information on which individuals may decide to trade," he said.

Frenkel is currently chair of law firm Dickinson Wright's government investigations and securities-enforcement practice.

"Well-advised companies require their officers and directors, in connection with proxy disclosures and annual reporting, to report conflicts and potential conflicts of interest," he added.

"In scenarios, as here, where there is an appearance both of non-disclosure of potential related-party transactions or conflicts of interest and possible trading while in possession of material non-public information, the SEC's Division of Enforcement takes interest and investigates."

The Three Contracts

To remain afloat the past four years, the aspiring LNG exporter had issued $825 million worth of shares; sold $50 million of preferred shares in 2018 to plant contractor Bechtel Corp.'s BDC Oil & Gas Holdings unit; sold notes; and took loans from various other parties.

Meanwhile, building all phases of its Driftwood LNG project south of Lake Charles, La., was estimated to cost $25 billion, according to the Aug. 27 proxy.

The first phase will include capacity of up to 11 million tonnes per annum (mtpa) or 1.5 Bcf/d. All phases would total

27.6 mtpa (3.7 Bcf/d) of liquefaction capacity on its 1,200 acres–mostly owned; some leased–on the Calcasieu River's west bank near Sempra Infrastructure's Cameron LNG plant.

It had a deal in 2019 with TotalEnergies, which at one time held a 19% position in outstanding Tellurian shares. But the international energy company withdrew in 2021 as Tellurian had not yet reached a final investment decision (FID) on plant construction.

As global LNG prices spiked in the first half of 2022 upon Russia's invasion of Ukraine, Souki ordered construction on Driftwood's Phase 1 to begin, although Tellurian didn't yet have enough financing to make a full FID on the project.

An FID is needed to keep a permit under Federal Energy Regulatory Commission (FERC) rules. Currently, FERC is requiring Driftwood's completion by 2029.

In other deals, Tellurian had 10-year sales contracts with Gunvor Group, Vitol and Shell for a combined 9 mtpa by early 2022, which a J.P. Morgan Securities analyst said at the time would "more than cover the [11 mtpa] first phase of the Driftwood project."

That summer, the company was able to raise $500 million by selling 6% convertible notes secured by its Haynesville E&P property in northwestern Louisiana.

Now, No Contracts

Then the tide turned. Later in 2022 and into 2023, all of the buyers canceled.

Global LNG prices had retreated from an early 2022 price spike as European countries secured non-Russian supplies.

And the owner of the 6% debt secured by the E&P property called in $166 million of the notes for cash.

While world LNG prices had returned to roughly $10/MMBtu, U.S. natural gas prices had free-fallen from about $9 to $2.

The Haynesville property's value had declined in step.

Then, Tellurian discovered that Souki had loans from banker UBS O'Connor and three others that were secured by personal property, including Tellurian shares, while UBS O'Connor had also banked Tellurian.

The news broke when Souki sued UBS O'Connor, which describes itself on its website as a provider of "bespoke lending solutions," and three others: its hedge fund Nineteen77 Capital Solutions, Cayman-based Bermudez Mutuari and a bank, Wilmington Trust.

UBS O'Connor had sold 25 million of Souki's shares in February and March of 2023, "putting significant downward pressure on the trading price of the company's stock," Tellurian reported Aug. 27.

The stock's price fell from about $2 at the beginning of February to $1 by the end of March.

Separately, two Souki-owned companies filed for bankruptcy–Ajax Holdings, which was the family's Aspen, Colo., real estate developer, and Ajax Cayman, which owned Souki's 100-foot sailing yacht.

"The board formed a special committee to investigate these matters," Tellurian stated Aug. 27.

Eye-Popping Under-Sight

The filing did not state, though, whether the Tellurian board or shareholders had ever asked Souki about the loan counterparties' identities, although Tellurian had reported annually that shares Souki controlled were collateral in a loan.

Tellurian did not reply to a Hart Energy request for comment.

The company's first disclosure of the discovery was in its May 2023 annual report.

"Our executive chairman, Charif Souki, has personal investments and interests that have at times become interrelated with the interests of the company. These investments and interests may result in conflicts of interest or other impacts on the company," it wrote in the SEC filing.

In particular, Tellurian reported it discovered in Souki's suit that he and UBS O'Connor "agreed in 2020 to approach the renegotiation of the terms of the Souki loans and the [2019] Tellurian loan 'holistically,' an agreement that was not disclosed to the company."

It added, "Policies and procedures designed to mitigate potential conflicts of interest are subject to inherent limitations and may not result in all such conflicts being identified and addressed in a timely manner."

Well Known

Souki's debt involving his Tellurian shares was well known by the company, according to its previous SEC filings, which also do not disclose whether Tellurian was aware of the identities of Souki's lenders.

His first loan led by UBS O'Connor was made in 2017, according to his lawsuit.

An August 2017 Tellurian proxy statement disclosed that Souki pledged 2 million of his shares in June of 2017 to secure a $5 million bank line of credit.

In April 2018, Tellurian's proxy statement reported that Souki pledged 1 million shares in a margin loan from a bank in October 2017 and that the 2 million shares pledged in a line of credit in June 2017 were moved to the margin account that held the 1 million shares.

In addition, Souki pledged 20 million shares in January 2018 in a "loan facility extended by another bank," Tellurian added in the 2018 proxy statement.

Global Price of LNG

$/MMBtu, monthly

SOURCE: FEDERAL RESERVE ECONOMIC DATA

Russia's invasion of Ukraine spiked global LNG prices to average $70/MMBtu in the summer of 2022.

TELLURIAN

When global LNG prices spiked in the first half of 2022 after Russia's invasion of Ukraine, Tellurian Executive Chairman Charif Souki ordered construction to begin on Driftwood LNG.

Driftwood LNG By the Numbers

$25B	1,200	27.6	~$900–960
expected total cost	acres	mpta estimated LNG capacity	per tonne expected development cost of Phase 1, 2

At that time, UBS O'Connor did not have any deals with Tellurian itself, according to various documents.

In the spring of 2019, Tellurian's proxy statement reported Souki had 25 million shares pledged in "a collateral package to secure a loan for certain real estate investments."

Also, it reported, the Souki family trust had 23 million of its 26 million shares pledged "as part of a collateral package to secure financing for various investments."

By then, Souki's direct and indirect shares had grown to a meaningful amount of public float: 54.6 million (22.6% of outstanding shares).

Within a year, that fell to 28.5 million (10.7% of outstanding), according to the 2020 proxy statement. The family trust no longer held shares, which totaled 26 million a year earlier.

Meanwhile, of Souki's remaining 28.5 million shares, Tellurian reported 25 million were "part of a collateral package to secure a loan for certain real estate investments."

The SEC filings don't indicate whether Tellurian's board asked Souki what happened to the family trust's shares.

Tellurian, UBS O'Connor

In May 2019, Tellurian made deals with Souki's lenders. It issued 1.5 million warrants to UBS O'Connor's Nineteen77 Capital Solutions. Separately, it borrowed $60 million in a senior secured term loan from Wilmington Trust.

At least one of Souki's fellow board members was aware of the Souki family trust's loans. Brooke Peterson, who is also an Aspen municipal court judge, had held an irrevocable power of attorney through year-end 2020 to vote the family trust's shares, according to the 2019 proxy statement.

Souki was the trustee and decisions were made by majority vote of his children, including Tarek Souki, who is Tellurian's executive vice president, commercial.

At the time, Peterson was also manager of the Souki family's Ajax Holdings since December 2012 as well as CEO since January 2013 of Aspen-based Coldwell Banker Mason Morse, the family's real estate firm.

He left these posts in May 2022, according to a 2023 proxy statement.

Lost Almost All of Them

As Tellurian issued more stock to remain afloat, Souki's holdings diminished to 7% of outstanding shares in 2021.

A footnote in that year's proxy said simply again that 25 million of Souki's shares were "part of a collateral package to secure a loan for certain real estate investments."

With stock awards as part of compensation, his holding grew in 2022 to 30 million shares. But Tellurian's continued equity sales diminished his position to 5.2% of outstanding.

Then suddenly, he lost almost all of them.

The April 27, 2023, proxy statement reported his holding as 8.3 million shares (1.5% of outstanding), including 6.7 million subject to options exercisable by June 20.

By this past spring, Souki owned just 1.7 million shares.

In late 2022 and early 2023, the lender group had foreclosed on the shares as well as the family's homes, its other Aspen real estate held by Ajax Holdings and Souki's yacht held by Ajax Cayman.

Boom, Bust, Bust

Souki, the son of a foreign news correspondent who was born in Egypt and spent his youth in Lebanon, had settled in Aspen after retiring in the early 1980s while in his early 30s from the international investment banking lifestyle of home- and hotel-hopping in New York, Paris and the Middle East.

In Aspen, he opened a successful restaurant, Mezzaluna, which he sold in 1993. It remains in operation today.

From that venture, he set off for the oil and gas business in Houston. In 1996, he founded an E&P, Cheniere Energy, that became an LNG importer in 2008 and was virtually mothballed on opening day when its business plan collided with a newly flush supply of U.S. shale gas.

Undeterred, he built an adjacent plant to export LNG from the southwestern Louisiana property. The Sabine Pass facility has since grown to 4.6 Bcf/d of capacity with three berths.

But activist investor Carl Icahn pushed Souki out in 2015 over Souki's compensation package–estimated at $142 million a year–that made him what was considered to be the highest paid executive in the U.S. at the time.

He swiftly founded Tellurian with friend Martin Houston, a former BG Group executive, in 2016 and took it public via a reverse merger in 2017 with penny stock Magellan Petroleum Corp.

'Begged' Him

In his lawsuit filed against UBS O'Connor and the three other lenders in March 2023 over their foreclosure, Souki called their actions "unconscionable."

They loaned him $90 million in 2017 and 2018 against collateral of 25 million Tellurian shares, the 800-acre Aspen ranch that included his and his children's homes, "and his prized sailboat," he told the New York Southern District federal court.

He added that, "in 2019, defendants loaned $60 million to Tellurian without disclosing the Souki loans to Tellurian" and "in 2020, when Tellurian was near bankruptcy," they "begged" him to ensure Tellurian would repay its debt.

"In exchange, [the lenders] promised Souki they would be flexible in their approach to repayment of his loans and would not act in ways that materially disrupt Tellurian's stock price," he told the court.

But "these were empty promises" that the lenders "had no intention of honoring," he added.

Tellurian paid off the lenders in March 2021, a year before maturity.

"Almost immediately" they demanded $5 million from Souki and full repayment, which had grown to $103 million with interest, by Oct. 30, 2021, Souki told the court.

They also "threatened to foreclose on his ranch and pressured him to sell his Tellurian stock in ways that would likely violate securities laws," his suit reported.

He refused their demands and they increased the interest rate, he added.

The lenders were now "selling his sailboat at a bargain basement price and are now selling Souki's Tellurian stock so recklessly that it has driven the stock price down nearly 25%," he said in the March 2023 suit.

Souki had paid a $50 million loan taken in 2017 down to $30 million in early 2018, he wrote. He borrowed another $70 million and brought the balance down to $90 million, secured by the Tellurian shares, the family's Aspen Valley Ranch and his equity interest in Ajax Holdings and Ajax Cayman.

Maturity was initially January of 2019.

They Didn't Say; He Didn't Say

In May of 2019, he told the court, he introduced the Tellurian board to UBS O'Connor and the lending group but didn't get involved in negotiations.

The group didn't disclose to the board its relationship with him, he added, when UBS O'Connor's Nineteen77 Capital Solutions bought stock warrants and Wilmington Trust loaned Tellurian $60 million.

Souki did not mention to the court if he disclosed the relationship to the board.

But, he told the court, "this created an inherent conflict of interest for [the lenders]."

The lenders could have affected Tellurian's stock price if foreclosing on and dumping Souki's stock and "this is something Tellurian would have wanted to know and protect against before entering into the loan," he told the court.

Throughout this time, Tellurian shares were averaging about $8 on the market.

But they tanked to less than $1 in early 2020 as global gas demand slumped in the midst of COVID lockdowns.

The 25 million shares were worth about $24 million then.

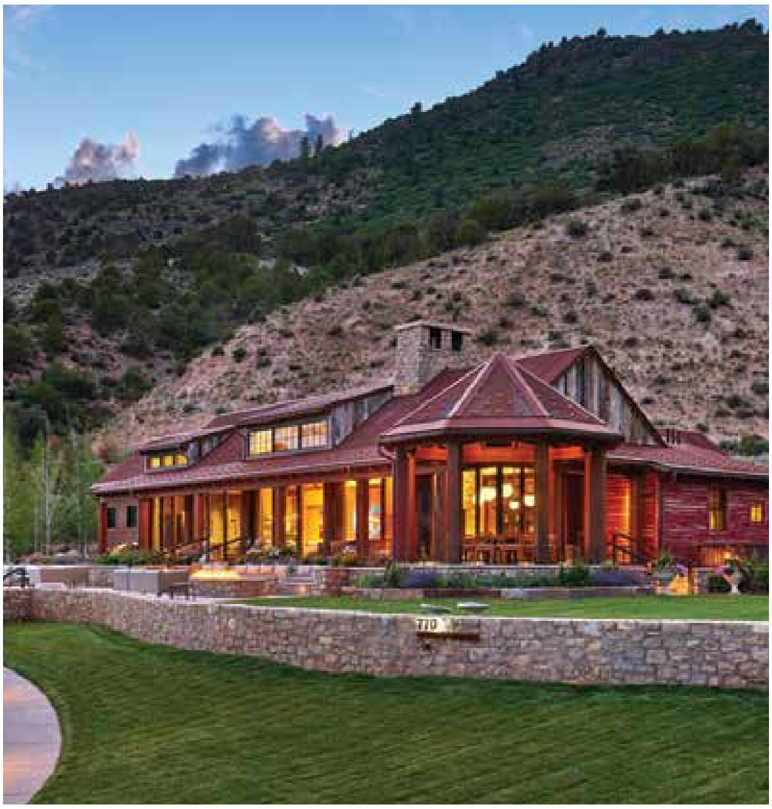
He got the lenders to agree to not foreclose on him "while he focused on repayment of the Tellurian loan," he wrote in the lawsuit.

Souki, who had been Tellurian's chairman, took the executive chairman position in June of 2020 to work on "righting its financial ship and in repaying expensive debt, including the Tellurian loan [that involved his own lenders]," he told the court.

Moving Out

With the UBS O'Connor group at the ranch's gate, Souki asked family members who lived in some of the homes on the property, "most of which had been built by my family," to move out and listed the homes for rent and for sale, he told the court.

Buyers offered a combined $46.5 million for three of them. He expected the net proceeds would allow him to pay $30 million to Alpine Bank, which had a lien on the homes and lots, leaving $12.6 million to send to the



SHUTTERSTOCK

Left: Yachts of a similar design to Charif Souki's custom-made vessel, Tango, *race near Mallorca, Spain. Right: Part of the Aspen Valley Ranch.*

UBS O'Connor group.

In April of 2022, the lenders increased the interest on his loans to the 15% default rate.

A few days before Christmas, they seized Souki's sailboat, Tango, which was undergoing regular maintenance and repairs, listing it for sale "as is, where is," he wrote.

On Feb. 8, 2023, they followed with seizing the 25 million Tellurian shares, dumping them into the market during the next 57 days, initially for nearly $2 and down to as low as $1.

Souki concluded in his lawsuit that, if the lenders had sold the shares in April of 2022 while they were $6, his debt would have been paid, he would have shares left over "and the rest of his collateral would not be subject to foreclosure."

Ultimately, the 25 million shares went for $37 million.

He told the court that the lenders violated securities law for trading stock while having Tellurian insider information, which he had provided to them when he argued for giving him more time to improve Tellurian's stock price.

The Yacht, The House

Built in 2017, the Cayman-flagged sailing yacht, *Tango*, was sold in the spring of 2023. Now known as *V*, the boat is a 100-foot Wally-built monohull designed by naval architect Mark Mills and accommodating four crew and six guests, according to SuperYacht Times.

Souki told the court that it took him three years to design and build the boat "and I was intimately involved in that process. It is very much a unique asset that I treasure."

As for his and his wife's home on the ranch, he wrote in the lawsuit that "the ranch is still my primary residence and it is an extraordinarily unique property that has taken nearly two decades to put together and cannot be replicated."

In addition, "the sentimental and familial value … could never be replaced."

To lose his own home "would render me homeless [in the U.S.]," he added. (He has two homes in France, he told Hart Energy in September.)

He no longer had the ranch for sale, he added in a supplemental court filing. "We plan to keep the ranch in the family."

His separate bankruptcy case, filed in Houston, was dismissed Aug. 16 after mediation.

What was left of the collateral—the downtown Aspen commercial real estate—was sold to a Chicago-based developer for $62 million in early August, according to Aspen Daily News.

Peterson, the Aspen city judge, remained on the board until this past March when he resigned, citing health concerns.

Tellurian's 'Going Concern'

In the midst of the 2023 fallout from the Souki loans discovery, Tellurian launched a new round of looking for takers for its LNG—contracts it needed to finance continued construction of Driftwood to meet the FERC-issued 2029 deadline for completion.

The targets were "large investment-grade energy companies with LNG trading expertise," it reported in the Aug. 27 proxy statement.

Among them, it met with Woodside CEO Meg O'Neill at an LNG conference in Vancouver that July.

In September, it met with a company it identified in the

WOODSIDE ENERGY

Woodside's Pluto LNG plant in Karratha, Australia. The facility was built by Bechtel.

proxy statement as "a global investment fund focusing on energy infrastructure."

Tellurian had refinanced its remaining convertible notes by issuing $83 million of new notes as well as $250 million in non-convertible notes.

That plugged one hole, but continued Driftwood construction costs as well as a sub-$3 price for its Haynesville gas resulted in less cash on hand.

By early October, it reported to shareholders "there was substantial doubt regarding its ability to continue as a going concern for the next 12 months."

Signing up long-term LNG offtakers was essential to refinance its debt, sell equity at a decent price or have any cash on hand, it reported in the Aug. 27 proxy statement.

Another unidentified entity described as "an energy-focused investment fund that held an interest in another LNG liquefaction project" got in touch in September 2023 and received a briefing on progress to date on Driftwood.

At an industry conference in London, Tellurian co-founder Houston, who was vice chairman at the time, let O'Neill know that the board "would consider any transaction proposed by Woodside, including a sale of the company," the proxy statement reported.

A couple of months later, the board learned that the first investment fund was interested but that it intended to partner with Woodside in any proposal.

O'Neill added that any proposal to Tellurian depended on winning a reduced contract cost from Bechtel for building the Driftwood plant. (Bechtel was already Woodside's contractor in its Australian LNG export operations.)

Souki Out

Souki's lawsuit against UBS O'Connor and the other lenders was set for trial on Dec. 11.

The board fired him on Dec. 8 after discussing the "impact of the trial on the trading price of the company's stock, potential financing transactions and its ongoing commercial discussions," Tellurian reported.

In-house attorney Daniel Belhumeur became president. Octavio Simoes remained CEO but resigned this past March after his contract was not renewed. He remained a special adviser as of August.

Kian Granmayeh had departed as CFO in March 2023 for another job. Simon Oxley, an investment banker for Barclays, was hired for the post the following May.

Houston assumed the chairman post and, in February, executive chairman, the position Souki had held.

While Souki was going to bankruptcy court in Houston on Dec. 11, Tellurian met in Washington, D.C., with Reston, Va.-based Bechtel along with Woodside's O'Neill.

Separately, while Woodside and its investor partner continued discussions with Bechtel, Tellurian board members received an update just before Christmas on the company's solvency.

Meanwhile, an unidentified, publicly traded pipeline company initiated a conversation with Tellurian about signing an LNG offtake contract.

WOODSIDE ENERGY

Bechtel, the contractor for Tellurian's Driftwood LNG export plant, is also the contractor for Woodside's Australian LNG operations, including the Pluto LNG plant in Karratha, Australia.

Woodside Energy By the Numbers

35	4.9	6	+27.6
years LNG exporter	mtpa LNG capacity at Pluto LNG	projects in execution phase	mtpa from Tellurian's Driftwood LNG

Separately, Tellurian hired investment banker Lazard Inc. to look into how it could raise some money.

The Pause

A sale of the company was not yet being discussed, although Houston had told Woodside in London that Tellurian would consider a sale of the company, according to the Aug. 27 proxy.

Then, Biden issued a pause on issuing permits to new LNG projects on Jan. 26.

Suddenly, the Driftwood permit was of limited edition.

The Tellurian board's meeting a few days later included discussion of progress in raising capital "and recent market and regulatory developments," it reported in the proxy.

The investment fund that held a permit for another LNG project met with Tellurian on Feb. 1 about combining the projects. A week later, the two discussed the fund taking an offtake contract with Driftwood, buying some of Tellurian's debt and/or other financing.

Tellurian announced in a press release that its Haynesville E&P property was for sale. By late May, 28 potential buyers had signed confidentiality agreements and five of them made a bid.

As for the balance of Tellurian's property—the land and the LNG permit—Woodside informally said in a videoconference that its offer would be $700 million.

To check other options, Lazard was hired to reach out to more than 40 parties, in addition to leading the E&P divestment assignment.

Among them, 10 signed non-disclosure agreements and, in the next 60 days, eight listened to Tellurian management presentations.

The pipeline company that had earlier indicated interest in a deal with Tellurian joined with two E&P companies and proposed they become a co-owner with Tellurian in Driftwood.

But the trio later said the structure was no longer viable.

The Bonuses

In March, Woodside and its investor partner offered $1.15 worth of Woodside stock per Tellurian share.

But the offer was contingent on winning a cost cut from Bechtel and securing financing. Also, Tellurian would have to retain its permit and there would be no surprises in change-of-control payments due employees post-closing.

Soon after, Woodside learned it would have to pay current and former Tellurian employees $250 million in bonuses in a "construction incentive program" (CIP) if the company is sold.

At year-end 2023, Tellurian had 168 full-time employees, and 80% of the $250 million would go to 20 current and former employees.

Woodside replied that the sum would have to be reduced or the difference in what Woodside had estimated bonuses would total versus the real sum would be trimmed from the purchase price.

And it twisted Tellurian's arm one more turn: Woodside added that it wouldn't pay Tellurian's bills prior to signing a definitive purchase agreement.

Souki With a Term Sheet

Tellurian still had options but it was running out of money, which "could affect its ability to pursue those options," it reported in the Aug. 27 proxy statement.

Among them: by late April, there was a buyout offer from Woodside, bids on its E&P assets, an investor's offer of a direct investment if Tellurian would combine its Driftwood project with its own, two other offers of direct investment and several potential offtakers with interest.

Although embroiled in an active bankruptcy filing, Souki showed up with an offer to buy between $100 million and $200 million of newly issued Tellurian shares, which were trading at about 40 cents at the time.

The board was doubtful about the option "due to concerns about the likelihood a transaction would be completed and potential regulatory issues," Tellurian reported.

Nevertheless, Souki got a meeting, reiterating that he would raise $100 million to invest in Tellurian and followed it up with a term sheet 10 days later.

The board declined, deeming Souki's offer "to be, among other things, highly speculative," it reported Aug. 27.

Aethon Shows Up With Cash

In early May, Tellurian and Woodside commenced pencil-fencing on merger terms and Woodside's investor partner bowed out, saying one of its principals couldn't approve a deal for at least the following two months.

On May 28, privately held Haynesville-focused operator Aethon Energy placed a winning $260 million bid on Tellurian's E&P property, consisting of 31,000 net acres and up to 100 MMcf/d of treating and gathering capacity.

It also signed a heads of agreement (HOA) to discuss a 20-year deal to buy 2 mtpa (267 MMcf/d) of LNG from Driftwood.

Aethon and Tellurian issued the press release on May 29.

The stock price improved from about $0.50 to $0.88.

With the E&P property jettisoned, its negotiations were now for a pureplay LNG company—and one with at least one HOA in hand.

Tellurian by the Tail

While the company was to receive $260 million from Aethon at closing June 28, most of the proceeds went to the 6% lender, since the property was collateral in the note.

Fund-raising options were now to sell the rest of Tellurian's real property, sell shares and win financing from the investment fund that was developing another LNG project.

It had received a bid from another potential offtaker but the offer was too low, Tellurian reported, and "could establish a precedent for discussions with other potential purchasers."

The offer was declined.

While the HOA with Aethon increased interest from other potential offtakers, "new agreements were unlikely to be entered … in the near term," the board concluded.

Woodside arrived with a revised bid: 94 cents in cash per Tellurian share.

In addition to being less than the $1.15 worth of Woodside stock per Tellurian share that was initially offered, a cash buyout would be a taxable event for Tellurian shareholders.

Woodside explained that the reduced bid was the result of its due diligence and because Tellurian had more shares outstanding than when it made the $1.15 offer, according to the Aug. 27 proxy.

But it threw in a bridge loan—sweetening the pot with something that could keep Tellurian afloat, which Woodside would need if wanting to buy a solvent company with an active LNG export permit.

Houston told O'Neill that the board would likely find the offer "inadequate."

Woodside returned in late June with $1 per share and said that was "the maximum amount it was willing to pay."

Meanwhile, Tellurian said some of its senior officers would agree to 40% less CIP bonus. Woodside replied that they would have to agree to a 70% reduction.

As for the investment fund that was interested in combining its LNG project with Driftwood, odds of a potential deal getting done quickly "were insufficient to justify continued negotiations," the board determined.

