DIRTY LITTLE SECRETS

OIL & GAS INDUSTRY OUTLOOK

2025 DOMESTIC OIL AND GAS INDUSTRY OUTLOOK

DIRTY LITTLE SECRETS 2025

COMMODITIES ARE TIED TOGETHER LIKE NEVER BEFORE

EAST DALEY
ANALYTICS

CEO Intro

Jim Simpson

Founder | Chief Executive Officer

No one has ever traded or managed risk in a market developing like the one in 2025. As we enter 2025, the U.S. has become the world's leading supplier of all three hydrocarbon commodities, natural gas, natural gas liquids, and crude oil. No country in history has done that, particularly a country with thousands of suppliers and distributors that all have different economic drivers. This market brings amplified volatility but also amplified investment opportunities. East Daley's unique approach to intersecting disparate data sets quickly distills facts into visuals to drive value for our clients. Welcome to Dirty Little Secrets 2025, East Daley's preview of upcoming opportunities in the hydrocarbon sector.

In 2014, I founded East Daley to bring transparency to major discrepancies between energy commodities and capital markets, focusing on energy infrastructure. Bringing visibility to previously opaque operations enhances understanding of market dynamics and price reactions while allowing our clients to maximize opportunities. Whoever has the most transparency wins.

Ten years later, we've succeeded in bringing transparency to energy markets by assembling the best data on the production and movement of natural gas, crude oil, and NGLs from wellhead to demand centers. As we'll explain in more detail in our Methodology section of this report, we developed a proprietary method to collect, confirm, correlate, and display micro-level supply and demand data that drives macro-level insights in North America. Now it is possible to see how a molecule moves through the value chain as well as see the rate of return that molecule generates along the path.

2024 brought much consolidation, and as we enter 2025 the ramifications of consolidation on transparency will become more evident – bigger companies report less detailed information, driving down the information needed to understand how energy moves from supply to demand. I also firmly believe in market cycles, soon we will see more EQT-Equitrans type M&A, big upstream (or downstream) desiring more control and transparency over both their volumes and their rates. Private Equity be prepared as the need to spin off non-core assets ramps to warp speed.

There is a looming issue in most energy organizations: the nat gas desk, the NGL desk, and the crude oil desk are siloed. By the end of 2025, it will become evident that a constraint at an LNG export dock will also constrain NGL and crude oil supply – any constraint will constrain all. The faster an organization designs its desks to work as one, the more money and more opportunity they are going to exploit.

Please enjoy the read, the East Daley team has designed 2025's Dirty Little Secrets to stretch your mind and challenge your understanding of the status quo. We'd love to hear from you.

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East Daley Analytics' Methodology

East Daley Analytics was created to bring transparency to energy commodities and capital markets. To achieve this, we developed a patented method to collect, verify, and display precise data about how hydrocarbon molecules—natural gas, natural gas liquids, and crude oil—move from wellheads to demand centers. This effort resulted in the East Daley Energy Data Studio.

OUR METHODOLOGY CREATES A WEALTH OF HISTORICAL, CURRENT, AND FORECASTED INFORMATION BY CATEGORIZING DATA ACROSS:

1,077,456
Wells

12,581
Producers

146
Midstream Companies

100
Downstream Companies

195
Natural Gas Pipelines

347
Gathering and Processing (G&P) Systems

52
Natural Gas Storage Assets

153
Crude Pipelines

15
Crude Terminals

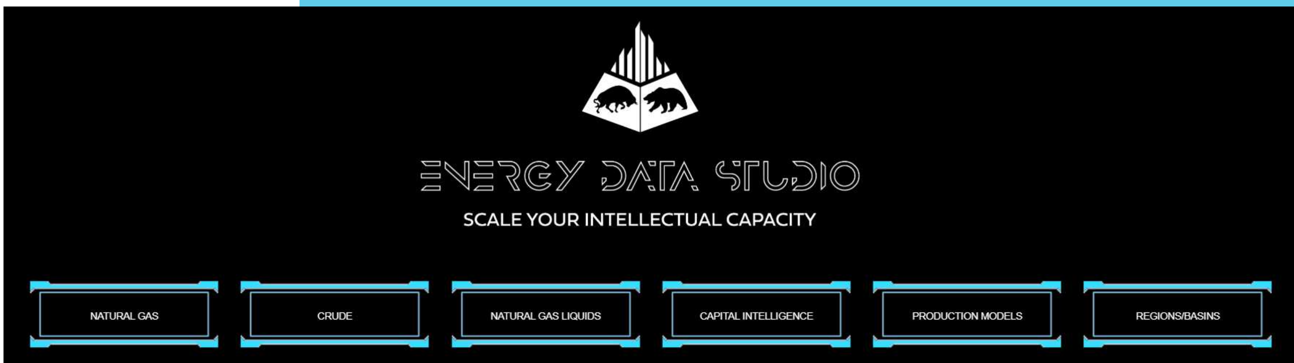
102
NGL Pipelines and Fractionators

By combining this data with producer guidance, quarterly financials and commodity prices, we build production models by asset, basin, producer, and commodity.

Our integration of financial and rate data is crucial for transparency in energy commodities and capital markets. Pricing influences investments, production, and end-user demand. We input extensive pricing data into the Energy Data Studio and gather information on fees and contracts using this combination to model commodity movements and financial returns.

East Daley's Energy Data Studio consolidates our robust data library and brings it to life with interactive visuals to distill the complexities of energy commodities and capital markets, providing vital insights into the industry.

Energy Data Studio provides the groundwork for our 2025 Dirty Little Secrets. Enjoy.



Unique Rig and Well Assignments
Since 2015, we've been assigning wells and rigs to gas gathering and processing systems on a weekly basis. This extensive historical data provides a foundational data point for our production forecasts, ensuring precision in tracking production trends.

Granular Production Models
We analyze rig counts, well allocations, and forecasted production by basin, starting at a regional level (e.g., Permian Basin) and drilling down to individual systems. By tying rig activity to commodity output (Crude Oil, Natural Gas, NGLs), we create detailed production curves aligned with market forward curves.

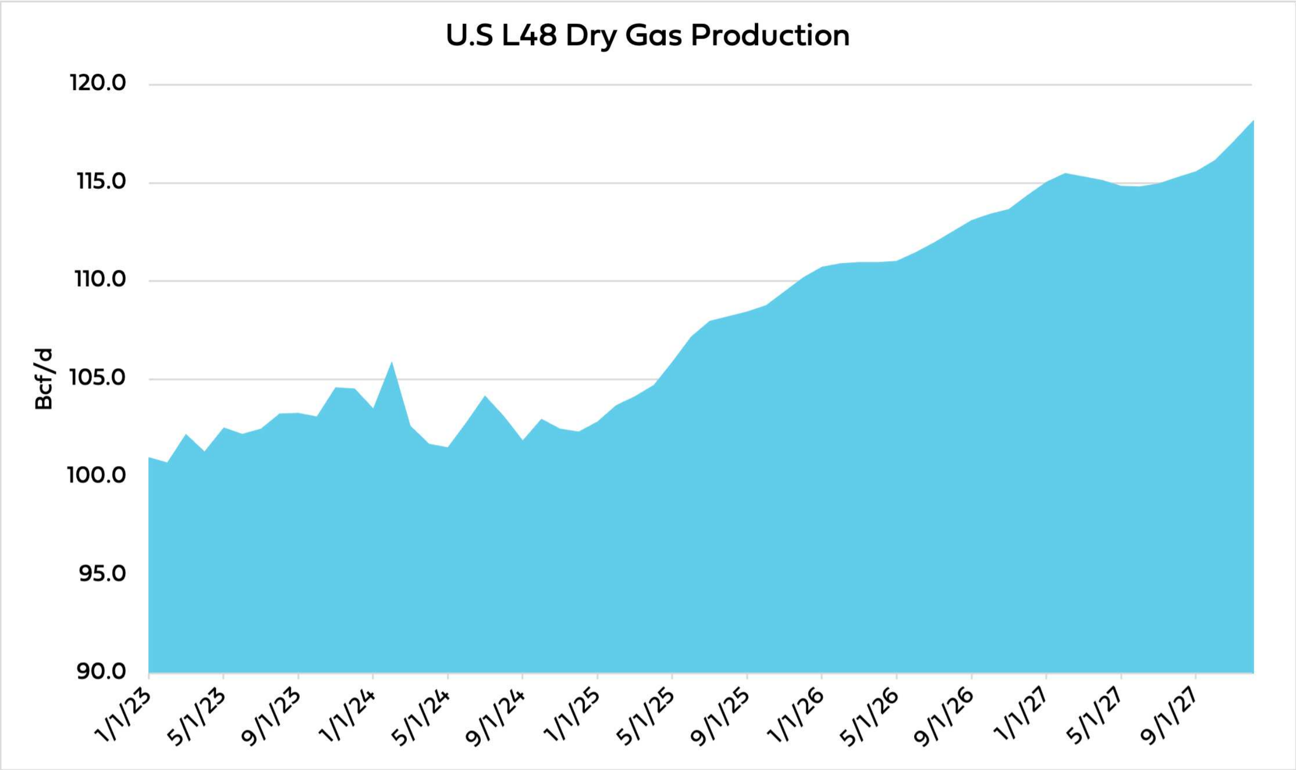
System-Level Forecasting
For each G&P system, we integrate plant inlet and flow data, capacity announcements, and historical trends. This allows us to forecast individual system performance accurately. Our ability to tag state and county-level data to these systems sets us apart, providing a granular understanding of system-level dynamics.

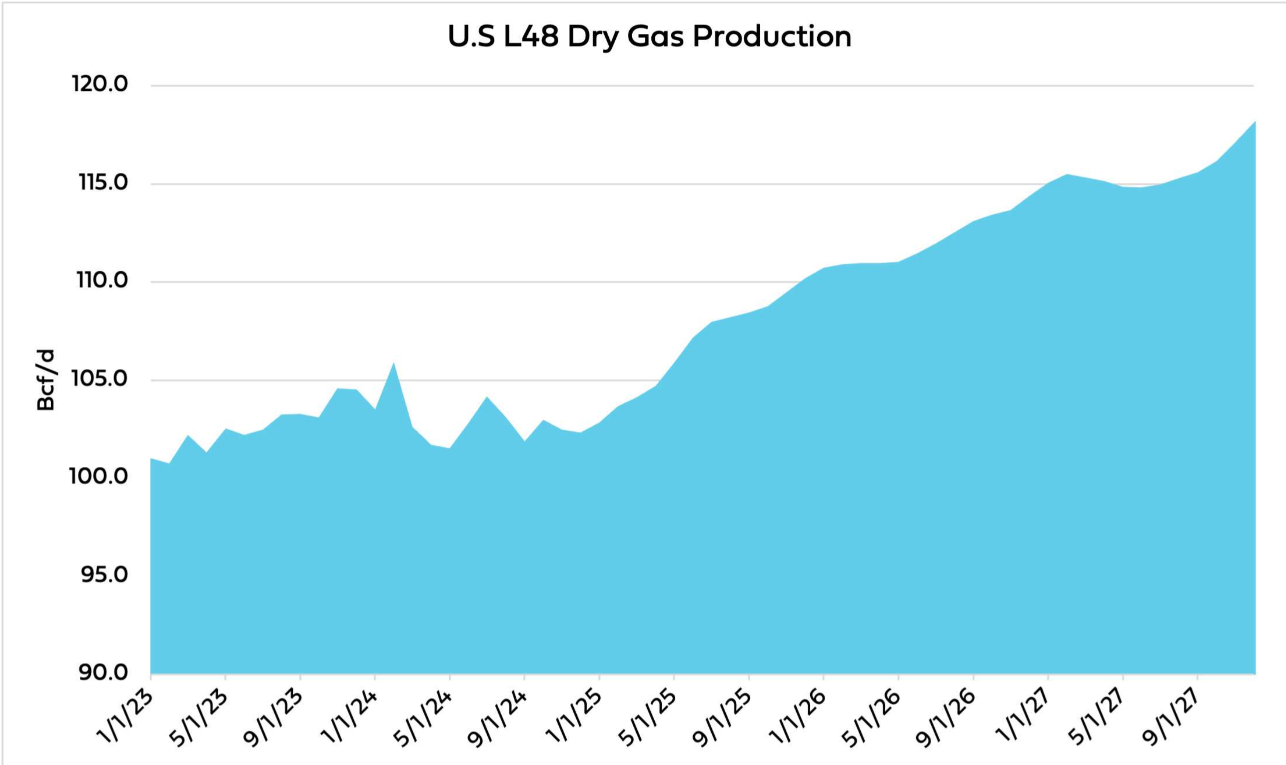
Comprehensive Pipeline and Plant Data
We map the flow corridors of pipelines, connect them to price dynamics, and analyze constraints to forecast future production and system volumes. Our models account for capacity limits, contract roll-offs, and transportation bottlenecks.

Asset-Level Financial Integration
We model companies down to an asset level, incorporating quarterly financial data to refine our volume forecasts. By comparing financial reports with operational data, we continuously calibrate our models to ensure our volume metrics are both accurate and forward-looking.

Forecasting the Future: Hydrocarbon Production Outlook for 2025

As outlined in our Methodology section, having the best data is essential for making informed investment decisions. Accurate forecasts of future crude oil, natural gas, and natural gas liquids (NGLs) are crucial for strategic planning by management and stakeholders in companies throughout the hydrocarbon value chain, from producers to end users.




