VALIDERE | EAST DALEY ANALYTICS

Emissions critical:

Flaring, methane, and the cost of looming Permian gas takeaway constraints

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Executive summary

When oil prices recovered post-pandemic, Permian production growth nonetheless fell well short of the 2018-2019 pace, as operators prioritized capital discipline, returning more of their cash flows to shareholders and putting less to the drill bit. This slower production growth, combined with the in-service of major long-haul gas pipeline projects, kept Permian flaring in check. But in East Daley Analytics' view, current rig counts signal a pace of production growth that would periodically exceed gas takeaway capacity through 2026.

In a gas basin, these infrastructure constraints typically delay either completions or turning wells in line because the main economic value is in the gas. In an oil-centric basin like the Permian or Williston, the operator could defer completions or shut in production[1], but doing so carries a large economic cost, relative to proceeding with crude oil production and flaring the gas until the gas infrastructure constraint resolves. In mid-2024, when we estimate the excess gas problem to be at its worst, shutting in enough production to avoid routine flaring of associated gas would take ~200 Kb/d of oil production offline, reducing U.S. exports and pushing up both domestic and global prices at a time when both consumers and policy makers are looking for relief from inflation-driven price pressures.

Several Permian gas takeaway expansion projects — and one new pipeline — are under development, but even if these projects meet developers' schedules, they won't come soon enough to avoid either another step-up in flaring, a sharper deceleration in supply growth, or a combination of both.

However, East Daley Analytics does not expect today's Permian rig count to last, based on the backwardated[2] West Texas Intermediate (WTI) forward curve. Even in East Daley Analytics' base case, which includes falling Permian rig counts, excess production (relative to pipeline capacity) peaks at 500 MMcf/d in May 2024, before Matterhorn Express Pipeline's planned completion. Additionally, KinderMorgan has already announced supply-chain related delays in its 500 MMcf/d expansion of Permian Highway Pipeline. Further delays, particularly to the 2.5 Bcf/d greenfield Matterhorn Express, would exacerbate the potential for weaker Permian production growth, increased flaring, or both.

East Daley Analytics and Validere expect the latter, for this excess gas production to translate a combination of increased flaring and weaker production. This tradeoff mirrors the energy trilemma — supplies that are secure, affordable, and clean — that has taken on increased salience following Russia's 2022 invasion of Ukraine. U.S. oil and gas production has long distinguished itself on security of supply, and in the shale era, U.S. production grew faster than any other country, bringing down global oil and gas prices but failing the "clean" leg of that trilemma. Gas flaring was estimated to have reached over 1 Bcf/d in mid-2019, among other environmental impacts attributable to the shale boom, including significant increases in methane emissions and significant declines in combustion emissions at power plants due to gas's displacement of coal.

But major operators' flaring pledges and commitment to capital discipline suggest that this time, more of the largest producers will choose to defer or shut-in production until long-haul capacity is available, delivering cleaner supplies rather than more volume. Smaller operators are more likely to increase flaring, which preserves their oil production and cash flows, and at the margin this oil on the market means lower prices for consumers.

[1] Operators have also explored other uses for excess gas production, such as small-scale power generation or bitcoin mining, but these solutions require upfront capital investment and therefore are not typically deployed to manage a short-term gas takeaway constraint.
[2] Prices for future delivery trading at a discount to those for prompt delivery.

Each 100 MMcf/d of flaring with 98% combustion efficiency adds 2.2 million tons per year of CO_2 emissions and 1 million tons per year of CO_2e emissions from methane, based on the 20-year greenhouse gas impact of methane. Each percentage-point degradation in flare combustion efficiency adds 0.5 million tons of CO_2e emissions per year. This backslide, in a world with a more stringent focus on climate change and more third-party aerial monitoring of performance, risks limiting access to capital and/or buyers, especially if increased flaring translates to rising methane emissions. By effectively monitoring operational data like thermocouples and quickly addressing any unlit flares, operators can limit the impact of rising flaring rates on the environment and their social license to operate.

Introduction

Permian Basin flaring caught the attention of governments, investors, and consumers when it spiked in 2019, as natural gas transmission capacity lagged the associated gas production coming along with explosive oil production growth. This increased Permian flaring undermined the emissions credentials of supplies not only from the play but also from the U.S. overall, just as governments and investors sharpened their focus on climate change. At its peak in 2019, flaring in the basin added at least 24 million tons of CO_2 equivalent (CO_2e) to the atmosphere[3], accounting for both the flared gas and, conservatively, 2% of the gas emitted directly as methane.

A series of long-haul pipeline projects came online in late 2019 and 2020, mitigating flaring levels in the basin, and now another round of infrastructure projects is under construction. However, Permian production growth is likely to exceed this infrastructure build over the next couple of years. Relative to the last time Permian gas production out-grew takeaway capacity, environmental concerns have become more prominent for Permian operators:

- In 2021, the United States, the European Union, and their partners launched the **Global Methane Pledge** — which a total of 150 countries have now joined — promising to enact legislation to reduce methane emissions by 30% between 2020 and 2030.

- **Third-party aerial surveys highlight that Permian methane emissions exceed estimates reported to the government** based on an inventory of equipment. The Environmental Defense Fund's 2020-2021 Permian Methane Analysis Project (PermianMAP) identified unlit flares and flares operating with degraded combustion efficiency as major sources of methane emissions. CarbonMapper continues to do aerial surveys and publish the results publicly, and EDF's MethaneSat is due to launch in January 2024.

- In recent years, **major U.S. operators have announced progress in line with the World Bank's Zero Routine Flaring[4] initiative**, which commits to end routine flaring by 2030. In April, ExxonMobil announced that it had ended routine flaring in the Permian and would end it worldwide by 2030. Chevron is working to end routine flaring by 2030, and ConocoPhillips targets ending routine flaring by 2025. Pioneer CEO Scott Sheffield said that smaller Permian operators' flaring needs to be "reined in" via increased regulation or divestiture. These four companies combined operate ~20% of Permian gas production.