The End

On July 8, Tellurian pushed back on Woodside's offer, but O'Neill didn't budge and instead submitted "a draft of the merger agreement which largely reverted back to Woodside's initial positions," the proxy statement reported.

Tellurian convinced nearly all of the officers involved in the CIP bonus to take a 70% cut.

No one but Woodside had made a firm offer to buy Tellurian, the board noted in a July 21 meeting.

It voted to do the deal for $1 share that came with a bridge loan of up to $230 million, representing "the best combination of value and certainty for the company's stockholders," Tellurian reported in the recent proxy statement.

The company borrowed $75.2 million from the line of credit the next day.

Cash on hand had been $19 million. Debt totaled $134 million due 2025 and 2028.

Shareholders were to vote on the deal Oct. 3.

Next for Souki

Souki spoke to Hart Energy on Sept. 4 from his home in Paris—he also has one on the coast of France—and planned to return this fall to his Aspen home, which he kept.

He has moved on from the yacht. "I wish the person who owns her now enjoys her as much as I did," he said.

He is in a non-compete with Tellurian through year-end.

"So, at the moment, I'm going to stay on the sidelines. But as you can imagine, I have some ideas." OGI

Souki: 'I've Been Buying Woodside Stock'

The LNG export pioneer is on the sidelines for the moment, but Charif Souki has ideas about his next move and is always thinking about the global gas market.

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Charif Souki, former executive chairman of aspiring U.S. LNG exporter Tellurian, also founded Cheniere Energy, which currently exports 4.6 Bcf/d of LNG from the Louisiana Gulf Coast.

Australian LNG exporter Woodside Energy has a deal to buy Tellurian for $900 million cash in an acquisition totaling $1.2 billion in value, including assumption of debt and other liabilities. Once built, Tellurian's Driftwood LNG plant will have export capacity of 27.6 million tonnes per annum (3.7 Bcf/d), also from the Louisiana Gulf Coast.

Souki was dismissed from his post in early December and resigned from the board later that month after Tellurian completed an investigation into Souki's loans from a lender from whom Tellurian was also borrowing, according to Tellurian's filings with the U.S. Securities and Exchange Commission.

Souki spoke with Hart Energy in early September about his plans, the outlook for global gas markets and whether data centers will amount to much in terms of drawing down excess U.S. gas capacity.

"It's very simple. Anybody can do the numbers," he said.

Nissa Darbonne: You were let go by Tellurian in December, so you weren't part of agreeing to the [$1.2 billion] sale to Woodside Energy this summer. What do you think of it?

Charif Souki: It's going to be a fantastic deal for Woodside [when it closes] and it's going to change the nature of Woodside. It's an existential change, and I think they understand it. They're smart enough to have recognized it.

I'm surprised nobody else has recognized the value. And it is very, very, very much in line with the deal [Woodside] just did with OCI NV [for a Beaumont, Texas, ammonia-production plant].

It's all about taking American gas and selling it on the international scene.

Woodside is paying $2.3 billion for an ammonia plant that is going to sell 1.1 million [metric] tonnes [per year]. It takes 30 Bcf to do that.

So, they're going to take 30 Bcf of American gas and sell it in the form of ammonia in Europe and in Asia at the equivalent of $11 and $12 an MMBtu.

It's the same kind of arbitrage—except, with the ammonia plant that they're paying $2.3 billion for, they're dealing with 30 Bcf per year.

With Driftwood, they're dealing with [an additional] 1.3 Tcf per year.

> *"I have a tolerance for risk that most people don't."*
>
> **CHARIF SOUKI,** former executive chairman, Tellurian

ND: That's a lot of gas.

CS: Both deals make sense, but the Driftwood deal makes 15 times more sense than [just] the one with the ammonia plant.

As you know, ammonia is 80% gas. So, all you're doing is taking American gas and selling it in a different form. A tonne of ammonia sells in Europe for close to $400.

So, your 1.1 million tonnes are going to generate about [$440] million a year of revenue and it takes 30 Bcf that you have to buy in the United States for $3 an MMBtu on average. You're going to buy gas for [$90] million, process it into ammonia for a $100 [million], transport it to Europe for $50 [million] and you'll make $200 million a year on the 30 Bcf that you're selling [as ammonia].

ND: Nice margin.

CS: They're going to have the opportunity to do the same thing with [Tellurian's] Driftwood [LNG export plant] where they're going to be dealing with 1.3 Tcf [a year] when the project is fully built.

It's going to cost them—without [financing] costs, if you just look at the cost of construction—$25 billion.

You'll buy the same gas in the United States at $3 an MMBtu and you will sell it on the global markets for $9, $10, $11 and you'll

Meg O'Neill, CEO of Woodside

CERAWEEK BY S&P GLOBAL

WOODSIDE ENERGY

Woodside Energy's corporate headquarters in Perth, Australia.

> *"Meg O'Neill's negotiating skills.... It doesn't reflect well on the counterparties."*
>
> *"The demand for natural gas in the United States is not going to increase dramatically in spite of what people are saying about data centers."*
>
> **CHARIF SOUKI,** former executive chairman, Tellurian

make a ton of money and it's going to be a game-changer for Woodside.

It's brilliant.

ND: Reading the background on how the Tellurian-Woodside merger came together, Woodside's CEO Meg O'Neill's negotiating skills appear to be impressive.

CS: I don't want to go there. It makes me sick.

Meg O'Neill's negotiating skills.... It doesn't reflect well on the counterparties.

But it's all in the proxy statements. I have nothing to say about that. But at the end of the day, it's a fantastic deal for Woodside. That's all I want to say.

ND: Do you have a position in Woodside? I know they're buying the Tellurian stock for cash, not equity. It seems you're being very generous to be supportive [of Woodside].

CS: Since they announced this deal, I've been buying Woodside stock. I'm already a significant shareholder. I have nothing but admiration for what Woodside has done.

ND: In number of shares, is it six figures you've accumulated now or seven?

CS: Definitely six. And I intend to get over seven figures.

ND: What will you build next?

CS: I am kind of stuck until the end of the year. I still have my non-compete [agreement] with Tellurian until the end of the year. So, at the moment I'm going to stay on the sidelines.

But as you can imagine, I have some ideas.

ND: It will involve U.S. natural gas?

CS: There are a few things that are very, very evident. One, the United States is not running out of gas anytime soon. Two, the increase in gas production is staggering.

Three, the demand for natural gas in the United States is not going to increase dramatically in spite of what people are saying about data centers. If you notice, it seems to be that most of the data centers are being thought about for Virginia because [nearby] Marcellus gas is plentiful and very cheap and it's the easiest place to put [data centers and their demand for electricity].

TELLURIAN

Work at the Driftwood site in April 2023 in Lake Charles, La.

Four, the rest of the world desperately needs this gas.

So, the arbitrage from [converting] American gas [into] global gas is going to continue to stay for a long time.

ND: From the proxy statement, it looks like Tellurian took the Woodside deal because it was running out of cash and new means of raising cash.

CS: Well, you know that that was not my position. But I have a tolerance for risk that most people don't.

ND: Yes.

CS: I did read the proxy statement, so I know what they say.

I don't agree with them, but I can understand how people can disagree in good faith.

They did not consult me. But for me, I'm very excited for Woodside. I think it's fantastic.

I am full of admiration for the move that they've done and I think it's going to be a game-changer for them.

American gas is stranded and having an American gas [E&P] company without an export option is going to be extremely difficult [thus needing to have contracts with LNG exporters].

We have the resource we need right here in this country and we have to find a way to put it on the global markets. I'm a fan of what Woodside is doing.

ND: Is Woodside's $1.2 billion offer for Tellurian a fair price?

CS: I wish they had paid more for Tellurian, but it's not material.

I mean, they're paying $1 billion in round numbers for Tellurian for a project that is going to cost $25 billion to build. So, paying $1 billion or $2 billion or $3 billion–at the end of the day, it makes no difference because your arbitrage is so large.

You're buying American gas for $3 and you're selling it for $10, $11, $12. You're making $9 an MMBtu [net]. That's $10 billion a year of cashflow [for 1.3 Tcf/year of gas that cost $3 per Mcf, net of operations, maintenance, liquefaction and other costs].

It's very simple. Anybody can do the numbers.

What I love about Woodside is that, one, they're integrated and, two, they're exposed to global indices.

ND: In the Pacific Basin and, with Driftwood, in the Atlantic Basin.

CS: The arbitrage is there. And they have the balance sheet to go along with it. They're very conservatively financed. So, I love everything they're doing.

And as I said, since they made the announcement, I built a pretty significant position and when the deal goes through, I'll build an even bigger position.

They're the perfect gas company at the moment–with Tellurian [in the portfolio]. OGI

Building a Better Non-op? Control the Purse Strings, Executives Say

Trailing E&Ps in the public markets, some non-operated oil and gas companies are taking firmer control of drilling decisions as executives look to reinvent their business model.

DARREN BARBEE
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"The main issue there is, I think, most investors view oil and gas companies as assets rather than businesses."

MICHAEL OTT, vice president, corporate development, Granite Ridge

The fairly audible grumbling from non-operated oil and gas companies is that they don't get their due on Wall Street.

Generally, they trade at a considerable discount to their E&P cousins despite generating consistent returns, carrying low debt and returning cash to shareholders—just like the E&Ps that get more investor attention.

Granite Ridge Resources, for instance, offers a yield of about 7% but trades at a discount to operated E&P peers of 1.5x to 2.0x (and trails other non-ops by 0.5x).

That doesn't mean non-ops lack a fan base. At EnerCom Denver in August, Megan Hays, a managing director and head of sustainable investment at Kimmeridge, lauded the not-so-niche sector.

"We think about $8 billion a year of capital is being spent on non-op," Hays said. "And if people are going to get more critical over how they're allocating it, that is going to continue to find its way to the sales process.

Granite Ridge's figures present the equation slightly differently: Lower 48 operators spend about $100 billion in gross development capital annually. About 25%, or $25 billion of that spend, is provided by their non-op partners.

The non-op model is not without its difficulties. For one thing it's hard to define and, not unlike mineral and royalties' companies, they often have to fastidiously ensure they're in line or ahead of the operator's drill bit. The non-op story is generally more procedural. Non-ops have a say in what E&Ps drill, to some extent, through authorizations for expenditure, known as AFEs. If a non-op passes on an AFE, the E&P can still drill, but without the non-ops' cash participation. Non-ops' other selling point: low expenses, particularly in overhead expenses.

The challenge for other non-ops—and simultaneously a core strength—is highly specialized diversification. Non-ops not only eschew homogeneity (although public non-ops are disproportionately investing in the Permian Basin), they consistently cash in on wherever they're at. But, again, they're also beholden to operators to drill.

That's led to a dilemma for some.

Granite Ridge, for example, is heavily invested in the Delaware Basin. But the company also holds interests in the Eagle Ford Shale, the Denver-Julesburg (D-J) Basin, the Haynesville Shale, the Midland Basin and other areas where the goal is rate of return rather than building massive, congruous footprints.

"The main issue there is, I think, most investors view oil and gas companies as assets rather than businesses," said Michael Ott, Granite Ridge vice president of corporate development.

However, Granite Ridge is in the process of changing part of its business model to function more like a capital partner, a kind of offshoot from more demanding or tight-pursed private equity firms. The effort comes as the company (and other non-ops) look to break out of the business model's reputation as a mostly silent partner.

Northern Oil and Gas (NOG) has done so successfully in a simpler and sexier story—dispersing hundreds of millions of dollars in multiple deals the past few years.

The company has found headline-stealing deals to attract investors. NOG is "the most reliable and consistent partner for the purchase and development of high-quality properties," CEO Nick O'Grady said after one recent deal.

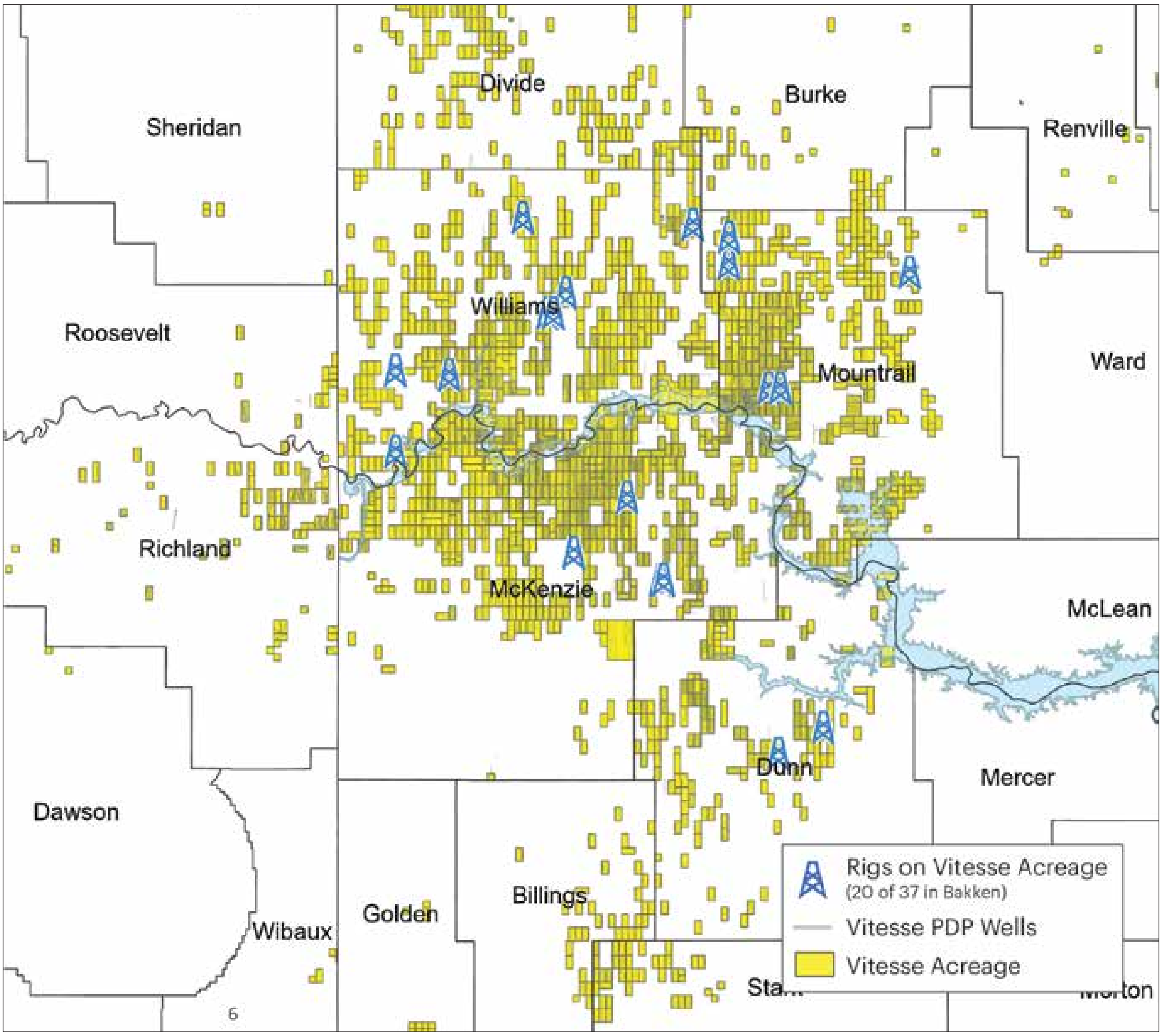
The remark came after yet another large-scale deal in which NOG played non-op financier. NOG has repeatedly engaged in deals with E&Ps, including SM Energy's pending acquisition of Uinta producer XCL Resources for $2.55 billion. That was in June.

In late July, NOG was at it again with a joint bid with Vital Energy (the companies' second partnership) to acquire Delaware Basin assets from Point Energy Partners for a combined $1.1 billion.

Not NOG

Vitesse Energy, by contrast, is a non-op deeply

Acreage in the Core of the Williston Basin with Exposure to Leading Operators

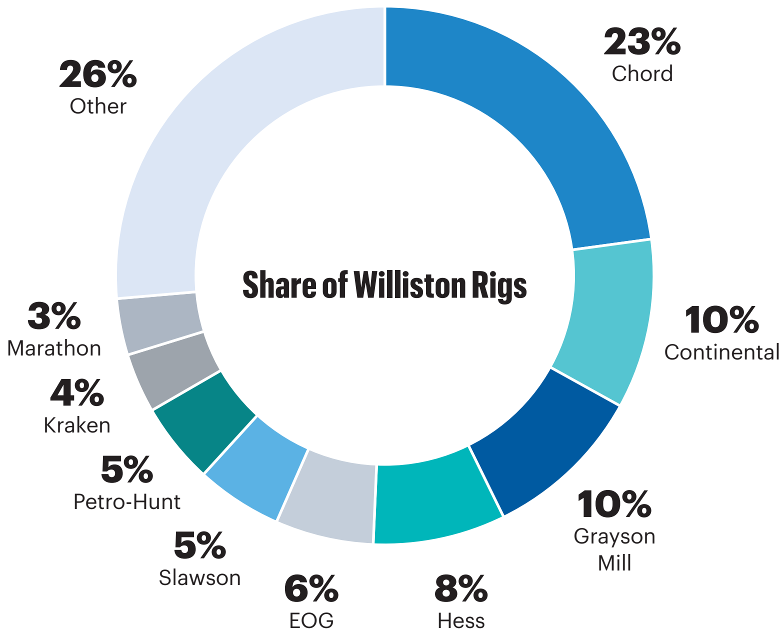


20–55%

Vitesse participation of rigs drilling in the Williston Basin.

48,266

Working Interest Net Acres



SOURCE: VITESSE

Drilling operations in the Williston Basin. Non-op Vitesse Energy rarely looks outside of the Williston Basin and CFO James Henderson says it will stay that way.

SHUTTERSTOCK

tied to the Bakken and Three Forks that seemingly seldom looks outside of the Williston Basin. The company's holdings are spread across 7,018 (163 net) producing wells with an average working interest of 2.8%.

"We've looked at other basins," Henderson said. "We just know the Bakken the best."

In North Dakota, the company's 50,000 piecemeal acres stretch north from Divide County, through the heart of Williams and south into Dunn County and beyond. Across that expanse, the company estimates it has more than 200 net remaining Bakken locations.

Vitesse CFO James Henderson, when asked if his company would consider some NOG-style tagalong deal, said the company simply isn't in the "same class." The company likes, knows, has studied and built an entire proprietary analytical system around the Williston.

"Everyone wants to compare [them to Northern] but they're way bigger, they've been around," Henderson told Hart Energy. "We think we've developed something. What they're doing is so different from what we're doing."

Besides, he said, opportunities continue to crop up in the Bakken. Devon Energy said in July it would buy Grayson Mill Energy in a cash and stock deal valued at $5 billion.

"The number of rigs in the basins doesn't really change a whole lot year to year," Henderson said. "With consolidation, maybe we'll see a little more [activity] as Devon and others bring more rigs to the basin. Or they'll spin off their non-op and we purchase some of that."

'Hybrid' Non-Op

Granite Ridge has recently started to head in a different direction. Speaking at EnerCom, Ott noted that the company is diversified by basin, operator, commodity, and private and public company.

Most traditional non-op work is the blocking and tackling ground game that Granite CEO Luke Brandenberg likes to call "burgers and beer"—the idea being that such deals are relationship-driven.

So, the company doesn't particularly distinguish buying opportunities in the Delaware, Bakken or the Haynesville, as long as the return on investment materializes.

Notably, the company's recent presentation included a new spot on its map: the Utica. However, Ott did not address the area other than to say, "we've got a new logo on that map as well, an area that we're excited about in the Northeast."

"We are not looking for PDP blowdown opportunities," Ott said. "We are focused on drill bit activities, strategic partnerships."

Granite has lately been moving into strategic partnerships—what Ott termed "a controlled capital program"—in which the company combines its relationships to increase deal flow.

"But also, as a non-op, we're trying to increase our control and the timing and development that we're investing in," he said.

West Texas Partners

Granite Ridge is involved in two new partnerships in West Texas, one focused in the Midland and the other in the Delaware.

Between the partnerships, Granite Ridge has accumulated close to 8,500 net acres with 70 gross (40.5 net) locations.

"In 2024, we're going to spend over $100 million with these partners on through the drill bit," Ott said.

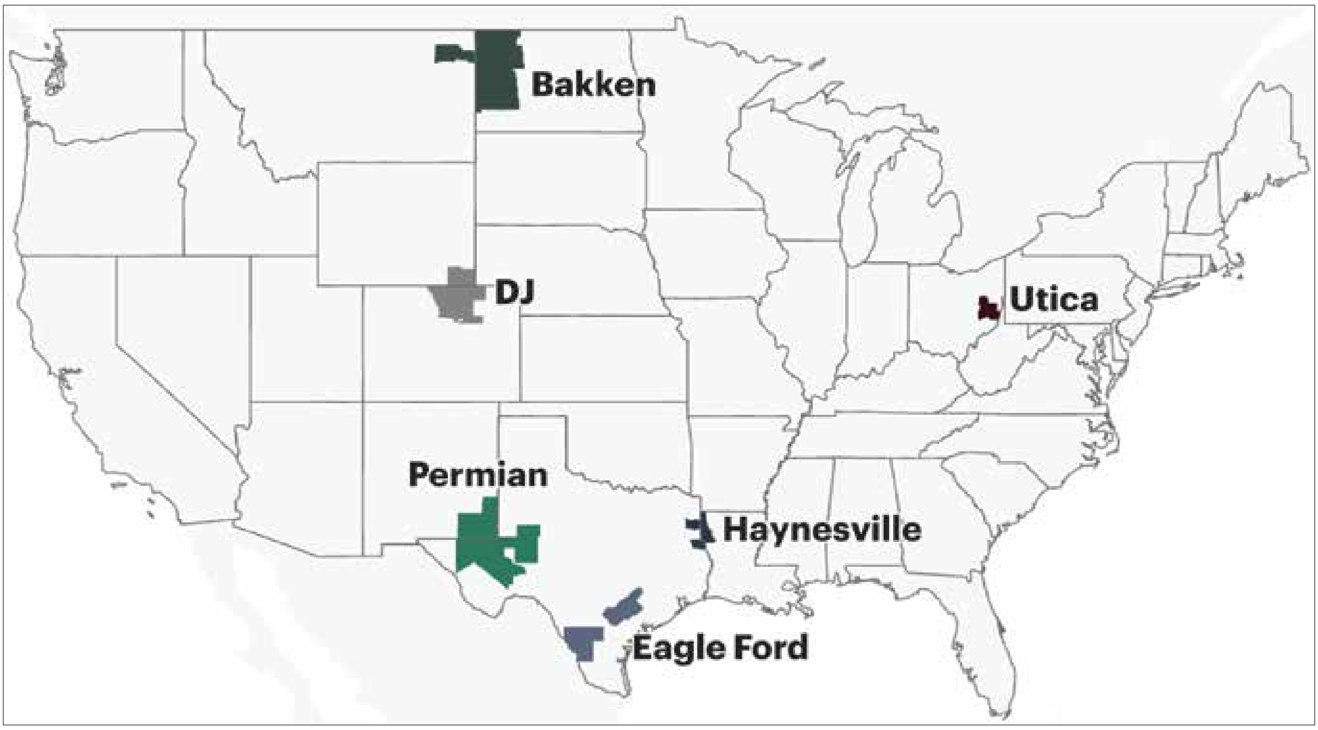
Granite Ridge's controlled capital program essentially gathers up successful private companies who have "done the private equity mouse trap for a long time," he said.

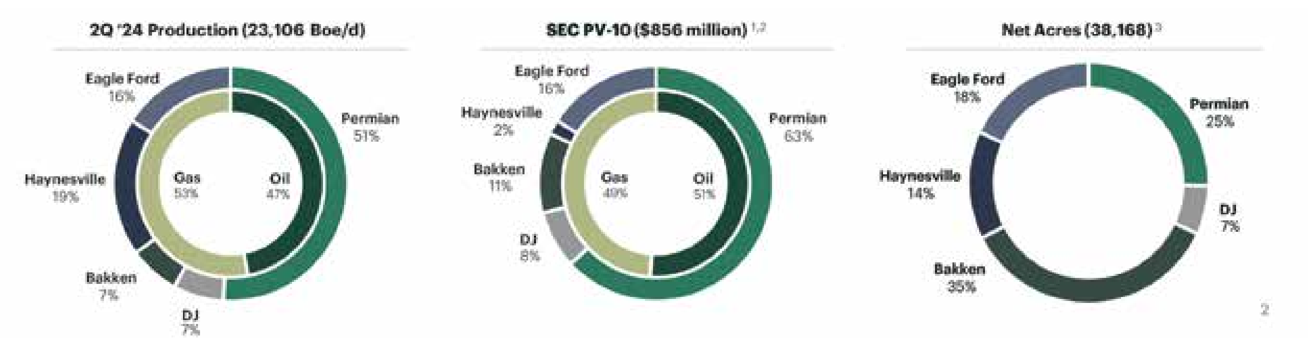
The teams were able to build a lot of value, gain experience and establish a proven track record but, because private equity fundraising has slowed, "that leaves a lot of teams on the sidelines with no committed capital."

Granite Ridge has sought out those teams and created this strategy "where they have the same economic or very similar economic outcomes, except they can control their business. And we control development time and we control the approval of acquisitions."

