Methane and Markets: Firm Incentives to Emit *

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Abstract

Methane is both a potent greenhouse gas and the primary component of natural gas. We explore the economic factors that influence oil and gas producers' methane emissions decisions. Using novel satellite data on emissions from the Permian Basin, we provide empirical evidence that emissions respond to high-frequency price variation and transmission pipeline congestion. To interpret these patterns and assess policy, we estimate a model in which firms choose how much gas to market and flare, and face transmission costs that endogenously depend on pipeline utilization. We use the model to evaluate key policy counterfactuals. In the absence of midstream congestion, the Inflation Reduction Act's proposed methane fee of $1,500 per metric ton would reduce venting and flaring by 3-12%, depending on the EPA's assumed flaring efficacy. However, pipeline congestion attenuates the fee's effectiveness by roughly one-third. Eliminating Texas' severance tax exemption for vented and flared gas yields modest additional abatement. Expanding natural gas pipeline takeaway capacity delivers similar emissions reductions to the IRA fee while increasing producer surplus. These results highlight the need for methane policy to address both price incentives and infrastructure constraints.

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1 Introduction

Methane is a powerful greenhouse gas. It is both far more potent and less long-lived than CO_2, making it a prime target for global emissions reductions efforts. About a quarter of U.S. methane emissions are from the oil and natural gas sector. Unlike most pollutants, methane emissions from the oil and gas sector exert not only a social cost, but a private one as well. Because methane is the primary component of natural gas, methane emissions from this industry represent billions of dollars of lost product. As a result, methane abatement measures can be net cost saving: the engineering and labor costs of such measures can be outweighed by the commodity value of the captured gas (IEA, 2023).

However, the value of natural gas is highly variable. Over the past few years, natural gas spot market prices at Henry Hub, the main North American trading hub, have ranged from nearly \$9 per million Btu to just over \$2 (Figure 2). On top of the fluctuations driven by market-wide supply and demand, producers also face price variation from changes in the cost of getting their gas to market ("marketing costs"). The largest component of these costs is the cost of gas transport. Currently, the main cost-effective way for producers to transport their gas intranationally is through pipelines.When pipelines near full capacity, transport costs increase, reducing producer surplus. In the Permian Basin, transport costs can be proxied for using the gap between the benchmark Henry Hub spot price and the local Waha Hub spot price (a gap referred to as "Waha basis"). Several times in recent years, high transport costs have caused Waha prices to drop into negative territory, even while Henry Hub trades well above zero (Figure 2).

As oil and natural gas prices fluctuate, producer incentives to abate methane emissions change too. In this paper, we explore how these changes in abatement incentives affect actual emissions from upstream oil and gas. We model forward-looking oil and gas producers who decide in each period (1) how many wells to drill and (2) what share of their gas production to sell. The well drilling problem is one of forward-looking investment: given producer expectations over future oil and gas prices and production, producers choose how many wells to drill today. Each period's production is a function only of past investment decisions, and so the firm decision of what share of gas produced to sell in each period is purely static.[1] Firms optimize current period profits by selling ("marketing") or disposing of gas depending on the current commodity value of natural gas and the firm's cost of transporting natural gas to market ("marketing costs").

In this model, emissions arise from two sources. First, for every period of its life cycle, a well releases a baseline level of methane emissions. These emissions result from well completion and equipment leakage, and are assumed to depend only on well age, not well productivity or producer decisions.[2] Second, emissions result from gas disposal through flaring (intentional burning) and venting (releasing unburned gas).[3] Therefore, greater flaring and venting activity leads to more emissions.

Informed by our model, we conduct an empirical analysis of the effects of oil and gas prices on overall

[1]As we discuss later, producers tend to have little to no influence on flows from existing wells. Producers could choose to shut-in wells to defer their production to later periods, but in practice, this option is only exercised in extreme circumstances.

[2]In practice, producers can influence emissions intensity through equipment upgrades and maintenance. However, we believe that in our context, these decisions do not significantly respond to short- or medium-term price signals.

[3]Through combustion, flaring converts the methane to CO_2. Although flaring is preferable to venting in terms of methane emissions, even flaring can result in significant methane emissions due to inefficient or unlit flares (Plant et al., 2022).

emissions as well as the activities that lead to emissions: venting, flaring, and well drilling. We focus on the Permian Basin, an area of rich natural resource deposits located in West Texas and the southeastern corner of New Mexico. The Permian is a natural setting for our investigation because it is an area of intense oil and natural gas production. It is the largest oil-producing region in the nation, and the second largest gas-producing region, accounting for 40% and 25% respectively of national totals. It is also a region where rapid production growth over the past decade has frequently strained pipeline capacity, increasing gas transport costs.

We first examine how emissions and flaring respond to price variation. Using the differential between the Waha Hub price and Henry Hub price as our proxy for gas transport costs, we find that Permian methane emissions and gas disposal are both significantly and positively correlated with transport costs. This is in line with our model, which predicts that producers will dispose of more gas in response to temporary increases in marketing costs, increasing methane emissions. However, flaring and emissions are only weakly negatively correlated with the Henry Hub price, implying that commodity price movements are a less significant driver of contemporaneous gas disposal decisions and associated emissions than transport costs and pipeline congestion.

Second, we directly test the relationship between drilling and commodity prices using a local projections setup. Similar to previous work, we find that Permian drilling activity is highly responsive to oil prices, but not to gas prices. This result is consistent with the economic centrality of oil to Permian producers, for whom gas is often an afterthought. We conclude that policies to reduce methane emissions by increasing the effective profits from selling gas do not run the risk of incentivizing significant new drilling, at least in the Permian Basin.

Together, our findings allow us to evaluate a range of counterfactual policies. We begin by analyzing a methane tax modeled after the U.S. Environmental Protection Agency's Waste Emissions Charge (WEC). We find that the effectiveness of the tax is highly sensitive to assumptions about flaring destruction efficiency—the proportion of methane that is destroyed during combustion rather than released to the atmosphere. If the implementation of the tax assumes a 91% destruction efficiency, consistent with recent scientific estimates (Plant et al., 2022), the tax would reduce venting and flaring by approximately 12% in uncongested pipeline conditions. However, under the more optimistic 98% efficiency assumption commonly used by the EPA in emissions inventories, the same tax would yield only a 3% reduction. Further, in equilibrium, the effect size is attenuated if egress pipelines are congested since increasing transmission costs (in response to the increase in marketed gas induced by the tax) decrease the incentive to abate.

Second, we find that taxing vented and flared gas at the same rate as other gas produced would result in small (under 2%) but significant flaring reductions. Lastly, we find the emissions reductions from relieving pipeline congestion could be more substantial: during periods of high congestion, relieving this congestion would reduce venting and flaring by as much as 20%. An incremental 2,000 MMcf/day of pipeline capacity (roughly equivalent to large, long-run Permian transmission pipelines) would have reduced venting and flaring from 2019 to 2023 by 4%. A back-of-the-envelope cost-benefit calculation suggests that such a pipeline would pay for itself in private and social benefits in under eight years.

This work is made possible by advances in atmospheric modeling and satellite measurement of methane emissions. Until recently, it has been impossible to accurately track methane emissions at any time scale, let alone at a high frequency. Work by Varon et al. (2022) and Varon et al. (forthcoming) uses satellite measurements and atmospheric inversion techniques to produce weekly measurements of methane emissions over the Permian Basin. Our empirical analysis leverages this novel dataset, as well as administrative data on natural gas flaring and venting, to analyze how emissions respond to short- and long-run variation in natural gas prices.

We contribute to an emerging literature on the marginal abatement costs of methane, much of which is summarized in Agerton, Gilbert and Upton (2023). Lade and Rudik (2020) calculates firm-specific abatement cost curves for oil and gas producers in North Dakota using flaring data and the estimated costs of connecting wells to pipeline infrastructure. We expand on this work by linking flaring behavior with methane emissions, which they are unable to measure directly. Furthermore, we provide a framework to explain how firm incentives to abate vary not just with the presence of infrastructure but also with the costs associated with its use. In complementary work, Hausman and Muehlenbachs (2019) estimates abatement in the context of natural gas distribution pipelines, finding that utility firms underspend on leak prevention because they can exercise their monopoly power to pass on the cost of leaked gas to consumers. This research highlights the importance of market incentives in firm emission decisions, a theme that our paper explores on the production side of the industry. Beatty (2022) examines how pipeline development and flaring decisions are made for wells in areas without existing pipeline connections. Concurrent work by Agerton et al. (2024) also provides provides reduced-form evidence of the relationship between midstream congestion and flaring in the Permian Basin.

Our work builds on Marks (2022), which estimates a marginal abatement cost curve for methane among oil and gas producers using annual, firm-reported statistics on emissions. There are known issues with these self-reported statistics, since firms may not be forthcoming about (or even aware of) their true emissions. The annual nature of the firm-reported data also makes it impossible for this methodology to capture high-frequency variation in both emissions and prices. The availability of more accurate, higher-frequency emissions data from Varon et al. (2022) gives us a better vantage point from which to examine the decisions that operators make. Furthermore, while Marks uses the average annual spot price of natural gas to infer abatement costs alone, our model provides a more complete picture: we factor in both oil and gas price and explicitly account for the multiple kind of decision (flaring, drilling) that drive emissions.

There is a substantial literature on optimal emissions regulation. For instance, Fowlie, Reguant and Ryan (2016) examines greenhouse gas regulation in the cement industry, Werner and Qiu (2020) simulates audit-based methane regulation policies, and Cicala, Hémous and Olsen (2022) models adverse selection in emissions reporting. Our work contributes to this literature by studying the way in which firms' emissions decisions vary with market forces. Rather than taking as given the cost of abatement, we work to better understand the factors entering into firm decisions and how regulation could interact with these factors.

Finally, our work builds on research into optimal production decisions in the oil and gas industry. In particular, Anderson, Kellogg and Salant (2018) shows that production from existing oil wells does not respond to oil prices. Instead, producers respond on the extensive margin, drilling more wells in response to higher oil prices. We build these patterns into our own model of production. We assume that production from wells drilled in previous periods is exogenous and declining over time, while new well drilling does respond to prices. We further incorporate the co-production of oil and gas, the emissions impact of drilling new wells, and an emissions intensity decision for current gas production.

2 Background

2.1 Oil and gas extraction in the Permian Basin

The Permian Basin's geological formations contain a substantial amount of both oil and natural gas. In this region, drilling for oil produces gas as a byproduct because Permian oil can contain significant quantities of dissolved natural gas. Oil is the more lucrative business in the Permian: even the basin's top gas producers earn between 70% and 90% of their revenues from oil sales (Table 1). As a result, producers are willing to sustain very low profits (or even losses) from the gas side of their operation if it allows them to continue producing oil.

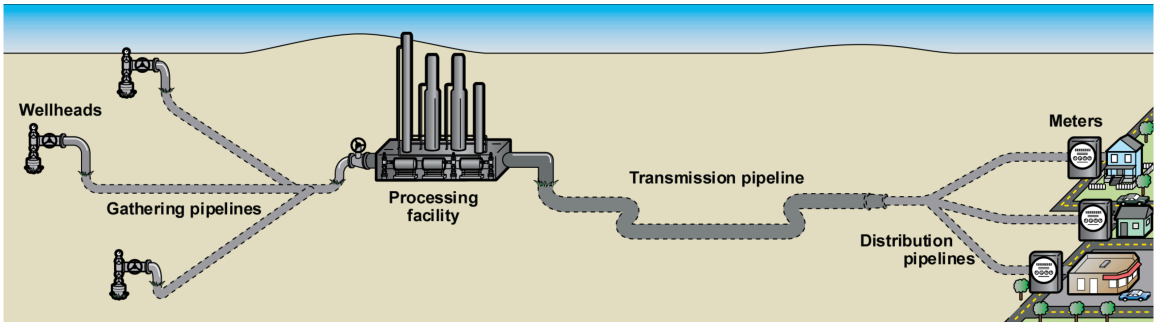
Oil is the dominant driver of production across the Permian, but gas-to-oil ratios vary significantly throughout the region. Occupying the eastern- and western-most portions of the Permian respectively, the Midland and Delaware Sub-basins are the most productive parts of the Permian. The Delaware Basin has higher gas-to-oil ratios (Figure B.1), and so a large share of the oil produced in the Delaware Basin is produced by wells whose gas-to-oil ratios qualify them as gas wells (Figure B.2). Nevertheless, these "gas" wells derive over three quarters of their revenues from oil.[4]

Natural gas is difficult to transport, far more so than oil. Whereas oil can be stored in tanks and carried on trains, natural gas cannot be cost-effectively moved long distances in its gaseous state except via pipeline. Aboveground storage of natural gas is also cost-prohibitive, and belowground storage is constrained by the availability of suitable caverns or depleted reservoirs.[5] Together, all of these factors imply that gas pipelines are critical to ensuring that producers can bring their gas to market. However, pipeline construction is not always able to keep pace with production growth. In the Permian, for instance, the rapid expansion of production due to the fracking revolution has often outstripped the ability of pipeline operators to build new transmission capacity. This has led to frequent shortfalls in pipeline capacity, which in turn have driven natural gas spot prices at Waha Hub (the main hub serving the Permian Basin) into negative territory. Capacity is a challenge further upstream as well: producers need to use gathering pipelines and processing plants to bring their gas to transmission pipelines in the first place (Figure 1). Construction of this upstream infrastructure in the Permian has also sometimes lagged gas production.