U.S L48 Dry Gas Production
Bcf/d
120.0
115.0
110.0
105.0
100.0
95.0
90.0
1/1/23
5/1/23
9/1/23
1/1/24
5/1/24
9/1/24
1/1/25
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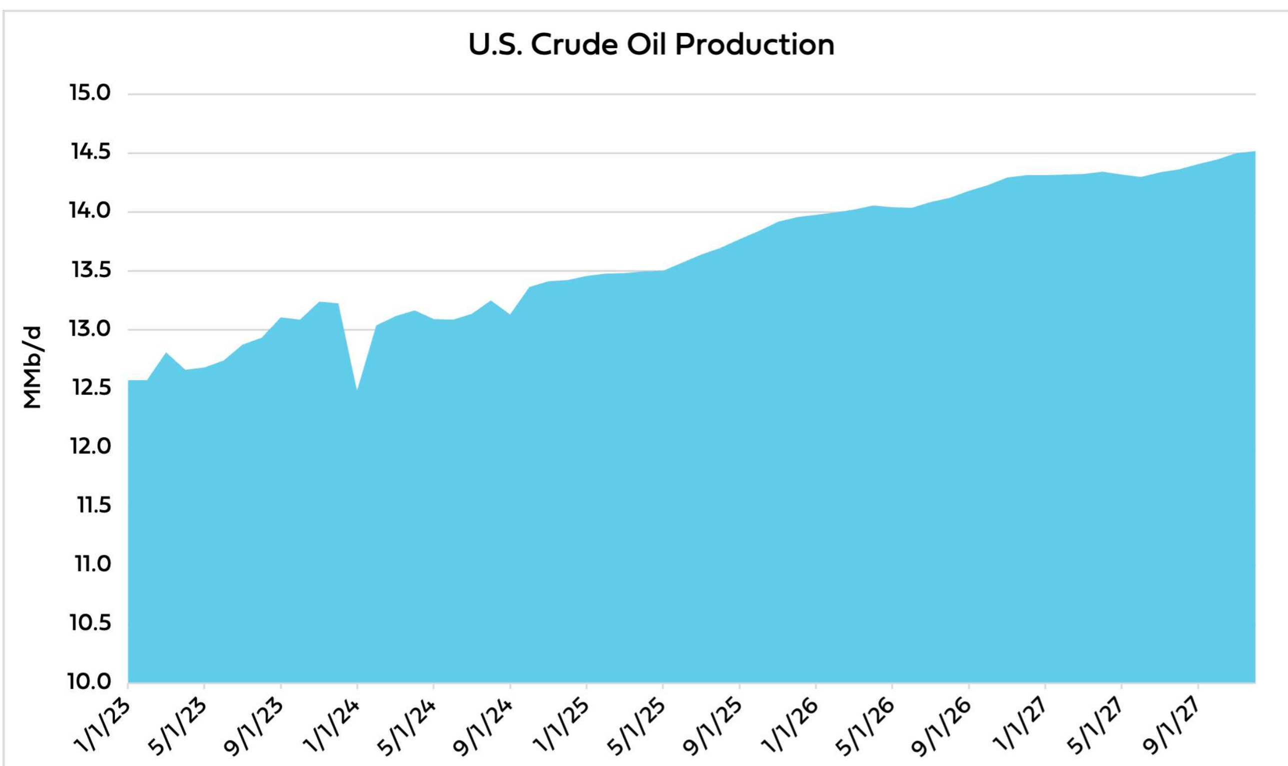
U.S. Crude Oil Production
MMb/d
15.0
14.5
14.0
13.5
13.0
12.5
12.0
11.5
11.0
10.5
10.0
1/1/23
5/1/23
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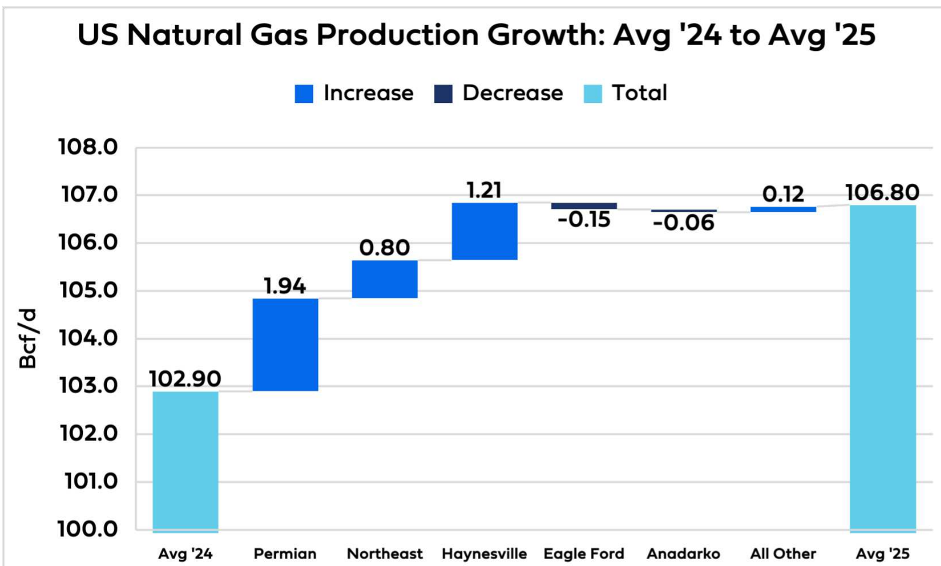
Natural Gas

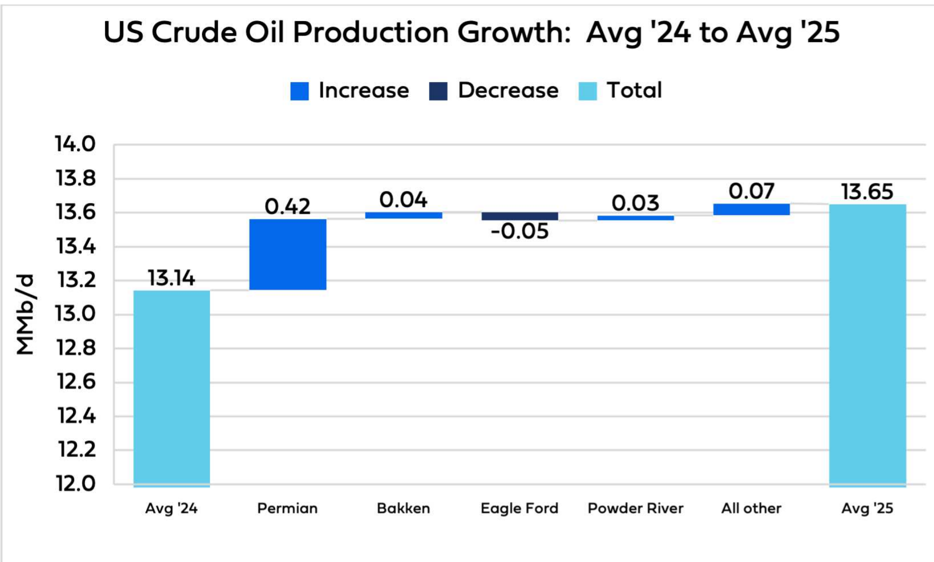
For natural gas, we anticipate dry production growing from 102.9 billion cubic feet per day (Bcf/d) in 2024 to 106.8 Bcf/d in 2025. A key factor in this forecast is our prediction of a Henry Hub price of $3.42 per million British thermal units (MMBtu) in 2025, which is over $1.00 higher than the year-to-date average of $2.20/MMBtu in 2024. This price increase is attributed to a more complex demand equation that will lead to a storage deficit. Domestic demand is expected to be driven by new data center projects, which will sustain steady gas demand through the end of the decade. Additionally, we have a greater exposure to international markets, fueled by an increase in liquefied natural gas (LNG) projects along the Texas-Louisiana coast. By the end of next year, we anticipate total export gas demand to rise to 15 Bcf per day. We also expect growth drivers from production efficiencies.

The majority of natural gas production growth will come from the Permian Basin, the Northeast, and the Ark-La-Tex region. Higher price scenarios are likely to benefit tier 2 basins such as the Barnett, Eagle Ford, Green River, and Piceance. There is potential for the Anadarko Basin to also react, although this will depend on how gas flows between South Texas and the Louisiana hubs.



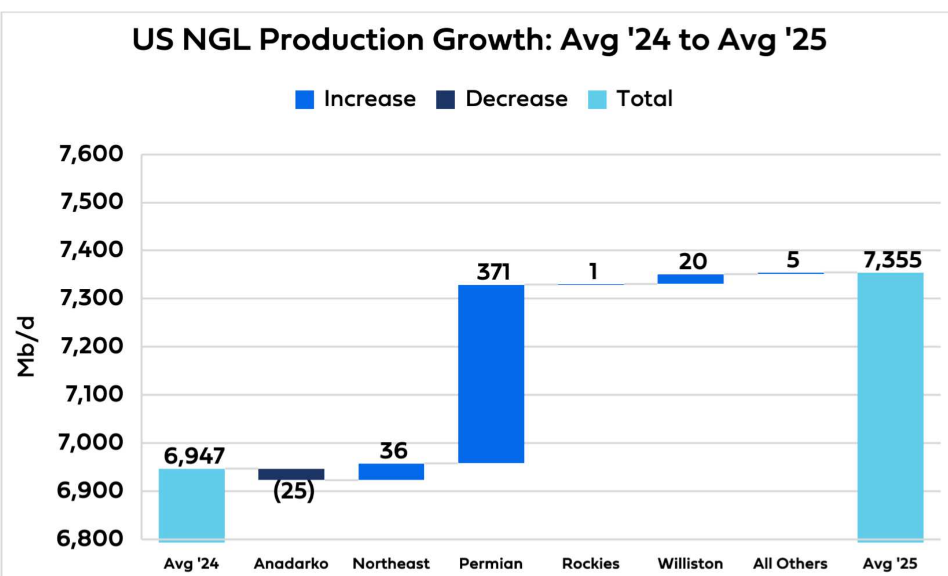
Crude Oil

For crude oil, we project output increasing from 13.14 million barrels per day (MMb/d) in 2024 to 13.65 MMb/d by 2025. The primary driver of this growth will be the Permian Basin, where we believe rising gas prices will spur an expansion of drilling and higher gas-to-oil ratios. Basins like the Permian, Bakken, and DJ have also substantially benefited from enhanced drilling technologies, including longer lateral drilling and multi-well pads. Once implemented, these technologies improve various well-to-rig metrics, such as higher well-per-rig rates, lower spot-to-spot rates, and increased initial production (IP) rates for gas and liquids.



NGL

Lastly, for NGLs, we expect production to rise from 6,947 Mb/d in 2024 to 7,355 Mb/d in 2025. Although production growth will be tempered by flat ethane production in the short term, the Permian Basin is expected to drive growth in C3+ output, particularly as an increase in export demand approaches.



Back to the Eighties: Integrateds Becoming More Integrated

No, we're not predicting a deep dive to the back of the closet for parachute pants, jelly shoes, and Ray-Bans, some of the trendiest gear of that iconic age. But our analysis of current economic and industry trends indicate that the oil and gas sector is likely poised for increased upstream, midstream, and downstream integration reminiscent of the structure four decades ago. In last year's DLS, we focused on the surging midstream and upstream consolidation driven by slower growth and fewer growth opportunities. We pointed out that a cash-flow obsessed Wall Street has been pressuring companies to increase efficiency and dampen volatility. The large-cap Midstreamers responded by acquiring assets from G&P companies to secure supply to downstream infrastructure, boost margins and provide additional flexibility to respond to emerging market opportunities. Upstream producers similarly reduced competition and captured synergies through massive acquisitions in key basins, especially the Permian. The results of this consolidation has placed the industry in the best financial condition in decades.

Inevitably, however, the opportunities for intra-sector consolidations have become much more limited. For example, public upstream companies now run 75% of the rigs in the Permian, up from 50% just three years ago. At the same time, the sophistication needed to own and operate assets along the supply chain is increasing as the US has become the world's leading supplier in all three hydrocarbon commodities, crude oil, natural gas, and NGLs. We believe this energy renaissance is likely to spur the large integrateds to become more integrated by acquiring major midstream assets to gain more value as molecules move from the wellhead to the end user.