"We are more or less creating a hybrid operated wedge within

Granite Ridge at a Glance





SOURCE: GRANITE RIDGE

1. NON-GAAP FINANCIAL MEASURE.
2. BASED UPON SEC PROVED RESERVES AS OF 12/31/2023.
3. AS OF 6/30/2024 AND INCLUDES 166 NET ACRES IN THE UTICA WHICH IS EXCLUDED FROM THE CHART.

our non-op company," Ott said. "We're trying to transition our company from being a traditional non-op company where things are lumpy. You don't control timing. You don't control things like spacing or what bench you're going to develop or how you're going to underwrite the investment."

As a non-op capital provider, "we're able to call the shots a little bit."

"Of course, it's a working relationship; of course, they have a say. But it's our ability to transition our portfolio from what is generally unpredictable in the non-op world to being more predictable," he said. "It's going to prove our ability to provide guidance, craft our capital structure and have more predictable timing around the development and investment of our dollars and the merit of this."

The ultimate goal is to make good returns, reinvest cash flow and "bridge that gap" between non-op and operated investment.

Ott said Granite Ridge's strategy comes from a traditional non-op space that the public space doesn't appreciate the same way they do operated players.

The company can't do much about that, except to prove over time it's able to generate new opportunities for the business to invest in.

"One thing we can do is what we're doing right now with transitioning our portfolio to our controlled capital strategy," he said.

The $100 million that Granite Ridge intends to invest in West Texas represents about 40% of the company's capital spend, while next year's controlled capital spending will be more than 50% of spending.

"The company's guided controlled capital production is going to be somewhere between 5% and 10% of our annual production next year," he said. "We expect it to be a lot higher, as we've invested a lot of money this year, but the operated side has much longer lead time than the non-op side, where non-op has tendency to come in at the last minute."

Ott added that, on the operated side, "we picked up a rig with one partner in the Delaware Basin last October, and that first pad came online in June," he said. "As we roll through what we call the J-curve and start to invest those dollars, we're starting to see the fruits of that labor here in the second half of the year." OGI

Sidley Austin: Debt Financing Returns to E&P Space

Funding sources evolve as reserve-based loans remain limited.

DANIEL ALLISON
SIDLEY AUSTIN

Daniel Allison is a partner in the energy and global finance practice of Sidley Austin. He is based in Houston.

Oil and gas upstream companies have seen debt financing return to the sector in the last few years. Although many traditional lenders have left the market, new funding sources have spurred upstream lending. These new sources of capital—including regional banks—have funded recapitalization and new development programs. These funding sources continue to evolve and present new opportunities and considerations, but some questions remain.

Although there is more access to debt investments in oil and gas companies, the traditional stalwart of reserve-based loans (RBLs) from big box banks remains limited. Many of the largest traditional lenders for RBLs have reduced their participation in these products or exited the industry entirely.

Instead, a number of alternative financing sources have stepped in to address the decrease in traditional RBLs and take advantage of a strong borrower market. Regional banks are the most similar lenders, as they have historically participated in RBLs so it's simple for them to step into this opportunity because they never really left. More recently, they have taken lead roles in originating and running their own deals.

Where the deal exceeds the limited size that a club of regional banks can provide, we have seen another development—the split senior lien, with both a regional bank revolver and a private credit term loan. These deals typically have a very large term loan component that is placed to a small group of private credit purchasers. However, many of the private credit purchasers cannot (or prefer not to) fund the frequent and unpredictable borrowings that are typical of the RBL revolver, so in private credit facilities, there is typically also a "super senior" revolver provided by a regional bank or a small club of lenders.

A newer alternative method to obtain larger amounts of debt financing or recapitalization is the oil and gas asset backed securitization (ABS). This debt product has been developed in just the last five years, and in that time, it has grown in popularity and become more streamlined. An ABS is a highly structured financing product that is marketed primarily to investors that are required to invest in investment-grade debt. Through many of the restrictions and structuring features, an issuer that is not otherwise investment grade can issue investment-grade debt.

In considering which type of debt facility makes the most sense in the world of alternatives to the RBL, it is important to consider both the initial burden and price, as well as the ongoing burden and costs for each facility.

The closing costs for a private credit term loan and an ABS transaction should be fairly similar. While the costs of execution of an ABS facility used to be significantly higher than other debt instruments, the process and timing have both become more efficient, and it is now in the same ballpark as other types of financings (though still slightly higher).

In terms of ongoing costs, the interest rate on investment grade notes is lower than the current benchmark plus margin that is available in private credit. However, in a decreasing interest rate environment, that differential may decrease over time, and ongoing interest payments saved in an ABS could vanish compared to a floating rate a few years down the road.

Structurally, there are differences between the two; for instance, a private credit term loan would be at a floating interest rate plus a margin, whereas the ABS transaction would be at a fixed interest rate that is set at issuance. Additionally, there are typically very lengthy call protections on the notes issued under ABS facilities, whereas private credit deals have short, if any, call protection. Some ABS transactions are portable, but many have limitations that make portability unfeasible. As such, it is worth considering whether there may be a need to redeem the notes prior to their maturity.

Lastly, the reporting requirements tied to the various types of financings should be taken into consideration. Most of the types of debt available to upstream companies have similar reporting requirements, although ABS facilities typically require monthly reporting in order to run the cash flow waterfall and distributions monthly (as opposed to quarterly reporting in other debt facilities).

On the other hand, private credit deals typically have much tighter covenants pertaining to operations, and this can affect decision-making through the life of the loan. And in many instances private credit restrictions occasionally require waivers or amendments from the lenders, which typically have fees involved.

While there have been multiple improvements and innovations in the debt financing available to upstream producers, each has its strengths and limitations. When considering which debt product is best, it is worth considering the initial closing dynamics as well as the ongoing burdens or limitations that each product creates. OGI

Kissler: How Long Will Geopolitical Unrest Support Crude Prices?

Slower global economic growth weighs on prices.

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BOK FINANCIAL SECURITIES

Dennis Kissler is senior vice president of Trading for BOK Financial Securities. He is based in Oklahoma City.

As concerns about slower economic growth in the U.S. and China have applied downward pressure to crude oil prices, they're not falling as much as they would if geopolitical unrest weren't applying pressure in the opposite direction. Still, the current situation begs the question of whether the conflicts in North Africa and the Middle East, as well as between Russia and Ukraine, will continue to support crude prices and, if so, for how long.

Geopolitical Unrest Heightens

The short answer is yes, but the support likely will be temporary. Political unrest in rich oil-producing regions such as Libya, which currently exports 1 MMbbl/d, can definitely change the microeconomic availability and near-term pricing of crude if those exports are taken off the global market. In fact, the current internal political tensions within the country could do just that.

Meanwhile, the Israel/Hamas war directly involves Iran. The tension has grown with Iran's statement that it will eventually make a calculated military response to Israel's assassination of Ismail Haniyeh, a Hamas political leader who was killed in Tehran. Not surprisingly, U.S. crude oil futures jumped 4% on the news, as the assassination reignited fears of a regional war that could have a major impact on oil prices. Iran exports 1.8 MMbbl/d.

And then there's the impact of the Red Sea attacks to consider. On Aug. 21, Houthi fighters attacked the Greek oil tanker *MV Delta Sounion*, setting it ablaze. The tanker, carrying more than 1 MMbbl of crude oil, was still on fire when it was towed to safety in mid-September, which averted a serious environmental disaster had there been a large leak. Meanwhile, crucial shipping lanes were disrupted near the tanker's location.

Unrest and Oil Supply Deficits

As I've written before, if the Red Sea attacks were to escalate–for example, if an oil tanker were to sink or tanker crew members were to be killed–then we could see a total stoppage or very long delays of shipments through that route, which would add a war-type premium to crude oil and other petroleum product prices. If that occurs, it would have a negative effect on global economies and could reignite inflation very quickly.

There are other scenarios that could upset the balance between oil supply and demand, resulting in higher oil prices. For example, if there continues to be unrest within Libya and exports are reduced or eliminated, and if Iran were to lash out and put a military blockade into effect, more than 2 MMbbl/d conceivably could be taken off the global markets.

'Sell the Rumor; Buy the Fact' Still Rings True

While these scenarios could unfold in the near future, the reality is as always: "Sell the rumor/buy the fact." Higher prices caused by temporary geopolitical events eventually bring on more supply, with OPEC, the U.S. and Russia ramping up production and exports.

Yes, even Russia could ramp up production, despite the Ukrainian drone attacks on the country's oil infrastructure. After all, Russia continues to export huge volumes of oil and a fair amount of natural gas, so the attacks don't seem to have made a large impact on the country's production capabilities.

History shows that producers benefit the most from selling/hedging into geopolitical unrest rallies rather than remaining on the sidelines. Keep in mind that events like these cause the participating countries to suffer financially. This quickly places them in a dealmaking mode, so oil supplies soon return to the marketplace.

Although these current events–and the potential for heightened unrest–is deeply concerning on many levels, oil supply isn't necessarily one of them and any support to crude prices from these events usually is just temporary. OGI

California Mergin': CRC-Aera Combination Creates Golden State Scale

CRC President and CEO Francisco Leon believes the state needs to bolster its own oil and gas production—not all citizens and lawmakers agree.

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When referring to the U.S. Lower 48 oil and gas sector, industry insiders will sometimes call it "the Lower 47." They see no reason to include California in the mix.

Oil and gas producers have long lamented the Golden State's stringent operating regime and focus on climate progress. For a fossil fuel producer, the Golden State may look more like gilded brass once you start peeling back the layers.

Despite the state's bountiful onshore and offshore oil and gas reserves and relatively cheap conventional drilling costs, it's become increasingly difficult to obtain permits for drilling and recompletion projects in California.

Most of the big oil majors with footprints in the state, including Exxon Mobil, Shell and Occidental, have limited their exposure to California over time. Just this summer, California supermajor Chevron solidified plans to move its corporate headquarters from San Ramon to Houston.

In the late 1990s, Exxon and Shell merged their California assets through a joint venture named Aera Energy. Occidental's conventional and unconventional California assets were spun out into a separate publicly traded company, California Resources Corp. (CRC), in 2014.

But California Resources and the company's president and CEO, Francisco Leon, are still committed to making it work in the Golden State.

CRC closed a $1.1 billion combination with Aera Energy in July, cementing itself as California's top oil and gas producer.

The combined CRC still plans to run a one-rig program with the permits it already has in hand. But Leon envisions an eight-rig program operating across CRC's massive land position, spanning from northern California to the San Joaquin Basin in the Central Valley.

Q&A

Environmentally conscious residents might think differently, but California still needs domestic oil and gas producers like CRC, Leon argues.

California was the largest jet fuel consumer and second-largest motor gasoline consumer in the nation during 2023, according to U.S. Energy Information Administration data. It ranked third in crude oil refining capacity last year.

But California relies heavily on foreign oil imports to meet its needs. Over 60% of the crude oil supplied to California refineries in 2023 came from foreign sources.

"Once upon a time, we had 1 MMbbl/d produced in California, and it's shrinking."

FRANCISCO LEON, president and CEO, California Resources

California's top foreign suppliers in 2023 were Iraq (21.7%), Saudi Arabia (15.7%), Brazil (15%), Ecuador (14.6%) and Guyana (9.73%).

Just around 24% of crude oil supplies to California refineries last year were produced in the state. The remaining 16% came from Alaska.

California crude production averaged 285,000 bbl/d this June, according to the EIA. It's a far cry from the late 1980s, when California oil output averaged about 1 MMbbl/d.

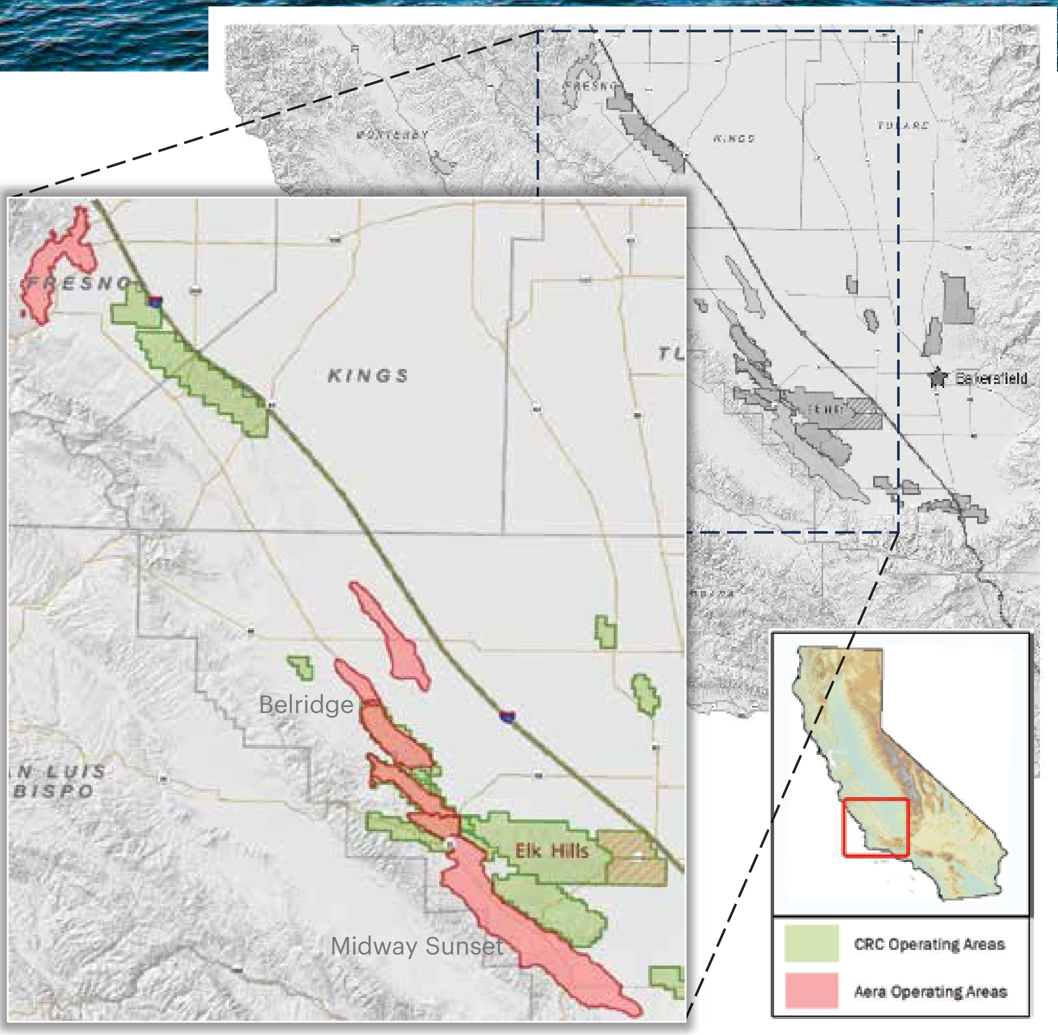
California residents and businesses also pay more for power than anywhere else in the Lower 48, according to EIA figures.

The nation's third-largest electricity consumer, California imports more electricity than any other state.

But Leon is hopeful that CRC and other California producers will be able to keep drilling to sustain—and ideally grow—output inside the state. CRC and other operators in Kern County are hopeful for a resolution in a years-long permitting battle with county and state regulators. Once that's resolved, he thinks CRC can get back to drilling and growing production. In California, that might be easier said than done.

Leon spoke with Chris Mathews, Oil and Gas Investor*'s senior editor for shale/A&D.*

▲ CRC operates the THUMS Islands assets in the East Wilmington Oil Field, just offshore Long Beach, Calif.



► CRC and Aera both hold large acreage positions in California's San Joaquin Basin, the heartbeat of the state's onshore oil and gas drilling activity.

SOURCE: CALIFORNIA RESOURCES CORP.

Chris Mathews: CRC recently closed a merger with fellow California producer Aera Energy. What do you see as some of the biggest needs for the deal, or the strategic rationale for coming together?

Francisco Leon: We see this as a transaction that's good for shareholders certainly, but also for California, and I'll explain. We're now the largest E&P company in the state by far. The state is a big energy consumer, but has chosen to satisfy the demand through imports, which is not good for environment consumers and even the state itself–they earn less taxes. So, we do feel this transaction is a win for everybody, and the assets are a very good fit.

California is mostly conventional–sandstones, big benches of very productive, very prolific rock. We haven't really had to go into shales, just because how the rock is so prolific. You have very few operators, and most of them are private. Aera has been privately run for 25 years through a combination of Exxon and Shell's portfolio. They formed a private company, put in a CEO that was a Shell representative and a CFO that was an Exxon representative, and they have had this very profitable partnership for many years. These are very well-run assets that you would expect coming from the legacy of two supermajors.

But the nice thing that was probably attractive to us and why I felt like this deal was always meant to happen is a lot of Aera's assets are adjacent and right next to our fields. The synergy potential from our operational sense is tremendous.

So, why did we do it now? Because we found a willing seller that we thought was reasonable in their price expectations. We did an all-stock deal at an attractive valuation to CRC shareholders. It's a unique deal in that it was accretive day one.

Ultimately, we're trying to build scale. I think we all recognize that bigger companies have a better trading multiple. You can attract more investors, and you have the benefits of cost of capital.

CM: Talk to me about drilling new wells, workover activities and managing your existing base in California. What do you find yourself doing day-to-day to maintain, or grow, production?

FL: Because we are conventional assets, we're not as drilling intensive. You have the benefit of very shallow declines. [For] Aera and CRC, on an average basis, the corporate decline of production is about 12.5%. That's your starting point, so you don't have to offset a lot of production. You're able to hang onto it.

The reason for that, again, is that these are very good rocks. Good permeability, good porosity, and you're able protect a lot of that production through injection–water injection, steam-flooding, sort of regular base-decline management. That's the nuts and bolts of the business.

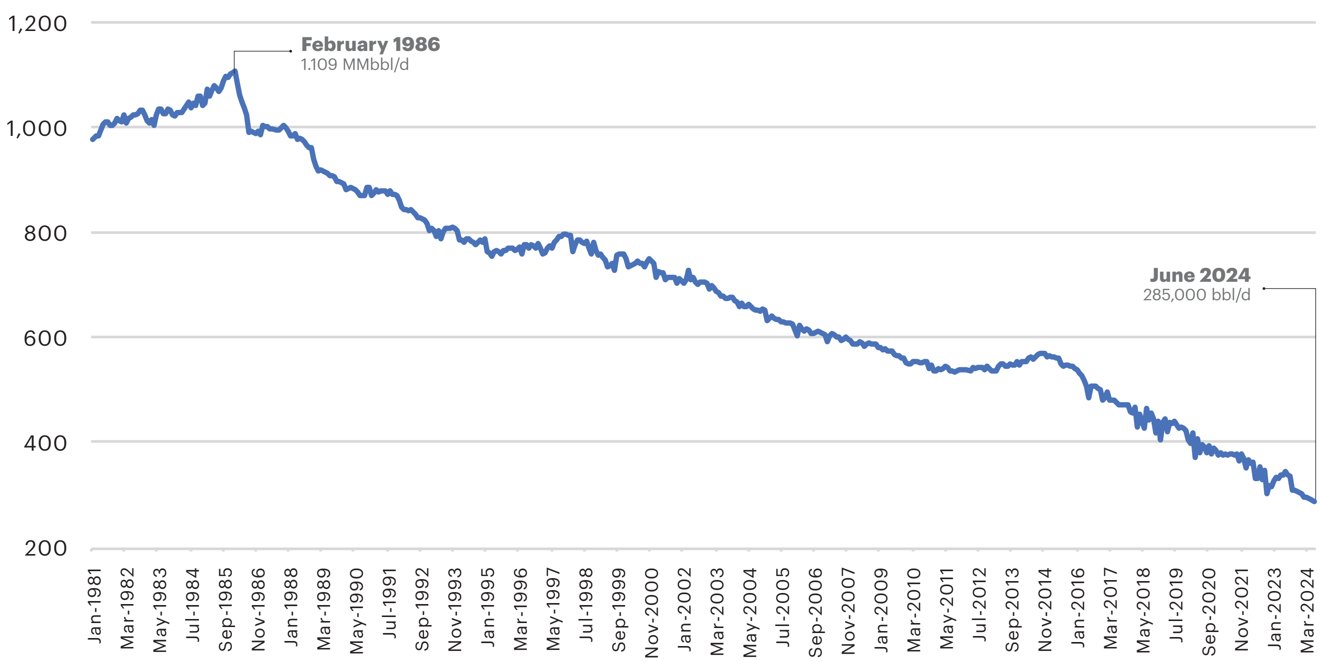
We do need new drilling–we cannot offset everything through the management of that. But, the first most cost-effective, highest-return activities are through capital workovers and sidetracks.

We have a lot of wellbores in the combined portfolio. We see wellbores as big assets that have multiple opportunities, multiple bites at the apple. Historically, California has been a lot of shallow drilling and a lot of vertical drilling. Oxy had been the company that really tested the deeper horizons, and what we inherited at CRC was a bit more focus on deeper drilling than peers.

That means our wellbores are going through multiple productive zones. For many reasons, the history has been to complete each zone at a time and to be somewhat conservative in the productivity of that wellbore.

As opposed to shale, which is about initial production and then you move on, the wells here are managed much more methodically over time. We have the opportunity to

California Field Production of Crude Oil
(monthly, Mbbl/d)



SOURCE: ENERGY INFORMATION ADMINISTRATION

A pumpjack operates in San Joaquin Valley, Calif. Approximately 73% of California Resources Corp.'s estimated proved reserves as of year-end 2023 are in the San Joaquin Basin.

CALIFORNIA RESOURCES CORP.

"The headwinds on permits are in Kern County and it's across the board to every operator. Aera has a tremendous inventory of new wells, but they don't have the permits on hand to execute it."

CALIFORNIA RESOURCES CORP.

go uphole, downhole, sidetrack existing wellbores. That second bite at the apple, if you will, is a very profitable next step forward.

We have a one-rig program. Basically, you can go from about 12.5% corporate decline to about roughly a 7% to 8% decline with workovers and sidetracks. So really, you're trying to offset the rest with new wells. That's where we see some of the headwinds in California.

CM: What are some of the permitting headwinds that CRC and other producers face in Kern County?

FL: It gets into very technical regulatory aspects of environmental impact reviews (EIRs). That's what's being challenged in court. At the end of the day, we see them as regulatory challenges that will be overcome.

This is not a political stance or anything, other than California has a lot of rules under something called the California Environmental Quality Act (CEQA). No matter what you're doing–real estate or drilling wells–you have to do EIRs on everything. That's where we're getting some headwinds to run through.

Right now, we are declining about 6% per year by not having the ability to drill new wells. That's also one of the reasons that prompted us to acquire Aera and grow more inorganically on a consolidated basis.

I don't think permitting is a long-term issue. I think it gets resolved this year. So, we'll go back to drilling. We want to get to about eight rigs combined to offset the combined company decline. It's very capital efficient and low-cost drilling. But, if there's an opportunity to acquire assets at the right price that are bolt-ons, we would also do that.

The headwinds on permits are in Kern County and it's across the board to every operator. Aera has a tremendous inventory of new wells, but they don't have the permits on hand to execute it. It's a potential down the road, but again, these assets are not declining very much. The focus in the near term is on synergy capture, which we think is going to be significant.

We don't see a line of sight this year to get back to permitting and then getting to the eight rigs that we want to do. But, what we have is an ability to grow cash flow per share. If you look back at the last three years from 2021 to 2023, even though we didn't have the full slate of permits and we declined production, we grew cash flow per share about 13% to 14% over that period.

With the Aera transaction, on a per share basis, now we more than double that amount. So, our focus is on cash flow. Production is critical–we do want to have production. We think it's the right thing for the state to have barrels that are operated by CRC and are going to be better than any alternative.

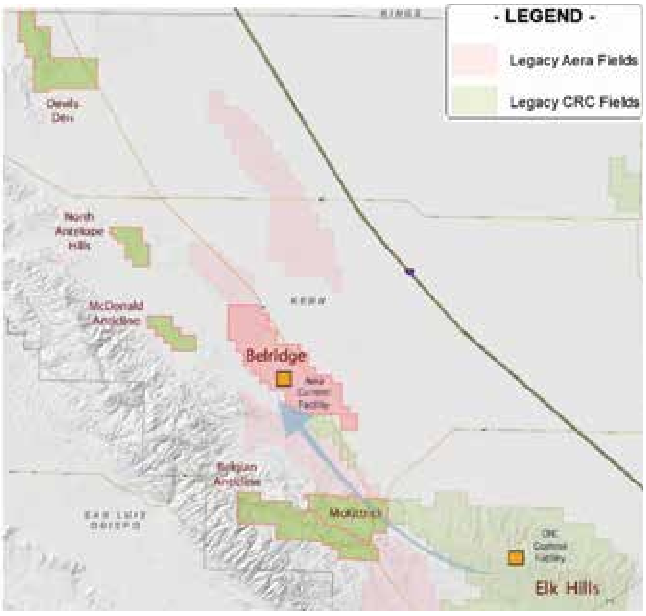
CM: Why is Kern County so important to California producers? Why not drill someplace else?

FL: Kern County is like the Permian for us. It's the heartbeat of the industry. It's where the most prolific fields are. It's where you have the right conditions away from any population centers.

Truly, some of the best fields in the U.S. are in Kern

CRC owns nearly all working, surface and mineral interest in the Elk Hills Field, the company's largest producing asset in the San Joaquin Basin.

CALIFORNIA RESOURCES CORP.



SOURCE: CALIFORNIA RESOURCES CORP.

CRC and Aera Energy each own massive swathes of land near one another in the prolific oil fields of Kern County, Calif.