[3] All produced gas is eventually burned, but the vast majority of this combustion is for a productive economic use: heating, industry, or power generation (either domestically or in export markets). If pipeline capacity out of the Permian were sufficient, then these no-longer-flared volumes would still be burned. But this additional gas on the market would reduce natural gas prices, thereby displacing coal in domestic power generation or reducing dry gas drilling. Therefore, even though the flared Permian Mcf would be burned regardless, its being flared in the Permian increases CO_2 emissions relative to a scenario in which that Mcf is transported and burned for productive economic use.
[4] According to the World Bank, routine flaring of gas is "flaring during normal oil production operations in the absence of sufficient facilities or amenable geology to re-inject the produced gas, utilize it on-site, or dispatch it to a market. Venting is not an acceptable substitute for flaring."

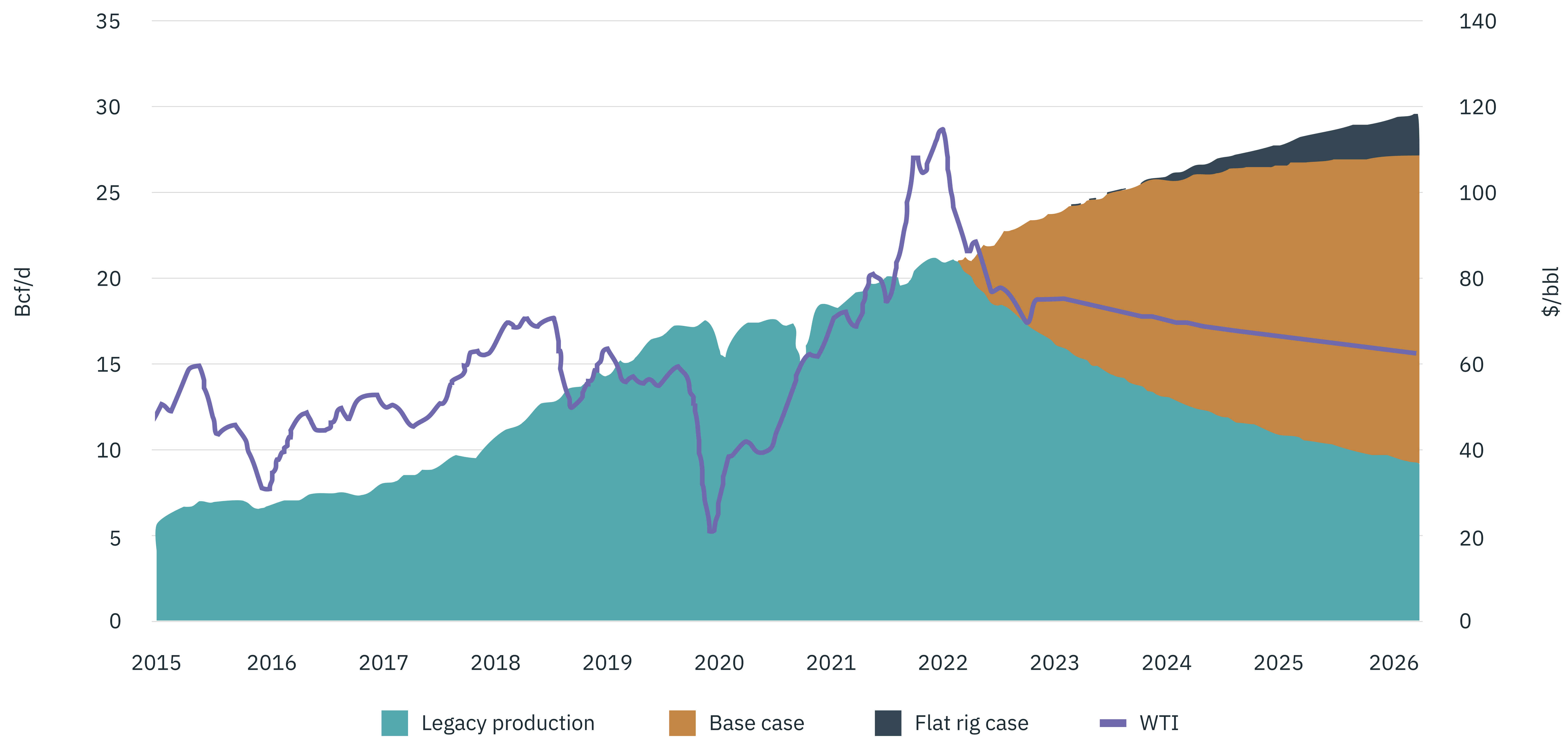
This report addresses the outlook for infrastructure constraints in the Permian and the potential for increases in flaring rates, and highlights how operators can manage greenhouse gas emissions from flares, because not all flares are created equal.

Permian production outlook

The most attractive portions of the Permian break even at $50/bbl WTI oil prices, and these strong economics mean that over the last five years, the play has led U.S. oil production growth. Although most drillers in the region primarily target the basin for its oil output, associated natural gas production has grown from 6 Bcf/d in 2015 to over 22 Bcf/d at the beginning of 2023, increasing from around 8% of U.S. dry gas production to over 22%. Even when oil prices dropped to average ~$40/bbl in 2020, Permian gas production remained relatively flat, before higher oil prices in 2021 and 2022 boosted the number of rigs operating in the region and the amount of natural gas produced, even as public operators remained committed to disciplined capital spend.

The teal area in **Figure 1** below shows Permian gas production from onstream wells, including a forecast for these wells' natural decline.[5] With WTI oil futures (purple line in **Figure 1**) currently in backwardation — meaning that the current price of oil is higher than the future price of oil — East Daley Analytics expects producers to drill fewer wells in the future. The orange area represents East Daley Analytics base case for incremental natural gas production from new wells, with ~500 wells being put on production each month. Nonetheless, even at this reduced drilling pace, activity is sufficient to drive production growth, albeit at a decelerating rate. If instead rig counts remained at today's levels, gas production would grow an additional 2.5 Bcf/d by the end of 2026 (navy area).

Figure 1 | Permian gross gas production



Source | East Daley Analytics

[5] The curves below are based on a well by well analysis, applying unique decline curves, initial production rates, and rig expectations across various productive areas of the Permian.

Beyond this production outlook, market dynamics also depend on infrastructure availability: these new wells require new gathering line connections and, depending on connectivity, total production growth, and downstream markets, may also require new processing and long-haul takeaway capacity. This infrastructure situation impacts producers' and midstream operators' commercial decisions, a topic we cover in depth in the next section.