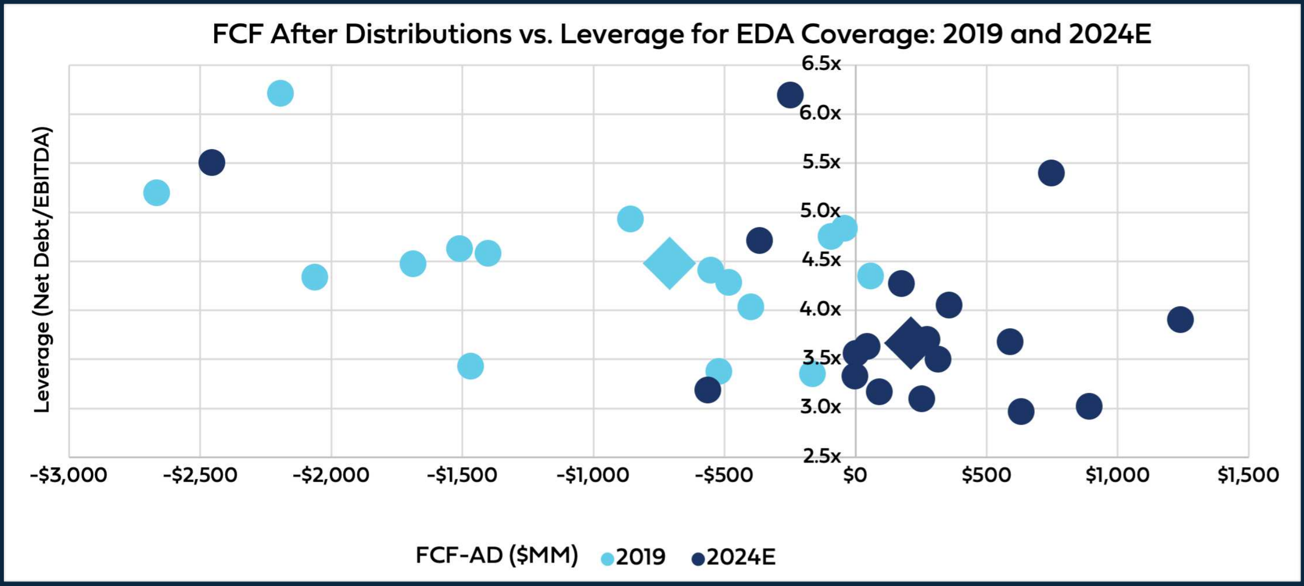
So we'll begin by taking a closer look at the midstream and upstream consolidation we focused on in last year's DLS. Then we'll move on to present the strategic and financial drivers of potential inter-sector integration, discuss the pros and cons for both the Major oil and gas companies and potential midstream partners, and speculate on some potential buyers and sellers.

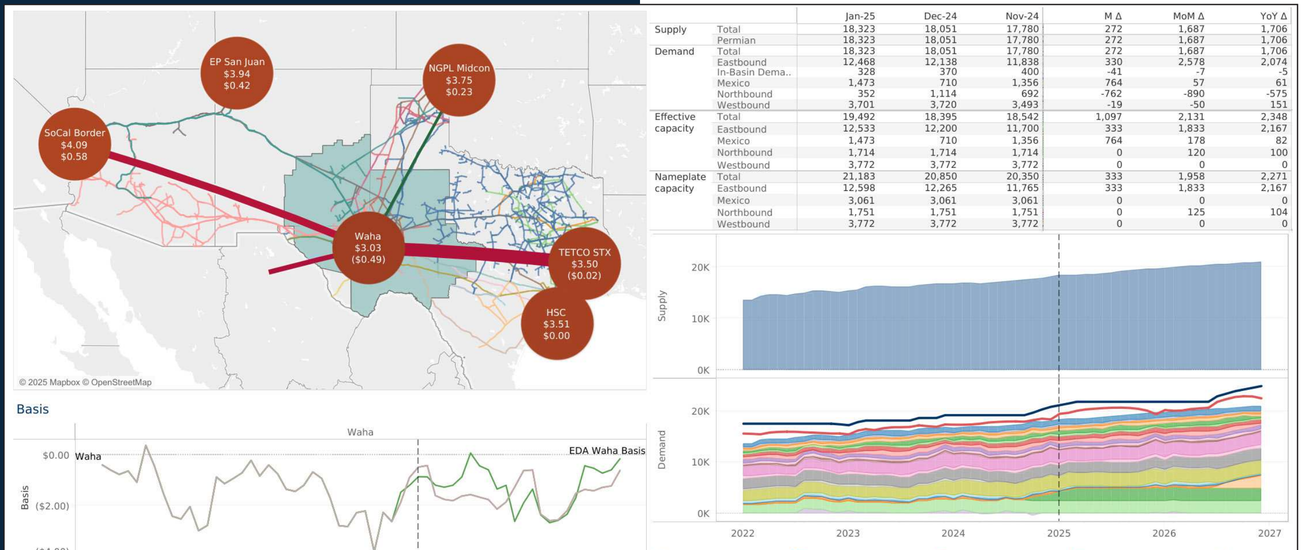
Midstream Consolidation

First, let's review the drivers and impact of the midstream consolidation we focused on in last year's DLS. We highlighted that the industry was in a much better position financially than perhaps it's ever been, or at least in more than a decade. Midstreamers were generating lots of cash flow, which was ample to cover interest payments, capital investment, and shareholder returns in the form of dividends and share buybacks. As a result, leverage was very low or trending lower, just above 3.5x Debt/EBITDA on average, down from 4.5x in 2019.

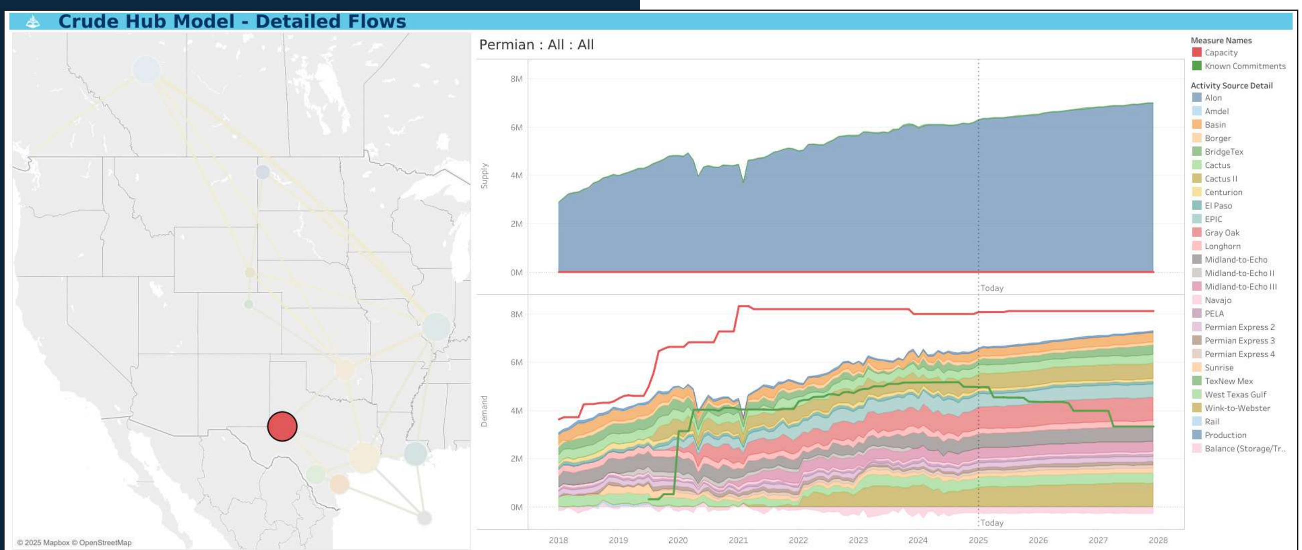
While balance sheets were solid, there were concerns about slower earnings growth based on shrinking opportunities for major projects. In the current slower production growth environment, new major multi-billion-dollar projects can't be built every year. Maybe data center and power demand growth will change that on the gas side, but otherwise, we only need perhaps one Permian gas pipeline every two years. We still might not see a new crude pipeline for another few years, especially if existing pipelines fully expand. NGLs may provide more potential growth, but the overall outlook for steady, significant revenue expansion from new infrastructure remains muted.

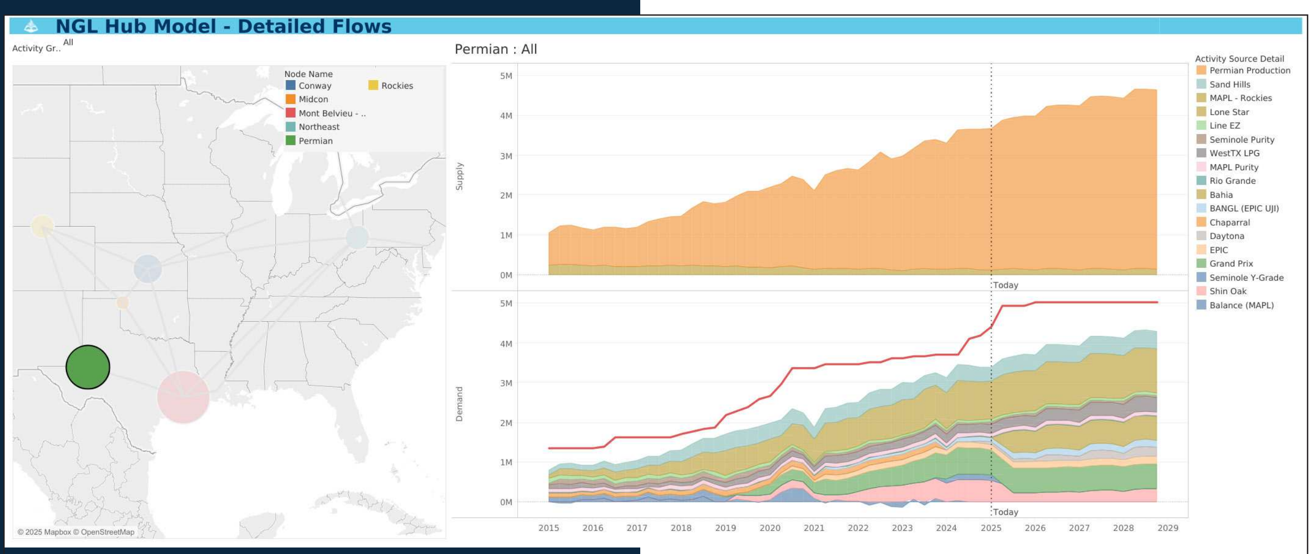
When we did our company analysis, we found that the large cap midstream companies that already had some integrated features were able to grow as fast (if not faster and at a larger scale) than smaller cap peers. Part of the reason was geographical diversity allowed them to position themselves in the few pockets of growth. But more importantly, they were able to extract more value of every hydrocarbon molecule because they controlled more assets along the entire value chain from gathering and processing to downstream end-user markets. Because they were generating more cash flow and had fewer growth projects to spend it on, they could afford to become more integrated by acquiring assets from upstream gathering and processing systems to feed their existing long-haul egress, fractionation, storage, or export infrastructure. The additional exposure to G&P assets allowed them to better utilize downstream capacity and extract value along the chain. Controlling the G&P system allowed them to have more insight into the volume growth that would feed their downstream assets, allowing them to make more precise investment decisions. Please see the charts and graphs on the following page.



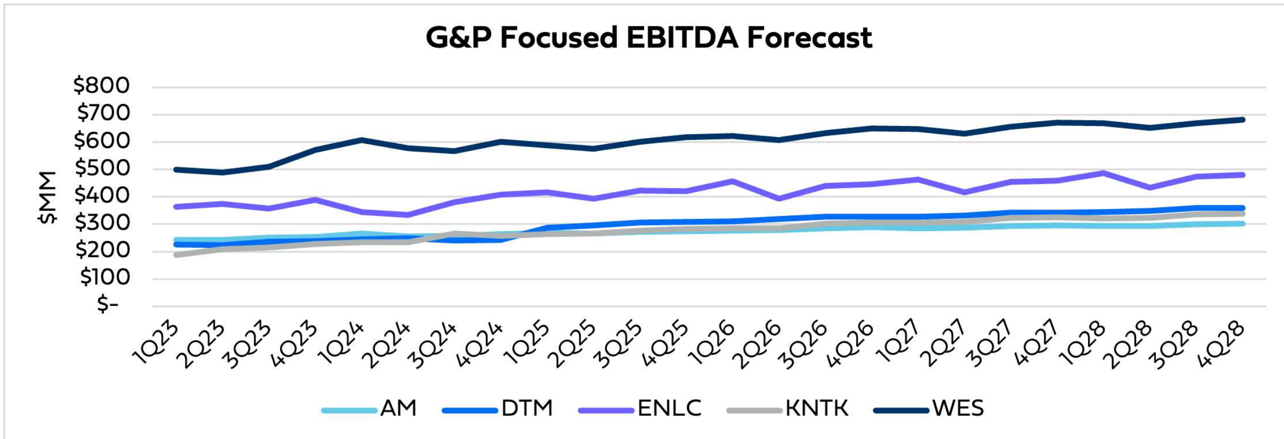


		Jan-25	Dec-24	Nov-24	M Δ	MoM Δ	YoY Δ
Supply	Total	18,323	18,051	17,780	272	1,687	1,706
	Permian	18,323	18,051	17,780	272	1,687	1,706
Demand	Total	18,323	18,051	17,780	272	1,687	1,706
	Eastbound	12,468	12,138	11,838	330	2,578	2,074
	In-Basin Dema..	328	370	400	-41	-7	-5
	Mexico	1,473	710	1,356	764	57	61
	Northbound	352	1,114	692	-762	-890	-575
	Westbound	3,701	3,720	3,493	-19	-50	151
Effective capacity	Total	19,492	18,395	18,542	1,097	2,131	2,348
	Eastbound	12,533	12,200	11,700	333	1,833	2,167
	Mexico	1,473	710	1,356	764	178	82
	Northbound	1,714	1,714	1,714	0	120	100
	Westbound	3,772	3,772	3,772	0	0	0
Nameplate capacity	Total	21,183	20,850	20,350	333	1,958	2,271
	Eastbound	12,598	12,265	11,765	333	1,833	2,167
	Mexico	3,061	3,061	3,061	0	0	0
	Northbound	1,751	1,751	1,751	0	125	104
	Westbound	3,772	3,772	3,772	0	0	0