[4] This figure was calculated at October 2024 prices.

[5] Liquefaction is an alternative to pipelines for long-distance transport in some cases, but is still very expensive and only economical at scale. Even for gas intended for liquefaction, pipelines are needed to move gas from the wellhead to liquefied natural gas (LNG) terminals.

Figure 1: The natural gas supply chain



Notes: Figure produced by the GAO.

2.2 Methane emissions from the oil and gas industry

Methane emissions from oil and gas production derive from a variety of sources, both intentional and unintentional. On the intentional side, producers often vent natural gas directly into the atmosphere for safety reasons or to maintain proper equipment pressure. Certain steps in the production process require venting, including well completions and workovers. Some equipment (e.g., pneumatic devices) vent natural gas as part of normal operations (Agerton, Gilbert and Upton, 2023).

It is also common for producers to flare natural gas. Flaring is the controlled combustion of natural gas, so that methane is transformed into CO_2 and water before entering the atmosphere. As with venting, flaring can be motivated by operational and safety requirements. For instance, flaring is common during drilling, well testing, and well completion. Flaring can also result from economic decisions. Sometimes, wells enter operation before gathering pipelines to connect wellpads to the transmission network have been completed. Other times, there is insufficient gathering, processing, or compression capacity to process all of the gas produced in an area. In either case, producers can choose to flare their gas to avoid the costs of higher marketing fees, well shut-ins, or lost oil sales. Qualitative work suggests a link between frequent capacity issues and flaring activity. A 2019 Dallas Federal Reserve survey asked 146 oil and gas executives why flaring increased in the Permian Basin that year. Nearly three-quarters of respondents attributed flaring increases to insufficient pipeline takeaway capacity, while nearly half cited a lack of gathering and processing capacity (Figure B.3).

Flaring imposes a significantly lower environmental cost than venting because most of the methane in flared gas is burned off. However, flaring does not entirely prevent methane emissions: Plant et al. (2022) find effective destructive removal efficiency in the Permian to be around 87% due to unlit and malfunctioning flares. This statistic implies that about 13% of "flared" gas (which is about 80% methane) is in fact vented to the atmosphere.

Flaring and venting are regulated in all oil- and gas-producing states, including New Mexico and Texas. In Texas, flaring is permitted in the first 10 days after a well is completed. Outside of this window, producers must file an exemption request with the Texas Railroad Commission (RRC) and pay a $375 fee. In theory, producers must provide justifications for an exemption, such as lack of takeaway capacity or a maintenance event. In practice, the RRC approves nearly all flaring requests. Venting is generally prohibited in Texas, but exceptions are made during and immediately after well completions or for short intervals (Texas Administrative Code, n.d.).[6] Monitoring and enforcement of venting and flaring regulations is challenging, even assuming that regulators are fully committed to finding violators.

Unintentional methane emissions come from leaks, which can happen at countless points along the path that natural gas takes from wellhead to consumer. Although producers are often unaware of leaks on their sites, there is some evidence that emissions from leaks respond to producer oversight effort, which in turn depends on beliefs about leak magnitudes (Lewis, Wang and Ravikumar, 2023).

Because of the vast amounts of natural gas produced and transported in the Permian Basin, the region's methane emissions are substantial. Permian methane emissions were estimated to be 2.5 Tg in 2019, about 15% of total U.S. oil and gas methane emissions, or equivalent to the carbon emissions from the electricity used to power 12 million U.S. homes over the course of one year (Lu et al., 2023). The Permian is not only the largest oil and gas basin by total methane emissions, but also one of the top oil and gas basins by methane intensity of production. Lu et al. (2023) estimate that Permian production had a methane intensity of around 3% in 2019, a significant decline since 2014 but still well above most other major oil/gas producing basins in the U.S.

Recent estimates by Cusworth et al. (2021) indicate that about half of Permian methane emissions are from production, which is the segment of the industry that we focus on in this paper.[7] Other work has shown that there is significant heterogeneity across oil and gas production sites in terms of methane intensity. Omara et al. (2018) finds that low-producing well sites emit a much larger proportion of their production than newer, high-producing well sites. Even controlling for production levels and basin, however, emissions remain highly stochastic across sites. The distribution of emissions has a fat right tail, such that the top 5% of high-emitting sites account for 50% of total emissions.

2.3 Satellite measurement of methane emissions

Previous research on the climate costs of oil and gas production has been hampered by the quality of data available on methane emissions. Until recently, large-scale methane measurement has only been possible using firm surveys, bottom-up inventories, and aircraft campaigns. The EPA's Greenhouse Gas Reporting Program is an example of the first: this annual survey is mandatory for large emitters, but relies on firms being honest and accurate regarding their own emissions. The second method, bottom-up inventories, involves measuring the carbon intensity of different activities (e.g., drilling for oil) and multiplying by units of activity (e.g., wells). This method is not suited to tracking how carbon intensity varies across units or over time. The final method, flying aircraft armed with methane sensors over areas of interest, is accurate but resource intensive. It has not been feasible to use this technique to create panel datasets of an entire region's emissions.

[6] Texas regulators permit venting up to 10 days after well completion and for up to 24 hours at a time (or up to 72 hours in a month).

[7] The authors estimate that the other half of methane emissions come from gathering and boosting (38%) and processing (12%). It is worth noting that this study limits its analysis to persistent point sources, i.e., those detected in at least three overflights. This rules out intermittent sources of methane, such as flares that are only sometimes operating properly.

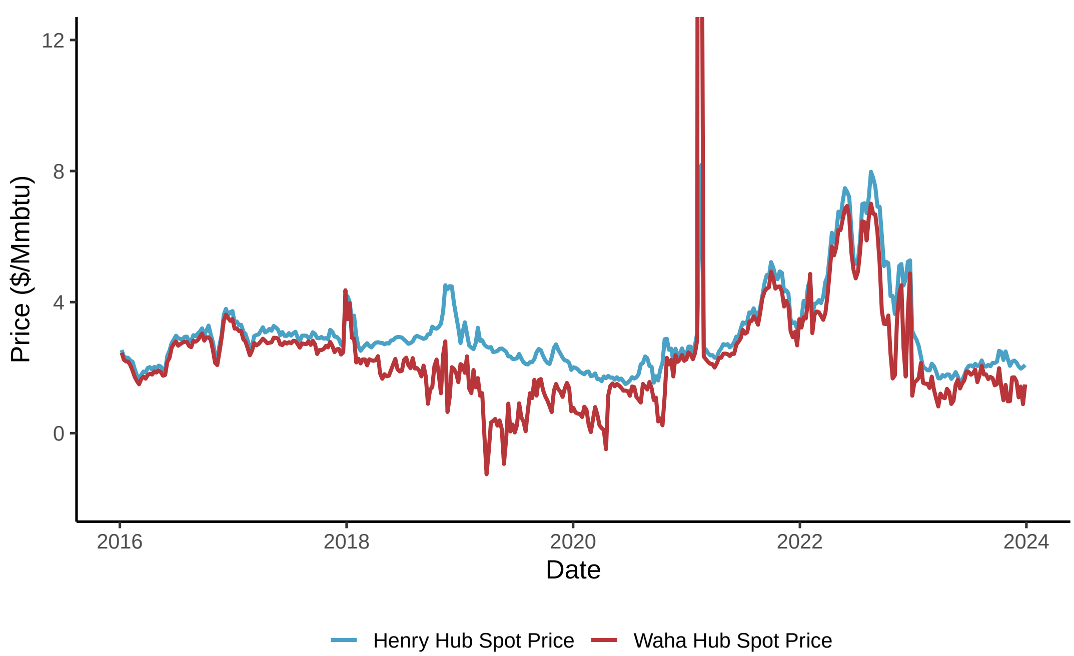
Recent advances in satellite instruments and atmospheric modeling have revolutionized methane measurement. Varon et al. (forthcoming) is an example of this progress. The authors' work is based on satellite observations from the TROPOspheric Monitoring Instrument (TROPOMI). The TROPOMI instrument can sense methane concentrations at a high spatial resolution, but is unable to determine where the methane originated from. To that end, the authors apply a cutting-edge model of atmospheric transport (GEOS-Chem) combined with prior estimates of emissions from the EDF's 2018 bottom-up inventory. The result is a set of weekly emissions estimates at a 25×25 km^2 resolution, covering the entire Permian Basin between 2019 and 2023. Due to the high frequency and comprehensive nature of this dataset, it is well-suited to our analysis of how emissions respond to prices.

3 Data and Descriptive Facts

3.1 Prices

We obtain daily natural gas spot price data for Henry Hub and Waha Hub from S&P Capital IQ (Figure 2). In general, prices at both hubs range from \$2 to \$4. Waha Hub prices tend to lie 10 to 60 cents below Henry Hub prices, though there are periods (such as between 2018 and 2021) during which this gap is much larger.

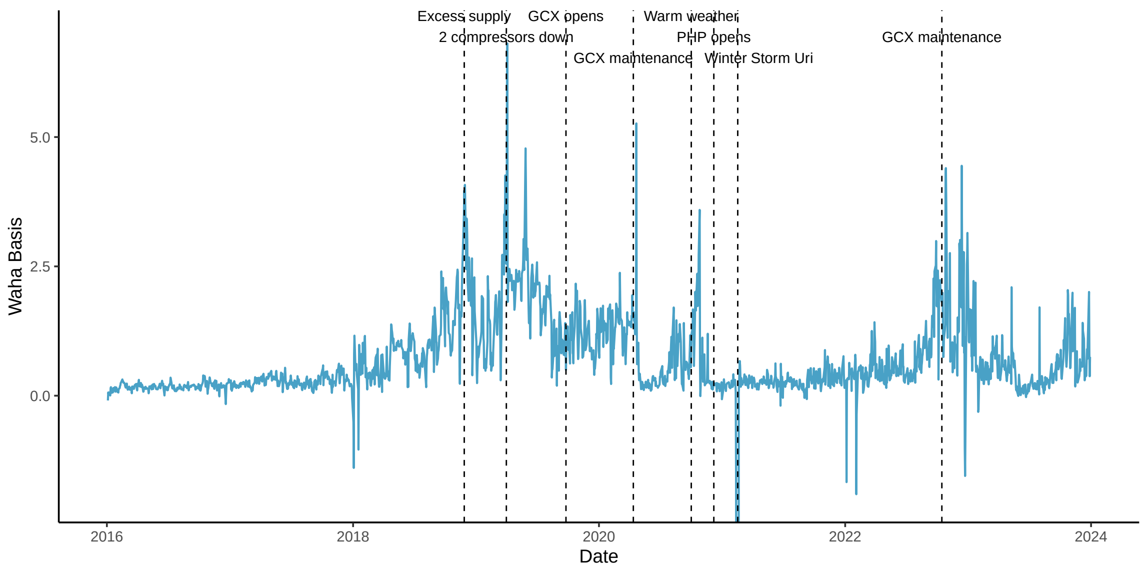
Figure 2: Local and benchmark natural gas spot prices



Notes: Daily gas spot price data from S&P Capital IQ Pro. The large spike in early 2021 corresponds to Winter Storm Uri.

The gap between Henry and Waha hub spot prices (termed "Waha basis") is a good proxy for the cost of moving natural gas to market from the Permian Basin. This cost is highly variable, much more so than the commodity value of gas. Commodity values are driven by national and international market dynamics, which are unlikely to be dramatically affected by any single event. Accordingly, Henry Hub spot prices display significant variation, but move relatively slowly (Figure 2). In contrast, Waha basis is quite sensitive to any imbalance of supply and demand (Figure 3). Particularly when pipeline capacity is tight, as it was from 2018 to 2021, maintenance issues or gas oversupply can cause Waha basis to rise dramatically. Even outside of these major disruptions, day-to-day swings in basis can be substantial.

Figure 3: Waha basis, annotated



Notes: Data from S&P Capital IQ Pro. Annotations added by the authors based on industry reporting. "GCX" is the Gulf Coast Express, a major natural gas pipeline. "PHP" is the Permian Highway Pipeline, another large natural gas pipeline.