County. Elk Hills is 47,000 acres. If you think about the size of that, it's like Washington, D.C. And it's a field that's owned 100% by CRC. It's fee simple–that means we own the surface and we own all the mineral rights of the entire field.

Aera owns the Belridge Field. That's actually bigger than Elk Hills and it's almost entirely held in fee simple, as well. These are billions of barrels of oil in place and these fields have been operated very safely for over 100 years.

If you think about California, it's Hollywood perhaps, or Silicon Valley. Well, the Central Valley is oil and gas and farming. A lot of the almonds, pistachios, carrots and strawberries that we consume nationally come from the Central Valley.

CM: Where does CRC-produced crude end up going?

FL: It's entirely for local consumption. I think California consumes 1.5 MMbbl/d. The local production is about 350,000 bbl/d of that, and all consumed within the state. Once upon a time, we had 1 MMbbl/d produced in California, and it's shrinking.

That's the problem. Some people feel like [production] needs to be coming down. Demand's not coming down. What's coming down is the local supply and then the backfill is imports. There's no change in the consumption of the product, but there is a change in how it's supplied.

So, we're going to foreign countries that don't have the world-leading safety, labor, human rights and environmental standards of California. You're bringing it from places where you have no control over.

What's shrinking is the one industry where you reap all the benefits. It's backwards. That's not the way it should be. We can decline production if it's a product that the world no longer needs. But we shouldn't be prioritizing imports versus local production. That makes no sense. OGI

Chevron's 'Remarkable' Permian Renaissance

The supermajor aims to grow its basin volumes past 1 MMboe/d in 2025—less than a decade after it averaged short of 100,000 boe/d.

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Chevron, which plans to pump 1 MMboe/d from its Permian Basin footprint by 2025, produced less than 100,000 boe/d on its legacy assets just a few years ago.

The meteoric production rise from the Permian has been "quite remarkable" to see, CEO Mike Wirth said in August at the EnerCom Denver conference.


Mike Wirth

"We don't have million-barrel-a-day assets," Wirth said. "Our big assets are a few hundred thousand barrels a day—and that's big by any standard."

In its pursuit of 1 MMboe/d, Chevron is chasing ways to boost resource recovery from its tight shale assets in the Permian Basin.

The supermajor has more than 2 million net acres in the Permian Basin, weighted more toward the Delaware Basin than the Midland Basin, Wirth said.

"[It's] legacy acreage that we've held for a long time—much of it we hold in fee," he said. "Virtually all of it has no royalty because we own the minerals on it, as well."

Relatively speaking, Chevron was late to the U.S. shale game. The company didn't have holdings in the earlier major shale plays, including the Williston Basin and Eagle Ford Shale.

Chevron did have assets in the Marcellus Shale, which it eventually sold to Appalachia gas giant EQT Corp. in 2020.

But the company began to develop its legacy holdings in the Permian Basin as horizontal drilling, hydraulic fracturing and U.S. unconventionals were proven out over time.

Chevron's Permian production averaged 880,000 boe/d during the second quarter. The company anticipates exiting this year at 940,000 boe/d.

By 2025, Chevron plans to boost Permian Basin output up above 1 MMboe/d.

Chevron is gathering field data to consider changes in well completion and fracturing techniques. The company is also piloting different chemicals and "using gas injection and gas lift in different ways" to improve flow in the Permian.

"We still leave a lot of the molecules behind with today's completion technologies," Wirth said. "We'd like to find ways to improve recovery and expect we will—we're working hard on that."

Rocky Mountain High

When Chevron acquired Noble Energy for $5 billion in 2020, the supermajor became acquainted with a new U.S. unconventional play: the Denver-Julesburg (D-J) Basin.

Entering Colorado was somewhat of a homecoming for Wirth, who grew up in the Denver area and graduated from Golden High School before attending the University of Colorado.

But Chevron itself didn't have first-hand experience drilling the D-J Basin when closing the Noble deal.

"As we gained experience, we really liked it—so much that we wanted to scale up in the D-J," Wirth said.

Chevron grew its Colorado footprint through a $6.3 billion acquisition of D-J producer PDC Energy last year.

Today, Chevron is the largest oil and gas producer in the state of Colorado, where output averages approximately 400,000 boe/d.

"Five years ago, we were not in the D-J," Wirth said. "It's one of the top assets by volume in our company now—tremendously important."

Chevron's pending acquisition of Hess Corp. would give Chevron a massive foothold in the Williston.

Hess produced an average of 212,000 boe/d from the Williston Basin in the second quarter.

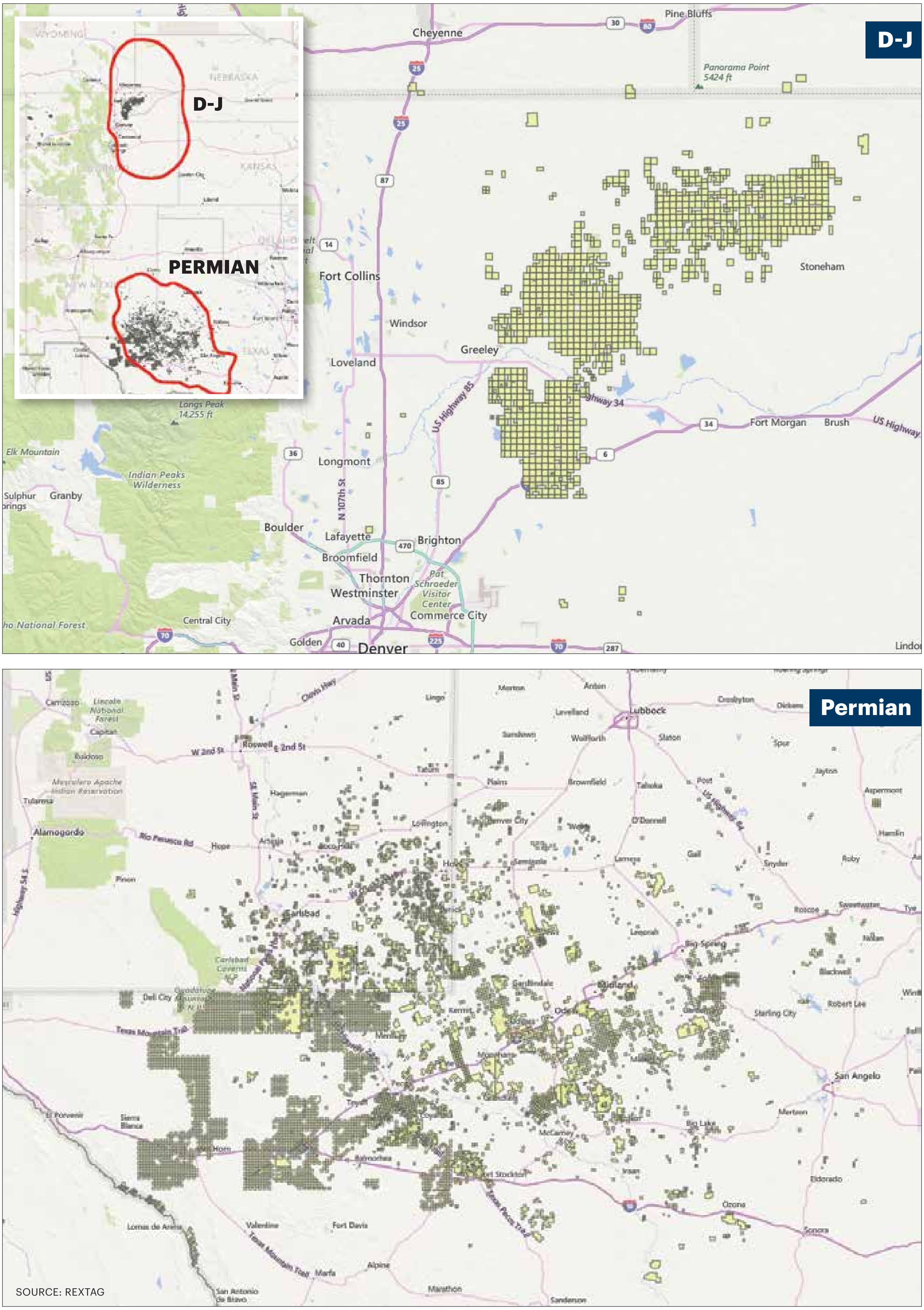
However, most of Hess' value is attributed to its non-operated position offshore Guyana—and the future of those offshore assets is uncertain.

Chevron has been working through the regulatory process to close the $53 billion Hess acquisition since the deal was announced in October 2023.

A Hess subsidiary, Hess Guyana Exploration, is currently in arbitration with respect to the right of first refusal in an agreement with Exxon Mobil and China National Offshore Oil Corp. regarding the Stabroek Block offshore Guyana.

But the pivotal arbitration hearing concerning Hess' position in Guyana won't take place until mid-2025. OGI

Chevron's Assets in the Permian, D-J Basins



SOURCE: REXTAG

Enterprise Expands Delaware Position With Piñon Purchase

The all-cash deal garners sizeable gas treatment facilities in the Permian Basin.

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Enterprise Products Partners purchased Delaware Basin-based Piñon Midstream for $950 million in a cash-only deal, the company said in late August.

With the acquisition, Enterprise gains control of a developing regional player in gas processing and sour gas disposal. In announcing the deal, Enterprise called Piñon's assets "highly complementary" to its midstream system, expanding the company's natural gas processing footprint with an entry point into the eastern flank of the Delaware.

"We believe the Piñon management team has developed the premier sour natural gas treating system in the Delaware Basin," said Jim Teague, co-CEO of Enterprise's general partner. "These assets accelerate our entry into this region by at least three or four years."

Both companies are based in Houston.

Piñon has been in a development cycle, and the company's assets have drawn interest from other companies. In June, oil producer Matador Resources bought a 19% stake in Piñon as part of an overall $1.9 billion acquisition of Delaware assets from portfolio company EnCap Investments.

The same month, Piñon announced the Environmental Protection Agency had approved plans to permanently store CO_2 in acid gas injection (AGI) wells at the company's primary facility in New Mexico. The approval satisfies a major requirement for 45Q tax credit eligibility, according to the Enterprise announcement.

Piñon's AGI system is the largest in the state and injects gas about 18,000 ft below the surface. The two gas wells are permitted for a total of 20 MMcf/d of CO_2 and hydrogen sulfide injection.

Enterprise said it was evaluating a third injection well as part of the acquisition.

The company's assets also include about 50 miles of natural gas gathering and redelivery pipelines, five three-stage compressor stations, 270 MMcf/d of hydrogen sulfide and CO_2 treating facilities.

Piñon is supported by fee-based contracts with long-term acreage dedications, including minimum volume commitments.

Teague said the acquisition would generate distributable cash flow accretion of $0.03/unit in 2025.

The companies expect the acquisition to be finalized by year-end 2024. Black Bay Energy Capital was a partner for Piñon during the process.

Piñon Midstream retained Piper Sandler & Co. as its financial adviser and Kirkland & Ellis as its legal adviser, while Locke Lord and Sidley Austin served as legal advisers to Enterprise during the process. OGI

Piñon Midstream's Assets in the Permian

SOURCE: PIÑON MIDSTREAM

Northwestern Movement

Canada's Completed Trans Mountain Expansion Pulling Crude Off of American-bound Pipelines

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Trans Mountain Pipeline traffic is moving a lot of crude out of Alberta, as signals indicate from both ends of the line.

At the Canadian line's terminus in Vancouver, British Columbia, tanker traffic has jumped from barely noticeable to constant, according to a professor emeritus from the local university.

David Huntley from Simon Fraser University monitors traffic in Vancouver's Burrard Inlet, according to the Canadian Broadcasting Co.

"It's a very sudden change, which, of course, is to be expected because there's an awful lot more oil (that) can be sent down the pipe," Huntley said.

Trans Mountain completed work on the company's namesake pipeline expansion on May 1. It was the end of a difficult and controversial pipeline project that started development in the 2010s under Kinder Morgan.

The Canadian government eventually bought the project and established Trans Mountain as a Crown corporation, meaning that it was owned by the government but acted as an independent business, and would eventually be sold by the government.

The project almost tripled the pipeline's capacity from 300,000 bbl/d to 890,000 bbl/d, greatly expanding crude egress out of Alberta.

Delays and cost overruns plagued the project, eventually costing CA$34 billion (US$25 billion). However, the pipeline has been full since ramping up to capacity, according to Trans Mountain.

The first tanker loaded the first cargo from the completed pipeline on May 21. By the end of August, TMX reported that more than 65 oil tankers had taken a load from the expanded pipeline. Ship traffic in Vancouver's Burrard Inlet has risen from two a month to more than 20 during the same time span, Huntley said.

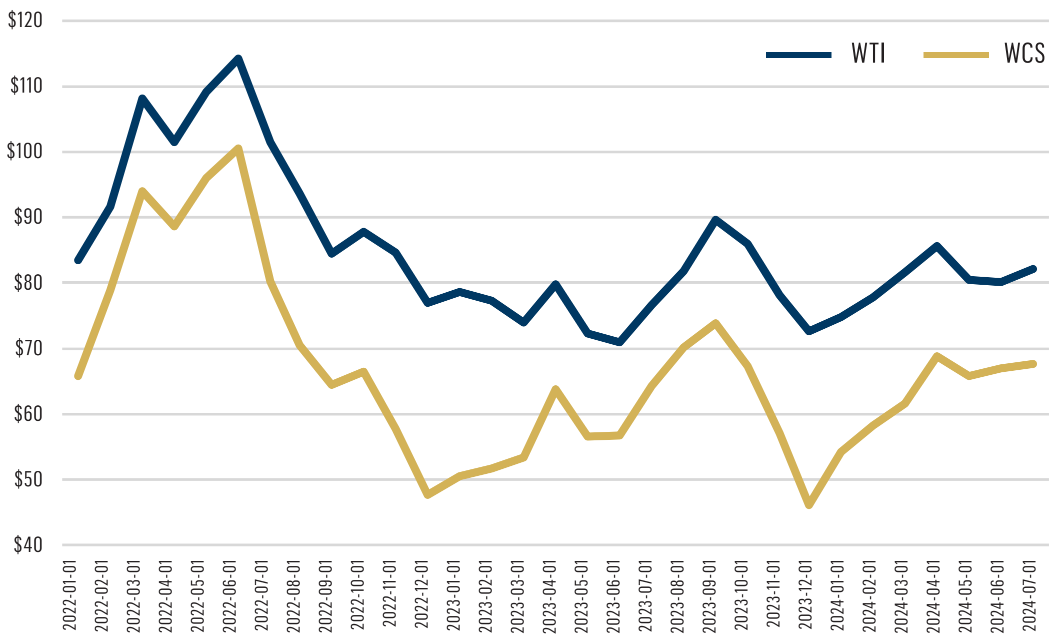
The Canadian government is still determining how and when to sell the pipeline. Trans Mountain is already planning to give First Nations along the pipeline's path a 30% stake in the pipeline, the company announced in May. At the end of July, Bloomberg reported that, as the pipeline is still a political issue, the sale of TMX will most likely not occur until after the next Canadian national election in 2025.

North/South Traffic

In Alberta, the line rapidly affected toll rates after operations began.

Enbridge's Mainline, the largest crude oil egress out of Canada into the U.S., began lowering spot rates in joint tariffs on Sept. 1, East Daley Analytics reported, an acknowledgment that the TMX is providing

Western Canada Select vs. WTI ($US)

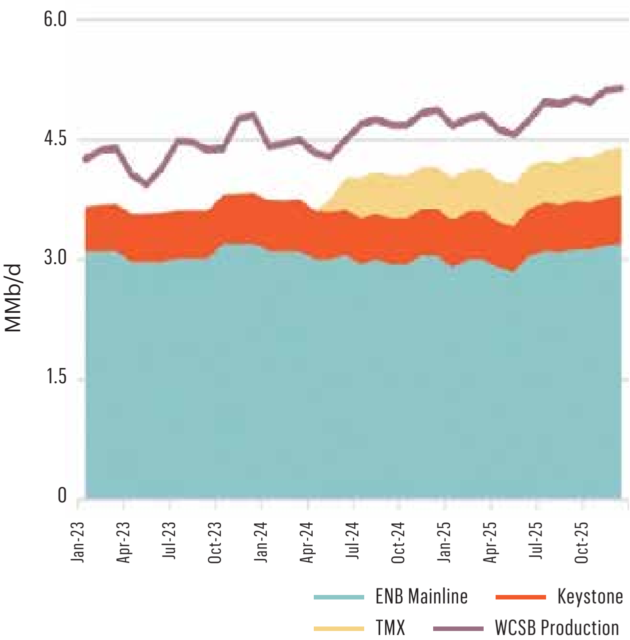


SOURCE: GOVERNMENT OF ALBERTA

Trans Mountain Expansion Project Configuration Map

SOURCE: TRANS MOUNTAIN PIPELINE

Canadian Oil Pipeline Egress



SOURCE: GOVERNMENT OF ALBERTA

more competition for Mainline's customers.

"The Mainline has been running effectively full, and the lower uncommitted joint rates will help keep throughput high," wrote analyst Gage Dwan. Enbridge's Mainline can carry 3.2 MMbbl/d from Canada to the U.S. Midwest.

Spot rates are market prices as determined between suppliers and midstream companies to ship a load of oil in bulk. The new rates only apply to joint services with downstream pipes and do not affect Mainline tolls from Alberta to Chicago.

According to East Daley's pipeline traffic monitors, uncommitted heavy crude tolls decreased for joint tariffs with the Flanagan South and Seaway pipelines, and Enbridge has cut heavy crude spot rates in the joint tariffs from Edmonton, Alberta, to Houston by more than a $1/bbl, from $10.9319/bbl to $9.8380/bbl.

"East Daley Analytics anticipates softer earnings ahead for ENB's largest asset," Dwan said.

TC Energy's Keystone Pipeline is another competitor to Trans Mountain. However, the line currently is fully utilized and 94% contracted. The line moved an average of 637,000 bbl/d in the first quarter. The company offers a market-low committed heavy crude rate of $2.508/bbl.

"Keystone throughput is likely to see little impact from TMX and the lower Mainline joint rates," Dwan said.

The* Garibaldi Spirit *crude tanker was one of 65 to load oil by the end of August at Trans Mountain Pipeline's Westridge Marine Terminal at the Port of Vancouver.

TRANS MOUNTAIN PIPELINE

Further downstream, pipes like MPLX's Capline, a major carrier for Canadian heavy crude, will transport more light crude from the Bakken Shale in North Dakota to offset the loss of Canadian heavy grades, analysts said.

For now, the government-owned TMX and other midstream companies will continue to fight over heavy Canadian barrels.

TMX, with minimum volume commitments totaling 525,000 bbl/d, is handling primarily heavy sour crude with some batching of synethic crude, according to EDA.

Tolls for TMX have not been finalized. The Canadian Energy Regulator is responsible for approving tolls. The current benchmark toll for shippers with a 15-year contract transporting less than 75,000 bbl/d from Edmonton to Burnaby is $11.46/bbl. The fixed rate is lower than the uncommitted joint tariff on Mainline to the Gulf Coast, making it a more attractive egress route for Canadian producers.

Looking East

The low rates also make the TMX attractive to the customers at the other end of the line, especially in Asia.

It was a "game changer" when Canada opened its export terminal on its West Coast, said Wu Qiunan, chief economist of PetroChina International at the S&P Global Commodity Insights' APPEC event in September. The transport from Vancouver to Asia is 19 days, as opposed to the more than 45 days it can take for crude loaded from the Gulf to arrive in China.

More Canadian crude could make its way to Asia, Wu said. The voyage from Canada is also competitive to the Middle East, taking about the same amount of time.

Crude exports from Canada to Asia rose by 240,000 bbl/d in July. China took 75% of the volume, while the remainder went to India, according to S&P. The previous high of 57,000 bbl/d was in June 2020.

"It is a very good option for Asia to receive more from Canada," Wu said.

Reality Sets In

The cheaper toll rates on the TMX are not likely to last.

The lengthy delays and cost overruns during construction are expected to eventually increase tolls, several analysts said.

According to the CBC, each individual Canadian subsidized the project at a rate of CA$850 (US$625). Eventually the debt will need to be repaid.

One disappointment for Canadian analysts has been the price of crude.

The expansion was meant to shrink the discount on Canadian oil versus U.S. crude. As of August, the differential had widened since start-up in May, Reuters reported.

Many analysts had forecast the differential on Western Canada Select (WCS) versus U.S. crude would gradually narrow to single digits thanks to the extra 590,000 bbl/d of export capacity offered by TMX.

But in August, WCS for delivery in Hardisty, Alberta, was $15/bbl below WTI. In May, the differential was $11.75/bbl below WTI. The primary long-term advantage of the expansion will be the ability of Canadian producers to worry less about "blow-outs," times when the egress out of Alberta is so full that the prices to a major discount against WTI, according to analysts.

Growth Overcomes

Analysts predict that TMX's pull from other pipelines would be a short-term situation. Volumes on rival pipelines are likely to pick up as Canadian oil output is expected to grow rapidly.

Output will rise about 500,000 bbl/d in 2025 from 2023, offsetting the additional capacity added by TMX, said Kristy Oleszek, director of energy analytics at East Daley.

Excess pipeline space will be filled relatively soon, Oleszek said. OGI

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Analysts: Midstream MLPs Outperforming S&P in 2024

The midstream sector has been able to take advantage as capex spending slows and cash flows increase.

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The midstream sector has been outperforming the energy sector as a whole in 2024, continuing its role as a stable niche for investors. That's due to companies by and large exercising capital discipline as cash flows increased, analysts said during an August seminar.

"If you look at the S&P 500 and break it down by sector, the energy sector is lagging the S&P, year to date," said Paul Baiocchi, chief exchange-traded fund strategist at SS&C ALPS Advisors. "But midstream, and especially midstream MLPs, are actually outperforming the S&P."

The total return of the midstream sector relative to the S&P 100 has been 19.9%, year-to-date, according to VettaFi. Baiocchi said that different economic factors are in play in different sectors of the energy industry.

"Despite the fact that we are at record levels of production in the United States for things like crude oil, natural gas and natural gas liquids, the macro environment is very much as uncertain as it's been over the course of the current decade," he said.

Several of the U.S. oil and gas industry's high-consumption customers, such as China, may be facing a recession. Analysts are also uncertain about OPEC's commitment to keep production rates low to maintain crude oil prices of more than $70/bbl.

The natural gas market expects to see a massive jump in demand with increased LNG exports and a developing power-hungry artificial intelligence data sector, but Henry Hub prices have stagnated at under $2.50/MMBtu for most of 2024. However, the U.S. Energy Information Administration said in August that a ramp-up of LNG exports from new facilities in Texas and Louisiana "will push the Henry Hub price to average about $3.10/MMBtu from November through March."

Large midstream companies, primarily dependent on a fee-based revenue model, aren't as susceptible to commodity price swings. Generally, midstream companies are paid at a steady rate for the molecules passing through their networks. Recently, the business model has allowed midstream companies to build up cash reserves.

The sector is in a different position than it was in the 2010s. According to an S&P report at the end of the decade, midstream companies had amassed massive amounts of debt, thanks to an infrastructure buildout required to keep up with a booming oil and gas sector. The large-scale buildouts slowed as the decade ended, and the sector began a general recovery.

Midstream companies began generating surplus free cash flow in 2020, said Stacey Morris, head of energy research at VettaFi.

"Now, the companies are very well positioned to return that excess cash to shareholders," primarily through dividends and buybacks," Morris said.

VettaFi reported that 94% of the companies in the Alerian Energy Infrastructure Exchange-Traded Fund, which focuses on the midstream sector, had increased their dividends year-over-year.

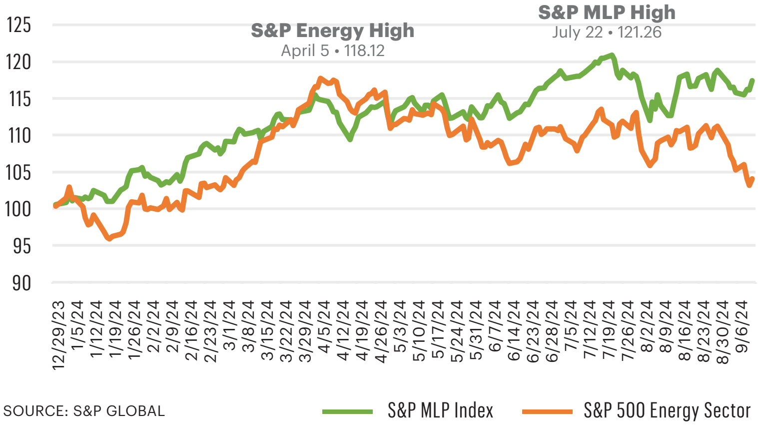
After the second quarter, several midstream companies either raised their guidance or reported that they were close to the top half of their estimates for the year, she noted. For example, Energy Transfer raised its full-year EBITDA guiding by $300 million when it released its projections on Aug. 7. For the second quarter, the company reported net income of $1.31 billion and adjusted EBITDA of $3.76 billion.

Morris said the trends should hold steady for now.