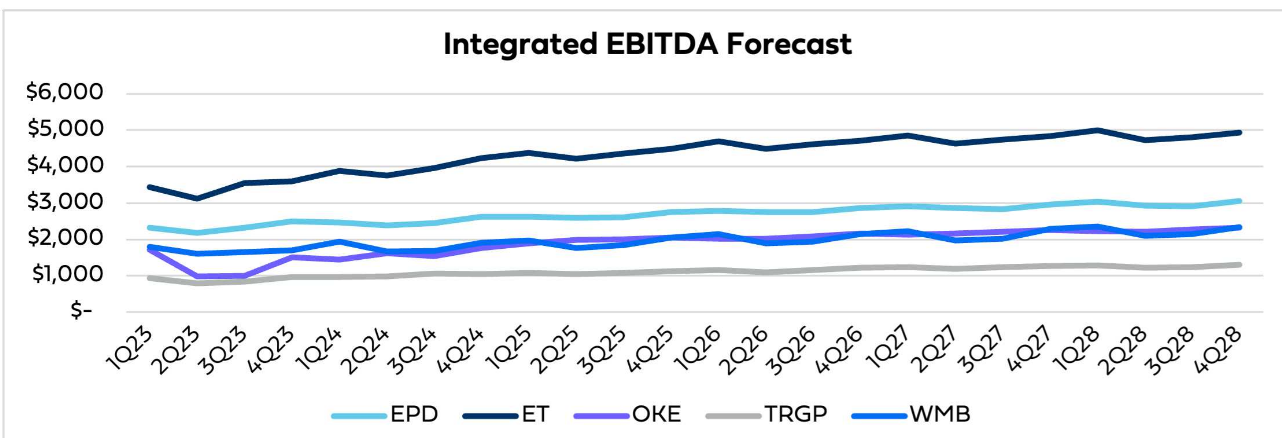


Comparing Growth: G&P-Only Companies vs. Integrated NGL Midstream Companies



	2023 EBITDA ($MM)	2028 EBITDA ($MM)	23-28 CAGR
AM	$989	$1,190	5%
DTM	$924	$1,409	6%
ENLC	$1,485	$1,876	5%
KNTK	$839	$1,319	9%
WES	$2,069	$2,672	5%

Growth of Integrated NGL Companies



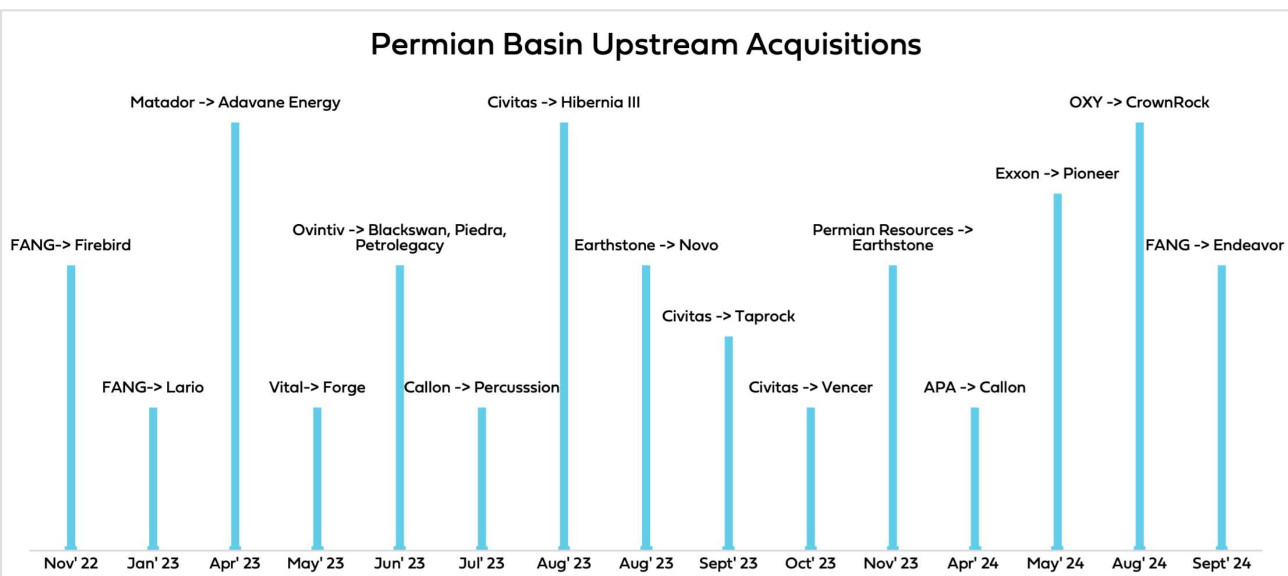
	2023 EBITDA ($MM)	2028 EBITDA ($MM)	23-28 CAGR
EPD	$9,318	$11,926	5%
ET	$13,698	$19,475	6%
OKE	$5,214	$9,023	7%
TRGP	$3,529	$5,031	6%
WMB	$6,763	$8,926	6%

G&P Capacity Growth Feeds NGL Pipes And Frac Capacity

Our analysis has shown that most of these acquisitions were accretive to both income and cash flow. In Texas alone, acquires added 6.3 Bcf/d of G&P capacity, 1.3 Bcf/d of pipeline capacity, and 1 MMb/d of fractionation capacity. Because the smaller companies were facing sharply diminished growth opportunities and any growth was directly tied to E&P growth plans, their valuations were declining and buyers benefited from using their higher-valued equity as currency along with their growing cash reserves. The more connected asset base made the midstream the best performers in the oil and gas sector over the last year. For example, anytime there was a weather event, the large caps have made a lot of money. Anytime there's a steepening of contango in the market, they use their storage to take advantage of widening margins. Anytime there's a dislocation in basis, they use capacity on their pipes to move product from one market to another so they can trade around their assets more effectively. They get better price transparency and information. They can operate their asset system more profitably.

However, most of the larger targets, especially G&P systems, have been consolidated, shrinking the pool for future deals and limiting future growth opportunities.

Permian-TXGC Growth YE23-YE27	G&P Capacity Growth (MMcf/d)	NGL Production @ 6.0 GPM	New Pipeline Capacity	New Frac Capacity	New C2 Export Capacity	New LPG Export Capacity
TRGP	1,605,000	229,286	400,000	442,313	-	25,000
ET	900,000	128,571	90,000	165,000	-	250,000
EPD	1,500,000	214,286	450,000	237,500	300,000	300,000
PSX	220,000	31,429	-	30,375	-	-
MPLX	400,000	57,143	75,000	-	-	-
OKE/ENLC	150,000	21,429	190,000	177,313	-	-
WES	550,000	78,571	-	(42,500)	-	-
KNTK	400,000	57,143	-	-	-	-
Other	580,000	82,857	75,000	-	-	-
Total	**6,305,000**	**900,714**	**1,280,000**	**1,010,000**	**300,000**	**575,000**



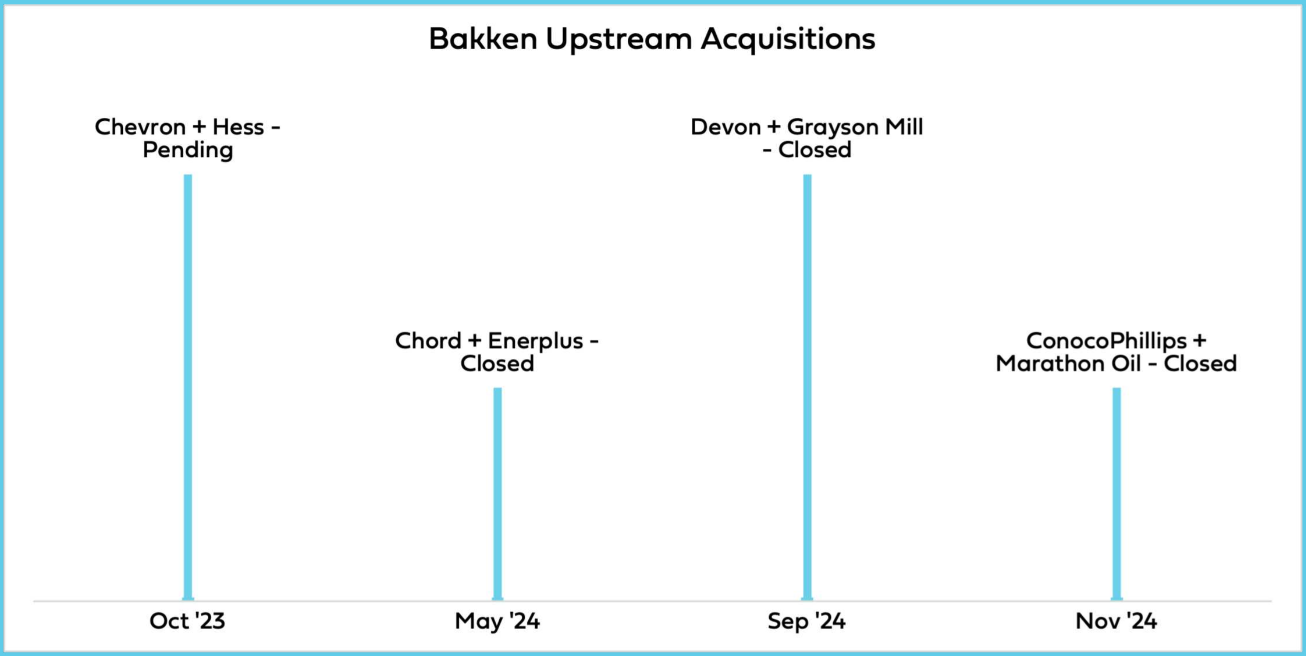
Upstream Consolidation

The drivers of upstream consolidation stem from the dramatic strategic transformation that brought oil and gas producers back from teetering on the financial abyss that began with the dramatic price plunge in late 2014-2015 and culminated in the demand destruction following the onset of the pandemic in early 2020. Investors nearly abandoned the industry as the S&P E&P Index plunged 95% from the 2014 peak. To win back support, producers shifted from a growth at any cost model to a strict focus on financial discipline and boosting cash flows to support strong shareholder returns.

The post-pandemic commodity price swelled producer coffers, which in turn boosted total annual shareholder yields to as high as 10% or greater. However, sustaining elevated shareholder returns became challenging as commodity prices moderated. The result was a massive wave of industry consolidation driven by two factors. First, consolidating acreage resulted in significant operating and financial synergies, which boosted margins. Second, and more importantly, eliminating competitors, especially private companies, gave large producers more control over output growth. In 2021, half the rigs running in the Permian Basin were from private E&Ps that were investing in strong growth to build scale to attract potential acquirers. Today, public companies fund 75% of Permian rigs, giving them more optionality to match supply with demand.

Soaring stock prices as yield-focused investors flocked to the industry allowed the consolidators to largely fund their purchases with equity. Superior returns persuaded sellers to take equity in low-premium buyouts that facilitated the completion of transactions. As a result, consolidators extended their inventory life, and high-graded the quality of that inventory to focus on the highest return projects. They have a longer runway of production and can drill longer laterals. Most importantly, they have more control over supply, which boosts their optionality on when to release it.

However, after nearly $500 billion in post-pandemic upstream transactions, the number of targets is dramatically dwindling, especially in major basins such as the Permian.



What's Next: Will Integrateds Become More Integrated?

The era of the integrated oil and gas company, which by definition includes both upstream and downstream assets, thrived in the 1980s and culminated in the major sector consolidation at the end of the last millennium, highlighted by the mergers of Exxon and Mobil, Chevron and Texaco, Conoco and Phillips Petroleum, BP and Amoco/ARCO, and Royal Dutch Petroleum and Shell. A decade later, at the dawn of the Shale Revolution, de-integration became the dominant theme as companies sought the highest valuation for their individual assets by separating high-growth upstream assets from less volatile but higher yielding midstream and downstream assets. The poster child was ConocoPhillips separation of Phillips 66 in 2011, a strategy soon followed by Marathon's spinoff of Marathon Petroleum and the sale by Hess and Murphy Oil of downstream infrastructure. Independent companies, for the same reason, followed suit by separating their upstream and downstream units. For example, Devon spun off EnLink, Anadarko created Western Gas and Western Gas Partners (now Western Midstream), and Williams spun off WPX Energy.

However, the landscape has dramatically changed over the past decade as upstream companies have abandoned strong growth as an investment strategy to a focus on efficiency and cash flow accretion. So, what's the next step for the integrateds, the largest companies in the oil and gas industry. ExxonMobil and Chevron have consolidated upstream production and have significant downstream and overseas assets. What they don't control is the infrastructure to get that production from the field to the market. Which is why we see the next major strategic shift in the market as the integrateds getting more integrated.

We've seen the integrateds participate in midstream in the past, and they continue to hold certain assets throughout this decade. Exxon holds stakes in the Wink to Webster and Permian Express pipelines in the Permian. Chevron holds a stake in the Matterhorn pipeline and gained the Noble Midstream assets through its acquisition of Noble Energy. But what we're projecting is a more dramatic acquisition of one of the major large cap midstream operators.