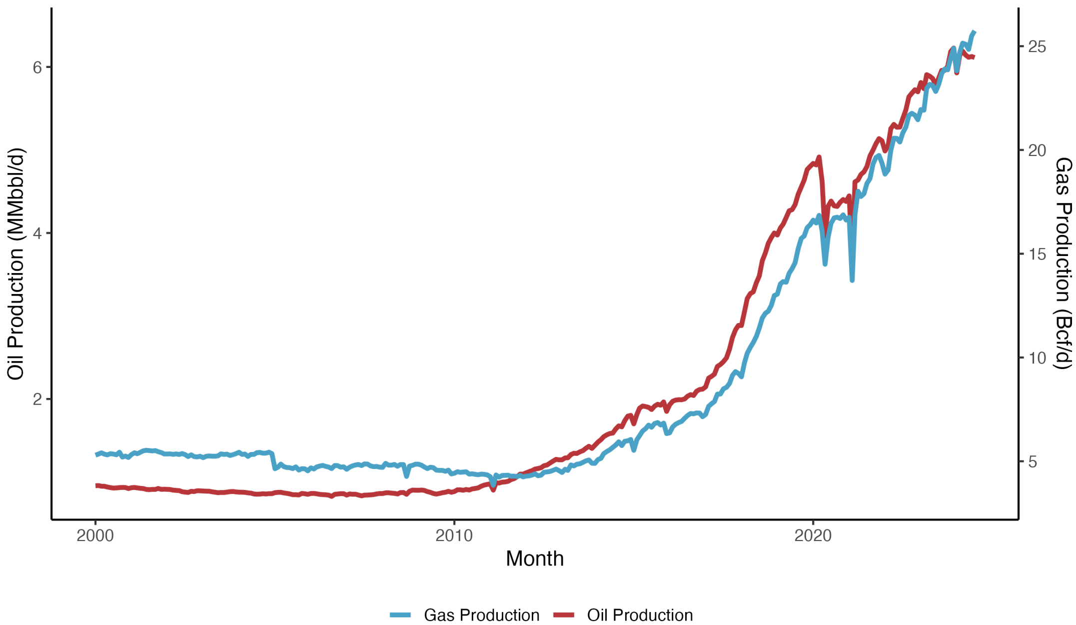
We also obtain oil price data from EIA. We use spot prices and future prices for Cushing WTI, the primary U.S. benchmark for oil prices. Prices per barrel ranged from about $40 to $100 between 2015 and 2023, dipping briefly below zero during the early months of the COVID-19 pandemic in the U.S.

3.2 Production

Oil and gas production data are from Enverus DrillingInfo and are available at the well-month level. This dataset includes information on drilling dates and monthly production, along with well operator and well type. We use this dataset to demonstrate key facts about oil and gas production in the Permian Basin.

First, as evidenced in Figure 4, innovations in hydraulic fracturing and horizontal drilling have led to an explosion of fossil fuel production in the Permian since 2010. Since oil and gas are produced jointly in this region, the rise in production of these two fossil fiels has been tightly coupled.

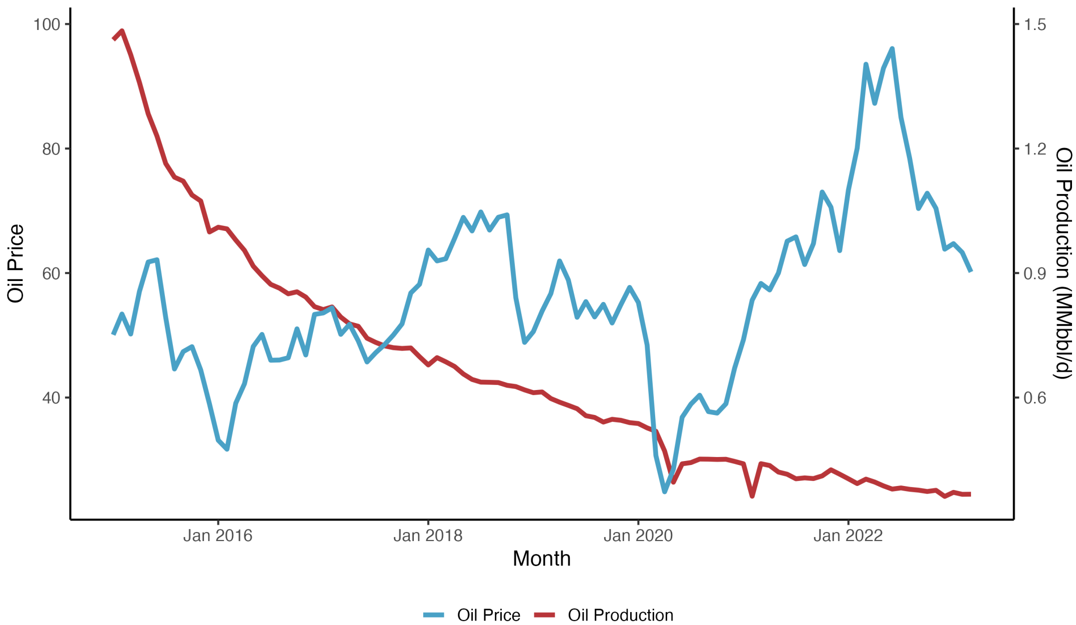
Figure 4: Permian oil and gas production



Notes: Data from Enverus DrillingInfo.

Second, production from oil and gas wells declines over the life of the well (Figures 5 and B.9). This pattern is driven by declines in reservoir pressure as more product is extracted, thus slowing the pace at which extraction can occur. It is common to model gas and oil production with decline curves that feature exponential decay, or initial hyperbolic decline followed by slower exponential decay. As demonstrated in Anderson, Kellogg and Salant (2018), these decline curves generally bind: producers do not respond to price shocks by adjusting production from existing wells. In our data as well, we observe that gas and oil production from existing wells is inelastic. We see no correlation between intensive margin production and oil or gas prices (Figures 5 and B.9). The few periods when production and prices appear to co-move correspond to external events (extreme weather, the COVID-19 pandemic) that affected both demand and production.

Figure 5: Permian oil production from wells drilled before 2015



Notes: We depict production data covering January 2015 through March 2023 for Permian Basin wells that were completed before January 2015. We plot this against Cushing spot oil prices to show that production from existing wells does not respond to price variation. We derive production data from Enverus. Spot prices are from S&P Capital IQ Pro.

In contrast, well drilling does move with prices. We verify this finding from Anderson, Kellogg and Salant (2018) for our data, finding that drilling in the Permian Basin visually tracks oil and gas prices (Figure B.6). We formalize this observation using a local projections approach in Section 4.3.

3.3 Revenues

We use data from Enverus on lease-month level revenues for Texan producers, including volumes of product sold (both oil and gas), total sales value, and buyer. This information is originally collected by the Texas Comptroller for tax purposes. In Table 1, we aggregate sales by seller to calculate the share of total revenues coming from oil. We show that, even among the top gas producers by volume, oil accounts for the vast majority (70-95%) of total revenues.

Table 1: Oil revenue shares for top gas producers, 2018

Producer	Gas Volume (BCF)	Oil Volume (MMBbl)	Oil Revenue Share
PIONEER NATURAL RESOURCES USA, INC.	270.41	74.45	0.8612
APACHE CORPORATION	226.77	30.34	0.7048
CHEVRON U.S.A. INC.	141.39	29.08	0.7083
XTO ENERGY INC.	124.38	52.29	0.8738
ANADARKO E&P ONSHORE LLC	107.23	25.68	0.8083
COG OPERATING LLC	106.42	26.26	0.7743
PARSLEY ENERGY OPERATIONS, LLC	71.43	22.77	0.8365
ENERGEN RESOURCES CORPORATION	71.05	27.73	0.8715
OCCIDENTAL PERMIAN LTD.	64.04	33.82	0.9434
LAREDO PETROLEUM, INC.	59.35	12.35	0.7793

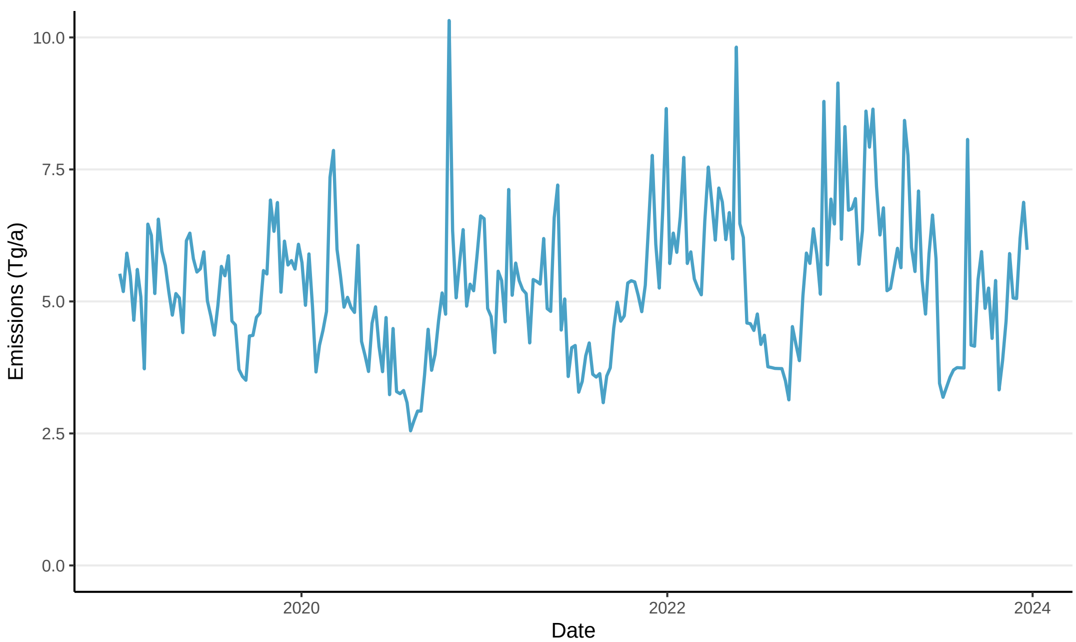
Notes: Lease-level sales data from Enverus. We aggregate sales volumes and values by reported seller name for all Texan lease-months in 2018. We present here the data for the top 10 gas producers by volume in 2018. We calculate the oil value share to be the ratio of oil sales value to the sum of oil and gas value for each producer.

3.4 Emissions

We use weekly estimates of Permian emissions from Varon et al. (forthcoming), as described in Section 2.3. These estimates cover the period January 2019 through December 2023 and are generated at the level of 25×25 km^2 cells. We primarily use basin-level and sub-basin-level aggregates of these estimates. Figure 6 plots methane emissions estimates aggregated for the Permian Basin. Methane emissions are highly volatile throughout the study period. There is no apparent trend in emissions, even though gas production increased over the period.

We supplement emissions data with Texas Railroad Commission (RRC) data on natural gas production, flaring, and venting. These data are collected at the lease-month level when firms fill out their monthly production report (Form PR). Firms must report the volume of gas that they flare or vent, but are not required to include fugitive emissions or gas released during well completion.

Figure 6: TROPOMI estimates of methane emissions from the Permian Basin



Notes: Weekly methane emissions are estimated using the methodology in Varon et al. (2022) and Varon et al. (forthcoming).

Although the RRC dataset does not separate gas that is flared versus vented, we can validate general trends in gas disposal using flaring data from Elvidge et al. (2013) and methodology from Lyon et al. (2021). This approach converts radiant heat and light detected by the Visible Infrared Imaging Radiometer Suite (VIIRS) satellite instrument into estimates of the number of flares and volume of gas flared each month. The methodology is unable to detect gas vented either intentionally or via malfunctioning flares. Despite this, trends in flared volumes detected from VIIRS generally line up with flared and vented volumes reported by producers to the RRC (Figure B.14).

3.5 Pipelines

We compile data on natural gas pipeline infrastructure serving the Permian Basin using a combination of industry publications and media reports. For each Permian egress pipeline, we document its in-service date and its designed takeaway capacity, providing a time series of expansions in regional midstream capacity. A list of Permian pipeline expansions is presented in Table C.1 and the total Permian takeaway capacity by month from 2010 to 2024 is presented in Figure B.7.

4 Reduced-Form Evidence

Producers alter emissions through three key decisions: the proportion of gas they choose to sell versus vent or flare, the number of new wells they decide to drill, and the investments they make in equipment maintenance. For this analysis, we focus on the first two decisions, since equipment maintenance is unlikely to respond to short- or medium-term price fluctuations. In this section, we examine the determinants of producers' emissions abatement and drilling decisions, and the extent to which these decisions explain the intertemporal variability in emissions observed in Figure 6. These findings inform our model of producer decision-making, which in turn enables us to analyze counterfactual policies and market scenarios.