"Investors who are maybe looking at the space wondering if it's run too much, if they're late to the party, ... this is not a space where evaluations have become overextended or where things are looking particularly expensive," she said. OGI

MLPs vs. Energy as a Whole

Comparison of the S&P MLP Index and the S&P 500 Energy Sector Index, Dec. 29, 2023 to Sept. 12, 2024. Baseline = 100



SOURCE: S&P GLOBAL

Segrist: An Underground Battle Over Pipeline Safety Rules

A 13-year process between the federal government and the midstream industry grinds to a finish, at least for now

BROCKEN INAGLORY VIA WIKIMEDIA COMMONS

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The federal government and a midstream organization spent years battling over rules that would have changed the way every natural gas pipeline in the U.S. is maintained and operated, with potentially billions in company budgets on the line.

But when the fight ended with a court ruling in August, there was little to mark the conclusion of a massive U.S. Department of Transportation (DOT) undertaking to examine and rewrite the rules governing pipeline safety standards. Which means it's possible that the process will continue.

There are roughly 2.7 million miles of natural gas gathering, distribution and transmission lines in the U.S., all of them regulated by local, state and federal agencies, including the Pipeline and Hazardous Materials Safety Administration (PHMSA), a division of the DOT.

PHMSA published a long list of new safety standards in July 2022. It was the end of a process that, like other reform efforts, began with a disaster.

On Sept. 9, 2010, a 30-inch-diameter natural gas pipeline in San Bruno, Calif., ruptured and exploded, killing eight people, injuring 66 and destroying or damaging more than 100 homes.

It took the pipeline's operator, Pacific Gas and Electric (PG&E) 95 minutes to shut off the flow. Five years later, PG&E agreed to pay a $300 million fine levied by the California Public Utilities Commission.

A nationwide review of the pipeline safety regulations was underway by 2011, mandated by Congress. Updating rules that were decades old was a monumental effort between the government and the midstream sector, according to the Interstate Natural Gas Association of America (INGAA), an industry group.

PHMSA and INGAA worked on a back-and-forth process that went well into the next decade. In 2016, both INGAA and API criticized the new rules that were taking shape. The organizations claimed PHMSA had both badly underestimated the compliance cost and overestimated the benefits of the new regulations.

The complaint would be repeated.

In 2022, PHMSA published its "final rule" that consisted of hundreds of highly technical regulations and requirements. While the government had worked with industry groups throughout the process, INGAA and its supporters considered five new rules as overreaching and unfair and petitioned the U.S. Court of Appeals, D.C. Circuit for relief.

The court struck four of the rules, agreeing

Damage after a natural gas pipeline in San Bruno, Calif., ruptured and exploded on Sept. 9, 2010. The explosion killed eight people, injured 66 and destroyed or damaged more than 100 homes.

BROCKEN INAGLORY VIA WIKIMEDIA COMMONS

with INGAA that PHMSA had not provided an adequate cost-benefit analysis proving the new regulations were worth the effort.

"For one rule, PHMSA failed to analyze the costs of implementing it altogether," noted RBN analyst Sheela Tobben in a look at the ruling.

Law firm K&L Gates gave a detailed breakdown of the disputed rules. The court ruled that PHMSA failed to give a proper cost-benefit analysis for standards involving pipe welds, cracks, dents and corrosion.

INGAA had especially fought the new crack standard.

Cracks in a pipeline can cause failures. PHMSA sought to raise the standard of when a crack must be immediately repaired, as opposed to monitored.

"The court rejected PHMSA's arguments that the standard was necessary for safety and that it was not obligated to consider these impacts separately, concluding that the standard must be vacated because of PHMSA's failure to provide a reasoned cost-benefit analysis for the standard," Gates wrote in the analysis.

The court also took PHMSA to task for contradictory language in the proposed rules regarding corrosion standards, when the agency stated that compliance would both add costs and not add costs.

"We thus cannot discern the agency's reasoning: Does the standard impose no costs at all or does it impose some costs that cannot be calculated?" the appeals court wrote in its appeal. "The agency's explanation contradicts itself and thus fails to meet the requirement of a reasoned cost-benefit analysis."

Starting Over

After the ruling, INGAA released a statement to *Oil and Gas Investor* praising the decision.

"INGAA is pleased with the outcome of this case. We look forward to working with PHMSA on continuing our efforts to improve pipeline safety, building upon the alternatives we proposed throughout the rulemaking process," said Ben Kochman, INGAA's director of pipeline safety policy.

Though the rulemaking process may eventually grind on, the next move will be PHMSA's. The agency must decide whether to restart the rules-making process over the four rules the court invalidated.

Analysts noted that the process would not last as long for the next round if PHMSA only focuses on the four regulations, as opposed to the entire natural gas safety code.

"We expect that PHMSA will make another attempt to advance these now-vacated regulations, as the agency views them as critical to pipeline safety," Gates wrote. "The agency will need to provide a clear statement of the cost-benefit analysis for each regulation to cure the errors highlighted by the D.C. Circuit."

Other organizations called for a better, more efficient rule-making process overall. Twelve years was too long, the GPA Midstream Association said in a statement.

"Operators have demonstrated the ability to manage risk with far more precise systems and technologies than what existed when the code was initially passed more than 50 years ago," the group wrote. OGI

Howard: The Making of a Tulsa King

ONEOK's M&A binge has propelled it near the top of the sector.

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.

In this column over the summer, I outlined how conditions were favorable for dealmaking in midstream. Those conditions produced several deals since then, and while those conditions remain in place, there are fewer deals to do.

That's because there are fewer companies left to buy each time a company gets bought, and there aren't new companies being formed. ONEOK announced the latest major acquisition, the control stake in EnLink Midstream in a $3.3 billion cash transaction.

When the transaction with EnLink closes, ONEOK will have been responsible for elimination of two of those companies in the last two years. After the Magellan Midstream Partners and EnLink acquisitions, ONEOK will have doubled its EBITDA through M&A in just a few years. The dynamics of less competition for big M&A than in the past, combined with industrial logic and big (but tangible) synergies allow for these larger deals to add value in a sector where big M&A has often been value destructive.

Sector Impact

This latest ONEOK deal has several broader sector implications near-term, including:

- **Deal takes ONEOK out of the market for a time.** ONEOK will be busy for a while closing this acquisition, integrating the assets and realizing synergies. That will keep the company too busy to be an acquirer of other companies that investors have speculated are targets, most notably Plains All American and Kinetik.
- **Market reaction could encourage more M&A.** ONEOK traded up on the day the EnLink transaction was announced. The simple reaction to that might be that the market investors are OK with delaying buybacks and dividend acceleration that has been promised if a company would rather opt for M&A. But the positive reaction was due to the nuances of this particular transaction. If the M&A is strategic enough, i.e., has big synergies, is struck at a reasonable valuation and does not come with equity overhang (ONEOK paid cash for the GIP units), then the market reaction should be positive. That combination of factors is hard to replicate, but I still think other potential acquirers took notice that the market is not automatically opposed to big deals.
- **Scarcity of remaining players supports valuations.** With fewer midstream companies left, investors will spread capital across the remaining names, supporting stock prices across the sector. Investors with dedicated midstream portfolios who may have owned ONEOK and EnLink will now probably look to upweight other midstream names with similar assets. Maybe to the benefit of mid-cap names that are not already full positions. Names like Targa Resources, Kinetik, Western Midstream and DT Midstream, which are also among the names that are speculated takeout candidates. A corollary on the scarcity value impact is that this transaction will eventually remove another name from the Alerian MLP Index, which will jack up weights of the remaining constituents, leading to a technical index version of scarcity value to the benefit of other names not already capped in that index.

Universe Update: Smaller, More Corpy

Viewed through the wider lens of the last decade, this is just another data point on the trend line of rationalization and consolidation of midstream companies into a few dominant players. That consolidation has transformed the sector, and the numbers highlight how dramatic that transformation has been when you add up all the data points.

Assuming the eventual full takeout of EnLink, the overall universe of publicly traded midstream corporations in North America stands at 29, including 23 that are greater than $2 billion in market capitalization.

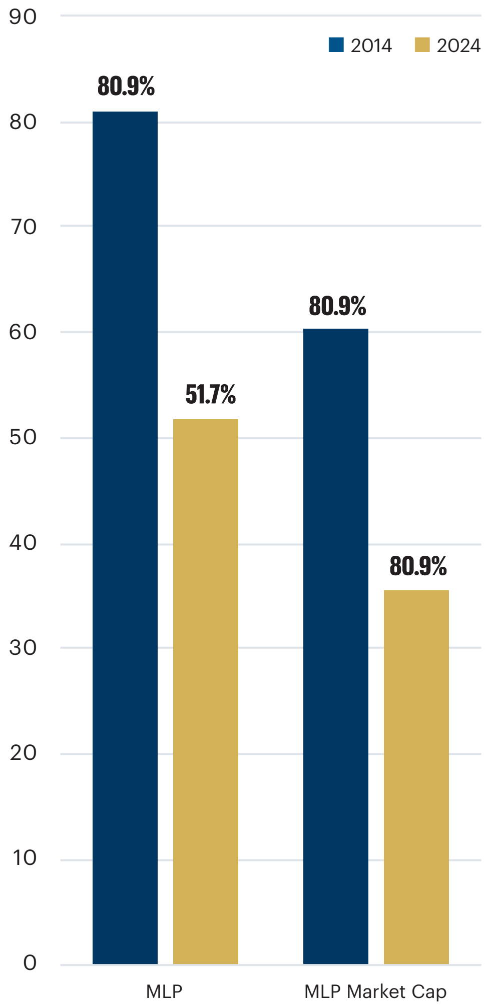
The five largest of those names make up almost 50% of the overall market capitalization of the universe, up from 28% in 2014. The consolidation continues, leading to fewer, larger companies with massive footprints.

Before the year is out, there will be a new company formed when South Bow spins out of TC Energy, but it still feels like the total number of companies will continue to go down for another few years.

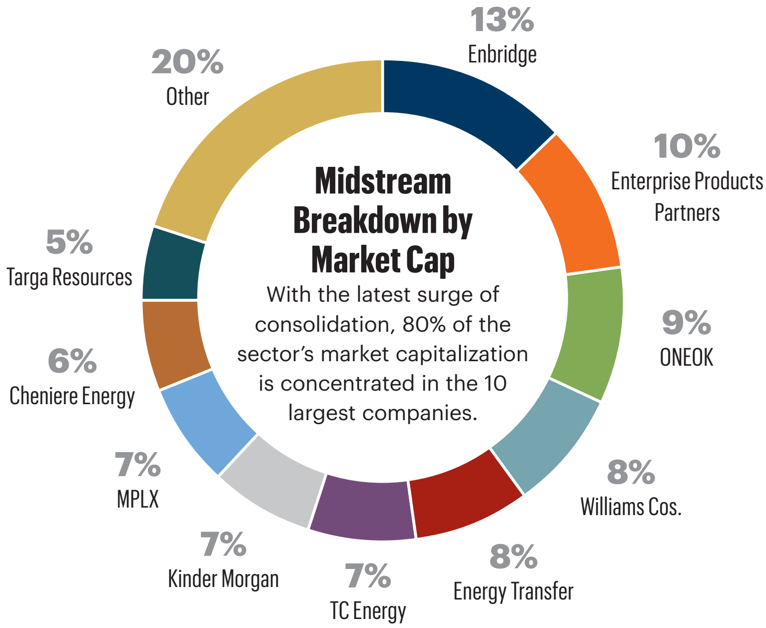
The 10-year rotation from MLPs has left the MLP structure with just 35.5% of the

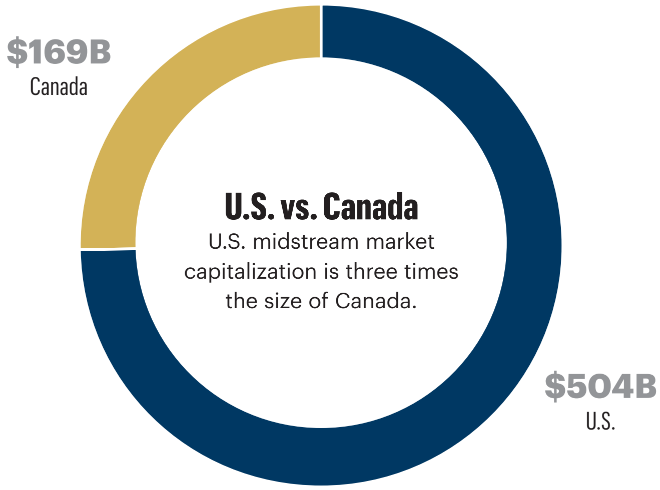
The MLP Trend

The MLP share of the midstream universe has declined in the U.S. and Canada, both in number and market cap.



SOURCE: HINDS HOWARD





market capitalization universe. This latest deal did not remove an MLP from the universe, but in updating the universe, the big shift over the last decade stood out.

New King of Tulsa

One more thing to note: After this deal, ONEOK will be the third-largest midstream company across the U.S. and Canada by market capitalization. It will be $12 billion larger than Kinder Morgan, and it will trail only Enbridge and Enterprise Products Partners. ONEOK is now larger than its local peer Williams Cos. and is therefore the largest midstream company in Oklahoma.

ONEOK being the consolidator of choice has been a surprising turn in the last few years. And the market seems to be more willing to support deals by ONEOK after it has so far produced on the synergies promised in the Magellan deal. But with ONEOK sidelined for a spell, it will be interesting to see who steps up to the plate next.

Early in September, reports surfaced (and were later refuted) that Williams had approached Targa Resources about a possible merger. Clearly, Williams would like the chance to take back the Tulsa crown.

But other big energy players like Kinder Morgan, Enbridge, Phillips 66 and Energy Transfer could also emerge as the next buyer. Enterprise, Pembina Pipeline and MPLX seem less likely to pursue strategic M&A, but they are probably still looking at deals.

As to who is left, there are a few that get mentioned most often: Kinetik and Plains All American Pipeline. But others like Western Gas and DT Midstream could make sense, or even Gibson Energy and Keyera up in Canada. Anything is fair game at this point. However, names like Targa, Antero Midstream and Hess Midstream seem less likely, each for their own company-specific reasons.

There are still more cost synergies to wring out from this sector, which may mean fewer executive seats available in this industry. The bloat of the 2000s and early 2010s has taken a long time to cut away, but the surviving empires will be stronger than ever, with huge barriers to entry.

For customers of these major midstream companies, it may mean less negotiating power on rates for services in the future. For investors, it should mean greater returns over time. OGI

Montney Production Set to Grow, U.S. Cos. Seize Opportunities

Canada's Montney Shale play has already attracted U.S. companies Ovintiv, Murphy and ConocoPhillips while others, including private equity firms, continue to weigh their options.

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Three American companies—ConocoPhillips, Ovintiv and Murphy Oil—are currently entrenched in Canada's Montney Shale. And with good reason as they continue to carry over the U.S. shale boom to north of the border.

The Montney boasts double-digit IRRs and Tier 1 acreage with a longer inventory lifespan than the Permian Basin due to lower activity levels than the extremely busy West Texas play. And new export infrastructure projects offer market diversity for varied products coming out of Montney.

In the Western Canada Sedimentary Basin (WCSB), the Montney is primarily a condensate-rich natural gas play in northwest Alberta and northeast British Columbia (BC). The play offers both a scaled and developmental runway, and provides a one-stop shop with multiple product optionality: gas, oil and condensate.

The Montney is one of the largest unconventional deposits in North America and has long been a mainstay for Canadian players. The play is highly concentrated with the top five producers—Calgary's ARC Resources and Tourmaline Oil, Ovintiv, Canadian Natural Resources and Malaysia's Petronas, in that order—controlling 59% of the oil and gas production in 2024, according to Wood Mackenzie.

Tourmaline's interest in the Montney centers around economics and resources, while, for Ovintiv, it's about inventory and returns.

"There has been increased interest in the Montney due to its strong economics and resource depth; newly relevant as many U.S. basins are starting to struggle from a supply-cost perspective and are running out of Tier 1 inventory," a spokesperson with Tourmaline told *Oil and Gas Investor (OGI)*.

"Ovintiv has significant scale in the play with over a decade of premium condensate inventory, and well over two decades of premium gas inventory," Ovintiv told *OGI*. "Our returns in the play are competitive with the top basins in North America, driven by superior well productivity, low drilling and completions costs, competitive royalty rates and strong price realizations."

As Permian acquisitions have grown more expensive, dealmaking has started to move farther north to the emerging Uinta Basin, the more mature Bakken Shale and the Montney, said Mark Oberstoetter, head

The largest Montney producer and the third-largest gas producer in Canada at 1.3 Bcf/day, ARC Resources is continuing to invest in the play.

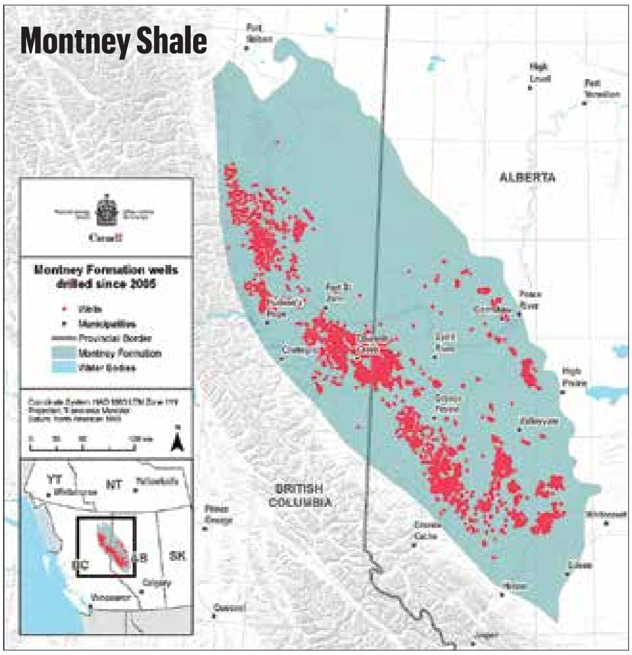
ARC RESOURCES

LNG Canada construction activities in August. New LNG projects coming online, including LNG Canada, provide much-needed additional egress options for Canadian LNG export, and increases investment opportunities in the Montney Shale.

LNG CANADA

"We're not shocked by the interest from U.S. companies just kind of checking things out. That said, those rumors have been spinning for two years now and no one's pulled the trigger yet. So, more consolidations? That's likely, but … it's not going to be a bonanza by any means."

MARK OBERSTOETTER, head of Americas (non-Lower 48) upstream research, Wood Mackenzie



SOURCE: NATIONAL ENERGY BOARD OF CANADA

of Americas (non-Lower 48) upstream research at Wood Mackenzie.

Despite the national boundary, more U.S. companies and investors are again eying the Montney, which is very established, has high-growth potential and strong economics, Oberstoetter told *OGI*.

The Montney has around 170 Tcf in the ground. In the past 10 years, the play has spiked to emerge with the dominant share of Canada's supply. Montney's production is just below 10 Bcf/d and represents 54.3% of the estimated 18.4 Bcf/d of WCSB gas supply, he said.

Wood Mackenzie expects Montney's gas production to exceed 10 Bcf/d by year-end 2024 and grow to 15.4 Bcf/d by 2030. By then, the Montney will represent 65.7% of the WCSB supply, which is projected to reach 23.4 Bcf/d in 2030.

The liquids-rich Montney regions rank among the top North American plays, with a sub-$45/bbl (or $2.25/Mcf) breakeven, according to Enverus Intelligence Research (EIR) analysts Tucker Keren and Jared Kugler.

"With about one-third the number of wells put on production each year as the Permian plays, the Montney has a long runway if activity levels hold," Keren and

“The expansion of TMX has certainly helped in terms of both increasing the volume of exports that are possible just simply on a raw numbers’ basis, but also allowing more access to a global market and global pricing.”

ROBERT FROEHLICH, partner, Norton Rose Fulbright

Kugler said. “Permian plays still hold the most remaining Tier 1 and 2 locations, but the Montney has a longer lifespan of Tier 1 and 2 sticks due to less activity in the play.”

Regarding increasing noise of private equity firms seeking M&A opportunities in Canada, Oberstoetter said a previous push didn’t work out well because it coincided with low prices at the Alberta Energy Co. (AECO) hub. AECO is the Canadian benchmark price in southern Alberta. Oberstoetter said U.S. companies continue to look at Canada for potential acquisitions, but most of the M&A activity remains dominated by the Canadians.

“You’re still dealing with a [Justin] Trudeau government regulatory uncertainty. So, there’s a lot of reasons not to pull the trigger, too. Maybe a Canadian consolidation might continue,” Oberstoetter said. “We’re not shocked by the interest from U.S. companies just kind of checking things out.

“That said, those rumors have been spinning for two years now and no one’s pulled the trigger yet. So, more consolidations? That’s likely, but … it’s not going to be a bonanza by any means.”

Ovintiv: Seeing Top Drilling and Completions Metrics

The Montney has been an anchor asset in Denver-based Ovintiv’s (and its predecessors’) portfolios for more than 20 years. There, the company’s acreage at year-end 2023 was 811,000 net acres and 441,000 net undeveloped acres.

“Ovintiv has significant scale in the [Montney] play with over a decade of premium condensate inventory and well over two decades of premium gas inventory,” a spokesperson with the company told *OGI*. “Our returns in the play are competitive with the top basins in North America, driven by superior well productivity, low drilling and completions costs, competitive royalty rates and strong price realizations.”

Ovintiv’s combined oil and gas flows from the Montney in 2024 represent around 13% of the play’s total. The Montney represented 42% of Ovintiv’s second-quarter 2024 production, according to data compiled by *OGI*.

Ovintiv’s average production in Montney was 251,000 boe/d in the second quarter 2024. Its Montney capex will range between $425 million and $475 million in 2024 to bring on 60 to 70 net wells, the company said.

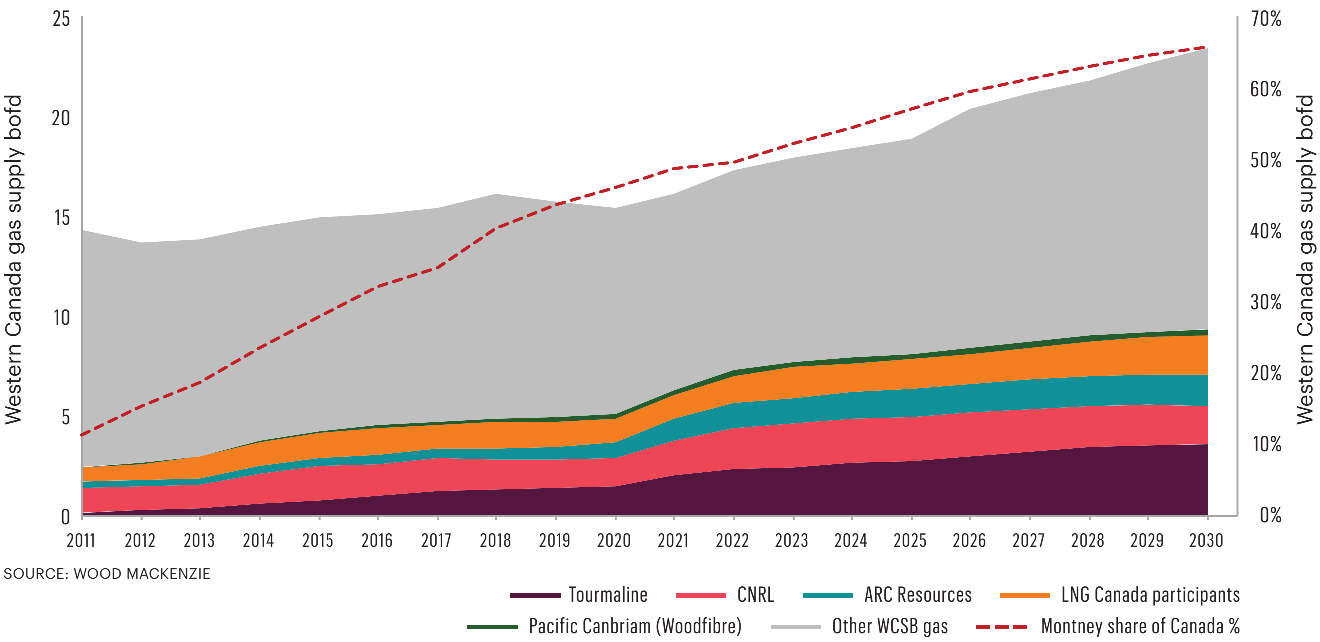
Ovintiv will continue to allocate capital to its Montney window as the fundamentals for condensate as a premium product remain intact, Ovintiv CEO Brendan McCracken said during the company’s second-quarter analyst call.

McCracken cited the startup of the Trans Mountain Expansion (TMX) pipeline as “being an incremental tailwind to those fundamentals.” He said he sees the need for significant condensate imports into Western Canada to supply demand for diluents from oil sands producers.

Murphy: Recognizing Size of Its Resource Base

Houston-based Murphy’s Tupper Montney acreage is located in the WCSB in BC. There, Murphy has 118,235 net

Canada Gas Top Producers



SOURCE: WOOD MACKENZIE

acres while boasting inter-well spacing of 984 ft-1,323 ft and 976 gross remaining locations.

Murphy's combined oil and gas flows from the Montney in 2024 represent about 4% of the play's total. The Montney represented 38% of Murphy's second-quarter production, according to data compiled by *OGI*. The Tupper Montney has 50 years of inventory, Murphy said in a second quarter 2024 presentation. And Murphy expects production in Tupper Montney to average 70,000 boe/d in the third quarter.

"We continue seeing great well performance from our optimized completion design; in particular, our average [30-day initial production] rate in our Tupper Main area has increased approximately 120% since 2019, and more than 200% since 2016," Murphy President and COO Eric Hambly said during the company's second quarter analyst call.