Infrastructure constraints

Midstream operators typically pay the capital costs to develop gathering[6], processing, and transmission assets in exchange for long-term commitments — whether of acreage, volume, or money — from shippers. In an ideal world, infrastructure would stay ahead of supply growth, but for both commercial and regulatory reasons, production-limiting constraints can occur in any of these three areas — gathering, processing, and transmission — as detailed in the following sections.

Gathering

Gathering systems collect gas from numerous well pads and deliver the supply to a central processing plant/complex. The Permian has been extensively developed dating back to the early 20th century, so almost all new pads are proximate to an existing system. The infrastructure already in place limits the costs of connecting a new pad, to the ~$1 million range. With these limited costs, midstream operators may only require an acreage dedication, rather than a minimum volume commitment. In the Bakken, which does not have the same legacy infrastructure in place, well connection costs are higher, often limiting gas production, whereas in the Permian, gathering constraints are rarely binding.

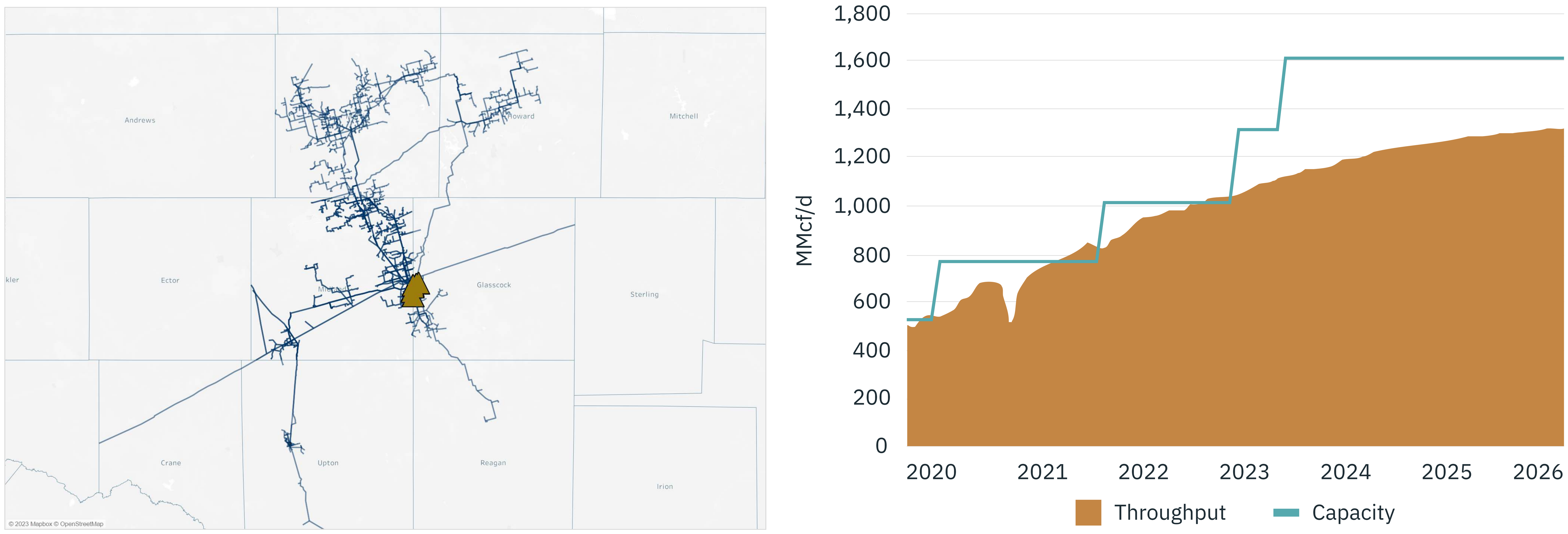
Processing

Gathering systems aggregate production from many wells, and in an oil play like the Permian, deliver these volumes to a gas processing plant, which separates the natural gas from natural gas liquids while also removing any impurities. Processing plant capital costs depend on the plant's size and complexity, but in the Permian, a typical plant costs ~$200 million and takes 12-18 months to build.

Using Enterprise's Navitas system as an example, East Daley Analytics' proprietary modeling of the massive, interconnected gathering and processing system tracks producers like Endeavor, Diamondback, SM Energy, Crownquest, and Apache, which as of April account for 80% of the on-system production and 12 of its 19 active rigs. As these producers have grown, the Navitas system enabled that growth by adding new plant capacity. As with gathering, often producers need to only dedicate acreage, not necessarily commit to drilling it, in order for a midstream company to add more plant capacity. As a result, plant capacity (teal line in **Figure 2**) tends to track production growth (orange area), with capacity coming online long before a 12-18 month build time would suggest, and the system is only constrained for a few months. In this example, Navitas now has excess capacity; Enterprise may use this capacity to manage volumes from nearby systems, or may expect producers to grow at a faster pace than East Daley Analytics' outlook.

[6] In some cases, upstream operators — typically larger, well-capitalized ones — build their own wellhead gathering, rather than contracting with a midstream operator. This setup typically avoids the dislocations in development timing between upstream and midstream operators that can cause temporary flaring.

Figure 2 | Enterprise Navitas system map, capacity, and throughput



Source | East Daley Analytics

Transmission

From the processing plant, natural gas and natural gas liquids feed into large diameter long-haul pipelines that deliver to downstream markets. Gas moves out of the Permian on 19 major pipeline systems across four primary corridors (**Figure 3**). Some gas flows to the West, Midwest, or Mexico, but a majority of Permian gas supply moves on nine pipeline systems toward the Gulf, where it reaches local end-users, salt cavern or depleted reservoir storage, or liquefaction plants for export.