4.1 Methane emissions

In Table 2, we regress methane emissions on variables related to fossil fuel prices and production. We estimate these regressions for the entire Permian, and then separately by sub-basin. First, we consider the relationship between emissions and gas transmission costs, as captured by Waha basis. Across all geographies, we find that Waha basis is positively correlated with emissions. For the Permian as a whole, a one dollar increase in Waha basis is associated with a 6.4% increase in methane emissions. This relationship varies across sub-basins. In the Midland—the most oil-intensive region of the Permian—a one dollar basis increase is associated with a 14.2% rise in emissions, while in the Delaware—the region with the highest gas-to-oil ratio—it is associated with a 4.6% emissions increase.[8] The coefficients on Waha basis for the Permian and the Midland are statistically significant at the 5% level, while the coefficient for the Delaware is not. Further, whereas there is always a negative relationship between emissions and Henry Hub price, the coefficient is largest in magnitude and significant only for the Delaware. In the Delaware, a one dollar increase in the Henry Hub price is associated with a 5.3% decrease in emissions.

Together, these results suggest that producers emit more gas when the cost of transporting gas to market is high, perhaps due to economically motivated venting and flaring. However, emissions in the Delaware appear less sensitive to gas transport costs. Producers with higher gas revenues, such as those in the Delaware, may be less exposed to transport costs because they have more transmission capacity secured under firm contracts, or hedge more against Waha price fluctuations by selling more gas under contracts tied to Henry Hub prices.

[8] See Figure B.2 for oil and gas production by Permian sub-basin.

Alternately, they may be more efficient in their gas operations, such that selling into a less favorable market is still profitable.

Across all sub-basins, we observe a seasonal pattern in emissions. Colder temperatures, as measured by Texas heating degree days (HDD), are associated with higher levels of emissions. For the Permian as a whole, a one standard deviation increase in HDD (6.6 HDD) is associated with a 10.0% increase in emissions. Despite higher emissions, we do not observe upticks in flaring or new well completion in colder weather (Figures B.12, B.13). Work in the scientific literature on urban methane emissions has uncovered similar patterns, and attributes wintertime increases in methane emissions to increased use of natural gas for heating.[9] Outside of urban contexts, Varon et al. (forthcoming) suggests that higher gas and oilfield emissions in the winter may be due to the physics of gas solubility (which decreases under colder temperature). For the remainder of this paper, we will abstract away from seasonal emissions patterns, focusing instead on producer-driven venting and flaring in response to economic factors.

Our other variables (production and new wells) do not have consistently significant relationships with emissions. In theory, we would expect a positive relationship between new wells and methane emissions because of the venting that typically accompanies well drilling and completions. Lagged new wells might correlate with emissions because newly drilled wells might not immediately be connected to gathering pipelines. In practice, neither the number of new wells nor the number of lagged new wells is significantly correlated with emissions. Colinearity might be an issue, since production, new wells, and prices are all linked.

In total, our variables collectively explain only about one-quarter of the observed variation in methane emissions. This could be due to large quantities of emissions being released unintentionally. The scientific literature suggests that the distribution of methane emissions exhibits a strong right tail, such that the top emitting sites account for a large share of total emissions (Cusworth et al., 2021; Omara et al., 2018). These "superemitters" (which include unlit flares, leaky equipment, and other malfunctions) may not respond to economic variables, thus limiting our explanatory power.

[9]For instance, Karion et al. (2023) studies urban methane emissions in Washington, DC, and Baltimore, Maryland, finding that wintertime emissions are about 44% higher than summertime emissions. Sargent et al. (2021) finds similar results in Boston, as does He et al. (2019) in Los Angeles.

Table 2: Methane emissions, prices, and production

	Dependent variable:		
	log(Emissions (Tg/a))		
	All	Midland	Delaware
	(1)	(2)	(3)
Henry Hub Price	-0.023	-0.014	-0.053^{***}
	(0.014)	(0.019)	(0.015)
Waha Basis	0.064^{**}	0.142^{***}	0.046
	(0.030)	(0.036)	(0.033)
Cushing Spot Oil Price	0.004^{*}	0.004	0.005^{**}
	(0.002)	(0.002)	(0.002)
log(Oil Production)	0.508	-0.504	1.701^{**}
	(0.692)	(0.542)	(0.734)
log(Gas Production)	-0.189	0.478	-1.655^{***}
	(0.500)	(0.352)	(0.615)
log(New Wells)	-0.042	0.201	-0.165
	(0.195)	(0.205)	(0.152)
log(Lagged New Wells)	0.092	-0.051	0.296^{*}
	(0.193)	(0.204)	(0.151)
Heating Degree Days (TX)	0.015^{***}	0.015^{***}	0.010^{***}
	(0.002)	(0.003)	(0.002)
Constant	-4.144	-0.761	1.393
	(3.244)	(3.486)	(2.326)
Observations	260	260	260
R^2	0.252	0.196	0.303
Adjusted R^2	0.228	0.170	0.281
Residual Std. Error (df = 251)	0.221	0.289	0.233
F Statistic (df = 8; 251)	10.555^{***}	7.654^{***}	13.661^{***}

Notes: An observation is a week. Sample covers January 2019 through December 2023. Emissions are in log teragrams per year (Tg/a). Prices reflect the average of daily prices over the week, where daily prices are winsorized at the 1% level. Oil and gas production and new wells are measured monthly and interpolated to the week level. Oil and gas production are in barrels and thousands of cubic feet (Mcf), respectively.
$^{*}p < 0.1,^{**} p < 0.05,^{***} p < 0.01$

4.2 Venting and flaring

Focusing on venting and flaring allows us to more directly examine the producer decisions that contribute to methane emissions, without the noise introduced by random variation from superemitter events. In Table 3, we present estimates of the relationship between prices and flared gas volumes, measured using the VIIRS instrument. We find a significant, positive coefficient on Waha basis: a one dollar increase in transport costs corresponds to a 32.4% increase in flared gas volumes in Permian as a whole, and a 47.1% increase in the Midland Basin. Table C.2 presents the same regressions, but using number of flares detected as the outcome rather than flared volume. In both, sub-basin-level analysis reveals that sensitivities to economic factors vary by sub-basin, similar to patterns observed in methane emissions regressions. Flaring in the Midland Basin is more responsive to transport costs, whereas in the Delaware Basin, it is more closely tied to natural gas prices.

Table 3: Flared gas, prices, and production

	Dependent variable:		
	log(Flared Gas (Tg/a))		
	All	Midland	Delaware
	(1)	(2)	(3)
Henry Hub Price	−0.027	0.104	−0.140*
	(0.072)	(0.095)	(0.074)
Waha Basis	0.324***	0.471***	0.284***
	(0.096)	(0.120)	(0.102)
Cushing Spot Oil Price	−0.0002	−0.0002	−0.002
	(0.007)	(0.008)	(0.006)
log(Oil Production)	3.114*	4.567***	1.006
	(1.781)	(1.488)	(2.264)
log(Gas Production)	−2.542*	−2.374**	−1.548
	(1.348)	(1.067)	(1.948)
log(New Wells)	0.026	−0.576*	0.256
	(0.274)	(0.316)	(0.215)
log(Lagged New Wells)	−0.046	0.087	0.065
	(0.241)	(0.292)	(0.218)
Constant	−4.942	−32.888***	12.490**
	(7.359)	(8.356)	(4.643)
Observations	46	46	46
R^2	0.656	0.661	0.664
Adjusted R^2	0.593	0.599	0.602
Residual Std. Error (df = 38)	0.263	0.360	0.273
F Statistic (df = 7; 38)	10.356***	10.595***	10.714***

Notes: An observation is a month. Outcome variable is the volume of flared gas, based on VIIRS observations and calibrated to match administrative data. Prices reflect the average of daily prices over the month, where daily prices are winsorized at the 1% level. Oil and gas production and new wells are measured monthly. Oil and gas production are in barrels and thousands of cubic feet (Mcf), respectively.
$^{*}p < 0.1$,$^{**}p < 0.05$,$^{***}p < 0.01$

4.3 Drilling

Methane policy interventions may affect not only how producers dispose of natural gas—whether to vent, flare, or market it—but also the total quantity of gas produced. As shown in Figures 5 and B.9, production from existing wells is highly inelastic, meaning that the primary channel through which policy can influence total output is via firms' drilling decisions. This introduces an important dynamic margin: if producers anticipate a policy's impact on the returns to production and adjust their investment in new wells in response, emissions levels will be affected in two ways. First, drilling new wells is itself emissions-intensive. Venting is common during well completion for both operational and safety reasons, especially when flares have not yet been installed.[10] Flaring is also widely used at new wells, which may not yet be connected to gathering pipelines or may be so productive in their first few months that their production overwhelms gathering or processing capacity (Beatty, 2022). Second, drilling additional wells means adding new, leak-prone equipment into regular operation, increasing total emissions over the decades-long lifespan of each well.

Investment decisions in oil and gas drilling are forward-looking and shaped by firms' expectations about

[10]During well completions, downhole pressures are often high and unpredictable. Venting is used to relieve this pressure and prevent blowouts—uncontrolled releases of oil or gas that can lead to explosions, fires, or equipment failure. In addition, early gas flows are typically unstable and may contain liquids or debris, making flaring unsafe due to the risk of flameouts or ignition hazards.

future commodity prices. Specifically, producers assess the anticipated returns from drilling, which depend on the projected prices over the investment horizon. However, even when firms adjust their expectations, their physical responses may be delayed. Operational constraints such as rig availability, permitting requirements, and regulatory frictions can impede the immediate translation of price signals into drilling activity.

To empirically estimate the dynamic response of drilling to changes in expected future prices, we adopt a local projections approach (Jordà, 2005). The estimation equation takes the form:

$$\log d_{t+h} = \beta_o^h \log \tilde{p}_t^o + \beta_g^h \log \tilde{p}_t^g + \gamma^h Z_t + \varepsilon_{t+h}^h, \quad h = 0, 1, \dots, 10, \tag{1}$$

where d_t denotes the number of wells spudded in period t, and $\tilde{p}_t^o$ and $\tilde{p}_t^g$ are the discounted production-weighted average futures prices for oil and gas, respectively.[11] Specifically, we compute

$$\tilde{p}_t^j = \left(\sum_{l=6}^{36} q_l^j \right)^{-1} \sum_{l=6}^{36} \beta^l q_l^j p_{t,l}^j \tag{2}$$

for $j \in \{o, g\}$, where $p_{t,l}^j$ is the futures price for delivery in month $t + l$ observed in month t, q_l^j is the average production l months after spud, and the monthly discount factor β is 0.992.[12] The vector Z_t includes three lags of both futures prices and drilling activity, capturing short-run dynamics and persistence, and ε_{it+h}^h is an error term. The horizon h ranges from contemporaneous ($h = 0$) to ten months ahead, allowing us to trace out the temporal profile of drilling responses to price expectations.

We assume a well takes six monthly to complete, which roughly corresponds to the median time between spud and completion we observe in the data.[13] We assume production intensity follows the hyperbolic decline curve estimated by the EIA for Midland County production in the Permian Basin, with an initial oil production of 1,090 barrels per day and an initial natural gas production of 707 Mcf per day, an initial decline rate of 0.169, and a hyperbolic parameter of 0.351. This decline curve implies 85% of a well's total lifetime production occurs in the first two and a half years of the well's operation, which corresponds to month 36 in our estimation.

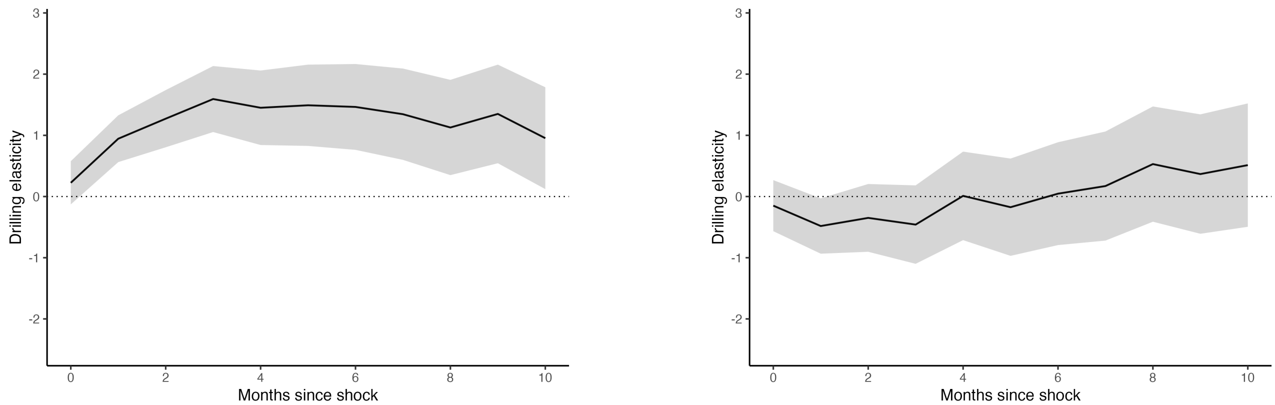
While using futures price may help mitigate contemporaneous feedback, a central identification concern is the potential endogeneity of futures prices. In principle, anticipated drilling activity can affect futures prices through market expectations. However, U.S. oil and gas prices (Cushing and Henry Hub prices respectively) are well-integrated with the global market, making it less likely that individual drilling decisions in the Permian Basin significantly influence futures prices. To the extent that Permian drilling decisions do affect prices, our estimated drilling elasticities would be biased downwards. Given the Permian's greater importance in the U.S. oil market compared to the gas market, this concern is more pronounced for oil than for gas.