Hambly said Murphy recognizes the size of its resource base and the remaining decades of gas it contains. Hambly said Murphy potentially could participate in the LNG space by selling its gas to some potential partners that are involved in the LNG Canada Phase 2 project.

ConocoPhillips: Modest Production Growth Expected

Houston-based ConocoPhillips had 297,000 net acres of land in the Montney at year-end 2023.

Last year, ConocoPhillips progressed early development and appraisal activities and completed construction of the second phase of its Canadian central processing facility (CPF2). The facility started up in the third-quarter 2023.

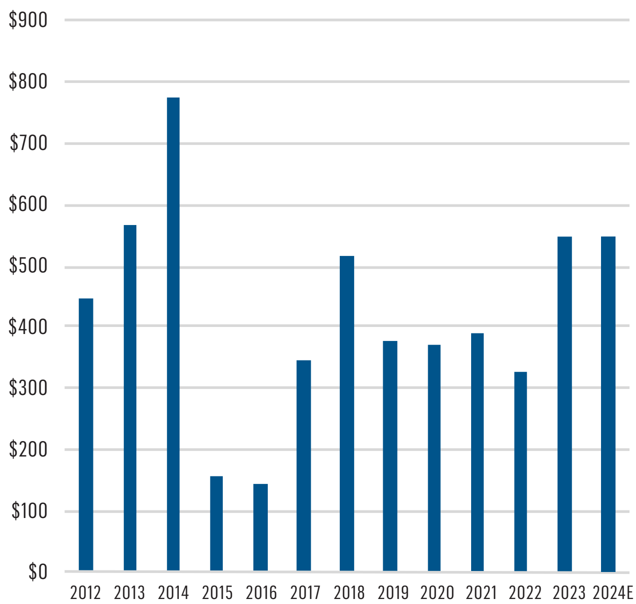
ConocoPhillips' combined oil and gas flows from the Montney in 2024 represent about 5% of the play's total. The Montney also accounted for 5% of ConocoPhillips' second-quarter production, according to data compiled by *OGI*.

"The Montney is a solid unconventional play in Canada that fits very competitively within our global portfolio. We added a second rig in the Montney in January, and the combination of this second rig and the increased capacity from the startup of CPF2 has allowed us to ramp up production," a ConocoPhillips spokesperson told *OGI*. "We expect to see continued growth in 2024, although it could be lumpy quarter-to-quarter due to well pad timing."

The Montney volumes are strategically delivered into Edmonton, the origin of TMX.

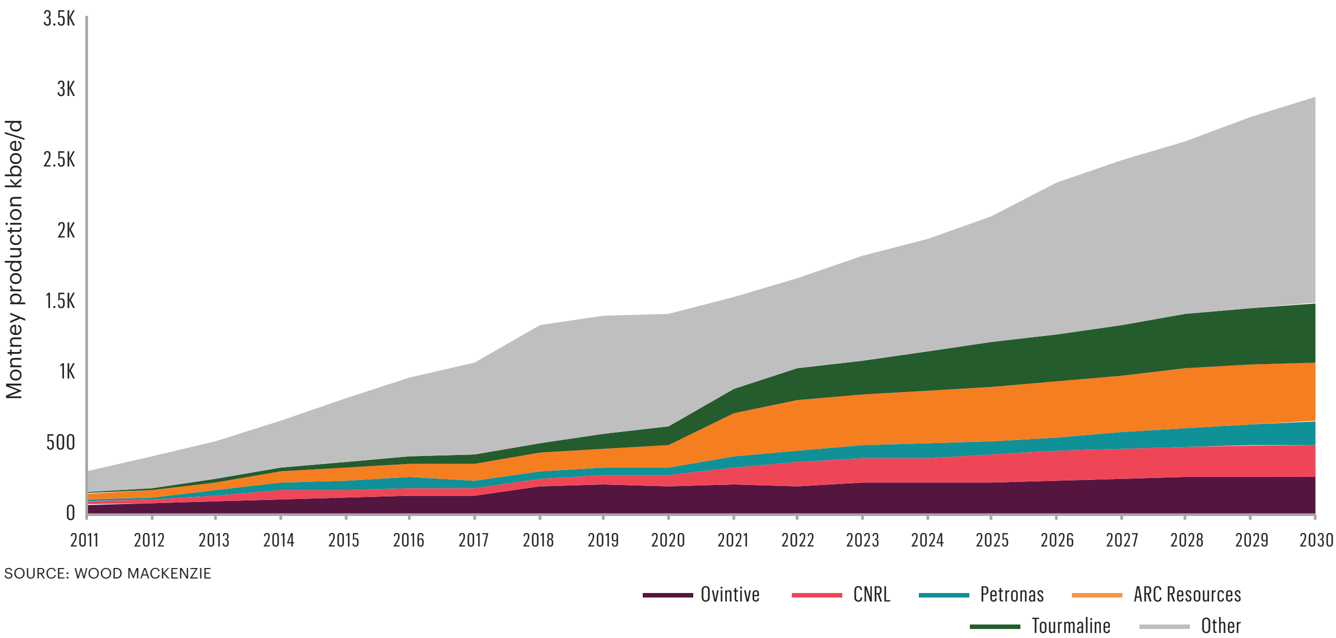
"We had a really strong start here in 2024, where in the second quarter … we averaged 43,000 boe/d. That's more than double relative to the same quarter last year," Kirk Johnson, ConocoPhillips' senior vice president of global operations, said said during the company's second quarter call.

Ovintiv's Montney Capex (US$ Millions)



SOURCE: OVINTIV

Montney boe Forecast



SOURCE: WOOD MACKENZIE

Houston-based ConocoPhillips had 297,000 net acres of land in the Montney at year-end 2023. ConocoPhillips' combined oil and gas flows from the Montney in 2024 represent about 5% of the play's total. The Montney also accounted for 5% of ConocoPhillips' second-quarter production

CONOCOPHILLIPS

Infrastructure Build-Outs Add Optionality

The only factors preventing the Montney from entering into a "hyper growth mode" are unrelated to the resource potential, said Oberstoetter.

"It's the markets, it's the access, it's the pipeline routes and getting those approved and built at a reasonable cost. That's always been the constraining factor," Oberstoetter said.

Norton Rose Fulbright Partner Robert Froehlich and Oberstoetter agreed the big reason the Montney is coming into vogue again relates to the news on LNG Canada and completion of the TMX.

Froehlich said it's been a long time coming for Canada to have some additional egress options because, traditionally, all of the country's exports went to the U.S.

Canada has three LNG projects slated to come online: LNG Canada (14 million tonnes per annum); Cedar LNG (3.3 mtpa); and Woodfibre LNG (2.1 mtpa).

"From a perspective of gas, I think those [projects] definitely do present more opportunities here in Canada," Froehlich said. "In terms of specific investments tied to those projects, the opportunities are somewhat limited because those projects have a bit of vertical integration, particularly LNG Canada, where the upstream owners, mainly Montney producers, have interests in the project.

"But I think the expectation would be that once [LNG] exports commence, it helps to sort of firm up prices of the gas market up here. And there is also a fairly substantial growth opportunity in utilization of gas in Western Canada from a petrochemical's perspective," he added.

ARC Resources also is bullish on Canadian LNG: "Having decades of top-tier, low-cost inventory, in combination with an investment-grade credit rating, opens up high-caliber opportunities for LNG supply," ARC said in its annual report.

Ovintiv told *OGI* it was supportive of all projects that enhance market access for the company's products.

"We believe the Montney can be an important contributor to the world's increasing demand for natural gas, supporting economic development and environmental solutions across the globe. With respect to condensate, we believe western Canada will remain a net importer of condensate for the foreseeable future, and as a result, the marginal western Canadian condensate barrel will remain closely tied to WTI prices," Ovintiv said.

Oberstoetter is most optimistic about the play's longer-term potential.

"You're dealing with super low gas prices so it's not really the time to be adding rigs, but the inventory is good. There's a long life there. The issue has been local gas prices," he said. "We think LNG helps that on the margins. We don't think it's going to create a huge tailwind either for the local gas price but, if Montney has been able to grow in the past decade under very volatile low gas prices, we think it's perfectly fine growing the next decade.

"We'll keep feeling these LNG demands, we'll keep pushing volumes in the U.S., and we'll hopefully be a little bit more stable on the pricing standpoint once we get some of these LNG projects going," he added.

TMX has also raised hopes.

On May 1, the TMX expansion began commercial operations, creating an expanded pipeline system with 890,000 bbl/d of capacity compared to 300,000 bbl/d earlier, according to Trans Mountain.

"The expansion of TMX has certainly helped in terms of both increasing the volume of exports that are possible just simply on a raw numbers' basis, but also allowing more access to a global market and global pricing," Froehlich said.

"And so, in terms of increased interest to the Montney, I think it has generally increased interests overall." OGI

Pitts: How Venezuelan Elections Impact Texas and Louisiana

Another questionable election comes as Chevron's quest to recoup debts continues. And Washington's likely next steps will include more of the same: sanctions.

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The ramifications of Venezuela's contested July 28 presidential election are felt far beyond the South American country's borders. This is especially the case for the U.S. energy sector's connections to crude supply chains and refinery operations.

With Chevron operating in Venezuela under a unique set of circumstances, and a handful of U.S. Gulf Coast refineries built to process the thick, sour Venezuelan crude, the latest developments in Caracas—with the ruling party claiming an allegedly false victory in the election—will continue to have significant impacts, particularly on the Lone Star State.

Venezuela, a founding member of OPEC and a past oil-producing and exporting powerhouse, was for decades a crucial supplier of heavy oil to U.S. refiners. And Texas and Louisiana refineries were major beneficiaries.

Companies such as Valero Energy, Phillips 66 and, of course, Venezuela's Houston-based refining arm, Citgo Petroleum, depended on a steady flow of imports from state-owned Petroleos de Venezuela (PDVSA) to maintain strong refining levels.

Things took a 180-degree turn in 2019 when then-President Donald Trump imposed sanctions on Venezuela with an eye on regime change. Sanctions, coupled with the COVID-19 pandemic, saw those oil import flows from Venezuela slow to a trickle as PDVSA crumbled.

Venezuela's production peaked at 3.2 MMbbl/d in 1997, according to the U.S. Energy Information Administration (EIA). The same year, Venezuela exported a record 1.8 MMbbl/d to the U.S. (56% of Venezuela's total production). In the first six months of 2024, Venezuela exported an average 194,000 bbl/d (23% of Venezuela's total production) of its total 827,000 bbl/d production, according to the EIA.

The fallout is significant for U.S. Gulf Coast refineries that were forced to seek alternative heavy oil sources at higher prices. It impacted profit margins and, ultimately for U.S. motorists, prices at the pump.

Heavy crude alternatives from Canada, Colombia and Mexico have filled the gap, but typically at higher costs. This has forced refiners to adjust their operations and product mixes to remain competitive and accommodate more lighter U.S. oil volumes.

Under the weight of sanctions, internal mismanagement and the continued exodus of what remaining skilled workers there are, Venezuela is producing at a mere shadow of its former self. Even after managing a partial recovery in production in recent years, due to concerted efforts by Chevron, Venezuela isn't expected to regain its former glory unless there is a drastic change in U.S. foreign policy or in the ruling regime.

Importantly, the U.S. has allowed Chevron to continue operating in Venezuela despite the stricter sanctions on almost all other companies looking to do business with the government of President Nicolas Maduro.

Part of the reason is to allow Chevron to recuperate its unpaid debts in Venezuela. The other part relates to Washington's beachhead theory to maintain an U.S. presence in Venezuela to hold off Russian, Chinese and Iranian influences, and to have a so-called energy foothold in Venezuela if and whenever a regime change occurs.

Chevron's ability to maintain this foothold is a key strategic advantage that could provide a lifeline to U.S. refineries if international relations were to eventually change for the better. Assuming the Maduro regime stays in power, another potential change would not technically emerge until 2030.

The administration of the next U.S. president—be that Vice President Kamala Harris or Trump—is expected to take a hard line on Maduro, especially in the wake of more election fraud allegations.

Another round of U.S. sanctions could further limit Chevron's ability to engage with Venezuela's oil industry. While unlikely, such a drastic measure could lead to a further tightening of supply, while boosting the costs for Texas and Louisiana refineries.

While Washington ponders its next steps, impacted U.S. companies are forced to continue to navigate an increasingly complex web of sanctions, legal battles and shifting oil supplies. Whether through Chevron's continued operations or the uncertain fate of Citgo—still being shielded from creditors seeking compensation for wrongful expropriations in Venezuela—Texas will remain a key player in the ongoing telenovela that is U.S.-Venezuelan political and energy relations. OGI

Paisie: Oil Prices to Rise in Fourth Quarter

Weakness in crude markets is connected to struggling economies in the U.S., EU and China.

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.

Oil prices have slid downward from the latter part of July through the early part of September, with the price of Brent crude falling below $75/bbl and the price of WTI falling below $70/bbl. Downward pressure continues to be put on oil prices by disappointing economic news, which has become a theme for 2024, and has been associated with all three major economies—the U.S., China and the EU.

The August jobs report shows that the U.S. added 142,000 jobs, which is well below the average monthly gains of 202,000 over the previous 12 months. The less-than-stellar jobs report for August follows the significant downward revision of 818,000 jobs for the period of April 2023 to March 2024.

Moreover, the underlying data are not robust, with private sector jobs increasing by only 74,000 in August, while full-time jobs decreased by 438,000 and part-time jobs increased by 527,000. Additionally, the number of manufacturing jobs decreased by 24,000.

The loss of manufacturing jobs is consistent with the latest Purchasing Managers' Index (PMI) from the Institute for Supply Management (ISM) which came in at 47.2. While the latest reading is an increase from 46.8 in July, the reading is still below 50 (for the fifth consecutive month), which indicates contraction.

Furthermore, there has not been a rebound in the manufacturing sector, despite the passing of the Inflation Reduction Act, with essentially no increase in the number of people working in the manufacturing sector since September 2022. Even with the post-COVID rebound, the number of people working in the manufacturing sector is no more than in November 2019.

As has been the case, China's economic data continues to cause concern. The manufacturing sector, according to China's National Bureau of Statistics, is at its lowest level since February and has been in contraction for the last four months. China's service sector is also showing weakness with growth slowing in August.

Europe's economy continues to be mired in a period of very low growth, in part, because of the struggling economy of Germany, with GDP growth forecasted to be just 0.1% for 2024. Recent business surveys indicate that export orders continue to decrease, in part, because of the weakness in China's economy.

The German automotive industry has been hit especially hard—not only the OEMs, but also the network of suppliers to the automotive sector, which together represent a major source of employment.

Given all the negative news, the sentiment of oil traders has become very bearish. Traders of WTI crude have reduced their net long positions six out of the last eight weeks, which has resulted in net long positions decreasing by 60% and falling to the lowest level since early February. Traders of Brent crude also have decreased their net long positions significantly during this period and are now at an exceptionally low level.

So where do oil prices go for the rest of the year?

The current low prices have led OPEC+ to delay the unwinding of voluntary cuts of 2.2 MMbbl/d (out of the total cuts of 5.86 MMbbl/d), which were scheduled to start unwinding in September and now are planned to start being phased out in December and continuing until November 2025.

Currently, Stratas Advisors is forecasting that oil demand will increase by 1.2 MMbbl/d in 2024 and by 2.08 MMbbl/d in the fourth quarter in comparison to fourth-quarter 2023. With this demand forecast, Stratas Advisors is forecasting that demand will outpace supply during the third and fourth quarters. The expected deficit during the third quarter and fourth quarters stems, in part, because we are forecasting that non-OPEC crude production will only increase by 320,000 bbl/d in comparison to 2023.

With expectations for more favorable fundamentals for the oil market and improvement in the sentiment of oil traders during the next few months, we are forecasting higher oil prices, with the price of Brent crude moving back above $80/bbl. The main downside risk is associated with faltering demand growth. There is also the risk that the cooperation among members of OPEC+ could deteriorate, but we think that this is unlikely as long as Saudi Arabia is willing to maintain its production cuts.

There is less upside potential associated with the fundamentals, but there is a potential boost to prices from geopolitical developments. The two major conflicts continue—and the direction of the two conflicts is toward escalation—which can lead to unexpected and unintended consequences that could rock the oil markets. The events surrounding the reduction in exports from Libya is another type of a geopolitical development that can affect the oil market. OGI

The end of the Trans Mountain Pipeline System, Burnaby Terminal, located just outside of Vancouver, Canada.

TRANS MOUNTAIN

Canada

TMX Provides Market Optionality for Western Canadian Products

Completion of construction and start-up of the Trans Mountain Expansion (TMX) pipeline provides market optionality for all western Canadian crude oil products, according to Canadian Natural Resources Limited (CNRL) President Scott Stauth.

"The efficient commissioning of the TMX pipeline during the second-quarter 2024 and the positive impact this incremental egress has on the Canadian economy represents a significant achievement for all Canadians," Stauth said in August in a press release.

"The impact on the energy industry has been positive with narrowing of heavy oil differentials, improved realized pricing along with the development of a more diverse market for western Canadian crude oil," Stauth said. "TMX is a significant accomplishment for Canada, adding much-needed egress capacity and increasing exposure to global market pricing for crude oil products."

ARC Resources Eyes Sales and Purchase Agreement by Year-end 2024

Calgary-based ARC Resources remains on track to execute a sale and purchase agreement by year-end 2024 with an investment-grade rated company for the entirety of ARC's LNG delivered from the Cedar LNG project.

"With the anticipated execution of the sale and purchase agreement, ARC expects to achieve its long-term market diversification strategy, which includes linking approximately 25% of its future natural gas production to international or LNG pricing," the company said in its second-quarter press release.

ARC Resources's Ante Creek operations.

ARC RESOURCES

Cedar LNG Partners took a $4 billion final investment decision (FID) on Cedar LNG in June 2024.

Cedar LNG has secured 20-year take-or-pay liquefaction tolling services agreements with ARC and Pembina Pipeline for 1.5 million tonnes per annum each. ARC will deliver 200 MMcf/d of gas for liquefaction by the project for a term of 20 years commencing with commercial operations, anticipated in late-2028.

ARC Resources Divests Non-Montney Assets for $80 Million

ARC recently closed the disposition of certain non-core, non-Montney assets for total cash proceeds of $80 million.

Proceeds from the divestment will be allocated to share repurchases as ARC's view of its intrinsic value exceeds the current share price, the company said in a September press release.

ARC didn't provide further details related to the assets.

ARC's operations are focused in the Montney region in Alberta and northeast British Columbia. The company is the largest Montney producer in Canada.

ARC expects its production to average between 380,000

ARC Resources Assets

SOURCE: ARC RESOURCES

and 385,000 boe/d in the fourth quarter. This includes the restored production at Sunrise and the growth in production relative to the first half of 2024 from ARC's condensate-rich assets such as Greater Dawson and Kakwa, as well as some contribution from Attachie Phase I coming on-stream.

Calgary-based ARC's Montney assets are capable of sustaining 500,000 boe/d of production, according to the company's website.

Veren Demonstrates Operational Strength in the Montney

Veren Inc. continued to demonstrate the strength of its operational execution in the Montney Shale play in Alberta, delivering the top four oil and liquids producing wells in the Western Canadian Sedimentary Basin (WCSB) based on recent monthly liquids volumes, the company said in July.

During the second quarter, Veren also drilled a new pacesetter well in its Gold Creek area of the play. This well, which was a part of an eight-well pad, was drilled in nine days with the overall pad averaging 11.3 days per well, an improvement of three days compared to Veren's average drill time in the area since entering the play.

Calgary-based Veren plans to remain focused on realizing further efficiencies through drilling optimization, consistent rig utilization and knowledge transfer across its assets in the play, the company said.

The Montney will represent around 50% of Veren's expected average production of 191,000-199,000 boe/d in 2024, the company said in an investor presentation.

In 2024, Veren expects capex of $1.4 billion-$1.5 billion, of which 45% will be dedicated to the Montney. Veren plans to maintain three active drilling rigs in 2024, drilling around 60 net wells.

In the Montney, Veren has over 1,400 premium net locations. This inventory provides attractive economics given location within the volatile oil window, the company said in its presentation.

Whitecap Eyes 100,000 boe/d Over Next Five Years

Whitecap Resources continues to run a two-rig program in the Montney and Duvernay. Production has grown by 27% over the past year-and-a-half to 61,000 boe/d compared to 48,000 boe/d in fourth-quarter 2022.

Whitecap's partnership with Pembina Gas Infrastructure (PGI) and the funding of Lator Phase 1 is an important milestone for future growth in the Montney and Duvernay to 100,000 boe/d over the next five years, Calgary-based Whitecap said in a press release.

The first eight Montney wells at Musreau have extended this trend with average 90-day IP rates of 1,600 boe/d per well (70% liquids) which is 19% above Whitecap's expectations, the company said.

Whitecap is currently completing a four-well pad at Musreau, the company's third pad overall and second targeting both the D2 and D3 Montney intervals. The thickness of pay and high liquids content at Musreau is favorable to multi-bench development. Whitecap expected this pad to be on production late in the third quarter.

Whitecap recently brought three (three net) Duvernay wells on production at Kaybob and will bring an additional five (five net) Duvernay wells and 10 (10 net) Montney wells on production in the second half 2024.

Results across Whitecap's Montney and Duvernay assets are increasing the company's confidence in the future deliverability of these assets and the economics of the 2,462 locations in inventory, the company said.

Paramount Licenses Montney Appraisal Wells at Sinclair

Paramount Resources has confidentially acquired over a multi-year period 167 sections of wholly-owned Montney rights in the Sinclair area of Alberta for a total cost of $51 million.

The Sinclair lands are prospective for high-rate gas production from the Montney Formation, Calgary-based Paramount said in a press release.

Paramount is in the process of licensing its first two horizontal Montney appraisal wells at Sinclair for drilling in the fourth quarter with no change to its previously disclosed capital budget.

Paramount will use the flow test and other data obtained from these wells to continue to advance its development plans for the property, which have included the recent securing of downstream transportation capacity that would enable the first phase of Sinclair production to commence as early as fourth-quarter 2027, Paramount said.

Strathcona Says Montney Volumes Impacted by Outages

Strathcona Resources said its Montney volumes in Grande Prairie were impacted by prolonged outages at two third-party gas processing facilities, as well as the failure of a major third-party gas compressor which has since been restored to service.

In Kakwa, Strathcona recently sanctioned the five-well 5-21 pad, Strathcona's first with 2.5-mile laterals, which are expected to lead to a 10% reduction in capital costs per well versus Strathcona's typical 2-mile design, the Calgary-based company said in August.

At Groundbirch, Strathcona finished drilling and completing its three-well 13-25 pad, and completed a short-term productivity test before shutting them in.

"Early results from the 13-25 pad are encouraging, with sustained strong flowing pressures between 18,000 and 21,000 kPa and achieved peak rates of approximately 10 MMcf/d across a 150-hour test period," Strathcona said. "As previously disclosed, given ongoing weakness to natural gas prices, Strathcona has deferred bringing these wells on production until natural gas prices improve."

Kelt Targeting 14-well Program in Montney

Kelt Exploration has drilled and completed the first six wells from its 14-2 pad in its Wembley/Pipestone Division. There, the company has a 14-well development drill and complete program targeting Montney oil and liquids-rich gas horizons as part of its 2024 capital program.

Calgary-based Kelt said the well offset two existing wells that had an average 30-day IP rate of 1,326 boe/d (59% oil and NGLs) per well. Kelt is currently flow-testing the 14-2 wells and expects to continue producing them. At the same time, Kelt plans to shut-in lower gas wells in the area as it awaits completion of a new gas plant that will add 50 MMcf/d of raw gas firm service processing upon start-up, expected prior to year-end 2024.

Kelt has commenced drilling operations on its five-well program off its 14-9 pad, after which the company will move to its three-well program off its 14-26 pad. Kelt expects to frac these remaining eight wells during September and October, bringing them on production in December with the anticipated start-up of a new gas plant.

At Wembley/Pipestone, Kelt also has 34 MMcf/d of firm raw gas processing capacity at another third-party gas plant. During the second quarter, this plant processed an average 21.4 MMcf/d (63% of Kelt's share of capacity). During the quarter, the operator shut-in the plant to conduct scheduled maintenance operations during which it was discovered that additional maintenance was required. The plant is currently running at 50% capacity but is expected to soon resume full capacity after completion of the additional repairs, Kelt said. OGI

Decarbonizing Natural Gas

Could a lower carbon revenue stream, focused on hydrogen and solid carbon, open up for natural gas players?

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There is a potential revenue stream that some natural gas producers should not overlook, experts say.

Depending on the production method, it has no CO_2 emissions. It has two main value-adding products. It is produced from natural gas–an abundant, low-cost energy source in the U.S. And, technology breakthroughs could elevate its status on the so-called Swiss Army knife of energy and amplify its impact on the world's decarbonization journey.

Pyrolytic hydrogen, or "turquoise hydrogen" for those familiar with the hydrogen color wheel, is produced via pyrolysis. The process involves heating natural gas, or methane (CH_4), to temperatures of at least 900 C to break the molecule into hydrogen and carbon–both of which have established markets.

Methane pyrolysis is seen by some as a promising decarbonization tool that can leverage the existing hydrocarbon value chain. The technology is gaining attention amid persistent efforts to lower global greenhouse-gas emissions. Although it still has hurdles to overcome, pyrolytic hydrogen could become a viable alternative to hydrogen production methods that require carbon capture and storage or methods that have little to no environmental advantages.