Figure 3 | Permian gas takeaway pipelines

Source | East Daley Analytics

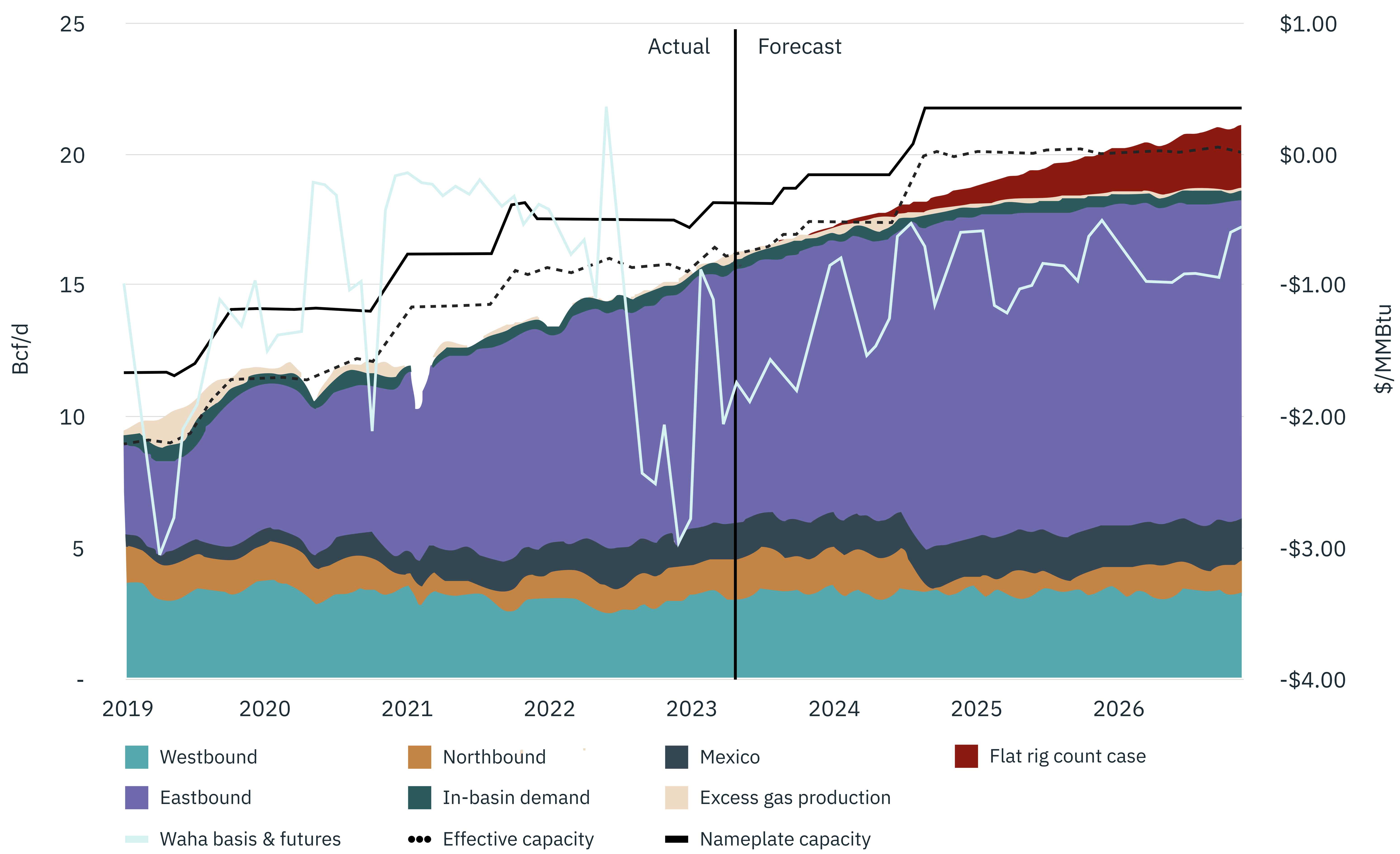
East Daley Analytics forecasts throughput on each of these 19 pipelines, along with new or expanded capacity. Traversing hundreds of miles and dozens of counties, and often crossing state borders, long-haul transmission pipelines require more complex negotiations with landowners and feature much higher construction and permitting costs than gathering or processing additions.

Transmission pipelines typically cost in the billions, and thus, midstream operators typically do not build them unless they have long-term firm transmission (FT) contracts covering most of the capacity. With these take-or-pay contracts, shippers pay a reservation, or demand, charge for the capacity regardless of how much they use — meaning producers' commercial incentive is to be conservative in committing to new capacity, to avoid burdening their cost structure with unutilized FT. These capacity commitments also add off-balance-sheet debt for shippers, so they need to have confidence in future prices, regulation, infrastructure commitments, and the economics of their assets before making FT commitments. Based on commitments to date, East Daley Analytics forecasts Permian takeaway additions as:

- Permian Highway and Whistler pipelines expand at the end of 2023.
- New-build Matterhorn Express Pipeline enters service in mid-2024.

Several other proposed pipelines or expansions — Energy Transfer's Warrior Pipeline, Kinder Morgan's Gulf Coast Express, and Targa's Apex Pipeline — are not included in the forecast, as they do not have sufficient commitments yet to move forward. Often, effective takeaway capacity (dotted black line in **Figure 4**) falls short of nameplate capacity (solid black line), for a variety of reasons including downstream capacity constraints, downstream demand, or major maintenance.