Figure 7 presents the drilling elasticities with respect to oil futures and gas futures, as estimated using equation (1). Panel (a) reveals a highly elastic response of drilling activity to shocks in the production-weighted average futures price. While the contemporaneous oil price elasticity is only slightly positive and not

[11] An alternative to calculating this production-weighted expected price is simply using the futures price at roughly the mid-point of a well's expected life. This is the approach taken in Kellogg (2014). Our results are unchanged using this approach.

[12] This corresponds to an annual discount factor of 0.908, approximately an annual hurdle rate of 10%.

[13] See Appendix Figure B.15 for the distribution of time from spud to completion.



(a) Oil futures

(b) Gas futures

Figure 7: Drilling elasticities, oil and gas futures

statistically significant, we observe a large and statistically significant drilling response in each of the subsequent nine months. The drilling elasticity climbs to roughly 1.5 within three months, implying that a 10 percent increase in expected oil prices increases well spudding by about 15 percent. This estimate is similar to that calculated by Newell and Prest (2019), who instrument for oil prices with a raw industrials commodities index and estimate an oil price elasticity of 1.6 for unconventional drilling. This drilling responsiveness is consistent with fairly short spud-to-completion cycles and the ready availability of drilling inventories in the Permian; firms appear able to mobilize rigs and crews quickly once price expectations improve.

By contrast, panel (b) of Figure 7 shows that the drilling response to a shock to gas price expectations is statistically indistinguishable from zero. Other studies estimating gas price elasticities often report larger effects when analyzing the U.S. as a whole. For example, Newell, Prest and Vissing (2019) estimates a gas price drilling elasticity of 0.9.[14] However, focusing on the Permian Basin, recent estimates align closely with our findings. In particular, Prest (2025) reports an oil price elasticity of 1.1 and a gas price elasticity that is statistically indistinguishable from zero. Even in the Delaware Basin, the most gas-intensive part of the Permian, oil accounts for roughly 90% of revenue from "oil" wells and around 75% of revenue from wells classified as "gas" wells.[15] The EIA notes that "producers in the Permian region typically respond to changes in the crude oil price when planning their exploration and production activities" (Energy Information Administration, 2023). Public comments by Permian operators corroborate this story.[16] Our finding that Permian drilling responds strongly to oil price expectations but not to natural gas price movements aligns closely with both industry reports and the underlying economics of the region.

One potential concern in interpreting these results is that oil and gas prices are collinear. Our main study period falls within the post-2016 period, when the rapid expansion of U.S. LNG exports integrated the domestic

[14]Though Newell, Prest and Vissing (2019) also focuses on Texas, their sample excludes oil wells and includes several regions that are primarily dry gas plays (the Barnett Shale, Haynesville). Their period of study also predates large increases in associated gas production (i.e., gas that is coproduced with oil), particularly in the Permian Basin.

[15]Calculated by the authors using October 2024 price levels.

[16]For example, in 2024, an Enterprise Products executive noted: "If you look at what drives the economics of the producers in the Permian, it's not natural gas" (Enterprise Products Partners L.P., 2024). In 2020, the CFO of Pioneer Natural Resources explained that "natural gas prices do not materially impact the economics of drilling oil wells" (American Oil and Gas Reporter, 2020).

gas industry into the global market. This integration led to a significantly tighter link between gas and oil prices (Stock and Zaragoza-Watkins, 2024). To account for the possibility that collinearity between oil and gas prices might confound our results, we conduct a robustness check restricting the sample to the 2010–2015 period, when U.S. natural gas prices were disconnected from oil prices.[17] The results, shown in Figure B.8, remain consistent: we continue to observe a large and statistically significant response of drilling to oil futures, and a null effect for gas futures. These findings are also robust to alternative specifications, including varying the number of lagged price controls and using 18-month-ahead futures prices rather than estimated production-weighted average futures prices.

Although we do not observe a response in the *number* of wells drilled, changes in oil and gas prices could, in principle, influence the *location* of drilling activity. In particular, when expected gas prices are low but oil prices remain high, producers might shift toward areas with lower gas-to-oil ratios (GORs) to minimize gas output relative to more valuable oil.[18] As a result, even if the number of new wells is not sensitive to natural gas prices, the quantity of gas produced from those wells may still vary in response. Using well-level data, we study this empirically by regressing the log GOR on 18-month-ahead log oil and gas futures prices at the time of spudding. The results, shown in Figure B.9 and Table C.5, indicate that expected gas prices are not statistically significant predictors of well-level GOR. Moreover, the within-operator R^2 values are extremely low—on the order of 0.001 or less—indicating that variation in expected oil and gas prices explains almost none of the within-firm variation in GOR. We conclude that operators cannot easily substitute across formations or adjust well design in response to market signals. Taken together, our results suggest drilling and overall gas production in the Permian respond primarily to oil prices, not gas prices.

5 Model

In order to formalize our empirical observations and allow for counterfactual predictions, we present a dynamic model of oil and gas producers' investment and emissions decisions. The model has an infinite horizon with discrete decision periods. In each period, firm i's production level is predetermined by actions in previous periods. The firm's state space in period t is given by $(\Omega_{it}, \varepsilon_{it})$, where Ω_{it} contains the observed state variables and ε_{it} is a disturbance term that is known by the firm but unobservable by the econometrician. The observed vector Ω_{it} is given by $(q_{it}, g_{it}, w_{it}, p_t, \tilde{p}_t, d_t, r_t)$, where oil and gas production from *existing* wells is indicated by q_{it} and g_{it} respectively; w_{it} is the total number of wells the producer operates; $p_t = (p^o_t, p^g_t)$ is the vector of net-of-tax unit prices of oil and gas; $\tilde{p}_t = (\tilde{p}^o_t, \tilde{p}^g_t)$ is the vector of discounted average oil and gas futures prices (weighted by the expected production from a new well drilled in period t); d_t is the rig dayrate for drilling a new well; and r_t is the cost of gas pipeline transmission.[19] We assume that each producer is small and takes

[17]This disconnect arose due to persistent domestic oversupply and limited export infrastructure. See Stock and Zaragoza-Watkins (2024) for details.

[18]Spatial variation in GORs across the Permian is primarily driven by geology: deeper zones tend to be more thermally mature and yield higher GORs, while shallower, less mature formations are more oil-prone. Additionally, because deeper wells tend to be gassier, the choice of drilling depth in a given location may also be endogenously linked to price expectations.

[19]We assume that the cost of transmission from the Waha Hub in the Permian basin to the Henry Hub is a sufficient statistic for transmission costs. This relationship is explored in other work, such as Oliver, Mason and Finnoff (2014).

p_t, d_t, and r_t as exogenous. Oil production q_{it} is predetermined by the firm's actions in previous periods and gas production g_{it} is an exogenous multiple of oil production.

Each period, the producer chooses how much gas to send to market (i.e., sell), m_{it}. It is constrained above by total gas production, so that $m_{it} \leq g_{it}$. We assume that the remaining gas is flared, generating methane emissions. Firms incur marketing costs $c_i^g(\cdot)$ when they send gas to market. Notably, the choice of m_{it} does not affect future payoffs for the firm. Separately, producers decide whether to invest in developing new wells, which begin producing in a subsequent period. We assume the marginal cost of production from existing wells is zero, and therefore do not consider exit decisions.

5.1 Emissions problem

In each period, firm i chooses how much gas to market in order to maximize the per-period payoffs from existing wells:

$$\bar{\pi}(\Omega_{it}) = \max_{m_{it} \leq g_{it}} \underbrace{p_t^o q_{it} - c_i^o(q_{it})}_{\text{oil profit}} + \underbrace{p_t^g m_{it}}_{\text{gas revenue}} - \underbrace{c_i^g(m_{it}; r_t, \boldsymbol{X}_{it})}_{\substack{\text{gas marketing} \\ \text{costs}}} - \underbrace{\tau\left(\ell_f(g_{it} - m_{it}) + \ell_w w_{it}\right)}_{\text{emissions tax}}, \tag{3}$$

where ℓ_f is the methane emissions factor of flared natural gas, ℓ_w is the per-well baseline methane emissions, and so $\ell_f(g_{it} - m_{it}) + \ell_w w_{it}$ is the total emissions from existing wells.[20] Producers are subject to tax $\tau \geq 0$ on each unit of emissions. We assume that producers cannot adjust ℓ_f and ℓ_w.

Firms face a competitive global market for oil and gas and are thus price takers. Oil profits are the difference between oil revenues, $p_t^o q_{it}$, and the cost of oil extraction, $c_i^o(q_{it})$. Gas revenues are the product of the gas price p_t^g and the amount of gas sold, $m_{it} \leq g_{it}$. The cost of marketing gas, c_i^g, comprises the costs of processing and transmitting the gas to the end user.

We parameterize marketing costs with the Waha basis r_{it} and time-varying producer characteristics $\boldsymbol{X}_{it}$. In this way, we capture several key features of this industry. First, producers usually sign long-term contracts for pipeline capacity for some share of their gas production, at rates that vary by firm (depending on volume, bargaining power, etc.). Second, for the gas that remains, producers face spot market prices, which generally move with Waha basis but also depend on where the gas is coming from and going to. Variation in prices arises due to congestion at any point in the natural gas supply chain (Figure 1).

Following Anderson, Kellogg and Salant (2018), we assume marginal production costs of 0, i.e., $c_i^o(q_{it}) = 0$. The first-order condition for marketed gas m_{it} when producers are within the feasible set ($m_{it} \in [0, g_{it}]$) is thus:

$$\begin{aligned} p_t^g &= c_i'^g(m_{it}; r_t, \mathbf{X}_{it}) \; - \; \tau\ell_f \quad \text{if } m_{it} < g_{it} \\ p_t^g &\geq c_i'^g(m_{it}; r_t, \mathbf{X}_{it}) \; - \; \tau\ell_f \quad \text{if } m_{it} = g_{it}. \end{aligned} \tag{4}$$

[20] Independent of producer decisions, some small unavoidable quantity of gas produced will be released into the atmosphere during normal operations of a well, e.g., from pneumatic devices, separators, dehydrators, and compressors. Omara et al. (2022) find that these baseline emissions tend to be fairly independent of production levels.

5.2 Endogenous transmission costs

Gas transmission costs are a function of pipeline utilization rates: when pipelines are more full, transmission costs increase. Policy changes that change m_{it} for many firms will affect demand for pipeline capacity and therefore affect the marginal cost of transmission r_t. Although we assume that individual firms take r_t as given, we need to account for policy feedback on transmission prices in order to model counterfactuals that impact producers more broadly. Thus, we need to be able to re-compute the equilibrium marginal transmission costs based on changes in demand for gas takeaway capacity. To this end, we parameterize the transmission cost as:

$$r_t(m_t, k_t) = \delta_1 + \delta_2 \mathbf{1}(m_t/k_t > \nu) \left(m_t/k_t - \nu\right)^2, \tag{5}$$

where $m_t \equiv \sum_i m_{it}$ is the total quantity of marketed gas from the Permian and k_t is the total pipeline takeaway capacity leaving the Permian.

The marginal cost response consists of a constant marginal cost, δ_1, and a function that increases in capacity utilization, where δ_2 parametrizes the penalty and $\nu \in [0, 1]$ is the utilization rate threshold at which the increasing costs binds. Following Fowlie, Reguant and Ryan (2016), we assume that above this utilization rate threshold, costs increase with the square of the capacity utilization rate, resulting in a "hockey stick" shape.

5.3 Drilling problem

A full structural treatment of the drilling decision would involve solving a dynamic discrete choice problem in which producers weigh the option value of delaying drilling. In such a framework, firms must account for the entire future path of prices, production, and costs, comparing the value of drilling today against the expected value of waiting and drilling in a future period. In this paper, we adopt a more parsimonious modeling strategy that retains the forward-looking nature of the decision without requiring a full dynamic solution. We assume that in each period, producers make a static binary choice of whether or not to drill a new well, based on their expectations of future revenues and current drilling costs. This static model captures the core economic tradeoffs—namely, that drilling is undertaken when expected profits are sufficiently high—while remaining empirically tractable and transparent.[21]

Consider a potential well w, controlled by producer i. Omitting the i subscript, let $a_{wt} \in \{0, 1\}$ denote the drilling decision for this producer at time t, where $a_{wt} = 1$ indicates that a well is drilled. The producer will drill well w if it is profitable to do so:

$$\pi_{wt} = R_{wt} - C_{wt} + \varepsilon_{wt} > 0, \tag{6}$$

where R_{wt} is the expected discounted value of future revenues from the new well, C_{wt} is the expected costs associated with adding a new well (including drilling costs and expected additional operational costs) at time

[21] Assuming that commodity prices follow a random walk, this simplification from a dynamic to a static problem does not introduce bias. Is this precisely true?

t, and ε_{wt} is an idiosyncratic shock to profitability observed by the firm but not by the econometrician. We assume that ε_{wt} follows a Type I Extreme Value distribution, leading to a binary logit model.