"Methane pyrolysis sits in this weird little space in between where it's currently proven and really interesting at distributed scale, takes advantage of existing infrastructure and has scalability potential, but it still has some challenges to solve along the way," said Lindsey Motlow, senior research associate of sustainability and energy transition for Darcy Partners.

Currently, about 95% of hydrogen is produced from steam reforming of natural gas, according to the U.S. Department of Energy. During the process, natural gas reacts with steam and a catalyst at high temperatures to create hydrogen–but the CO_2 is released into the atmosphere. While this so-called "gray hydrogen" dominates production, green (electrolytic) hydrogen and blue hydrogen (essentially gray plus carbon capture and storage) dominate headlines.

Still, methane pyrolysis is on the radar of some large oil and gas operators. However, the scalability of some of the technologies involved is of concern. Plus, like blue hydrogen, it also faces challenges because of its hydrocarbon roots.

"There's the sector of thought that kind of stands against any hydrocarbon-based hydrogen production process, especially on the West Coast in the U.S.," Motlow said. "Certain areas have been pushing to develop policies and incentives surrounding which technology choice can be made most economically, with credits or incentives and things like that. And, some folks are really pushing against any type of technology that is from hydrocarbon sources."

Getting Natural Gas

The natural gas community is uniquely placed to capitalize on pyrolytic hydrogen, according to Mothusi Pahl, vice president of business development for Modern Hydrogen.

"Rather than just thinking about natural gas equivalents and a Henry Hub value, now we can convert that natural gas into hydrogen that has significant value multiple," Pahl said. "And you convert that natural gas into carbon, which we're showing also has a significant value multiple."

Modern uses a thermal non-catalytic process to produce hydrogen and solid carbon, starting with natural gas. The process involves heating natural gas to a point where it is hot enough to dissolve the carbon and hydrogen bonds–about 2,000 F or hotter.

The process occurs inside two chambers: one for combustion and another for pyrolysis. Natural gas is initially injected into the

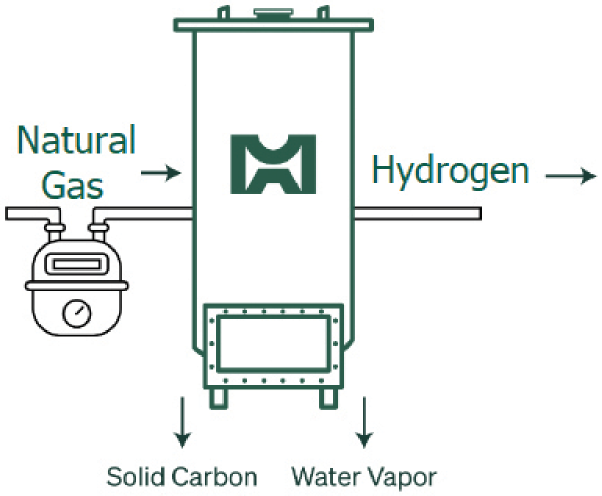
"Wherever you have a natural gas connection today, you can quite literally remove the carbon from that natural gas and deliver a clean fuel for any commercial, industrial or transportation operation."

MOTHUSI PAHL, vice president of business development, Modern Hydrogen

Modern Hydrogen technology is shown on an industrial site rendering.

MODERN HYDROGEN

Modern Hydrogen Process



SOURCE: MODERN HYDROGEN

Modern Hydrogen uses methane pyrolysis to produce hydrogen and solid carbon.

combustion chamber, resulting in a CO_2 footprint; however, as the system gets up to operating temperatures, some of the hydrogen produced is used to provide ongoing heat. After the hydrogen and carbon are separated and floating freely, the two are separated. The carbon atoms join each other to form a solid.

"The hydrogen is used as a fuel for transportation or industrial operations or chemicals or power generation. And what makes it really, really unique is that the heat that we use to drive our process comes from combusting a subset of the hydrogen that we produce," Pahl said.

The process takes place inside Modern Hydrogen's MH500, which can be bolted onto existing infrastructure to remove carbon from natural gas, LNG or RNG. The technology can be deployed where needed, reducing transportation and storage needs.

"Wherever you have a natural gas connection today, you can quite literally remove the carbon from that natural gas and deliver a clean fuel for any commercial, industrial or transportation operation," Pahl said.

Modern takes a modular approach to decarbonizing natural gas, depending on the challenge its customers are trying to solve.

"The more natural gas you're consuming and the more

Monolith's Olive Creek 1 facility in Nebraska has capacity to produce up to 15,000 tons per annum of carbon black and about 5,000 tons of hydrogen.

MONOLITH

carbon that you want to remove, the more filters you would put in place," he said. "So, each one of our boxes is really optimized to output about half a ton of hydrogen per day. But we don't really think about our application spaces with that as the scale. Really, the question ultimately comes down to the end user and how much decarbonization are they looking for.... We deploy the number of boxes required to get to that decarbonization threshold."

Modern, which is not yet manufacturing the MH500, has deployed pilot projects and is working toward its first scheduled deliveries of full-sized projects, expected in late 2025/early 2026. The company has orders under contract that are now pushing its next phase of deliveries out through late 2026 and early 2027, Pahl said.

Following positive field operation results in Miami, Washington State and Oregon over the last eight to nine months, the company is moving into early stage manufacturing mode.

Another company focused on methane pyrolysis is currently the only commercial-scale producer: Monolith.

Getting Bigger

Nebraska-based Monolith uses a thermal plasma process to produce carbon black and carbon-free hydrogen from natural gas.

"Unlike other pyrolysis companies, our advantage is that we turn solid carbon into a high-quality carbon black.... That carbon black is used for tires," Kelsey Roste, vice president of decarbonized solutions, told *Oil and Gas Investor*. "This is one of the toughest industries to enter into since the tire is the No. 1 safety element of a vehicle. Our process utilizes less electricity, and we're extremely efficient with the natural gas. We turn over 98% of the CH_4 molecule into the two high-value products."

Roste said the company's process is able to create a significantly more decarbonized hydrogen product today, without the need for carbon capture and sequestration requirements, at a price that's competitive with traditional ways of producing hydrogen such as steam methane reforming (SMR).

Although SMR is considered affordable, the process releases 11 tons of CO_2 into the atmosphere for every 1 ton of hydrogen produced, the company said. Electrolysis, which uses renewable energy-powered electrolyzers to split water molecules, is more expensive and requires seven times the electricity than methane pyrolysis. Instead of combustion, heat is used with methane pyrolysis, eliminating the release of CO_2.

Monolith's Olive Creek 1 facility in Lancaster County, Neb., became the U.S.' first commercial-scale methane pyrolysis facility in 2020. It has the capacity to produce up to 15,000 tons per annum of carbon black and about 5,000 tons of hydrogen. Looking to replicate the success, Monolith is expanding with Olive Creek 2. The facility will have up to 12 reactors and be capable of producing 180,000 tons of carbon black and about 60,000 tons of hydrogen per year.

After the expansion, Monolith plans to build production facilities of similar sizes in the U.S. and eventually around the world, she said.

"The hydrogen we plan to turn into ammonia/fertilizer," Roste said. "Carbon black is an essential material that's most notably known for making up one-third of the tire worldwide. The process currently uses fossil natural gas as well as clean electricity. But we do have the opportunity to use other hydrocarbons as our feedstock such as renewable natural gas."

On the East Coast, Empire Diversified Energy is also planning to use pyrolysis to transform RNG into hydrogen as one of the projects selected for the Appalachian Regional Clean Hydrogen Hub (ARCH2). Working with Heartland Water Technology, Empire plans to produce hydrogen from anaerobically digested food waste at a facility in Follansbee, W.Va.

"From a sustainability standpoint, we knew that we could capture methane coming from food waste and sludge byproducts or waste products," said Bernard Brown, COO for Empire Diversified. "And … looking at thermal conversion technologies, it was not hard to bring two existing known processes together, meaning capture the food waste and generate a biogas."

He added that thermally separating carbon can be accomplished with either pyrolysis or gasification technology.

The company plans to produce about 2 million kilograms of hydrogen per year, but that depends on how much waste material comes in, he said. "Now, could you scale up? Absolutely. But we're not looking to do that. We found a very good point of equilibrium in the design process to make it financially profitable."

Getting Credit

Like other hydrogen players, companies that use pyrolysis are positioning themselves to take advantage of hydrogen production tax credits if final guidance from U.S. regulators is favorable.

However, Pahl pointed out that the current hydrogen production pathway for the 45V hydrogen production tax credit is heavily weighted toward hydrogen generated from renewable sources.

Hydrogen producers meeting certain prevailing wage and registered apprenticeship requirements could qualify for a credit ranging from $0.60 per kilogram (kg) of hydrogen produced to $3/kg, depending on the life-cycle greenhouse-gas (GHG) emissions from hydrogen production, including its power source. The fewer emissions, the higher the credit.

"But if you're generating hydrogen from natural gas, even if you deliver the same CO_2 impact as the renewable originated hydrogen, you're not eligible for the same benefits," Pahl said. "And that, I think, fundamentally is a problem that we as the energy community need to work together to resolve."

Similar sentiments were shared for solid carbon and the 45Q for carbon capture.

"If I can capture and sequester an equivalent amount of carbon in the form of Modern's solid carbon that are avoiding CO_2 emissions, they should be eligible for the same carbon capture and sequestration incentives under 45Q as all of the oilfield-captured CO_2 is eligible for it," Pahl said. "We think the upstream community should really see this as a bolt-on benefit for natural gas in creating long-term demand and long-term understanding of natural gas as a feedstock for decarbonization. That whether you're capturing the carbon after you've burned the fuel or you're capturing the carbon before you burn the fuel. If the outcome is the same, the incentives should be the same."

Modern's produced carbon has a unique binding quality makes it ideal for use in asphalt materials with asphaltene. When mixed with materials that asphalt producers use to make asphalt for roads, the carbon makes the road stronger, he said.

Modern has NextEra Energy and National Grid among its backers, and NW Natural is among its customers. The company currently does not have any strategic partners in the E&P or midstream space.

"Unlike other pyrolysis companies, our advantage is that we turn solid carbon into a high-quality carbon black."

KELSEY ROSTE, vice president of decarbonized solutions, Monolith

Getting Onboard

Pyrolysis, which has been around for a long time, has been traditionally used for the production of solid carbon, Motlow said. It wasn't until the early 2000s that hydrogen—then a byproduct of the process—was considered for hydrogen production amid decarbonization goals. But the molar ratio of solid carbon is significantly larger than the hydrogen output, she said.

"Methane pyrolysis due to, I guess, the demonstrated scale of some of those reactors and inherent R&D related to the scaling of those technologies has been a concern for a lot of oil and gas operators," she added.

Oil and gas companies are looking to move forward with projects with technologies that can be deployed at a large scale. "These technologies need a little bit more time to get to that point in scaling."

Still, some of the oil and gas industry's biggest players are involved in methane pyrolysis projects or backing companies developing such technologies.

Chevron Technology Ventures, Shell and Williams Cos., for example, are among Aurora Hydrogen's investors. The Canadian startup is developing microwave pyrolysis technology that converts natural gas into hydrogen and solid carbon without consuming water or generating carbon emissions.

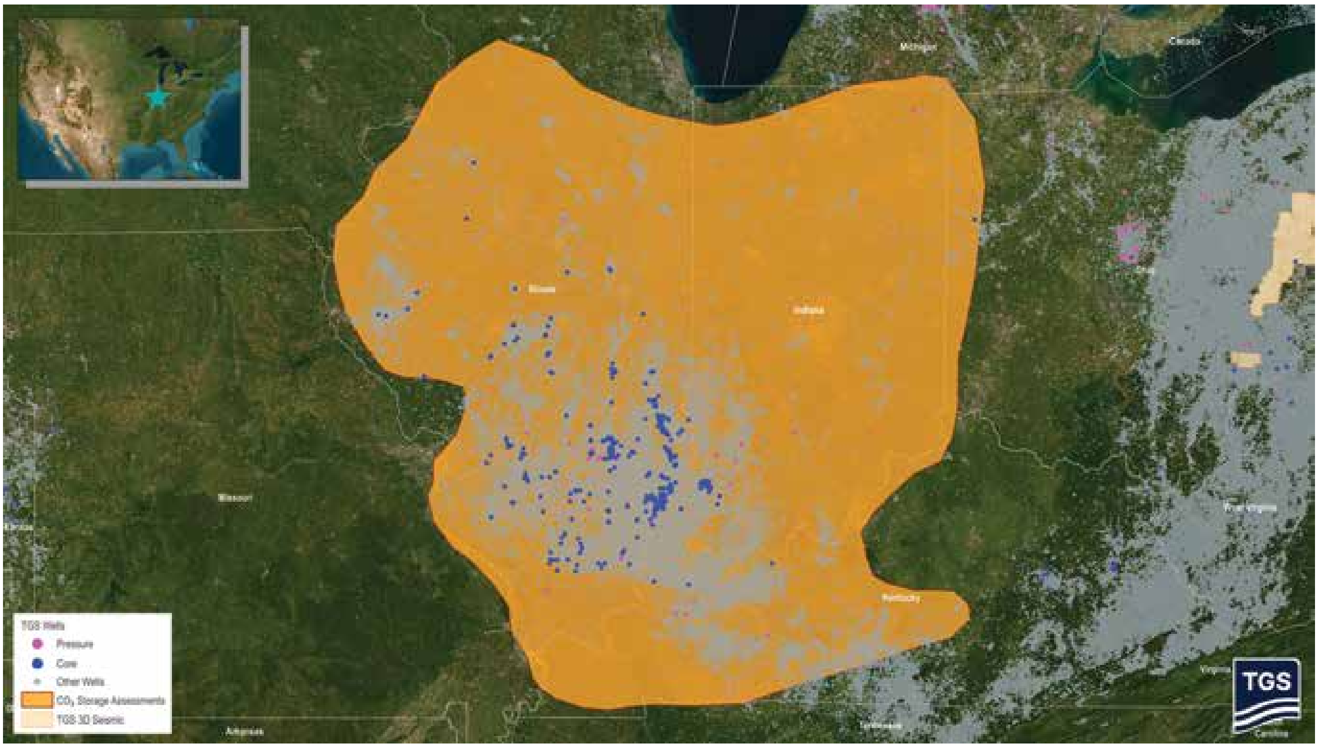
Pyrolysis is something that perhaps more companies, specifically those in natural gas, could find value, Pahl said. He said he thinks the upstream natural gas community has been segmented in its thinking of the gas ecosystem historically but that could change.

"Whether or not you agree with the politics of decarbonization, the market pull for decarbonization is significant … a lot of our gas production and gas utilization is going to be influenced by big industrial and commercial end-users that are trying to solve decarbonization challenges," Pahl said.

There is marketplace potential outside the traditional natural gas value chain.

"It is a strategic imperative for the upstream gas community to really understand the marketplace that we're creating for decarbonized natural gas," he said. "There's a significant opportunity in creating value to deliver decarbonized natural gas. The real question is: who's going to capture that value creation?" OGI

TGS wells in the Illinois Basin



SOURCE: TGS

Carbon Management

TGS Releases Illinois Basin Carbon Storage Assessment

Seismic and geophysical data company TGS released an assessment that identifies prime reservoirs for CO_2 sequestration across 66 million acres in the Illinois Basin.

The assessment is intended to help energy companies and environmental stakeholders make informed, data-driven decisions for carbon storage projects.

"The Illinois Basin Carbon Storage Assessment sets a new industry standard with its unmatched data coverage and expert analysis, pinpointing the most effective reservoir and seal formations for CO_2 sequestration," Carel Hooijkaas, executive vice president at TGS, said.

The assessment provides insights into reservoir quality, capacity and sealing integrity with data from 2,500 wells and analysis of key geologic formations. It also includes regional mapping of storage properties, volumetric visualizations, an all-encompassing stratigraphic framework, petrophysical analysis and log curve interpretations, TGS said in the news release.

The Illinois Basin covers areas in Illinois, Indiana and Western Kentucky.

Petronas, Carbon Clean Sign Deal to Explore Carbon Capture Tech

A carbon capture subsidiary of Malaysia's Petronas agreed to collaborate and evaluate Carbon Clean's carbon capture technology, according to a news release.

CARBON CLEAN

Carbon Clean's CycloneCC industrial unit

The companies, which signed a memorandum of understanding, will evaluate various carbon capture methods for potential integration into different areas of Petronas' operations. The multinational oil and gas company has said it aspires to have net-zero carbon emissions by 2050.

The agreement with U.K.-headquartered Carbon Clean will center on the company's CycloneCC technology.

"CycloneCC's modular design enables companies to stagger their investment, adding units in line with their decarbonization goals," said Carbon Clean CEO Aniruddha Sharma. "We are making carbon capture logistically viable and easy to scale."

The pre-fabricated carbon capture system uses centrifugal force to increase the efficiency of the carbon capture process, the tech company said. Occupying up to 50% less space than conventional carbon capture units, CycloneCC has the potential to lower total installed cost of carbon capture by up to 50% compared to conventional units, Carbon Clean said.

SLB Introduces Carbon Storage Well Integrity Assessment Methodology

SLB unveiled a new well integrity methodology that aims to simplify carbon storage site selection and evaluation, helping carbon storage developers quantify risks at prospective storage sites.

The methodology "incorporates advanced failure mode effect and criticality analysis to assess potential leakage pathways, well barrier, failure mechanisms and resulting consequences," the global technology company said.

The process involves use of advanced multi-physics 3D modeling to assess the volume and flow rates of brine and carbon leakage, SLB said in a news release.

"The significance of the risks associated with each well and the costs of remediation to mitigate leakage risks can make a project economically unfeasible," said Frederik Majkut, senior vice president of industrial decarbonization for SLB. "By addressing potential well integrity issues early in the development process, SLB's well integrity assessment solution can help storage developers avoid costly delays or operational disruptions, and drive companies toward their net zero ambitions."

Geothermal

Meta, Sage Geosystems Enter Geothermal Deal

Meta Platforms, formerly known as Facebook, tapped with Houston-based Sage Geosystems to deliver up to 150 megawatts (MW) of geothermal energy to help meet the tech company's growing data center electricity needs.

Sage said it will use its geopressured geothermal system to provide carbon-free power to Meta's data centers.

The partnership continues the momentum of Big Tech turning to renewables, including geothermal energy, to power operations amid ambitions to reach net-zero emissions. It also takes shape as the U.S. aims to bolster the

META

Meta has been ramping up construction of data centers, including in Temple, Texas. The data center is designed for next-generation artificial intelligence systems.

geothermal sector, having laid out a roadmap to grow output with next generation technology and funding projects.

Sage's geopressured geothermal system technology, which was field tested in 2022, will provide carbon-free power for Meta. Its technology involves pumping large volumes of water into an artificial reservoir created by a fracture to harvest heat from hot dry rock. Pressure causes it to balloon open and hold the water under pressure. When electricity is needed, the water is brought back to the surface, where a turbine converts the heat to electricity.

Hydrogen

ADNOC, Exxon Mobil Partner to Develop Hydrogen, Ammonia Facility

Abu Dhabi National Oil Co. (ADNOC) will acquire a 35% equity stake in Exxon Mobil's proposed low-carbon hydrogen and ammonia production facility in Baytown, Texas, the U.S.-based energy giant said.

The move came as companies across the world took additional steps to help decarbonize sectors with high greenhouse gas emissions while meeting growing demand for lower-carbon fuels.

The facility is expected to produce up to 1 Bcf of hydrogen daily and more than 1 million tons of low-carbon ammonia per year, if it receives required regulatory permits. Nitrogen is combined with hydrogen to produce ammonia, which is a key ingredient in fertilizer and other products.

The facility, which Exxon said is also contingent on supportive government policy, will also capture about 98% of the associated CO_2 emissions.

A final investment decision on the facility is expected in 2025, a year later than previously expected. Anticipated startup is in 2029, Exxon said.

Linde Plans to Build $2B Hydrogen, Atmospheric Gases Facility

Industrial gases company Linde plans to invest more than $2 billion to build, own and operate a hydrogen and atmospheric gases facility in Canada after securing a long-term supply agreement with Dow.

Linde said it will supply clean hydrogen for Dow's Fort Saskatchewan Path2Zero Project in Alberta, Canada, and capture CO_2 emissions of more than 2 million metric tons per year for sequestration. The new complex is expected to become Canada's largest clean hydrogen production facility when it is complete in 2028.

Linde said it will use autothermal reforming with its proprietary HISORP carbon capture technology to produce clean hydrogen and recover hydrogen contained in off-gases from Dow's ethylene cracker.

Dow's project includes a hydrogen-fueled ethylene cracker; expanded polyethylene production; power and steam cogeneration, offsite carbon sequestration; site infrastructure upgrades, including roads, rail and utilities; and control centers with office, storage and maintenance facilities, the chemicals company said.

The project will triple Dow's ethylene and polyethylene capacity at the site, while helping to lower carbon emissions.

During the project's first phase, Linde said it will supply clean hydrogen, nitrogen and other services to support Dow's first net-zero emissions integrated ethylene cracker and derivatives site. Linde's new facility will also supply clean hydrogen to existing and new industrial customers seeking to decarbonize their operations.

The hydrogen production facility marks Linde's largest single investment in hydrogen, the company said.

RW Energy, Nu:ionic Team Up for Hydrogen, Carbon Capture

Energy park developer RW Energy and Nu:ionic Technologies plan to work together to accelerate hydrogen production and carbon capture projects in the U.S., targeting Northern California, the Texas Gulf Coast and Ohio, the companies said.

Oklahoma-based Nu:ionic will supply modular, pre-engineered low-carbon hydrogen production equipment with integrated carbon capture. Texas-based RW Energy will lead and oversee project identification, facility design and business development, and provide expertise in sustainable and distributed capacity energy solutions, according to a news release.

The sites will use Nu:ionic's Teal Hydrogen production equipment with capacities ranging from 1.2 tonnes to 6 tonnes per day, according to a press release. The company's Nu-X Smart Reformer will also be utilized. Nu:ionic's equipment produces high purity hydrogen and cryogenic liquid by-product CO_2.

RW Energy estimates the projects will come online in fourth-quarter 2025.

Oxy's 1PointFive Lands Federal Funds for South Texas DAC Hub

Occidental Petroleum subsidiary 1PointFive's direct air capture (DAC) hub has secured up to $500 million in funding from the U.S. Department of Energy (DOE), marking a milestone for the planned commercial-scale facility in South Texas.

The funding, which will be doled out in segments, could increase to $650 million to further expand the regional carbon network. The initial award is for $50 million, Occidental said in a September news release. Engineering, permitting and procurement of long-lead equipment are among the upcoming activities for the project.

"Large-scale direct air capture is one of the most important technologies that will help organizations and society achieve their net-zero goals," said Occidental CEO Vicki Hollub. "This award demonstrates how the U.S. Department of Energy is committed to realizing the full potential of DAC and its confidence in the South Texas DAC Hub to deliver CO_2 removal at a climate-relevant scale."

DAC technologies can pull CO_2 directly from the atmosphere anywhere, avoiding the need to be near the point of emissions. It is seen as a route to lower emissions, but the energy-intensive process must overcome challenges, which include costs. Federal funding—such as from the Bipartisan Infrastructure Law that enabled 1PointFive's award, and incentives offered in the Inflation Reduction Act's carbon sequestration tax credit—are expected to help improve the project's economics.

The facility will initially be capable of removing and storing 500,000 metric tons of CO_2 per year. But plans are in place to increase that to more than 1 million tons per year in the future, Occidental said. OGI

TECHNOLOGY

Civitas: 4-mile Colorado Laterals Are a 'Competitive Edge' in the D-J Basin

Civitas Resources poured billions of dollars into Permian M&A, but the company still sees room to run in its foundational portfolio in Colorado.

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Civitas Resources is seeing efficiencies from drilling longer laterals in Colorado, despite a challenging regulatory and land acquisition environment.

The Denver-based company began flowing back production from 13 4-mile Denver-Julesburg (D-J) Basin wells in late June.

"To our knowledge, they're the longest wells ever drilled in the state of Colorado," said Civitas CFO and Treasurer Marianella Foschi during the 2024 EnerCom Denver conference.

Results from the wells are still early, but each mile drilled is contributing meaningfully to production, Foschi said.

Being capable of drilling longer 4-mile wells in the D-J Basin gives Civitas "a massive competitive edge," she said.

Civitas saw around a 5% reduction in per-foot drilling costs on its 4-mile wells compared to 3-mile wells.

"Obviously, that speaks to the capital efficiency," Foschi said.

The company has gotten much more comfortable drilling longer laterals in the D-J over time. When planning its 2022 capital program with risky 3-mile laterals, Civitas wasn't sure what kind of performance it would see from the wells.

The company was pleased to see essentially no degradation in performance for a 3-mile well compared to a 2-mile well.

"If you think about our outperformance in 2022 and 2023, it was very much underpinned by the fact that we heavily risked that third mile, relative to the two," she said.

Going longer underground in the D-J Basin can also provide some relief to a challenging land acquisition game.