We think there are compelling offensive (financial) and defensive (strategic) drivers of this consolidation phase. The offensive reasons begin with the fact that a company can either pay a broker or service fee for midstream services or pay themselves. If you're paying yourself fees, you gain a much more stable, through-cycle cash flow. You also gain better information and transparency on what can be opaque markets. There is often a mismatch between the timing of supply and the timing of infrastructure capacity, which creates constraints in the market and disruptions in price. The integrateds can benefit from disruptions by trading around assets like the large cap midstream firms have been doing for a long time.

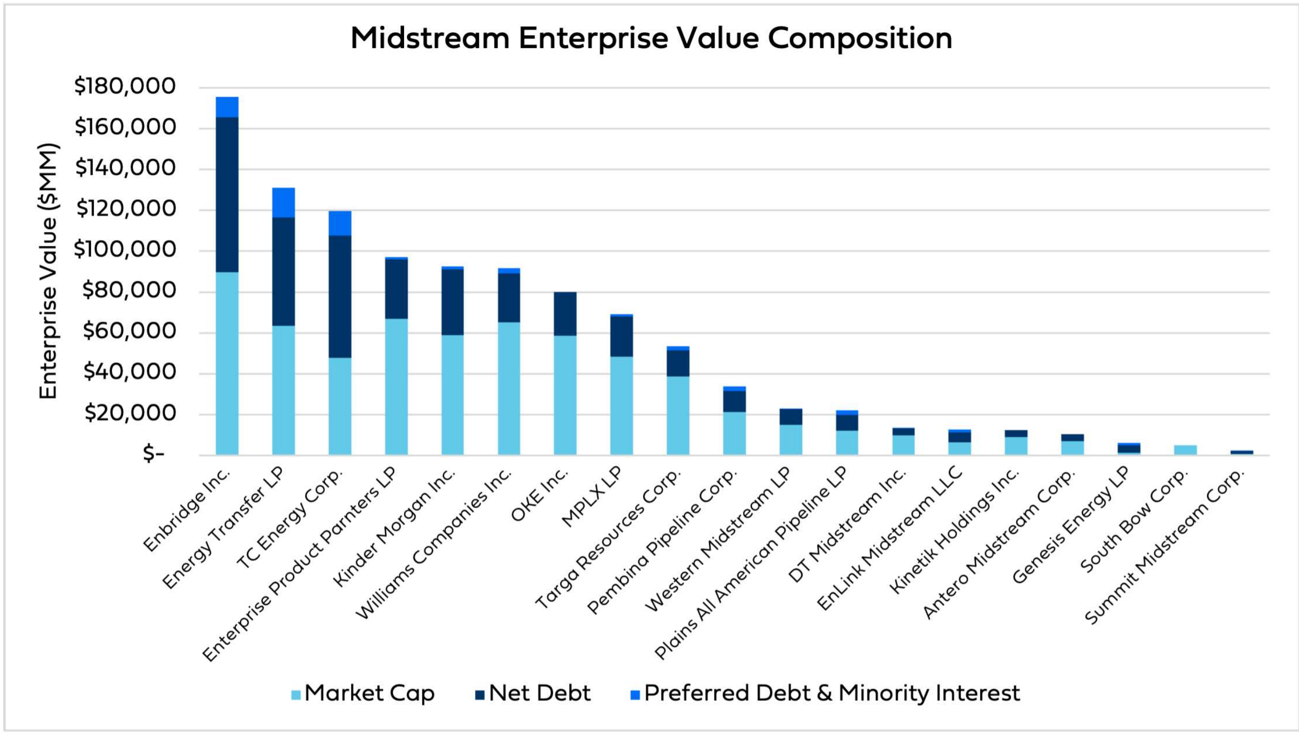
This is especially important because the Permian and other major plays are not just crude basins anymore. They are also natural gas and NGL basins, so having full control of the molecules from wellhead to end user maximizes optionality to find the best markets and generate higher netbacks. A fully integrated firm can better allocate infrastructure investment and time production to better allocate supply and demand.

The defensive, or strategic, reasons to control the molecules from supply to demand markets are a geopolitical setting that is getting more uncertain and more variable. As more of US crude, gas, and NGL supply makes its way on to the water, companies need to be more sophisticated in understanding where shipments are going and how to negotiate with buyers. The large integrateds have decades of experience in selling to and operating in international markets. This is particularly valuable in maximizing the value of the lighter end of the barrel, NGLs. Relatively stable low prices have provided the opportunity for billions of dollars to be spent on infrastructure like ethylene crackers and PDH facilities. There's a lot more certainty about future strong demand for plastics and petrochemical production than there is for demand for refined crude productions. While there is some investment in the US, most is in Southeast Asia, the Middle East, Europe, and even Canada. Choosing the right arena for investment and negotiating supply deals is crucial for stability and profitability.

We have some evidence of the benefits of upstream and midstream integration in the Marcellus. Antero Midstream has been vocal about the advantages of owning Antero Midstream, which is located in the same building. That has led to easy coordination matching infrastructure build to drilling. EQT didn't have that anymore when they spun off Equitrans, so they recently bought it back in a $5.8 billion transaction that significantly lowered operating costs in the first quarter after deal completion. The benefits for the integrateds could be exponentially greater.

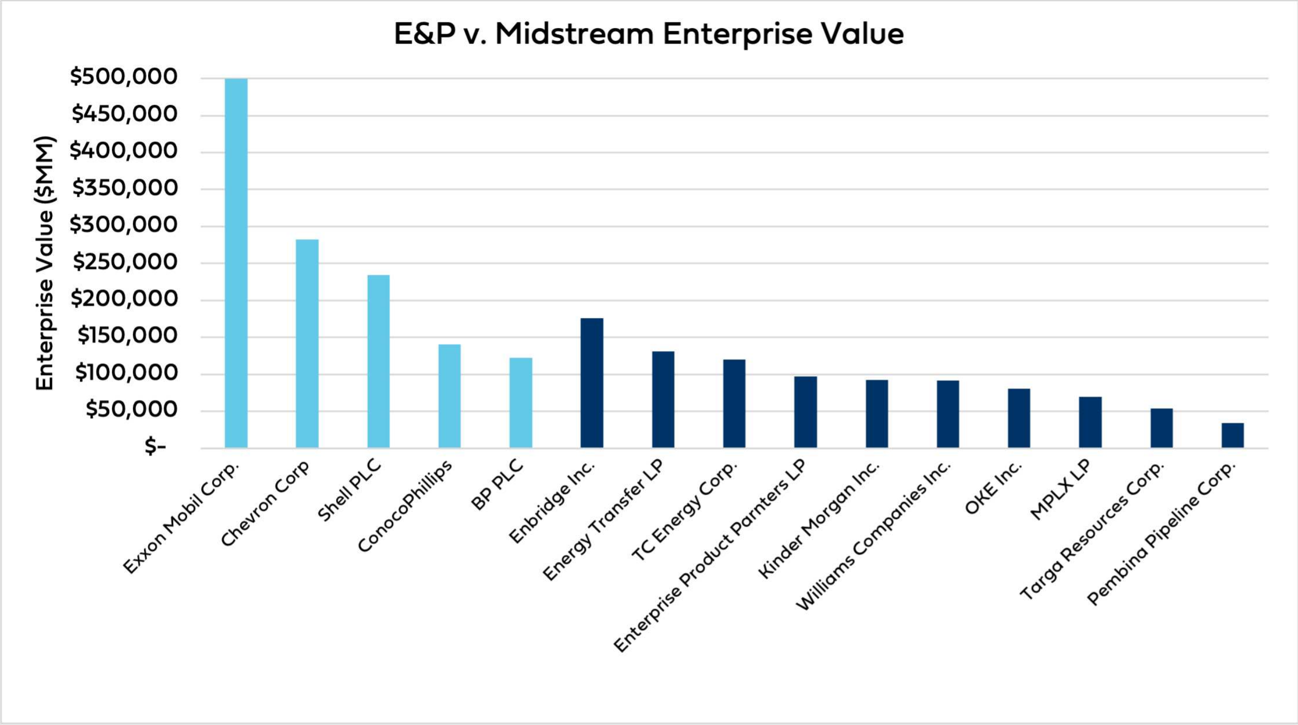
It Takes Two: Why Would Midstreamers Consider Merging with an Integrated?

We previously discussed the benefits large-cap midstreamers have garnered from controlling infrastructure from the wellhead to the demand centers. So, what's the incentive for management to sell a potential buyout to shareholders? The answer begins with the fact that companies must prepare to be in business over decades. And growth in the United States is slowing quite a bit. There are pockets of natural gas and LNG demand growth. But unless a company is directly exposed, entrance is difficult and it's hard to build new infrastructure, even in pockets of high demand. The frontier of growth is exports and integrated companies have a much greater advantage in that arena. Many international opportunities don't exist for a stand-alone midstream company.



There is also the incremental margin expansion that comes from fee reduction and more efficient management by expanding integration from just the midstream portion of the value to chain to include production and downstream end-markets. That may be slower growth than gains from major acquisitions or new infrastructure projects, but it is growth nevertheless. Geographic, product, and asset diversity also provides a natural hedge against headwinds in the energy sector. Current midstream shareholders would gain stakes in larger entities with lower costs of capital, greater income and cash flow growth trajectories, lower volatility, and higher dividends and share buybacks.

Now, there certainly will be some investor pushback against combining businesses into a larger conglomerate. We're still seeing a lot of pressure from activist investment firms to spin off assets to take advantage of higher multiples. The bottom line is that any deal would have to have a good story to sell and a compelling plan on how to integrate the two businesses and drive the most value.



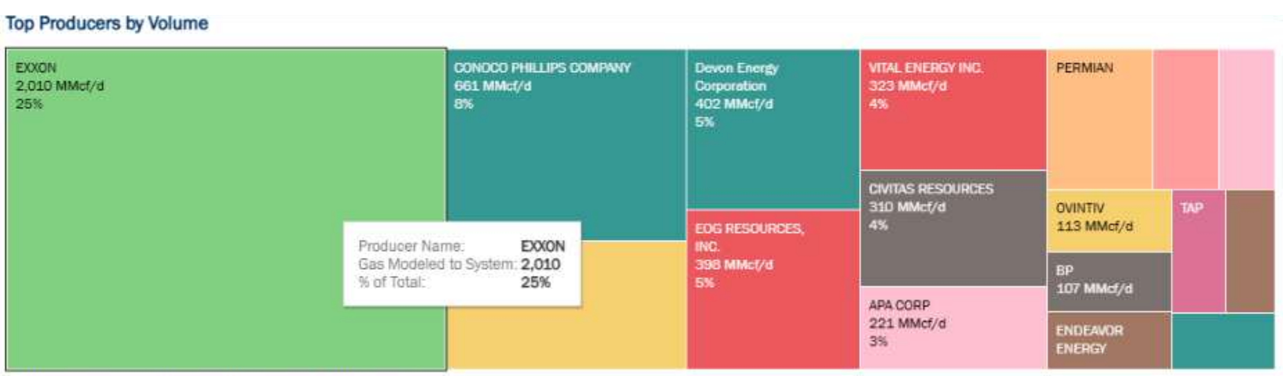
A Potential Combo: ExxonMobil and Targa

An integrated oil or large producer is not going to target smaller midstream operators. If the focus is the Permian, the target is likely to one of the "Big Six": Targa, Enterprise, ET, MPLX, Oneok, or Phillips 66. If we're talking gas, the majors are Williams, Kinder Morgan, TC Energy, and Enbridge. Let's look at a logical example, ExxonMobil buying Targa.

Right now, Exxon provides about 30% of Targa's volumes through their systems in the Permian. Exxon does own a slice of Targa's assets, a 27% interest in its Midland system through the acquisition of Pioneer Natural Resources. Exxon helped build out that gigantic Midland system, where it is the anchor shipper and supplies about 50% of the volumes. Exxon "pays rent" to Targa to get its product, mostly NGLs, to the Grand Prix or Daytona pipelines to Targa's storage, frac, and downstream facilities, including LPG export. Exxon feeds Targa's Delaware system, too. For Exxon, purchasing that company and owning the entire value chain provides a significant cost benefit. It wouldn't do it at any price. But Exxon generated $36 billion in free cash flow in 2023 and ended the year with $31 billion in cash and just a 5% net debt to capital ratio. It could easily fund the purchase of the $40 billion market cap Targa.

The cost of that acquisition could be significantly offset by the sale of Targa assets that are non-core to Exxon. The driver of acquiring the midstream company is to connect its upstream and downstream assets, not to provide third party operations for other producers. Although Exxon is a top producer in the Bakken, it recently announced it was marketing part of its assets in the play. The remainder might not be a good fit to benefit from Targa's system. A clearer candidate for divestment is Targa's Anadarko Basin assets, where Exxon would be unlikely to allocate capital.

The non-core assets that may be divested by Exxon or another integrated that moves into the midstream may be very attractive to private equity firms. We're going to cover that topic in detail in the Private Equity section of this report.



Targa top producers by volume all basins

Targa Midland Basin top producers by volume

Summary

Supply growth in the United States has slowed, but it hasn't stopped. And anyone who thinks the energy renaissance is over is wrong. The three commodity streams, crude, natural gas, and NGLs are closely linked and the need for sophistication in owning supply and assets is higher than ever. In every basin, it matters who owns the assets, where the constraints are, and how companies can maneuver to most efficiently move molecules to market. A great deal of this supply is being fed to international markets, which requires a whole new dynamic. There is opportunity for infrastructure owners, especially integrateds that can add midstream assets to their upstream and downstream businesses.