We express the expected revenue as

$$R_{wt} \equiv \mathbb{E}_t \left[\sum_{s=l}^{\infty} \beta^s \left(p^o_{t+s} q_{w,t+s} + p^g_{t+s} m_{w,t+s} \right) \right], \tag{7}$$

where $\beta \in (0,1)$ is a discount factor, l is the number of months between spud and first production, p^o_{t+s} and p^g_{t+s} are the expected oil and gas prices at time $t+s$, and $q_{w,t+s}$ and $m_{w,t+s}$ are the marketed oil and gas from the new well at time $t+s$, respectively. We assume that costs take the form

$$C_{wt} \equiv \underbrace{\kappa_1 + \kappa_2 d_t + \tau \ell_a}_{\text{drilling costs}} + \underbrace{\mathbb{E}_t \left[\sum_{s=l}^{\infty} \beta^s \left(c^g \left(m_{w,t+s}; r_{t+s} \right) + \tau \left(\ell_f (g_{w,t+s} - m_{w,t+s}) + \ell_w \right) \right) \right]}_{\text{operational costs}} \tag{8}$$

where κ_1 is the fixed cost of drilling and operating a new well, d_t is the drilling rig dayrate, and ℓ_a are the emissions from well drilling and completion. Operational costs are expressed analogously to the static problem, again assuming that production costs are zero.

We assume that firms' expectations of future prices are consistent with the observed oil and gas futures curves. Under this assumption, expected revenues from oil production can be expressed as $\tilde{p}^o_t q_w$, where $\tilde{p}^o_t$ is the discounted, production-weighted average oil futures price and $q_w \equiv \mathbb{E}\left[\sum_{s=l}^{\infty} q_{w,t+s}\right]$ is the expected cumulative oil production. An analogous expression holds for gas revenues. Defining $Q_w \equiv q_w + m_w$ as the expected total cumulative marketed energy production from the well (including both oil and gas), we can write total expected revenues as

$$R_{wt} = \underbrace{\left[\alpha_w \tilde{p}^o_t + (1 - \alpha_w) \tilde{p}^g_t \right]}_{\equiv \tilde{p}_t} Q_w, \tag{9}$$

where α_w is the oil share of total marketed energy output. This formulation allows us to express expected revenues in terms of a single composite price index that depends on the oil and gas futures strips and the well-specific energy mix. The choice probability is then given by

$$\mathbb{P}(a_{wt} = 1) = \frac{\exp\left(\left[\alpha_w \tilde{p}^o_t + (1 - \alpha_w) \tilde{p}^g_t \right] Q_w - C_{wt} \right)}{1 + \exp\left(\left[\alpha_w \tilde{p}^o_t + (1 - \alpha_w) \tilde{p}^g_t \right] Q_w - C_{wt} \right)}. \tag{10}$$

For tractability, we assume that drilling and operating costs (including gas marketing costs) are unaffected by fluctuations in oil and gas prices.[22] So, we can express the gas price elasticity of drilling as:

$$\varepsilon^g_{wt} = \frac{\partial \mathbb{P}(a_{wt} = 1)}{\partial \tilde{p}^g_t} \frac{p^g_t}{\mathbb{P}(a_{wt} = 1)} = (1 - \alpha_w) \tilde{p}^g_t Q_w (1 - \mathbb{P}(a_{wt} = 1)). \tag{11}$$

[22] In practice, drilling costs do tend to increase with oil prices due to increased demand for drilling crews (see Anderson, Kellogg and Salant (2018)). Similarly, marketing costs can also vary with commodity prices when pipelines are congested. Our reduced-form estimates of these price elasticities can be considered the equilibrium impact of prices on drilling, given feedback from drilling and marketing costs.

We can also write the elasticity of drilling with respect to production-weighted average price $\tilde{p}_t$ as:

$$\varepsilon_{wt}^{\tilde{p}} = \frac{\partial \mathbb{P}(a_{wt}=1)}{\partial \tilde{p}_t} \frac{\tilde{p}_t}{\mathbb{P}(a_{wt}=1)} = \tilde{p}_t Q_w (1 - \mathbb{P}(a_{wt}=1)). \tag{12}$$

Equations 11 and 12 imply that we can express the gas price elasticity of drilling as a rescaled version of the production-weighted average price elasticity:

$$\varepsilon_{wt}^{g} = \frac{(1-\alpha_w)\tilde{p}^g}{\tilde{p}} \varepsilon_w^{\tilde{p}} \tag{13}$$

In Section 4.3, we estimated a gas price elasticity of drilling using a specification that allows for differential responses to oil and gas prices, not imposing the assumption that firms respond identically to a dollar of expected revenue regardless of source. We find that the elasticity of drilling with respect to gas prices is statistically indistinguishable from zero.

As an alternative, we estimate the elasticity of drilling to our constructed energy price index, imposing the assumption that firms treat oil and gas revenues symmetrically. We re-estimate the local projections described in equation 1, replacing separate oil and gas price variables with the composite energy futures price index. The results are presented in Figure B.10 and imply a composite energy price elasticity of 1.4. We use equation 13 to recover a gas price elasticity of only 0.26. We interpret this estimate as an upper bound on the true gas price elasticity, since it relies on an assumption that oil and gas prices have equal weight in firms' drilling decisions. Given the revenue mix and production structure in the Permian, where gas pipeline congestion can mean high marginal costs to market gas and higher volatility in gas revenues, we believe it is reasonable for producers to weight oil prices more heavily than gas prices in this region. Further, since much of total gas production is from existing rather than new wells, the true impact of dynamic drilling effects on counterfactual outcomes like flaring and venting may be quite small.

As a result, for the main estimation and policy counterfactuals that follow, we assume there is no dynamic drilling response to gas prices. This choice reflects our empirical finding that, in the Permian Basin, drilling activity is not significantly responsive to gas price variation. However, in Appendix A, we explore how our counterfactual results would change if we incorporated a gas price elasticity of drilling consistent with the upper bound described above.

6 Estimation and Results

Our estimation proceeds in three stages. First, we estimate the parameters of the per-period profit function. This includes the parameters governing how marketed gas quantity, transmission rates, and gas prices affect the marginal cost of gas marketing. Next, we estimate parameters of the transmission cost curve. Finally, for counterfactuals of interest, we employ an iterative convergence procedure to re-compute equilibria based on the endogenous transmission cost response.

For our estimation, we restrict the sample to oil and gas leases that meet certain criteria. We limit our sample to Texan leases located within the Permian Basin (Texas Railroad Commission districts 7C, 8, and 8A) during the period from January 2016 to January 2023. To be included, a lease must report disposition data for at least 12 months during the sample period. Additionally, after its first appearance in the dataset, the lease must report disposition data for at least 90% of the subsequent months. These restrictions ensure that our analysis is based on leases that are observed at length and continuously, reducing the risk of bias from irregular or incomplete reporting.

In order to describe methane emissions under our counterfactuals, we rely on estimates from the scientific literature of the methane content of natural gas, the methane emissions factor of flared natural gas, and per-well baseline methane emissions. We assume that the methane content of natural gas is 80%.[23] We use two different values for the methane intensity of flaring. First, in line with analysis by Plant et al. (2022) based on airborne sampling, we assume that flaring is 91.1% effective, meaning that 8.9% of the gas producers decide to flare is emitted as methane rather than fully combusted. Second, we assume that flaring is 98% effective, which is the upper bound that the EPA assumes in implementing the Inflation Reduction Act's methane fee. This higher efficiency value assumes that flares are all functioning properly, whereas the Plant et al. (2022) number reflects unlit flares and other malfunctions that affect flaring efficacy in practice.[24] We consider our counterfactuals under both $\ell_f = 0.02$ and $\ell_f = 0.089$. Lastly, we assume that wells emit baseline methane emissions of 1,300 kg per month, or about 68 Mcf ($\ell_w = 68$).[25]

6.1 Flaring model estimation

The firm first-order condition (Equation 4) implies that log flared gas f_{it} can be expressed as

$$\log(g_{it} - m_{it}) = f_{it}(p_t, r_t, \boldsymbol{X}_{it}, \tau) + \varepsilon_{it} \tag{14}$$

for gas prices p_t^g, transmission costs r_t, and time-varying firm characteristics $\boldsymbol{X}_{it}$. Within firm characteristics, we include firm fixed effects, logged oil and gas production, new wells, lagged new wells, and the firm's gas-to-oil ratio in each period. To estimate the parameters in this equation, we use data that producers report to the Texas Railroad Commission on monthly production, drilling, and venting and flaring. We exclude producer-months in which producers report that they marketed over 99% of gas produced. This restriction allows us to exclude cases where the first-order condition does not hold with equality (i.e., $m_{it} \approx g_{it}$), allowing for some margin of error due to unavoidable venting and flaring. The results reported below are robust to other capture rate thresholds (e.g., 98% and 99.5%).

[23]Although this value varies across basins, the 80% methane content assumption is standard in work focusing on the Permian, such as Varon et al. (2022).

[24]In fact, Plant et al. (2022) finds that flaring efficacy in the Permian is 86.8%, even lower than is observed in other major U.S. gas-producing basins. Experimental work by Evans et al. (2024) shows that variation in flaring efficacy can be explained by factors including gas composition, flow rate, and wind velocity.

[25]To derive this number, we first scale the 1.8 kg/hr/site estimate from Omara et al. (2018) up to the month level. Notably, this paper finds that site-specific emissions are largely invariant to the volume of gas produced at each site. Then, we multiply by 0.75 to difference out emissions from flaring. This factor is based on work by Cusworth et al. (2021) showing that 12% of detected plume emissions in the Permian Basin were from flares, as compared with 50% total from production. This is of course a rough approximation, as the degree and sources of methane leakage from oil and gas sites have been shown to vary significantly within and across production sites.

Table 4 provides estimation results for the static producer decision under several specifications. Columns (1) and (2) present OLS estimates, where the outcome is the log volume of vented and flared gas:

$$\log(g_{it} - m_{it}) = \gamma_1 p_t^g + \gamma_2 r_t + \gamma_3 r_t^2 + \gamma_4 \log g_{it} + \gamma_5 \log q_{it} + \gamma_6 w_{it} + \gamma_7 w_{i,t-1} + \gamma_8 g_{it}/q_{it} + \varepsilon_{it}. \quad (15)$$

Columns (3) and (4) present analogous results under alternative specifications where the outcome is instead the rate of venting and flaring, $1 - m_{it}/g_{it}$, estimated via beta regressions. Our main specification is column (1), which includes the Henry Hub price, Waha basis, and squared Waha basis. Columns (2) and (4) control for Waha prices directly rather than separately controlling for the Henry price and Waha basis. As we observed in Table 3, in which the outcome is aggregate estimated flared gas volumes from satellite imaging, there is a fairly large and significant relationship between the Waha basis and flared gas volumes. There is also a strong negative correlation between Henry Hub prices and flared gas volumes, consistent with the idea that higher prices incentivize producers to market more gas rather than venting or flaring it.

Table 4: Static model estimation

	OLS		Beta	
	log(Vented and Flared Gas)		Vent/Flare Rate	
	(1)	(2)	(3)	(4)
Henry Hub Price	-0.051***		-0.037***	
	(0.018)		(0.008)	
Waha Basis	6.300***		5.417***	
	(2.032)		(0.885)	
Waha Basis Squared	0.798		-1.218	
	(1.220)		(0.867)	
Waha Hub Price		-0.064***		-0.050***
		(0.016)		(0.007)
log(Gas Production)	0.721***	0.723***	-0.198***	-0.196***
	(0.067)	(0.067)	(0.019)	(0.018)
log(Oil Production)	0.174**	0.174**	0.135***	0.136***
	(0.070)	(0.070)	(0.017)	(0.017)
New Wells	0.006	0.006	0.003	0.003
	(0.004)	(0.004)	(0.003)	(0.003)
Lag New Wells	0.008*	0.008*	0.004	0.005
	(0.004)	(0.004)	(0.003)	(0.003)
Gas-Oil Ratio	0.001*	0.001*	0.001***	0.001***
	(0.000)	(0.000)	(0.000)	(0.000)
Observations	9826	9826	9826	9826
R^2	0.878	0.878	0.604	0.604
Firm Fixed Effects	Yes	Yes	Yes	Yes

Notes: An observation is a producer-month. Prices reflect the average of daily prices over the month, where daily prices are winsorized at the 1% level. Oil and gas production and new wells are measured monthly. Oil and gas production are in barrels and MMBtus, respectively.
$^{*}p < 0.1, ^{**}p < 0.05, ^{***}p < 0.01$

6.2 Transmission cost response estimation

As detailed in Section 5.2, we specify the following functional form for the relationship between transmission costs and pipeline utilization:

$$r_t(m_t, k_t) = \delta_1 + \delta_2 \mathbf{1}(m_t/k_t > \nu)\,(m_t/k_t - \nu)^2 + \mu_t. \quad (16)$$

Because pipeline utilization, m_t/k_t, is determined simultaneously with transmission costs, estimating this relationship directly would yield biased estimates. In particular, this simultaneity would lead us to understate the sensitivity of utilization rates to transmission costs: higher transmission costs incentivize producers to vent or flare gas, thereby reducing pipeline utilization and bringing down transmission costs.