Figure 4 | Permian gas takeaway capacity and Waha basis differentials

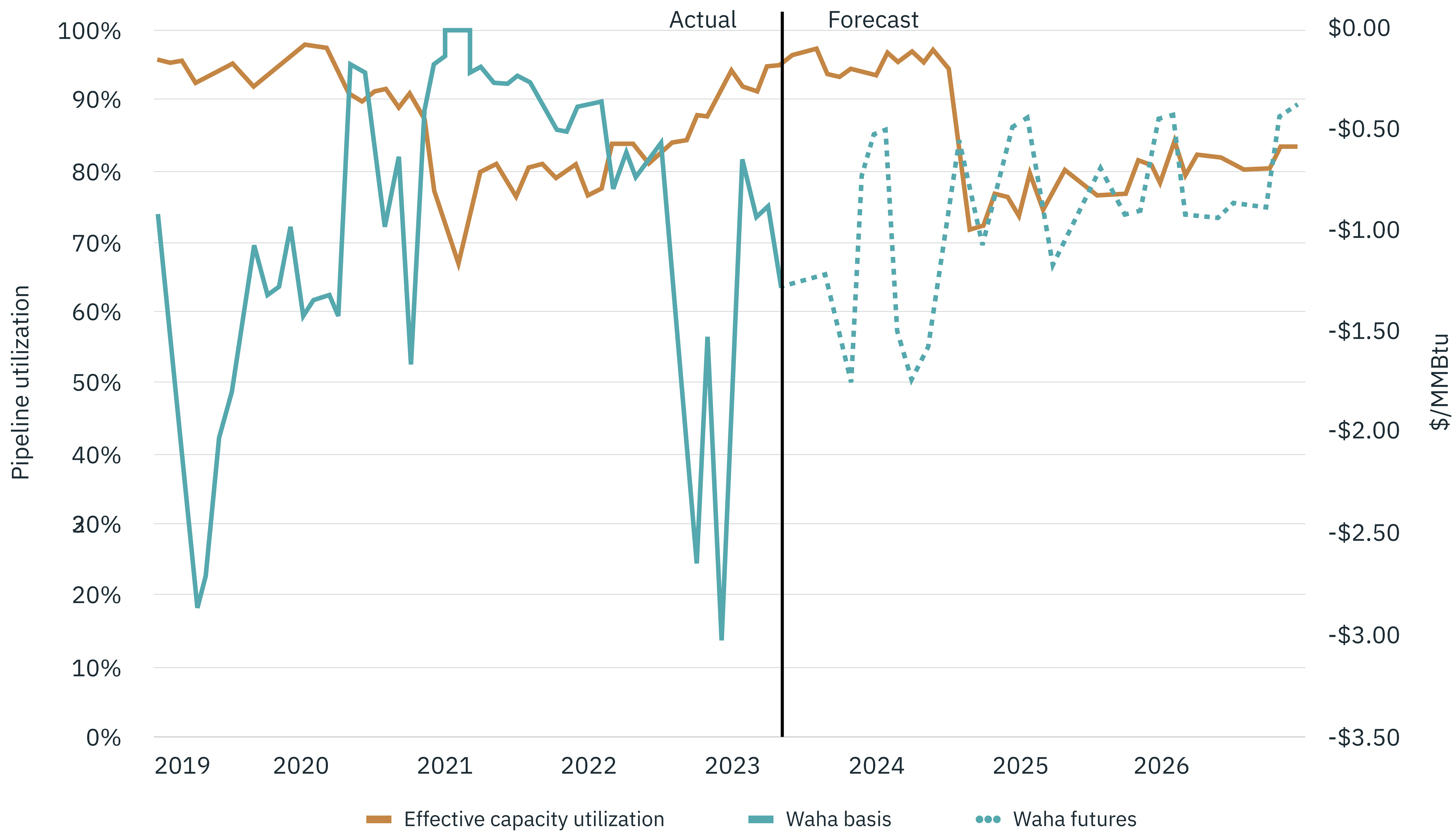


Source | East Daley Analytics

This effective capacity dictates natural gas prices in the region. As production approaches this effective capacity, Waha basis differentials (blue line in **Figure 4**) widen relative to the benchmark Henry Hub in the Louisiana Gulf Coast, reaching discounts in excess of $1/MMBtu for almost all of 2019. In contrast, when spare takeaway capacity is available, Waha basis differentials typically trade closer to a $0.50/MMBtu discount to Henry, roughly in line with the cost of transport to reach Gulf Coast markets. The wider these differentials go, the more willing producers and other shippers are to make commitments to build additional pipeline takeaway to downstream markets.

Currently, Waha futures (dotted teal line in **Figure 5**) narrow by winter 2023-2024, as the market expects expansion capacity to alleviate constraints. However, East Daley Analytics' base case outlook is that utilization will remain above 95%, in line with utilization levels in 2019 and suggesting potential for volatile and weak basis differentials and rising flaring levels. Past 2024, when Matterhorn Express Pipeline comes online, East Daley Analytics expects utilization will drop below 80%, in line with the market's expectation for narrowing basis differentials, telling shippers that aggregate takeaway capacity is sufficient and that they do not need to commit to another pipeline.

Figure 5 | Permian basis differentials and takeaway capacity utilization



Source | East Daley Analytics; Intelligence Press

However, in a dynamic and volatile commodity market, uncertainty about future production growth highlights producers' dilemma around pipeline capacity expansion and, therefore, flaring levels. In East Daley Analytics' flat rig count case, new takeaway capacity is needed by late 2025 — but pipeline contracting decisions are not so simple as each producer signing up for as much FT as it expects to have production. In that case, the basin would be over-built in terms of pipeline capacity — with the commensurate environmental disruption from capacity expansion — because consumers also hold capacity from the Permian.

The availability of consumers' pipeline capacity depends on aggregate production growth in the basin, but each operator must make independent capital allocation decisions without knowledge of other operators' growth plans. This collective-action problem, combined with operators' reticence to add leverage in today's capital markets environment, means that transmission capacity expansion is the most challenging constraint to solve, and thus a driving factor for excess gas production (brown area in **Figure 4**). In the spring of 2019, production growth outpaced expansions that came online later that year, driving Waha basis to $3.00/MMBtu below Henry Hub. On many days, Waha absolute prices dipped into negative territory, as producers tried to out-compete each other for consumers' available capacity, paying counterparties to take their natural gas away to avoid being the company that needed to flare or shut in oil production.