Power Surge: Data Centers Driving Energy Demand and Gas Growth

Changes in energy consumption typically evolves over time, which makes the emergence of the enormous demand for electricity to fuel surging construction of data centers seem as sudden as the Greek goddess Athena bursting fully-formed from the forehead of her father Zeus. While that metaphor may be a bit extreme, the energy use of these facilities hosting vast banks of networked computers are of mythological scale: the typical new data center consumes 100 to 1,000 megawatts, a load equivalent to 80,000 to 800,000 homes. The frenzy was triggered by the late 2022 emergence of ChatGPT, the first public generative artificial intelligence (AI) program, which has led to plans for construction of facilities focusing on AI powered tasks from speech and image recognition to predictive analytics to generative AI. Most AI centers are hyperscale facilities, which feature banks of 5,000 or more servers and can range up to one million square feet.

Although the emergence of this demand is so new that forecasts are constantly evolving, the most reliable estimates are that data centers will account for nearly half of an expected 10%-26% increase in U.S. electrical demand over the next five years. Utilities are scrambling to meet the expected surge through a wide mixture of sources that range from renewables like wind and solar to reopening previously mothballed nuclear power plants. Private capital is also being accessed to fund co-generation facilities like small-scale nuclear reactors. However, we believe that for the remainder of this decade, natural gas will be the most available, reliable fuel for new generation.

In this section, we will delve into the details of data center expansion and forecast the impact on U.S. natural gas demand. Until recently, most analyses of future gas demand growth have centered on the expansion of LNG exports. We believe that the increase in demand to fuel generation to service data centers will add a second, significant level of consumption that provides additional optimism about significant growth in gas pricing and production in the rest of the decade. This growth will have major impacts on new opportunities for both producers and midstream companies.

Data Center Growth and Consumption

The number of data centers in the U.S. doubled from 2,700 to over 5,300 from 2021 to 2023. While these include cloud servers, web-hosting facilities, and cryptocurrency/bitcoin mines, the recent surge comes from AI-powered tasks such as speech and image recognition, predictive analytics, logistics/mapping applications, personalized diagnostics, fraud detection, and, most notably, generative AI. About 80% of their power usage is consumed by the 1,066 current massive hypocenters. Siting these facilities depends on three main factors, access to reliable and affordable energy, access to water, and then the ability to connect to an existing fiber optic network. Today, the largest number are in northern Virginia, where they consume about 25% of total grid demand. California, Texas, and Illinois have the next largest number of sites.

However, Virginia and Texas are the dominant locations of the more than 100 new hypercenters expected to be online by the end of 2025. Those markets are joined by Georgia, Ohio, and Arizona as hot spots for future facilities, as shown by Figure 1 below. A major factor is the cost of land, which is limiting future siting in tech hot spots like California and Washington. A second incentive is a friendly political environment for new energy projects that facilitates permitting for projects that will generate significant future tax revenues. Local and state governments in these areas generally reflect a sentiment that encourages domestic data center growth to boost national security and economic competitiveness.

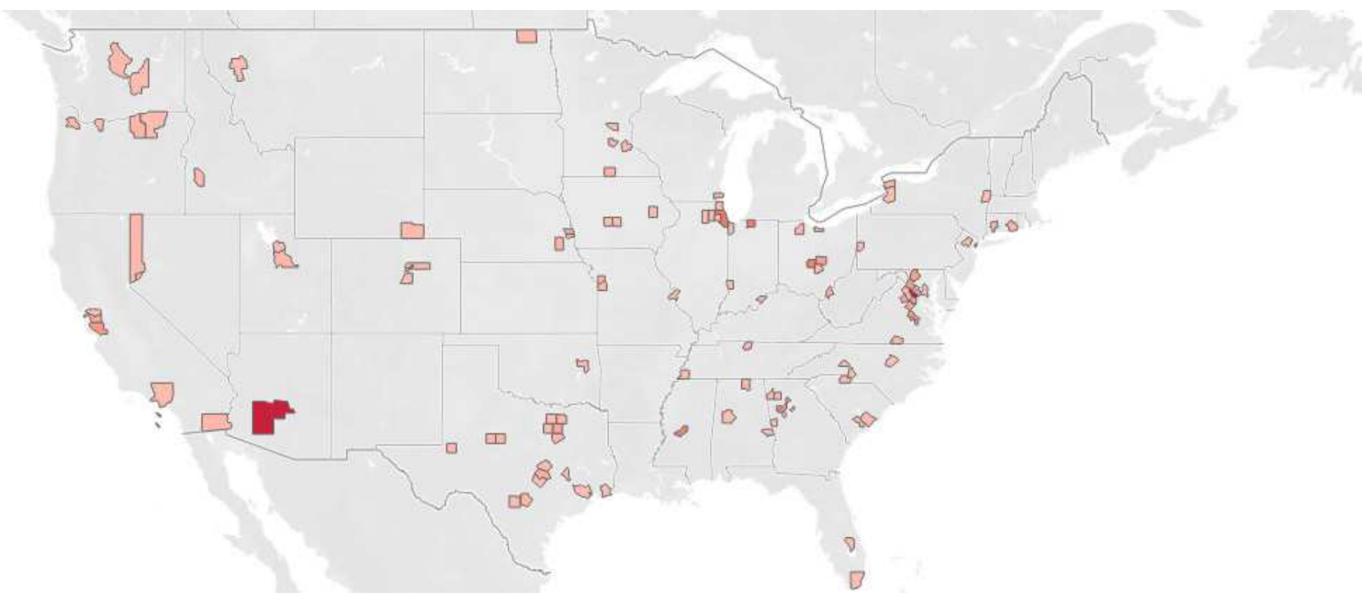


Figure 1: Data Centers Projects Estimated Load Heat Map-Source: East Daley

The energy consumption by these centers is expected to account for nearly half of the expected 10%-26% increase in total U.S. electricity consumption by 2030. This dramatic boost comes after just a 5% increase in demand in the past 20 years through 2023. Our estimate is that these new centers will add 115GW of demand by 2030, as highlighted in Figure 2 below. The percentage of total usage attributed to data centers is forecast to rise from the current 3% to 6%-9% by 2030.

State	Est. IT Load (MW)	Est. Total Load (MW)	Gas Equivalent (Bcf/d)	Natural Gas Generation Share (%)	Demand Captured By Gas (Bcf/d)
Virginia	22,589	30,495	4.90	48%	2.35
Arizona	9,768	13,186	2.12	39%	0.83
Ohio	7,100	9,585	1.54	57%	0.88
Texas	5,467	7,381	1.19	46%	0.54
Georgia	5,464	7,377	1.18	40%	0.48
Illinois	4,931	6,657	1.07	15%	0.16
Indiana	4,665	6,298	1.01	38%	0.38
California	4,454	6,013	0.97	26%	0.25
Mississippi	3,910	5,279	0.85	73%	0.62
Maryland	3,320	4,482	0.72	37%	0.27
Others	13,283	17,932	2.88	39%	0.70
Total	**84,952**	**114,685**	**18.42**	**39%**	**7.48**

Figure 2: Natural Gas Data Center Demand Captured by Gas-Source: East Daley

Although the political sentiment toward data centers has been positive, the magnitude of the anticipated demand has raised concerns about the impact on the reliability of the grid and the potential increase in the cost of electricity for consumers. The potential fragility of the grid in Texas is particularly concerning after Winter Storm Beryle in 2021 knocked out power for millions of people for multiple days.

The major concern for the companies constructing data centers is matching the timing of construction with the timing of connection to the grid. In the past, the two-to-three-year completion of data center construction generally matched with the wait for connection to the grid. But the queue of projects waiting for connection is growing longer, especially in growing areas like the Southeast where data centers compete with new industrial and residential projects.

That has led to the search for creative solutions, one of which is on-site generation. This doesn't just mean building a data center near utility-constructed generation. In many cases, the developer of the project would partner with private entities and build on-site power that is uniquely suited for that facility or for a group of facilities that are in the same industrial park. One of the main conclusions of a recent Federal Energy Regulatory Commission (FERC) convention is that the reliability afforded to data centers is significantly higher when co-located with a generator. The need to invest in generation has drawn in capital, particularly private equity. For example, KKR and Energy Capital Partners recently announced a $50 billion dedication to data center and power generation projects.

Fueling Generation and Co-Generation for Data Centers

It's not a surprise that every source of generation is being called upon to meet the soaring data center demand needs. That includes power purchase agreements for renewable energy projects that are wind and solar-based. And then we're seeing some unique agreements involving nuclear generation. Amazon Web Service recently purchased a 960-megawatt Pennsylvania data center complex from Talen Energy, which is powered by Talen's Susquehanna Steam Electric Station. Susquehanna is the sixth largest U.S. nuclear power plant, with a generation capacity of 3.5 gigawatts. In another deal, Microsoft has signed an agreement with Constellation Energy to draw power from a restart of the Three Mile Island nuclear power facility, also in Pennsylvania. Other proposed project sponsors are exploring co-generation provided by smaller-scale nuclear reactors.

However, the lack of sufficient battery storage makes the reliance on renewables alone difficult to meet the 24-hour, seven days a week demand of data centers. The time frame for new nuclear developments or permits to reactivate moth-balled nuclear facilities can be extensive. That's why we believe that natural gas will fuel an increased share of the new grid generation and co-generation facilities over the next few years until the time battery technology advances to stabilize power from renewable projects.

To calculate additional natural gas demand from added data center generation, we took our estimate of 115 GW of new capacity and applied a very conservative average capture rate of 39%, which is slightly below the 43% average weighted share of the 2023 generation reported by the EIA. We converted from megawatts to a volume of gas, making caloric and chemistry-style assumptions, and we calculated a heat rate of about 6.95. As you can see in Figure 2 above, applying that to 39% of 115 gigawatts leads to about 7.5 Bcf/d of incremental gas demand that we're attributing to data centers by 2030. As shown in the table, the share of demand for natural gas ranges from a high of 57% for Ohio projects to a low of 15% in Illinois.

That 7.5 Bcf/d in draw from data centers will augment our projected 12 Bcf/d increase to feed new LNG export facilities. These two main factors as well as additional demand expected from exports to Mexico and industrial and non-demand center-related electric generation projects translate to the need for a 15%-20% increase in U.S. gas production.

The downside to our 7.5 Bcf/d estimates comes in the form of project viability and timelines. As with any large-scale construction effort, projects fall behind schedule and can be shuttered. We have not risked any of the 304 projects that we located in our data set, and there is a possibility that some projects will not be online by 2030. Nonetheless, new projects are announced every week adding to the upside potential not captured in our 304-project list. At this time, we take these factors to be offsetting.

The level of investment needed to meet the extraordinary growth in electric demand from data centers is likely to increase both the residential and commercial costs of power. And the major increase in gas demand will have significant impacts on both natural gas producers and U.S. midstream companies.

Impact on Electric Rates—Rates Rise as Demand Surges Past Supply

We expect the surging demand for electric generation will drive significant increases in power pricing. Strong evidence was provided by the recent power capacity auction conducted by PJM, a regional transmission organization that coordinates the movement of wholesale electricity in 13 states from Illinois to New Jersey and the District of Columbia. The auction, which secured the rights to 135 gigawatts from June 1, 2025, through May 31, 2026, resulted in a price of $269.92 per megawatt day, nearly ten times the $28.92 per megawatt-day for the 2024-2025 auction. The result reflects a steep step-up in demand and a lack of infrastructure being built to cover the retirement of certain coal-fired and other facilities. A PJM spokesman said that auctioned generation, which reflects the distribution of power when systems reach capacity, influences about 8% of overall power prices. The enormous new demand for electricity is also expected to drive scarcity in other regions.

Another factor driving price increases is shortages of equipment and raw materials needed for the increased construction of generation facilities, such as transformers, electrical steel, and copper. These are the same types of increases that drove post-pandemic inflation in areas such as oilfield equipment and services. One mitigating factor for electric demand and pricing could be increased chip efficiency which lowers the growth of electrical demand. However, it will likely take several years before technological innovation can offset the huge demand that will drive shorter-term higher rates.

Impact on Producers—
Rising Prices Trigger Strategy Shift to Dry Gas Drilling

The sudden emergence of data center demand further brightens the outlook for the renaissance in gas pricing already expected in the second half of this decade as 12 Bcf/d of LNG export capacity comes on stream. The obvious benefit to producers is increased drilling opportunities to provide the growing supply. Gas producers have been concentrating on their wetter acreage to produce NGLs while gas prices are weak. On the East Coast, data center demand in Virginia and the Southeast should spur drilling in the dry areas of the Marcellus. The twin demand drivers of Gulf Cost LNG export facilities and Texas data centers will likely drive a similar focus shift to dry areas of the Eagle Ford and in Haynesville, where drilling has been sharply curtailed over the last three years. Over time, there will have to be an analysis of balancing NGL supply with an increased need for just dry gas. Now we might see an increased drilling in dry gas, which could reduce NGL production. So there will need to be a finer read on truly where NGL demand is and how much targeted drilling is needed to source that level of NGLs.