To address this endogeneity, we instrument using two sources of plausibly exogenous variation in the pipeline utilization rate: oil production and the timing of new pipeline entry. Our identifying assumption for the pipeline entry instrument is that, while the development of new pipelines is endogenous, the exact timing of completion is not. The completion of a new pipeline induces a discontinuous change in utilization as k_t increases while m_t is slow to adjust to the new capacity level. To form this instrument, we determine the timing of completion and calculate the percentage increase in pipeline capacity from new entry based on industry reports.

Our oil production instrument exploits the coproduction of oil and gas: although *marketed* gas production is endogenous to transmission costs, total production is not. There is effectively no intensive margin response to prices for oil and gas production (see section 3.2 and Anderson, Kellogg and Salant (2018)). Further, on the extensive margin, as shown in Section 4.3, drilling in the Permian is driven primarily by oil revenues rather than movement in the gas markets.[26]

We set the utilization threshold at $\nu = 0.9$ and estimate parameters δ_1 and δ_2 of the transmission cost function using two-stage least squares. The F-statistic in the first stage is 19.1, indicating that the instruments are sufficiently strong to address concerns about weak identification. The resulting estimated transmission cost curve is presented in Figure 8. When pipeline utilization is below 90%, the estimated transmission cost from the Waha Hub to the Henry Hub is \$0.18. The cost increases to \$1.04 at 95% utilization, to \$2.02 at 97.5% utilization, and to \$2.80 at 99% utilization.

7 Counterfactuals

With our estimated model, we evaluate a series of policy counterfactuals aimed at reducing flaring and methane emissions. We consider two policies that would directly change the cost of flaring: a methane tax and equalization of tax treatment between flared and marketed gas. We also consider a policy that would indirectly reduce flaring by alleviating pipeline congestion.

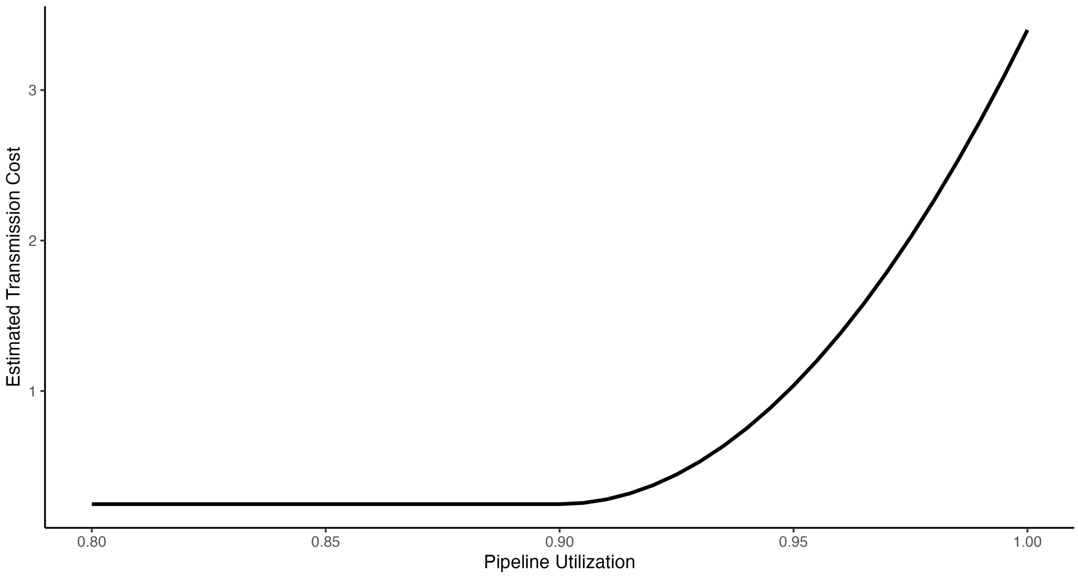
In all counterfactuals, we quantify the benefits of emissions reductions assuming a social cost of methane ranging from \$1,500 to \$4,000 per ton.[27] We take these figures from work by Interagency Working Group on the Social Cost of Greenhouse Gases (2021) and Azar et al. (2023) respectively, though the range of values in the literature does extend even higher.

Although all policies could in principle affect drilling decisions, we take our results in Section 4.3 to suggest that drilling responses would be small relative to other impacts. In Appendix A, we explore the magnitude of drilling responses that would be plausible given our drilling elasticity estimates.

[26] We rely on oil production as our instrument rather than total gas production because of concerns that producers may not correctly report the total gas produced. The results are qualitatively indistinguishable when we use total (marketed and non-marketed) gas production. As shown in Figure 4, total oil and gas production co-move closely over time.

[27] These values of the social cost of methane correspond roughly to social costs of carbon between \$51 and \$192.

Figure 8: Estimated transmission cost curve



Notes: Results from equation 16 estimated via two-stage least squares with $\nu = 0.9$.

7.1 Methane tax

7.1.1 Background

First, we consider a methane tax modeled after the Waste Emissions Charge (WEC) mandated by the Inflation Reduction Act and implemented by the U.S. Environmental Protection Agency (EPA). The EPA's rule, finalized in November 2024, imposes a fee per unit of methane emitted by oil and gas facilities. Emissions are assessed based on subpart W of the EPA's Greenhouse Gas Reporting Program (GHGRP). Though the details of subpart W are complicated, the rule essentially mandates that emissions be calculated by multiplying certain self-reported measures of activity (e.g., number of hours of operation for a pneumatic pump or amount of flared gas) by an activity-specific emissions factor.[28] The rule only applies to facilities above a certain emissions threshold (25,000 metric tons of CO_2 equivalent annually), and only on emissions exceeding 0.2% of gas sold. The proposed methane fee started at \$900 per metric ton for 2024 and increases to \$1,500 per metric ton by 2026. Although Congress repealed the EPA's rule implementing the WEC in February of 2025, the WEC itself is still legally required as per the Inflation Reduction Act (Environmental and Energy Law Program, 2025).

We abstract from the particularities of the WEC to consider a general methane tax τ of the same magnitude. We assume that the tax applies at the level of a producer, and that all producers are above the emissions threshold and are thus subject to the tax. We focus exclusively on how the tax would impact flaring. As noted

[28]Environmental advocates have raised concerns about relying on self-reported data. Even assuming that producers do not misreport, they can still can choose among different reporting methods to minimize reported emissions. In an attempt to address compliance challenges, the EPA has introduced measures to incorporate third-party verification and advanced measurement technologies to track methane emissions. The IRA provided over \$1 billion in financial and technical assistance to help monitor, measure, quantify, and reduce methane emissions from the oil and gas sector. Further, as part of the EPA's Methane Super-Emitter Program, third-party notifiers can use EPA-approved remote-sensing technologies to detect super-emitter events. The future of these programs is unclear under the Trump administration.

above, we do not consider how the tax would impact drilling decisions. Similarly, our estimates do not account for tax-induced investments in emissions-reducing technologies such as flares with automatic shut-offs and real time monitoring. The EPA's proposed rule primarily estimates taxable emissions by applying emission factors uniformly based on engineering calculations. However, the agency is increasingly shifting toward frameworks that reward direct measurement and equipment upgrades, which may better incentivize operators to adopt more effective mitigation technologies.[29] Consequently, our estimates reported here can be interpreted as a lower bound on the potential impact of the methane tax.

7.1.2 Estimation and Results

We assume producers are price takers for commodity prices and transmission costs. However, because a methane tax would affect aggregate gas supply, we allow for the tax to have secondary effects on both prices and costs. In equilibrium, these secondary effects influence the total emissions response expected due to the tax. For flaring f_{it}, the equilibrium impact of tax τ is given by:

$$\frac{df_{it}}{d\tau} = \underbrace{\frac{\partial f_{it}}{\partial \tau}}_{\text{direct effect}} + \underbrace{\frac{\partial f_{it}}{\partial p_t}\frac{\partial p_t}{\partial \tau}}_{\text{price response}} + \underbrace{\frac{\partial f_{it}}{\partial r_t}\frac{\partial r_t}{\partial \tau}}_{\text{transmission cost response}} \tag{17}$$

The direct effect captures how producers alter flaring behavior due to the increase in the cost of flaring due to the tax. The price response term combines the effect of the tax on prices (via changes in total marketed gas) with the effect of prices on flaring. The transmission cost response term captures the tax's effect on transmission costs (via changes in total marketed gas) and the effect of these transmission cost changes on flaring.

For estimation, we assume that producers respond to τ as they would to an equivalent change in p_t, i.e., $\frac{\partial f_{it}}{\partial p_t} = \frac{\partial f_{it}}{\partial \tau}$.[30] Furthermore, because gas and oil are globally traded commodities, we assume in our main analysis that $\frac{\partial p_t}{\partial \tau}$ is 0. Finally, due to our assumptions on the structure of transmission costs, we assume that the tax does not affect transmission costs when pipeline utilization is sufficiently low. That is, $\frac{\partial r_t}{\partial \tau} = \frac{\partial r_t}{\partial m_t}\frac{\partial m_t}{\partial \tau} \geq 0$, with equality when $m_t/k_t << 1$ (no congestion). But, as pipeline utilization m_t/k_t increases, so too does the responsiveness of transmission costs. When pipelines are more congested, then additional gas marketing induced by the tax will significantly increase transmission costs, decreasing gas marketing and thus blunting the effects of the tax.

To estimate the equilibrium effect of the tax, we account for feedback between producer behavior and transmission costs: the tax impacts the quantity of gas flared, which influences transmission costs, which in turn affect flaring decisions. To capture this interaction, we implement an iterative procedure to re-compute

[29] For instance, in 2024, the EPA introduced revisions to Subpart W of the Greenhouse Gas Reporting Program that make assumed flare efficiency a function of the particular flare technology used by each producer. Producers that invest in flare equipment that meets the highest standards can claim a flare efficiency of 98% rather than the default 92% (40 CFR 98.233(n)).

[30] This equality may not hold if producers respond differently to transitory price changes (such as commodity price fluctuations) than they do to more permanent changes (such as new taxes). For instance, producers facing persistently high flaring costs might invest in more long-term pipeline capacity contracts. To the extent that this would happen, our results here underestimate the impact of a tax on flaring.

the equilibrium. The procedure proceeds as follows: (1) we estimate the direct effect of the tax on flaring quantities, m_t, by aggregating changes across all producers; (2) we update transmission costs, r_t, based on the changes in m_t; (3) we re-estimate m_t by modeling producer responses to the updated transmission costs; and (4) we repeat steps (2) and (3) iteratively until the values of m_t and r_t converge. This iterative approach ensures that our estimates reflect the equilibrium outcomes, accounting for endogenous interaction between flaring quantities and transmission costs.

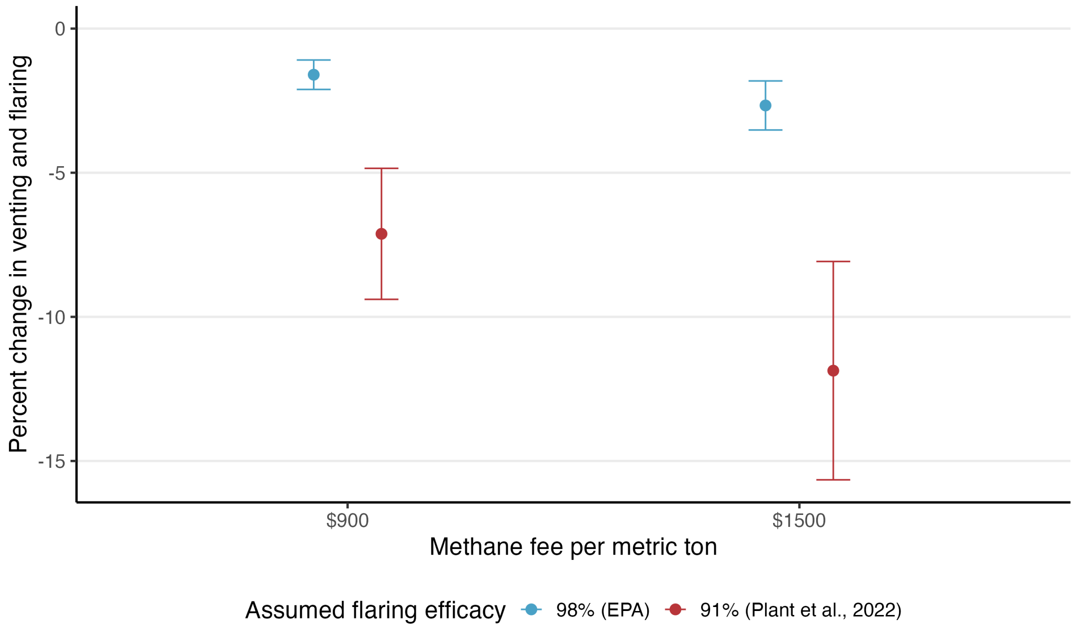
We convert τ, the tax per metric ton of methane emitted, into an equivalent tax τ' per unit of flared gas. As in Section 6, we assume that the methane content of natural gas is 80% and use two values for the destruction efficiency of flaring: 98% from the EPA and 91% from Plant et al. (2022). Under these assumptions, a \$900 per metric ton fee converts to \$0.31 (EPA) or \$1.39 (Plant et al., 2022) per MMBtu of gas flared.