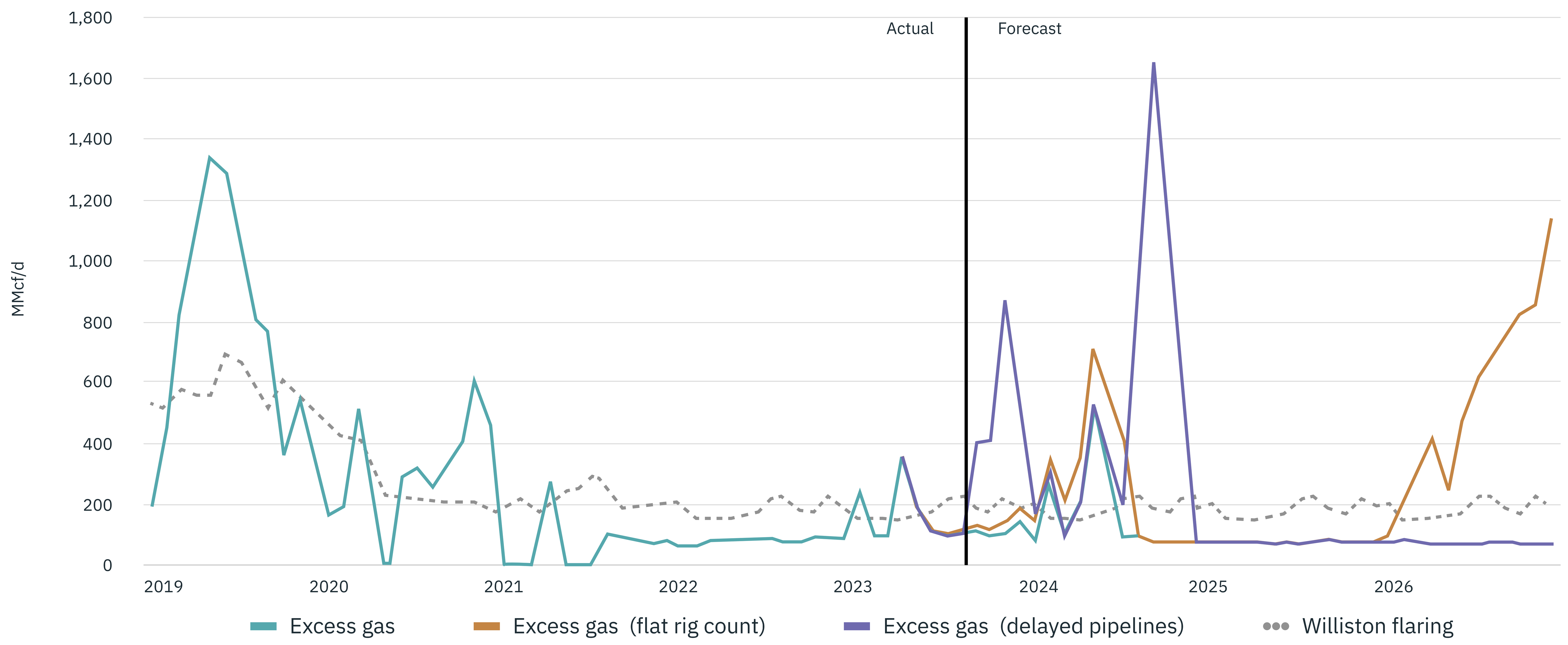
Flaring outlook

Flaring is an operational management and safety tool. When constraints do not allow producers to move their associated gas to sales, the gas is often flared to avoid an impact on oil production, keeping oil volumes onstream. This flaring favors the "affordability" leg of the energy trilemma by continuing to bring oil volumes to market at the expense of the "clean" one — burning gas for non-productive use.

East Daley Analytics forecasts total effective pipeline takeaway capacity for residue gas supply leaving each of 50 different Permian gathering and processing systems, with each of more than 85,000 Permian wells connected to these 50 G&P models. After peaking in 2019, East Daley Analytics estimates that excess gas production has steadily fallen as new capacity accommodated production growth. However, production is now expected to ramp more quickly than the next wave of capacity, which is expected to once again result in an increase in flaring, across three scenarios for production and pipeline completion schedules (**Figure 6**):

- In the **base case, the backwardated forward curve drives down Permian rig counts**, and productivity improvements do not offset this drilling decline. Excess gas production mostly stays low but spikes to ~500 MMcf/d just before the Matterhorn Express Pipeline is brought online in mid-2024.
- In the second scenario, **rig counts stay flat**. In this scenario, excess gas production would double through the forecast period, ramping significantly in 2026 if new capacity is not added. This production and flaring trajectory could also result from reduced rig counts in combination with higher productivity from new wells being drilled.
- In the last scenario, **drilling declines but under-construction pipelines are delayed**, three months for brownfield expansions of Permian Highway and Whistler pipelines and six months for the more complex, greenfield Matterhorn Express Pipeline. In Kinder Morgan's latest earnings call, the company already estimated a one-month delay, to December 2023, in the Permian Highway expansion, due to supply chain issues in getting equipment and materials. Assuming producers do not further reduce drilling — which is more likely if any pipeline delays catch them by surprise than if they are telegraphed ahead of time — excess gas production would spike dramatically, to over 800 MMcf/d at the end of 2023 and 1.6 Bcf/d at the end of 2024, also double the base case.

Figure 6 | Permian excess gas production and Williston flaring outlook



Source | East Daley Analytics

Relative to other basins, the Permian is most at risk of intermittent flaring increases because of where it sits in the gas pipeline grid. Flaring has also been prevalent historically in the Williston basin in North Dakota (dotted line in **Figure 6**), but dynamics in that basin mean that future flaring increases are unlikely. In the Bakken, as more wells are connected to the grid, this gas largely displaces Canadian supplies that historically came through the region, meaning that commensurate new transmission development is not needed. The Permian does not have that option, since no gas supply flows into the region, meaning that Permian growth requires expensive new pipeline capacity development. When the timing of capacity is mismatched with production growth, as we expect will be the case through at least mid next year, some producers likely will opt to flare rather than defer putting wells to sales, as they wait on the completion of several new pipelines.

Inasmuch as operators turn to flaring to preserve oil production, they avoid a worst-case environmental scenario of emitting methane into the atmosphere directly, because methane traps much more heat than does CO2: it is 84 times as potent over a 20-year time horizon. In short, reducing methane emissions delivers the biggest near-term climate impact. Because of the near-term Permian infrastructure constraint, operators' near-term environmental challenge is to manage their flares as effectively as possible.

Not all flares are burning equally

Historically, flares have been considered both a critical safety device and a go-to for emissions control. They have been assumed to operate with high combustion efficiency (98+%), meaning that the vast majority of gas sent to flare is completely converted into combustion products (CO2 and water). Accordingly, most emissions estimating methods for gasses controlled by flares include the assumption that 98% of the gas sent to flare is combusted, including the U.S. Greenhouse Gas Reporting Program (GHGRP). In other words, regulatory reporting assumes that 98% of the flare gas is burned (converting the hydrocarbons to CO2), with 2% escaping combustion and being emitted directly to the atmosphere.

However, flaring is dynamic, and many scenarios result in departures from 98% combustion. In addition to operating with (1) **high combustion efficiency** (which can even meet or exceed 99% for natural gas flaring); flares have been observed to be completely (2) **unlit**, operating as a cold vent and emitting 100% of the flare gas directly to the atmosphere; and others operate under some scenarios of (3) **degraded combustion efficiency**, meaning that the emitted portion of source gas can be much greater than 2%.