Drilling in the Permian has, and will continue to be, targeted on crude oil. Periodic negative gas pricing at Waha has resulted in a strategy that focuses on dampening the production of associated gas. Rising gas prices and demand will likely remove the concern for producing dry gas, leading to more balance in total output coming out of the Permian. Optionality in sourcing Permian gas to different Southeast demand regions will begin to be more important. Rather than simply getting gas out of the Permian basin, or just to the Gulf Coast, there will be increasing value in being able to route the associated gas molecules to a larger and more diverse group of end users.

Some producers have explored the idea of directly supplying gas to data center co-generation facilities. There may be certain unique opportunities where producers own land or local infrastructure, especially in fields where they have their power generation onsite. However pipeline capacity will become increasingly valuable as gas demand rises, and producers will find it difficult to find parties willing to sell interests in infrastructure. That rising demand for pipeline capacity instead becomes a major opportunity for midstream companies.

Impact on Midstream Companies: Capacity Constraints Drive Higher Pricing for New Build and Recontracting

We believe that the midstream industry has a little bit of runway before the bulk of the LNG export capacity is completed. There will be some increase in the back half of 2025, but it's 2027 when there's a lot of this data center and LNG export demand that will come online. We believe the industry has two to three years to build out some infrastructure projects and will miss major opportunities if it is too conservative to commit investment dollars to this effort.

The reason is that there is so much demand for generation that both utilities and the entities that are funding co-generation facilities will pay more to source natural gas. Key evidence is early-stage expansions that are serving both primary utility load and some data center development. These are the Southeast Supply Enhancement project on Transco and the South System Expansion 4 on the Southern Natural Gas system. Both are charging what we consider astronomically high negotiated rates for capacity on the expansions. The Southeast Supply Enhancement Project is charging ~$0.7159 per Mcf to transport gas while the South System Expansion 4 is seeing rates of ~$1.40/Mcf.

These are far higher than the maximum tariff rates approved by FERC, which limits rates to a "reasonable rate of return" on what it costs to operate and maintain the pipe. We define "reasonable" as a return of 10%-16%.

The combination of LNG and data center demand is inevitably going to spur new projects to serve these markets. We expect to see this expansion in the Atlantic Coast and Southeast, which will likely result in projects moving gas from west to east. We believe we are going to see negotiated rates on these expansions, locked in for 15 to 20 years, that far exceed the maximum tariff rates.

We also believe that contracting capacity on long-term deals will be increasingly competitive in the near term. With people pounding the drum for growing demand, there is far less risk associated with contract roll-offs and an increasing likelihood that shippers will renew at rates in line with the max tariff rate, with potential for upside in the negotiation of negotiated tariff rates.

Impact on Gas Storage: Data Center Demand Intensifies Need for More Capacity

Until the last couple of years, gas storage capacity had not changed for over 10 years. Even before the emergence of the data center theme, when the primary, macro event was the ramp-up of LNG demand in the Gulf Coast, we were already sounding the alarm that there was a need to build more storage. Weather events affect LNG offtake: if there's a storm on the Gulf Coast, those boats are not coming into port and picking up their cargo. That has heightened the demand for storage, which in turn is boosting prices to the point where it is economical to build more, just for LNG.

Now, with data centers, we are adding a baseload. They operate 24 hours a day, 365 days a year. This contrasts with utility demand, which varies widely depending on factors such as the time of day to especially hot or cold weather. Most utility systems have been constructed to accommodate those peaks, with a safety buffer zone to diminish reliability concerns. However, data centers are pushing the baseload to the peak capacity of many systems. There is going to be an increased need for storage so withdrawals can cover the spikes in utility demand while maintaining that increase in baseload. So, the value of storage is certainly going to rise. We believe we are at a point where we will see more announcements of storage capacity construction over the next 12 to 24 months.

Summary

The emergence of AI has triggered a surge in the construction of massive data centers that consume enough electricity to power small cities. The result is an enormous demand for new electric generation. While a wide spectrum of energy sources will be tapped, the abundant reserves of U.S. natural gas are likely to be called upon to fuel a dominant portion of this generation. A conservative estimate of the increase in gas demand is 7.5 Bcf/d, already two-thirds of the much-heralded demand coming from new LNG export facilities. That demand could well be higher.

Rising prices from rising demand will trigger a renaissance in U.S. dry gas drilling and likely rebalance U.S. production among the three hydrocarbon commodities, crude oil, natural gas, and NGLs. It will also spur profitable opportunities for midstream companies to expand existing pipelines as well as new construction projects. Meeting data center baseload will exacerbate the current existing shortage of gas storage and will also likely lead to announcements of new major infrastructure projects.

Private Equity: Filling the Infrastructure Void

As Jim Simpson said in his CEO message that opens this report, we are very excited about the next six years, when the U.S. is going to be the world's largest supplier of all three hydrocarbon commodities, crude oil, natural gas, and NGLs. While renewables will continue to attract investment, the pendulum has been swinging back toward oil and gas, and the recent election is likely to accelerate that momentum. We're confident that we see significant investment opportunities emerging in 2025, particularly for private equity.

Those opportunities are in large part driven by the three main themes in this DLS: upstream and midstream consolidation that will lead integrated to become more integrated; surging power usage by data centers joining LNG exports to drive up total natural gas demand; and future strong natural gas production growth will influence trends in both crude oil and NGL output. Recent reports indicate that capital providers share our enthusiasm for the industry, as private equity announced the raising of almost $20 billion, most of it targeting oil, gas, and midstream development, in the last ten days of October.

East Daley is uniquely positioned to provide the data and insights crucial to identifying and maximizing the value of investment opportunities across the energy value chain. As we explained in our methodology, we track every molecule and every asset across all three commodities from wellhead to end user. Correlating this data allows us to provide macro-level insights into a holistic view of commodity and energy capital markets in the Lower U.S. 48. We also generate micro-level models of individual assets, which we can roll up to provide forecasts at the system, basin, and regional levels for crude oil, natural gas, and NGLs. Then these base models can be modified to provide accurate scenarios using different demand and pricing assumptions. We also provide proprietary insights into how infrastructure interacts, such as how Permian gas trends can impact other regions such as the Rockies.

Let's take a look at what kind of opportunities generated by our three major 2025 themes could provide for private equity and other investors.

Basins	Number of E&P Companies	Total Midstream Companies	Number of Public Midstream Companies	Number of Private Midstream Companies
Anadarko	1,706	16	7	9
Appalachia	78	32	14	18
ArkLaTex	419	23	14	9
Fort Worth	457	11	5	6
Permian	780	26	9	17
Rockies	272	36	15	21
Texas Gulf	499	14	6	8
Williston	100	17	9	8

Integrated Become More Integrated

As we discussed earlier in DLS, slower growth and fewer opportunities for large-scale growth projects have driven surging midstream and upstream consolidation over the last three years. Large-cap midstream companies have been able to grow faster than small-cap companies by extracting more value from every hydrocarbon molecule by controlling more assets along the entire value chain from gathering and processing to end-user markets. Similarly, large producers have focused on boosting margins by capturing operating and financial synergies from consolidating acreage while eliminating competitors to gain more control over output growth.

The strategy of maximizing profits and living within cash flow has put both sectors in the best financial position in decades. But consolidation also creates significant investment opportunities for outside capital in two ways, particularly in the midstream. First, corporate mergers can't be accomplished ala carte, so every deal comes with assets that are non-core to the combined entity. Second, consolidation gives integrated companies more pricing power, which can lead major customers to explore infrastructure alternatives to lower costs and regain more control over their output.

First, non-core assets. Consolidation focuses on complementary assets that boost margins and create synergies. However, the buyer generally ends up with assets that don't fit so neatly into the combined entity's portfolio. Investing within cash flow and maximizing margins means some non-core assets are not going to be able to compete for capital for several reasons, including location, scale, commodity focus, and short-term vs. long-term growth potential. For example, Anadarko Basin infrastructure may be non-core to a buyer's Permian-focused core. Major firms are more likely to prioritize billion-dollar projects over a series of smaller $25 million or $50 million investments. The buyer may see limited short-term growth opportunities for associated gas or NGLs in a specific region where prices are low or takeaway capacity is constrained. So it's logical for the buyer to monetize these assets to reduce debt from the acquisition or to fund higher-margin investment opportunities.

These non-core assets are obvious investment opportunities for private equity, which may prefer smaller-scale investments, have a higher risk appetite, or have a longer-term investment horizon. The key issue is accurately assessing their valuation, a process in which

East Daley can provide critical data and analysis. We have a proprietary model that can produce financial results, including valuations, for individual assets. A $50 million investment that doesn't interest an integrated company may well provide double-digit returns to the right owner. We can also craft scenarios for longer-term growth opportunities based on our macro-analysis of demand growth on a regional and national basis.

The second set of opportunities stems from integration limiting the optionality of competitors to get their products to market. Mergers in any sector limit competition, which can trigger an anti-trust review. Although oil and gas sector consolidation has been spared government intervention so far, large producers can be limited in their pricing and capacity options to get their output to market. Rather, the more sophisticated companies may prefer to contract for each part of the value chain individually to get a better rate overall. In addition, they may want to market their gas instead of relying on a midstream company.

This situation provides an opportunity for private equity to step in. A prime example is Whitewater Midstream, formed in 2016 by multiple private equity funds and direct investors to build out new pipelines from Texas gas hubs. Major projects include the Whistler Pipeline from the Waha Header in the Permian Basin to a terminal near Agua Dulce, Texas, and most recently, the Agua Blanca pipeline from the Delaware Basin to Waha. Another example is EPIC, formed in 2017 to build crude oil and NGL pipelines across Texas and New Mexico for delivery into Corpus Christi and other Gulf Coast demand and export markets.

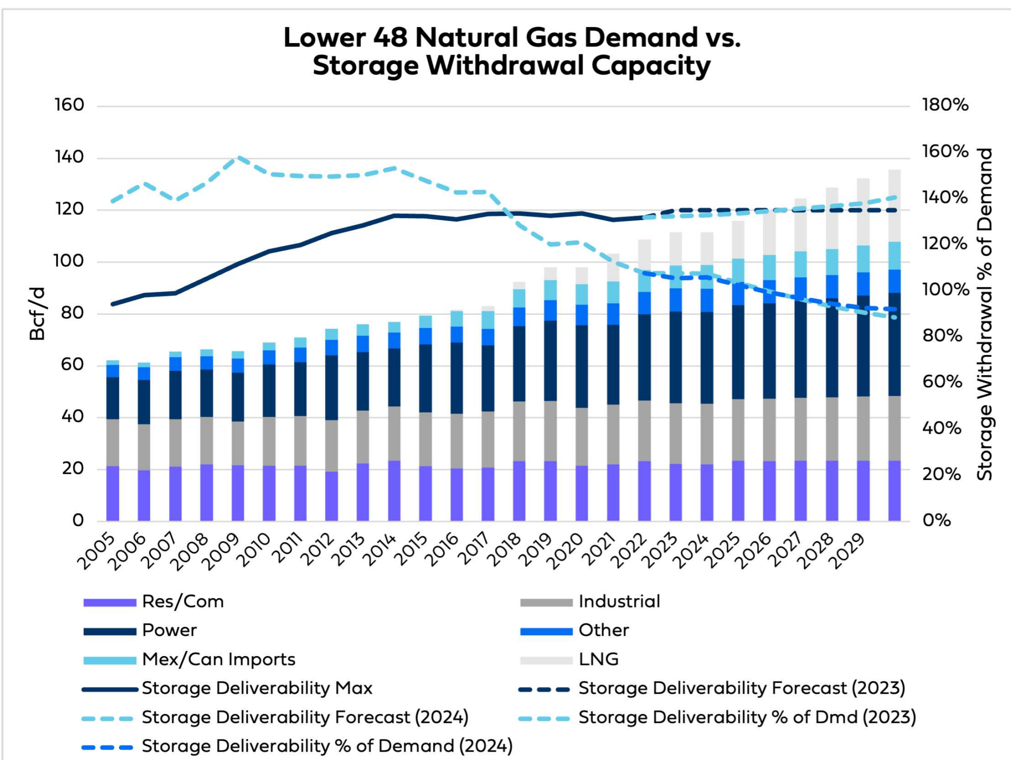
We believe there will be continued opportunities for private equity, in many cases in collaboration with large producers, to build out alternative delivery systems in the Permian and other major plays as production rises. Our holistic views of molecule flow, fees, and capacity constraints allow us to provide forecasts for potential investors in such projects.

Data Center Power Demand

As we discussed previously in this report, data center power demand is surging, driven by the dramatic emergence of AI. In turn, these massive projects are projected to dramatically boost demand for natural gas, which will fuel by far the largest portion of the necessary generation. Together with the previously forecasted dramatic rise in U.S. LNG exports, these dual factors will drive significant production increases, significant price volatility, and significant infrastructure capacity needs.

Much of the recent build-out in natural gas infrastructure has been focused on delivery to the developing LNG export facilities on the Gulf Coast. The more recently developed data center power demand is far more geographically diverse. The dominant locations for massive hypocenters expected online shortly are Virginia and Texas, followed by Georgia, Ohio, and Arizona. But future demand can develop anywhere that provides inexpensive access to land, water, energy, and fiber optic network access.

Existing utilities in hub areas have been stressed to provide additional generation quickly enough to meet the two-to-three-year construction span of these new centers, which has subsequently boosted their demand for natural gas. In our data center section, we explained that midstream companies have been able to significantly boost rates for expansions to their existing infrastructure and demand higher rates when contracting capacity. We see many additional opportunities for future expansion projects on existing infrastructure from the current major supply basins, as well as the opportunity for new entrants to construct takeaway capacity to high-growth areas from existing major producing basins.