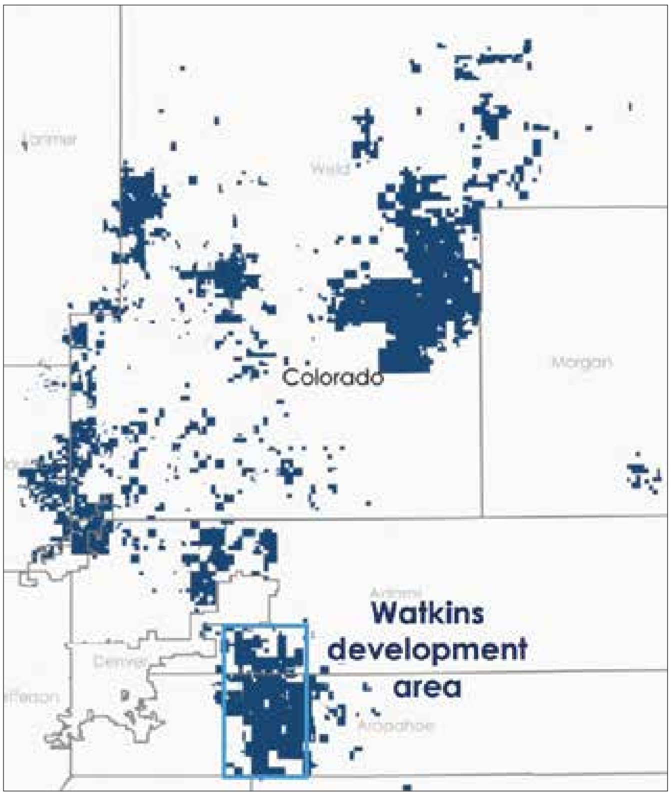
It can be difficult to find and buy surface drilling locations in Colorado, where acreage is already heavily consolidated in the portfolios of a handful of operators like Chevron, Occidental Petroleum and Civitas itself.

The extra fourth mile on Civitas' 13 4-mile D-J wells is equal to about six 2-mile wells—and well over 60,000 ft of resource recovery potential, Foschi said.

And despite Civitas' major investment into the Permian Basin, the company still has future drilling plans in store for its foundational Colorado asset.

This summer, the Colorado Energy and Carbon Management Commission (ECMC) approved a comprehensive area plan (CAP)

Civitas Resources Acreage in the D-J Basin

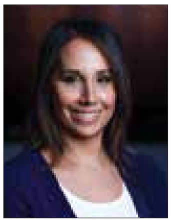


SOURCE: CIVITAS

Civitas had 371,000 net acres and production of 157,000 boe/d (43% oil) in the D-J Basin as of the end of the second quarter.

SHUTTERSTOCK

Denver-based Civitas Resources started production from 13 4-mile wells in Colorado's D-J Basin this summer.



"If you think about our outperformance in 2022 and 2023, it was very much underpinned by the fact that we heavily risked that third mile, relative to the two."

MARIANELLA FOSCHI, CFO and treasurer, Civitas Resources

for Civitas to develop the Lowry Ranch project in the southern D-J Basin.

The Lowry Ranch CAP calls for up to 166 wells on 10 new or expanded well pads in Arapahoe County, Colo.

Foschi said Civitas aims to have an additional CAP approved by state regulators early next year.

Permian Prowl

Despite Civitas' drilling runway in the D-J Basin, the company's hunt for inventory led it to allocate nearly $7 billion of M&A into the Permian in the past year.

Civitas closed its first two Permian acquisitions in August 2023, scooping up Hibernia Energy III in the Midland Basin for $2.2 billion and Tap Rock Resources in the Delaware Basin for $2.5 billion.

In early January, Civitas closed a $2 billion acquisition of Vencer Energy, a Midland Basin E&P backed by international commodities trading house Vitol.

"We're grateful and fortunate that we were able to enter the Permian when we did," Foschi said. "According to the best we can tell, there was a meaningful, meaningful step-up in prices of assets in the Permian Basin shortly after we bought in."

When Civitas bought in the Permian, it paid around 3x debt-to-EBIDTA and around $1 million to $2 million per net drilling location.

Today, Civitas is seeing Permian assets trade for closer to 4x debt-to-EBIDTA and around $2 million to $4 million per location.

"The current market is tough," Foschi said. "You have to pay for capital efficiencies ahead. You have to pay up for upside zones that perhaps haven't been proven to be repeatable."

While Permian prices are high, Civitas still has boots on the ground in the Midland and Delaware basins scouring for acreage trades, swaps and other small-ball M&A.

Civitas produced approximately 186,000 boe/d from the Permian Basin in the second quarter. OGI

How a Wave of Innovation Supported Chevron's Deepwater Dare

Taking on an environment 34,000 feet below sea level in the Gulf of Mexico required a new completion system, more advanced drillships and the first 20,000-psi BOP.

CHEVRON

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To understand Chevron's engineering feat at its 20,000-psi Anchor project offshore Gulf of Mexico (GoM), imagine a standard quarter, stamped with the likeness of George Washington.

Then imagine an elephant standing on that quarter.

"That's the pressure that we're operating in," Chevron CEO Mike Wirth said in August at EnerCom Denver.

Chevron made the Anchor discovery in 2014, Wirth said, about 130 miles south of New Orleans. The environment some 34,000 ft below sea level was a treacherous mix of high pressure and high temperature.

To operate in such environment would require a whole series of new equipment and technology that didn't exist, at least not yet.

"We had to think long and hard about developing in conditions that had never been produced from before," he said. "There was no equipment. You didn't have BOPs rated at 20,000 psi."

"The hook loads for running casing were higher than the highest hook load you could put on a deepwater drill ship. We didn't have trees and subsea infrastructure rated at those conditions."

Chevron started oil and natural gas production from the Anchor project in the deepwater GoM, the company said in mid-August. The $5.7 billion project reached final investment decision (FID) in 2019.

To get there, Chevron conducted endless R&D by equipment manufacturers finding new ways to produce drilling equipment and subsea production technologies capable of withstanding Anchor's harsh operating conditions.

"There was a whole series of equipment and technology advancements that were required in order to develop this field," Wirth said. "It took a lot of hard work and a decade of time to advance these things, to qualify the technologies, to work closely with critical vendors, to design equipment that would operate safely under the conditions required. We had to build a first-of-its-kind drill ship with two 20,000-psi BOPs, a 3 million-pound hook load for running casing."

Enter the service companies.

Deepwater Innovation

Dril-Quip produced an economically viable 20,000 psi "in-the-wellhead" completion system capable of withstanding 350 F. Prototype testing of the tool started around 2019.

Transocean built and brought online its *Deepwater Titan* and *Deepwater Atlas* vessels. The vessels are the first deepwater drillships equipped with a 1,700-ton hoisting capacity, 20,000-psi well control fittings and a 10,000-psi mud system.

And NOV produced the industry's first 20,000-psi BOP for use on the Transocean rigs.

With those advancements, Chevron sees the potential for unlocking a considerable amount of new production. Chevron said the discovery could hold recoverable reserves up to 440 MMboe.

"The new gear promises Chevron's Anchor and similar projects by Beacon Offshore Energy and BP will deliver a combined 300,000 bbl/d of new oil and put 2 Bbbl of previously unavailable U.S. oil within producers' reach," Wood Mackenzie analyst Mfon Usoro said in an August report.

"These ultra-high-pressure fields are going to be a big driver for production growth in the Gulf of Mexico," she said.

Anchor represents a breakthrough for the energy industry, said Nigel Hearne, Chevron's executive vice president. "Application of this industry-first deepwater technology allows us to unlock previously difficult-to-access resources and will enable similar deepwater high-pressure developments for the industry."

A second well in the Anchor project is also nearing first oil, according to Bruce Niemeyer, president of Chevron Americas Exploration and Production Co. The Anchor semisubmersible floating production unit has a capacity of 75,000 bbl/d and 28 MMcf/d.

Usoro said the U.S. GoM has repeatedly proven itself as a hub for technological innovation and the deployment of the ultra-high-pressure technology puts the region once again at the forefront of a technology breakthrough.

Chevron is leading the way to unlock ultra-high-pressure reservoirs in the Inboard Paleogene, a formation which has never been produced, she said. "Production from the untapped reservoir has the potential to permanently change

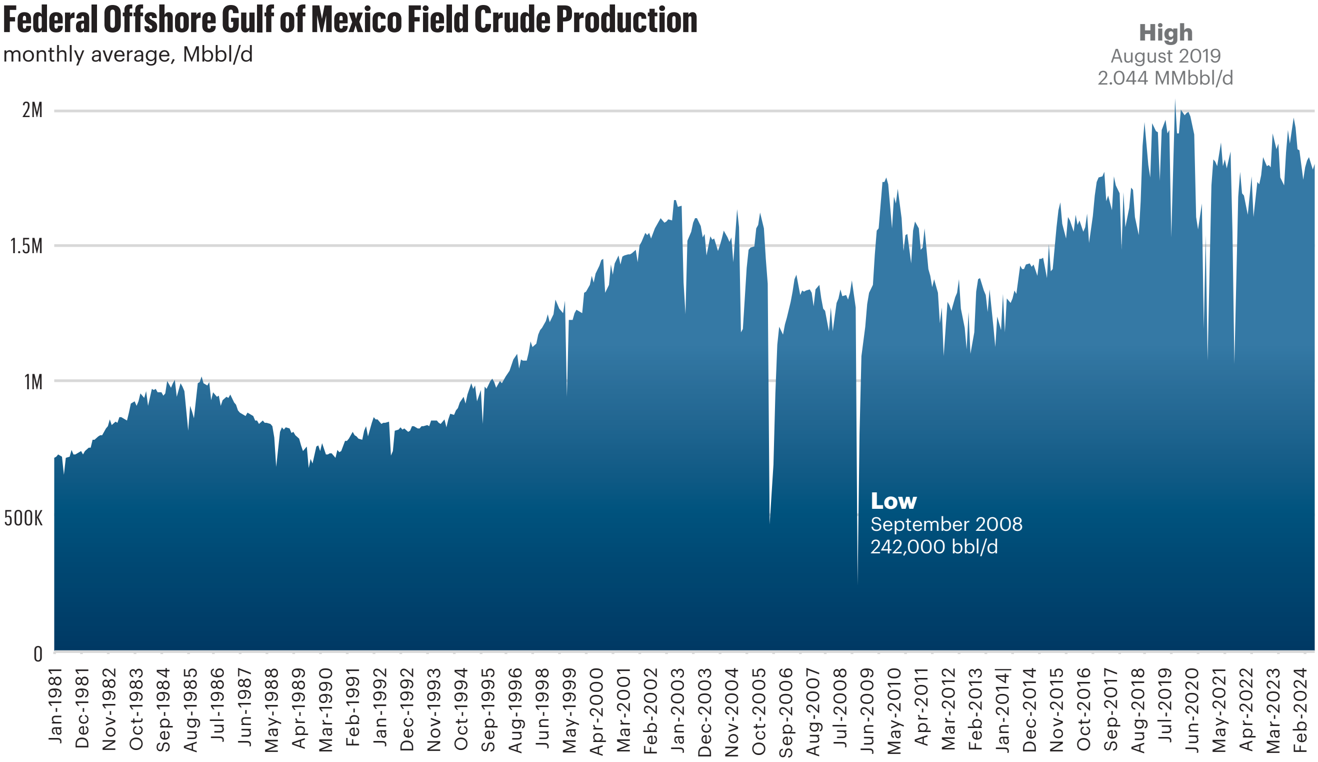
Anchor FPU Specs and Stats

SOURCE: CHEVRON

- Location: U.S. Gulf of Mexico, 140 miles offshore Louisiana
- Water depth: 5,000 ft
- Reservoir depth: 30,000-34,000 ft|
- Maximum reservoir temperature: 250°F (121°C)
- FPU height: 25 stories
- FPU topsides area: 42,080 sq ft
- Sea water displaced: 70,000 metric tons
- Production life: up to 30 years
- First oil: 2024
- Peak production: up to 75,000 net barrels per day
- Total production: up to 440 MM net barrels over 30 years

Federal Offshore Gulf of Mexico Field Crude Production

monthly average, Mbbl/d



SOURCE: ENERGY INFORMATION ADMINISTRATION

The new drilling and production equipment in trial at Anchor will help other deepwater operators bring online stranded assets, such as BP's Kaskida.

CHEVRON

the landscape in the U.S. GoM," Usoro said. "Operators expect individual wells to recover at least 30 MMboe."

GoM Oil Output to Soar

The U.S. portion of the GoM has produced below the record 2019 level of 2 MMbbl/d, but the additional crude from the deepwater high-pressure/high-temperature fields could help push the region well above its previous peak output.

The GoM provides roughly 15% of U.S. oil production. That share was much higher before the onshore shale boom in the Permian Basin.

"Yet absolute oil production in the region has generally grown over the past decade and been pretty stable—with some big exceptions—for a long time," said S&P Global analyst Bob Fryklund. "We often call it a kind of forgotten basin," but slated for more growth. S&P sees deepwater output rising above 2 MMbbl/d then plateauing for five to seven years.

Wood Mackenzie sees a 30% increase in deepwater output from 2023-2026, peaking around 2.7 MMboe, partly due to projects like Anchor.

Breaking the 20k-psi Barrier

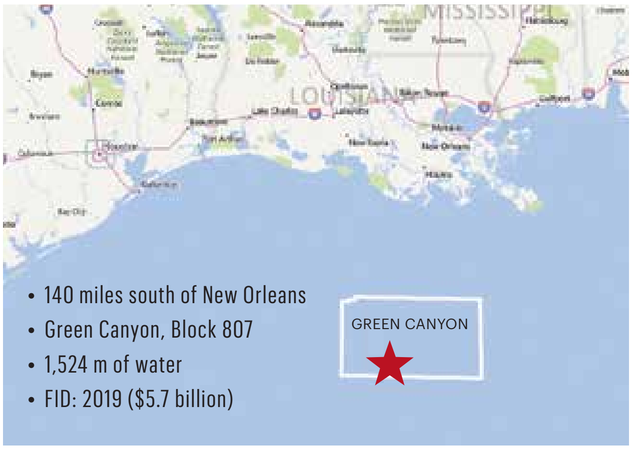
The new drilling and production equipment in trial at Anchor will help other deepwater operators bring stranded assets online.

BP has its own high-pressure field challenge and hopes it can use the new kit to tap 10 Bbbl of discovered resources across its Kaskida and Tiber areas. Its first 20,000 psi project, Kaskida, was discovered in 2006, yet was put aside because of a lack of high-pressure technology.

"Developing Kaskida will unlock the potential of the Paleogene Formation in the Gulf of Mexico for BP, building on our decades of experience in the region," said BP Executive Vice President Gordon Birrell.

"Kaskida will be BP's sixth hub in the Gulf of Mexico and will feature a new floating production platform with the

Chevron's Anchor Project



SOURCE: REXTAG

capacity to produce 80,000 bbl/d from six wells in the first phase," Birrell said. Production is expected to start in 2029.

Similar HP/HT fields that would also benefit from the 20,000 psi technology are found off the coasts of Brazil, Angola and Nigeria, said Rystad analyst Aditya Ravi. "The Gulf of Mexico will be the proving ground for the new gear."

The potential for the Anchor project and others has come from a "tremendous amount of work by not only engineers and technical people within our company, but with critical partners and vendors."

Wirth said Anchor continues the industry's track record of advancing technology to continue unlocking resources and help provide the world with affordable and reliable energy.

"We took FID in 2019, saw first oil last week," Wirth said. "We've got one well drilled and completed. We've got two more wells and we'll be completing here over the balance of this year. And really now, it's opened up a whole new regime in the deepwater Gulf of Mexico." OGI

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KidLinks is a 501(c)(3) nonprofit organization that provides healing, hope, and happiness for children and families through music therapy programs, therapeutic music entertainment, and online music media. For over four decades, KidLinks has provided healing experiences for children with special challenges, funded therapeutic music initiatives, implemented university-level music therapy training, and offered free/low-cost treatment programs for children in need. KidLinks has proudly and positively impacted the lives of over 433,000 children and caregivers.

For more information on KidLinks, including services or news and events, please visit our website www.kidlinks.org or follow us on Instagram @Kid_Links.

***supporters as of print deadline 09.13.24**

EVENTS CALENDAR

Investment and networking opportunities for industry executives and financiers.

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EVENT	DATE	CITY	VENUE	CONTACT
2024				
Energy Capital Conference	**Oct. 3**	**Dallas**	**Thompson Hotel**	**hartenergy.com/events**
2024 Gas Machinery Conference	Oct. 6-9	Tampa, Fla.	Tampa Convention Center	southerngas.org
SPE Asia Pacific Oil & Gas Conference and Exhibition 2024	Oct. 15-17	Perth, Australia	Crown Perth	spe-events.org
A&D Strategies and Opportunities Conference	**Oct. 23**	**Dallas**	**Thompson Hotel**	**hartenergy.com/events**
IPAA Annual Meeting	Oct. 28-29	Boca Raton, Fla.	The Boca Raton Resort	ipaa.org
Offshore Windpower Conference & Exhibition	Oct. 28-30	Atlantic City, N.J.	Atlantic City Convention Center	cleanpower.org
SEG 4D Forum	Nov. 4-6	Galveston, Texas	Grand Galvez	seg.org
ADIPEC 2024	Nov. 4-7	Abu Dhabi, UAE	Abu Dhabi National Exhibition Centre	adipec.com
DUG Appalachia	**Nov. 7**	**Pittsburgh**	**David L. Lawrence Convention Center**	**hartenergy.com/events**
International Geomechanics Conference	Nov. 18-21	Kuala Lumpur, Malaysia	Intercontinental Hotel Kuala Lumpur	igsevent.org
DUG Executive Oil Conference & Expo	**Nov. 20-21**	**Midland, Texas**	**Midland County Horseshoe Arena**	**hartenergy.com/events**
National Pipe Line Conference	Nov. 28-29	Houston	Omni Houston Hotel	plca.org
North American Gas Forum	Dec. 2-4	Washington, D.C.	TBD	energy-dialogues.com/nagf
SPE Thermal Well Integrity and Production Symposium	Dec. 2-5	Banff, Alberta, Canada	The Fairmont Banff Springs	spe-events.org
2025				
Floating Wind Solutions 2025	Jan. 15-17	Houston	The Marriott Marquis	floatingwindsolutions.com
Mexico Infrastructure Projects Forum	Jan. 22-23	Monterrey, Mexico	Hotel Camino Real Monterrey	mexicoinfrastructure.com
SPE Hydraulic Fracturing Tech Conference and Exhibition	Feb. 4-6	The Woodlands, Texas	The Woodlands Waterway Marriott & Convention Center	spe-events.org
NAPE	Feb. 5-7	Houston	George R. Brown Conv. Ctr.	napeexpo.com
6th American LNG Forum	Feb. 10-11	Houston	Westin Galleria	americanlngforum.com
Oil & Gas Automation and Technology Week	Feb. 11-12	Houston	Hyatt Regency Intercontinental Airport Hotel	oilandgasautomationand technology.com
SGA 2025 Spring Gas Conference	March 2-5	Charlotte, N.C.	TBD	southerngas.org
SPE/IADC International Drilling Conference and Exhibition	March 4-6	Stavanger, Norway	Stavenger Forum	drillingconference.org
CERAWeek	March 10-14	Houston	Hilton Americas-Houston	ceraweek.com
SPE/ICoTA Well Intervention Conference & Exhibition	March 25-26	The Woodlands, Texas	The Woodlands Waterway Marriott & Convention Center	spe-events.org
AI in Oil & Gas Conference	April 8-9	Houston	Hyatt Regency Houston West	aioilandgas. energyconferencenetwork.com
Energy Workforce & Technology Council Annual Meeting	April 9-10	Frisco, Texas	The Westin Dallas Stonebriar Golf Resort	energyworkforce.org
Monthly				
ADAM-Dallas	First Thursday	Dallas	Dallas Petroleum Club	adamenergyforum.org
ADAM-Fort Worth	Third Tuesday, odd mos.	Fort Worth, Texas	Petroleum Club of Fort Worth	adamenergyfortworth.org
ADAM-Greater East Texas	First Wed., odd mos.	Tyler, Texas	Willow Brook Country Club	etxadam.org
ADAM-Houston	Third Friday	Houston	Brennan's	adamhouston.org
ADAM-OKC	Bi-monthly (Feb.-Oct.)	Oklahoma City	Park House	adamokc.org
ADAM-Permian	Bi-monthly	Midland, Texas	Petroleum Club of Midland	adampermian.org
ADAM-Tulsa Energy Network	Bi-monthly	Tulsa, Okla.	The Tavern On Brady	adamtulsa.org
ADAM-Rockies	Second Thurs./Quarterly	Denver	University Club	adamrockies.org
Austin Oil & Gas Group	Varies	Austin, Texas	Headliners Club	coleson.bruce@shearman.com
Houston Association of Professional Landmen	Bi-monthly	Houston	Petroleum Club of Houston	hapl.org
Houston Energy Finance Group	Third Wednesday	Houston	Houston Center Club	hefg.net
Houston Producers' Forum	Third Tuesday	Houston	Petroleum Club of Houston	houstonproducersforum.org
IPAA-Tipro Speaker Series	Third Tuesday	Houston	Petroleum Club of Houston	ipaa.org

Email details of your event to Jennifer Martinez at jmartinez@hartenergy.com.
For more, see the calendar of all industry financial, business-building and networking events at HartEnergy.com/events.

AT CLOSING

Uinta Basin Outcrops: The Geologic, the Human-made, the Political

The oily western Uinta features layers of sedimentary deposits on view for visitors, mostly uninterrupted by human-made features but having an unseen pall of federal interference.

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Driving from Salt Lake City into the Uinta Basin in northeastern Utah, the route explodes with long bursts of visible layers of deposition—eye candy to geologists and the untrained alike, the latter not knowing exactly what they're looking at but certain it is significant.

A taste of what's to come is upon arrival at the Salt Lake City airport upon exiting the security-cleared side into a long hall with a wall covering that protrudes, creating a water-sculpted canyon cave.

Seating is in the form of stratigraphically layered mesas that beg to be climbed—and some visitors likely have, but quickly before being told to climb down.

South and east of Heber City, cell service, thus any streaming music or GPS service, will be lost for about 40 minutes of silence as entertainment turns solely to witnessing verdant mountainsides and green plains that give way to what was once an ancient lake bed: the Uinta Basin.

The roadside outcrops are brilliant red, orange, peach, a pale tan or yellow, depending on composition and, as photographers will find, the time of day. To find that spectacular crimson feature somewhere west of Duchesne again is quixotic.

Suddenly the land flattens again into an arid plain with intermittent pockets of irrigated land, fed by the Strawberry River that drains into the Duchesne, then the Green River and eventually the Colorado.

Cattle graze, while their owners tend hay and alfalfa crops, rebuilding the winter stock.

And human-made outcrops begin to appear.

Drilling rigs, workover rigs, pumpjacks, man camps, oil-tank batteries and frac spreads are within easy sight of a motorist with nothing to block them from view. That is, nothing except for oil-hauling trucks delivering to Salt Lake City or south to a rail terminal, or dead-heading back to the pads to empty another batch of tanks.

The Hideout steakhouse appears off to the right on Monument Butte just before reaching Myton and comes with an obvious recommendation: the lot is filled with oilfield trucks—every day and every evening.

There, customers can choose to go ancient: You can cook your steak yourself on a hot rock at the table. (Warning: Choosing this option may result in bragging.)

Whether you or the kitchen cooks it, the steak will be one of the best one has ever had and accompanied by sauteed vegetables that are melt-in-the-mouth down to the very last (whole and fresh, not canned) green bean.

Underneath the Hideout is the southwestern end of the Eocene-epoch Green River Formation that has been cooking organic matter into oil for 60 million years.

Laid down while the basin was a lake, the deepest member, the Uteland Butte, features tight carbonate reservoirs at between 4,000 and 6,000 feet in the area.

Within it are two layers of shale with three dolomitic members in between ranging in thickness

NISSA DARBONNE/HART ENERGY

Travelers are welcomed to Utah at the Salt Lake City airport by a water- and wind-swept tunnel and mesa-style benches.

of 1.5 to 8 feet and having up to 30% porosity but 0.1 millidarcy or less of permeability, according to the Utah Geological Survey.

While the potential for stimulated horizontal application in the Uinta has been known for two decades, there are figurative outcrops in the basin that have delayed the rollout.

One is the waxy nature of Uinta crude and the market. Until the growth of a rail option in the past few years, the only economic place to send Uinta oil was Salt Lake City's five refineries.

Waxy oil has to be heated in the field and carried in insulated trucks rather than pipelines or the wax will solidify. Also, it has to be cracked and the nearby refineries' cracking capacity is less than 100,000 bbl/d.

A figurative outcrop that has cast a pall on the basin recently is a new one: the Federal Trade Commission (FTC). The nearby refineries' economics depend on the waxy crude. An E&P wanting to build scale via M&A among the roughly half-dozen sizable drillers today could have too much command of Uinta supply, the FTC has theorized.

Recently, Uinta operator XCL Resources, which was already prevented in 2022 by the FTC from buying out EP Energy in the basin, wanted to buy neighbor Altamont Energy, which has mostly undeveloped leasehold.

Rather than continue to pursue FTC approval, XCL decided to simply sell itself to SM Energy, a new Uinta entrant, which then also bought Altamont.

A basin operator told *Oil and Gas Investor*, "The FTC took it too far when they got involved in this Altamont deal: It's a very small deal. It didn't make sense for them to make an issue out of that." OGI

NISSA DARBONNE/HART ENERGY

An outcrop of shale and interbedded sandstone in Monument Butte Field. The shale weathers into slopes and the sandstones are the resistant beds that make the ledges.

Oil and Gas Investor

COMPANIES IN THIS ISSUE

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