Although most flares operate normally most of the time and burn almost all of the flare gas, the potency of methane as a greenhouse gas means that the implications for greenhouse gas emissions are profoundly different depending on whether the number flares that are unlit or improperly combusting is 2% or 10%. And two recent environmental studies found aggregate flare combustion efficiency well short of that 98% weighted average figure:

- In 2020, the Environmental Defense Fund conducted three Permian aerial surveys, assessing 300 flares using optical gas imaging (OGI) cameras. The researchers reported that 11% of flares had combustion issues, including ~5% that were completely unlit. They extrapolated and applied these observations to flare rate data estimated from VIIRS satellite data, deriving an estimated aggregate flare combustion efficiency of 93%.
- In late 2022, a team of University of Michigan and Stanford researchers published a study that used airborne sampling to survey flare efficiency in the Permian, Bakken, and Eagle Ford. This group estimated aggregate flaring efficiency of 91%, due to a combination of unlit flares and degraded combustion efficiency at operational flares.

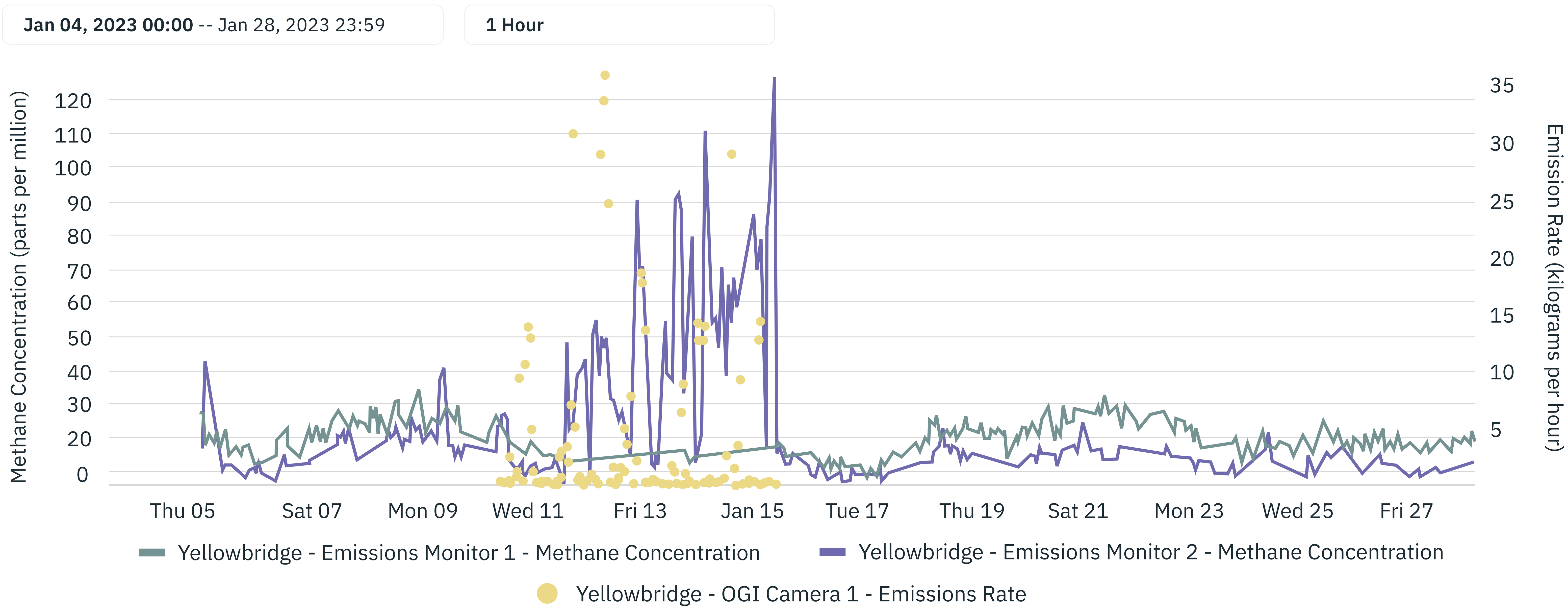
In Validere's view, it is difficult to apply observations across a number of flares (e.g., 5% of 300 flares observed) across a flare volume basis, because other flaring research has found that the flares most at risk of being unlit or operating with degraded combustion efficiency are those operating at low rates. Flare volumes are not evenly distributed across flares and, in particular, as flaring in the basin increases, flare volumes will likely be concentrated at newer, higher-producing wells — or potentially even centralized at gas processing plants — and less likely to be unlit or operating with degraded combustion efficiency. Therefore, the aggregate combustion efficiency across the Permian Basin is likely better than the 91-93% range estimated in these studies, especially during periods of time where flaring is ramping up due to production increases.

Ensuring flares are lit

In recent years, operators have sharply ramped up spending on environmental monitoring, deploying a range of new measurement technology including aerial surveys and fixed monitors. Fixed monitors, which are typically mounted around the perimeter of a site, measure methane concentrations continuously and report these figures to operators. Relative to all other measurement options, these fixed monitors have the distinct advantage of taking continuous measurements.

An example of continuous monitoring data is shown in **Figure 7**, including methane emissions concentration data (purple and teal) from two fixed point source monitors and emission rate estimates derived from a stationary quantification optical gas imaging (OGI) camera (yellow). Emissions monitor 2 (purple) and the OGI camera both reveal an emissions event, where the point source monitor is located downwind of the flare and the OGI camera is positioned to enable flare observation. Neither monitoring source provides a reliable quantification of the emissions event relative to the flow meter totalizing the flare gas flow, but both promptly identify the emissions event.