Perhaps more opportunities lie in the development of cogeneration facilities to serve data center hubs, given the struggles of existing generators to match output growth with rising demand. While utilities may be involved in some of these dedicated co-generation facilities, a more logical step is a three-way partnership between data center developers, producers, and private equity investors to fund the infrastructure to connect the transport of the gas from the wellhead to end-users. These types of projects are too small to attract large-cap midstream companies but can produce generous, long-term returns. Given the geographic scope of data center development, these projects are suitable for producers in virtually any producing area. East Daley's expertise can be invaluable in modeling the expected costs and returns of such projects.

As we also discussed previously, another consequence of soaring gas demand from the utility, LNG export, and industrial development is the need for more gas storage. However, current market rates do not support the high costs of developing storage today. Our fundamental outlook is that this is likely to change in the future. There has been little storage construction over the last 20 years, but large-cap midstream companies have been buying individual storage facilities and investing in certain new assets in anticipation of future constraints. We believe that there is a role for private equity to step in to build out smaller-scale storage projects and the connecting "last mile" infrastructure to specific end-use facilities. The investment is currently high risk, but storage rates have the potential to skyrocket in the future because no major projects are emerging to meet future demand.

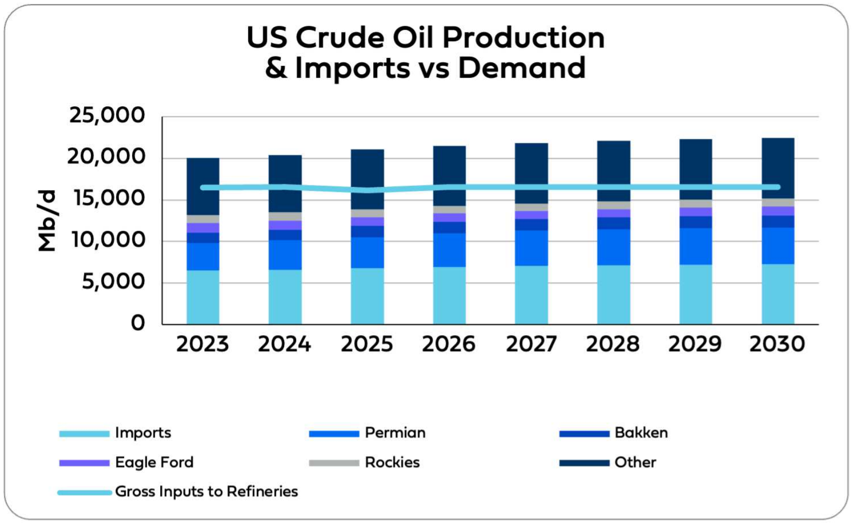
Owner	Asset	Capacity (Bcf)	Capital ($MM)	In-service
Kinder Morgan	Markham Storage Facility	6	$46	2Q2024
Boardwalk Pipelines	Midland Storage	5.7	Not Disclosed	2Q2024
Boardwalk Pipelines	Boardwalk Storage Compression	5.4	Not Disclosed	2Q2024
ONEOK	Reactivation of Texas Storage	3	$60	3Q2024
Enbridge	Tres Palacios	6.5	Not Disclosed	4Q2024
ONEOK	Oklahoma Expansion	4	$100	2Q2025
Caliche	Golden Triangle	14.4	Not Disclosed	2Q2026
Kinder Morgan	NGPL Gulf Coast Storage	10	$94	2Q2027
EnLink Midstream	Jefferson Island Storage Hub	8	$85	1Q2028
Enstor Gas	Mississippi Hub	33.5	$238	1Q2028
Gulf Coast Midstream Partners	Freeport Energy Storage & Sequestration Hub	12	Not Disclosed	2Q2028

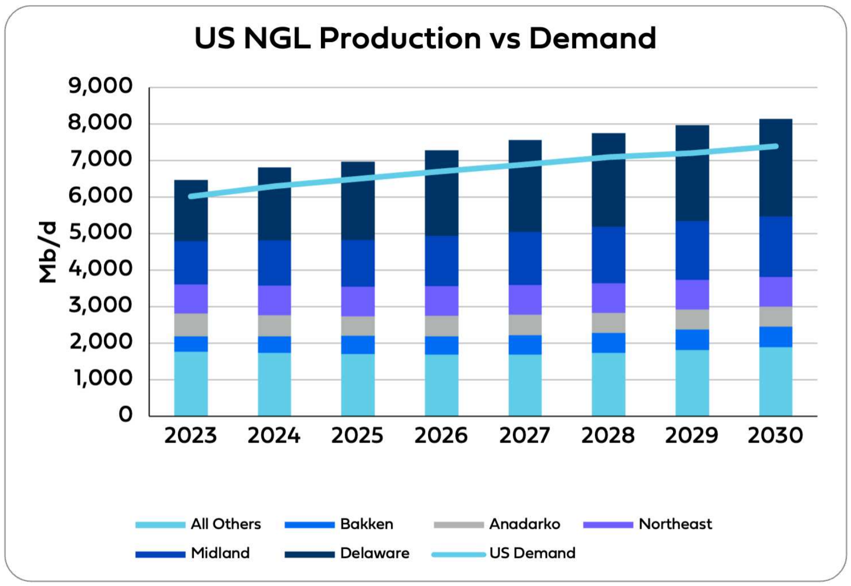
Buyer	Target	Capacity (Bcf)	Price ($MM)	Date
Williams Companies	Hartree Partners, LP Storage Portfolio	115	$1,950	3/1/2024
Enbridge, Inc.	Tres Palacios	35	$335	4/3/2023
Williams Companies	MountainWest*	56	$1,500	2/14/2023
Infrastructure Investment Fund	Enstor Gas	110	Not Disclosed	11/5/2022
Williams Companies	NorTex Midstream	36	$423	8/31/2022
Kinder Morgan	Stagecoach Gas Services*	41	$1,195	9/7/2021
WhiteWater Midstream	Enstor Gas Waha Gas Storage	10	Not Disclosed	2/16/2021
Gulf South Pipeline Company	Bistineau Storage Facility	18	$19	4/1/2020
Berkshire Hathaway Energy Company	Dominion Natural Gas Transmission and Storage*	900	$9,700	2/11/2020
NJR Midstream	Macquarie Leaf River	32	$368	10/11/2019
ArcLight Capital Partners	Sempra Energy Mississippi & Alabama Assets	43	$328	2/7/2019
WEC Energy Group	Bluewater Gas Storage	23	$230	6/30/2017

*Acquisition includes assets in addition to storage facilities

Natural Gas Production Rises to Meet Demand

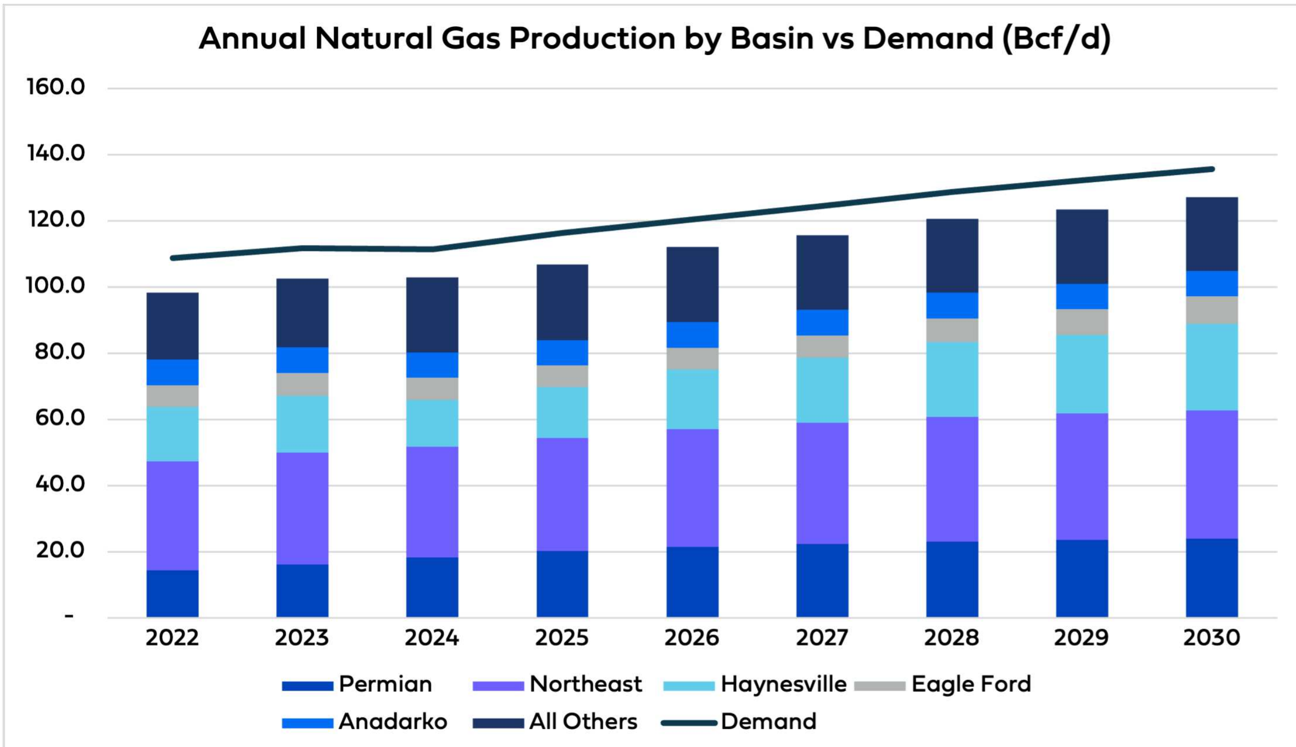
We forecast natural gas production will increase by 3.9 Bcf/d in 2025 from 102.9 Bcf/d to 106.8 Bcf/d. However, we forecast that demand from data centers and LNG facilities will increase by 20 Bcf/d by 2030 and continue to rise into the next decade. We believe that some of the gaps will be filled by ramping up production in Haynesville and expansion of drilling in the dry gas Eagle Ford. But the rest could come from what we call "marginal molecules", production from fringe or less explored areas of the Permian as well as Tier 2 basins in the Rockies and Anadarko Basin. For large public producers, these areas do not compete for capital today. Similarly, midstream infrastructure in these areas also doesn't compete for capital and is likely to be considered non-core by large-cap companies.





But eventually, these molecules will need to move to markets and this will make these regions ripe for investment. Because these markets are currently secondary, there is a knowledge gap about the market dynamics in these areas and how to move molecules to end users. However, because we track every rig and well in the Lower 48 and monitor commodity flows, East Daley is well-positioned to unveil the assumptions that can yield a successful economic investment. We believe interest in these regions is going to grow—a recent indication is private equity firm Quantum Capital's $1.8 billion acquisition of gas assets in the Piceance Basin.

Shifts in natural gas demand and production will also inevitably impact the other two commodities, crude oil, and NGLs. Because we track all three commodities across all producing basins, we can provide perspective on how infrastructure interacts and where constraints might develop. We provide our base case and optional scenarios on what could impact pricing and production well outside the current operating areas or interests of producers, midstreamers, and private equity investors



Summary

We believe the remainder of this decade, in which the U.S. is the largest global producer of all three hydrocarbon commodities, will provide rich investment opportunities for private equity firms and major direct investors. East Daley's comprehensive data collection and proprietary analysis brings visibility to previously opaque operations, unveil new market dynamics, and forecast pricing and potential project profitability to maximize investment returns. Among the major drivers of significant opportunities are significant divestitures of valuable, high-return non-core assets after major midstream and upstream consolidation and a wide range of potential projects, including co-generation facilities and transportation and storage infrastructure, stemming from soaring natural gas demand driven by data centers and LNG export.

2025 Oil & Gas Outlook

Commodity Ties Create an Abundance of Opportunity

At East Daley Analytics, We Are Driving Transparency in Energy Markets
Our approach combines cutting-edge data integration with unparalleled market insight to deliver the most accurate forecasts for energy production and infrastructure across the U.S. From upstream drilling activity to downstream demand centers, our methodologies reflect the complexity and dynamism of the energy landscape.

Why East Daley?

- **Unique Rig and Well Assignments**
  Tracking wells and rigs weekly since 2015 provides the foundation for our production forecasts. Our unmatched historical data ensures precision and reliability.
- **Granular Production Models**
  Basin-level insights down to individual systems. We tie rig activity directly to commodity output, creating forward-looking production curves that guide market decisions.
- **System-Level Forecasting**
  We forecast performance at the G&P system level, integrating plant flow data and capacity trends to anticipate constraints and opportunities.
- **Comprehensive Pipeline and Plant Data**
  We connect pipeline flow corridors to price dynamics and capacity constraints, ensuring our forecasts reflect the full supply chain.
- **Asset-Level Financial Integration**
  Our models integrate quarterly financials with operational data to provide asset-level insights and refine volume forecasts.

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- **Crude Oil Edge**
  Weekly updates on crude flows, market constraints, and production trends.
- **Gas & Midstream Weekly**
  Combining East Daley's analytics with Hart Energy's reporting to provide comprehensive weekly coverage of natural gas, LNG, and midstream.

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