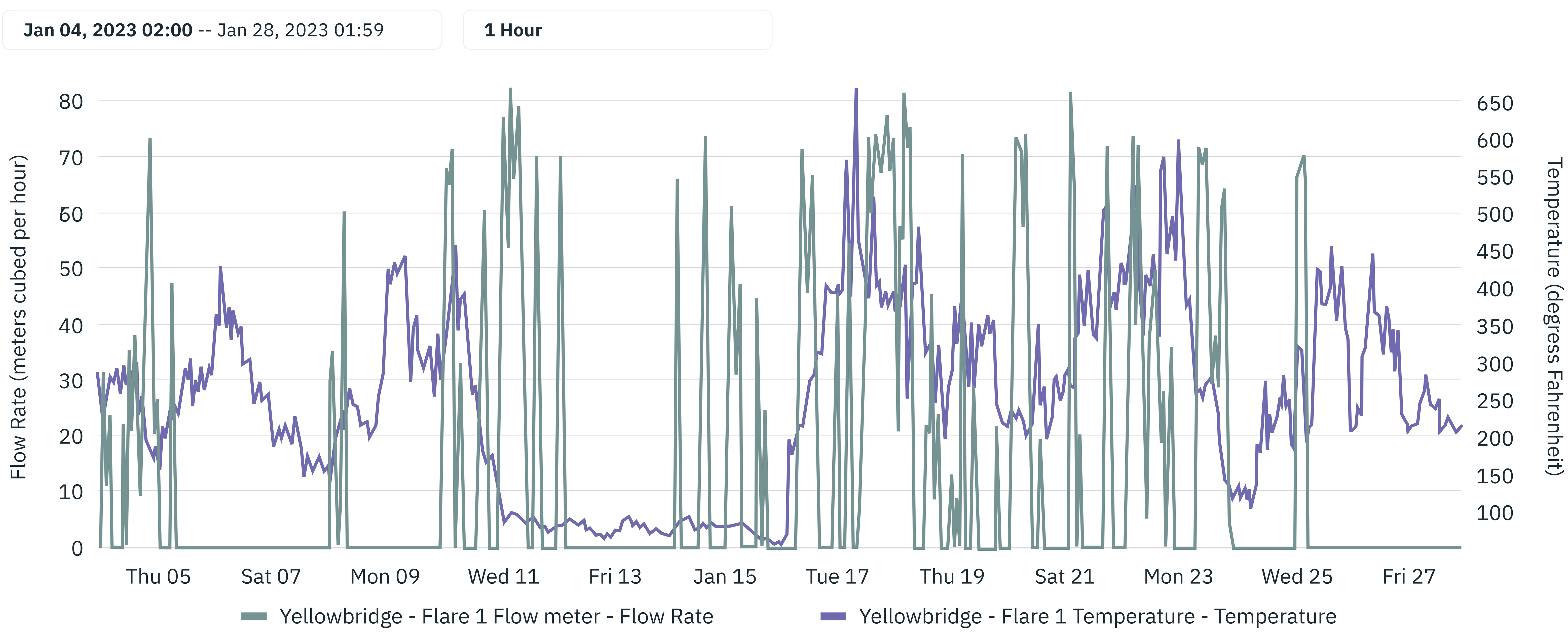
Figure 7 | Emissions estimated from fixed monitors



Source | Validere Carbon Hub

The more important good news for operators, however, is that this event was also observable by monitoring operational data, even absent independent methane continuous monitoring data. Thus, operators do not necessarily need to invest in fixed monitors to effectively reduce an important source of flare gas methane emissions — those from unlit flares. Regulations, such as the general provisions for U.S. New Source Performance Standards (40 CFR 60 subpart A), require flares to be operated with a flame present at all times, and assure the presence of a flare pilot flame via monitoring using a thermocouple or an equivalent device to detect the presence of a flame. From operational data (**Figure 8**) for the same site and time period, an operator can see whether gas is flowing into the flare[7] (green line), along with the temperature reading from the thermocouple (purple line). By effectively ingesting, monitoring, and alerting readings from existing thermocouples — such as with Validere's Carbon Hub — operators can quickly diagnose and mitigate unlit flares.

Figure 8 | Flare flow and temperature



Source | Validere Carbon Hub

[7] In this case, the flare does not operate routinely, in contrast with the flaring increase we expect in the Permian this year, so gas only flows inconsistently to the flare. Nonetheless we believe the thermocouple use-case is relevant for routine flaring, and indeed likely even more important for consistently operating flares.

Conclusions

In East Daley Analytics' base case, excess gas production peaks at ~500 MMcf/d in May 2024, and averages 200 MMcf/d over the course of 2023 and the first half of 2024. If all of this gas were flared, it nonetheless likely would be concentrated at higher-volume sites and therefore more likely to be combusting properly. However, rising flaring rates will nonetheless bring increased environmental scrutiny on all Permian operators.

Each 100 MMcf/d of flaring with 98% combustion efficiency adds ~6 Mt of CO2 emissions per day and ~3 Mt of CO2e emissions from methane, equivalent to 2.2 million and 1 million tons per year, respectively. However, each percentage-point degradation in flare combustion efficiency adds 0.5 million tons of CO2e emissions per year, based on the 20-year greenhouse gas impact. By effectively monitoring operational data like thermocouples and quickly addressing any unlit flares — even if those are not likely to be at the same sites seeing increased flaring due to transmission capacity constraints — operators can limit the impact of rising flaring rates on the environment and their social license to operate.

About Validere

Validere is a measurement, reporting, and verification (MRV) SaaS company that helps energy organizations transform disconnected, incomplete data into clear and immediately actionable pathways to financial and environmental value. Over 50 of North America's leading energy companies rely on Validere's technology and multidisciplinary experts to understand their physical and environmental commodities and navigate an increasingly complex environment with clarity and ease. Validere is on a mission to better human prosperity by making the energy supply chain efficient and sustainable. The company has offices in Houston, Calgary, and Toronto.

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About East Daley Analytics

East Daley Analytics specializes in identifying, understanding, and monitoring operational risk at the asset-level and how that translates to financial risk. We have built the largest U.S. energy asset database to help identify which are most important and isolate their operational value. We can help with the heavy lifting by providing access to capital and commodity market experts through reports and data sets and consulting services.

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Justin is a Founder and Chief Commercial Officer of East Daley Analytics, a data and research company focused on commercial analytics of energy infrastructure through extensive energy value chain analysis to connect the molecules to the money. His addiction to creative outlets combined with his engineering background have made the oil and gas markets a fruitful sector for him to explore over the last 15 years working as a data analyst, consultant, and entrepreneur. Over his career he has led numerous transformational market studies and led the development of hundreds of customized analyses regarding asset acquisitions, strategic planning, development projects, and other market events in the oil, gas, and natural gas liquids' sectors. His work experience includes roles at Accenture, Bentek Energy, Platts, and S&P.

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