Venting and flaring not the only source of Permian methane emissions. Williams et al. (2025) estimates that 68% of methane emissions from the U.S. oil and gas sector originate at production well sites. In the Permian, this share is slightly higher—over three quarters of total methane emissions are attributable to well sites. At the producer level, we observe the impact of the tax on vented and flared gas, but do not directly observe the associated methane emissions. Using TROPOMI satellite data, we estimate that the basin-wide gas-price elasticity of methane emissions is -0.023 (Table 2), while the gas-price elasticity of venting and flaring is -0.051 (Table 4). These estimates imply that slightly over half of emissions come from less price-responsive sources, and we therefore assume that the effect of our counterfactual policies on aggregate methane emissions from the Permian is 45% as large as the impact of the policies on venting and flaring. Using the Williams et al. (2025) estimates, this suggests that just over half of emissions from well sites are price responsive. While these emissions may not all be classified as venting or flaring, they appear to respond to market incentives in a similar way, and may also be influenced by other operational choices at the wellhead such as the timing of fixing leaks.

Figure 9 displays the direct effect of the tax, which can be interpreted as the effect of the tax under a regime with no pipeline congestion. Under the EPA's maximum assumed flaring efficacy of 98%, the \$900 per metric ton fee would reduce the quantity of vented and flared gas by 1.6%. A \$1,500 per metric ton fee would reduce the quantity of vented and flared gas by 2.7%. However, under the 91% flaring efficacy suggested by satellite data, the \$900 and \$1,500 fees would reduce venting and flaring by 7.1% and 11.9%, respectively. The results demonstrate that nuances in the implementation of a tax can result in large differences in its magnitude and potency. A shift from 98% flaring efficacy to the 91% suggested by satellite data would roughly quadruple the estimated emission reductions.

Using the TROPOMI satellite estimates of methane emissions, we estimate that, under no pipeline congestion, a \$1,500 per metric ton fee with an assumed flaring efficacy of 91% would have reduced methane emissions by 0.28 teragrams (Tg) per year over our sample period, equivalent to 14.84 Bcf of methane. The corresponding reduction in climate damages amounts to between \$425 million and \$1.13 billion annually. Furthermore, at an average Henry Hub price of \$3.31 per MMBtu, this represents an annual savings of \$70 million per year in recovered gas value. Altogether, the estimated annual social benefit of the tax ranges from \$495 million to

Figure 9: Direct effect of the methane fee on vented/flared gas



Notes: Results use column (1) parameters from Table 4. The proposed $900/metric ton methane fee converts to $0.31 (EPA) or $1.39 (Plant et al., 2022) per MMBtu of gas flared.

$1.20 billion. By comparison, a smaller fee of $900 per metric ton with an assumed 98% flaring efficacy would result in an estimated social benefit of $67 million to $162 million annually.

Given persistent pipeline congestion in the Permian, it is crucial to evaluate the equilibrium effects of a methane tax under conditions of limited pipeline capacity.[31] Table 5 presents the results when we treat transmission costs as an endogenous object. Our findings indicate that congestion significantly attenuates the impact of the tax. The reduction in flaring increases the volume of marketed gas, which in turn increases the marginal cost of transmission, thereby reducing the net returns from selling gas. When the pipeline system operates at 99.5% of its maximum capacity, the reduction in venting and flaring attributable to the tax is 37.4% smaller than it would be under uncongested conditions. We conclude that the endogenous market responses in the presence of infrastructure constraints can have a large, mediating effect on the efficacy of price-based emissions reduction policies.

7.2 Equal tax treatment for vented and flared gas

Second, we examine the impact of taxing flared gas at the same rate as marketed gas. In Texas and New Mexico, natural gas is subject to severance taxes of 7.5% and 3.75%, respectively, of the value of the sold gas. However, in both states, gas that is lawfully vented or flared is exempt from this tax. In this counterfactual, we consider a policy that would impose a severance tax on vented and flared gas based on the market value of that gas, equalizing the tax rates across all gas produced. Although similar policies have been considered

[31] Analyses such as Newman (2025) suggestion that congestion is expected to continue in the coming years, despite the recent addition of new pipeline capacity.

Table 5: Interaction between methane fee and gas takeaway capacity

	Low Tax[a]		High Tax[b]	
Pipeline Utilization	%Δ Vent/Flare	Congestion Impact	%Δ Vent/Flare	Congestion Impact
90%	-1.6%	0%	-11.84%	0%
95%	-1.43%	10.39%	-10.62%	10.28%
97.5%	-1.24%	22.41%	-9.19%	22.39%
99%	-1.07%	33.12%	-7.91%	33.19%
99.5%	-1%	37.33%	-7.41%	37.42%

Note: Congestion impact is the percent change in equilibrium response to the tax, relative to the baseline response under a congestion-free scenario (pipeline utilization ≤ 90%).
[a] Low Tax: Proposed 2024 IRA methane fee ($900/mt), assuming 98% flaring efficacy.
[b] High Tax: Proposed 2026 IRA methane fee ($1,500/mt), assuming 91% flaring efficacy.

in these states, none have yet been enacted.[32] In other settings, efforts to tax flared gas have met with mixed results. In North Dakota, laws aimed at reducing flaring include a provision that after the first year of a well's production, continued flaring incurs the same taxes and royalties as if the gas were marketed, unless an exemption is granted due to economic infeasibility (North Dakota Century Code Section 38-08-06.4). However, a rule proposed by the Bureau of Land Management that would have (among other things) charged royalties on gas vented or flared by oil and gas producers on public lands, has been blocked pending litigation.

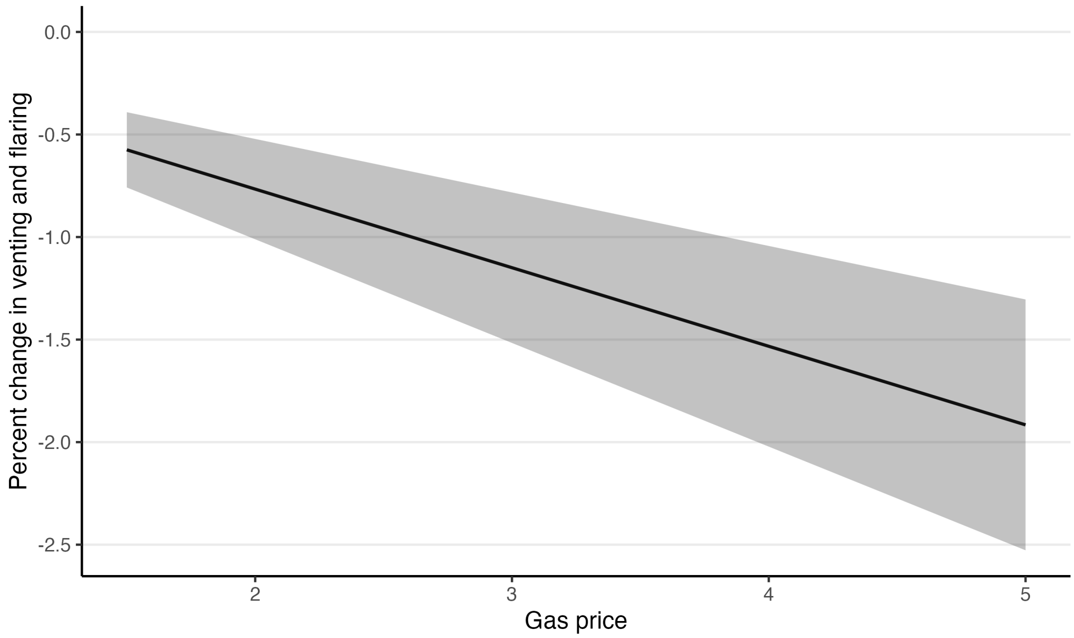
We focus on wells in Texas and estimate the effect of broadening the 7.5% severance tax to include vented and flared gas. In Figure 10, we present our estimates of counterfactual gas venting and flaring, assuming that the tax only changes producer decisions by increasing the cost of gas disposal (i.e., assuming that there is no transmission cost response). At the average natural gas price of $3.31 per MMBtu in the sample period, we estimate that the equalization of tax treatment for all produced gas would decrease the quantity of vented or flared gas by 1.3%, which is around 80% of the estimated impact of the proposed $900/mt 2024 IRA methane fee. Allowing for the endogenous response of transmission costs, when pipeline utilization is at 95%, the effectiveness of the tax is reduced by 14% relative to its impact in a congestion-free regime, and at 99.5% the effectiveness is reduced by 59%.

7.3 Relieve pipeline congestion

In the absence of pipeline congestion, transmission costs between the Waha Hub and the Henry Hub remain relatively steady at around 18 cents per MMBtu. However, as Figure 11 illustrates, recent pipeline congestion has sometimes led to significantly higher transmission costs. In some cases, the Waha basis has risen to well over $2, occasionally higher than the Henry Hub spot price itself. Pipeline congestion raises not only transmission cost levels but also transmission cost volatility. When the pipeline system is operating near capacity, outages or disruptions significantly amplify transmission costs due to the system's inability to absorb shocks. Conversely, when there is little congestion, the system is more resilient, and transmission costs are less sensitive to such

[32] Texas House Bill 228 from the 88th Legislature proposed making flared or vented gas subject to the gas production tax at a *higher* rate than the severance tax, but this bill was not enacted. The bill would have taxed vented or flared gas at 25% of its market value, based on the average price for gas sold in the month it was vented or flared.

Figure 10: Change in vented/flared gas from removing flaring subsidy



Notes: Results use column (1) parameters from Table 4.

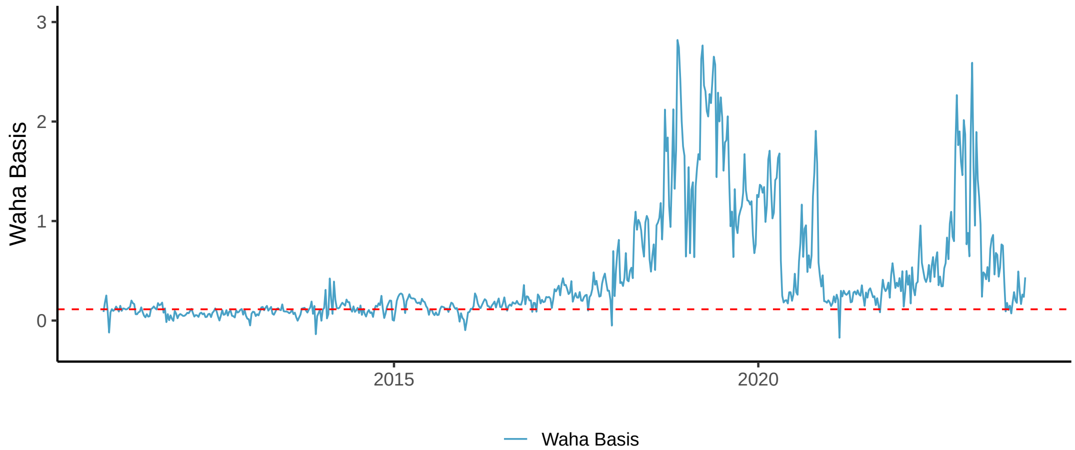
disruptions. We capture this dynamic in our model with our functional form assumption for transmission costs (Figure 8).

To evaluate the implications of elevated transmission costs due to congestion, we compare actual flaring levels to those under two counterfactuals in which takeaway capacity is increased. In the first counterfactual, we assume that transmission costs are exogenously reduced to the congestion-free level. We are agnostic about the specific policies that could achieve this outcome.[33] In our second counterfactual, we assume that pipeline capacity increases by 2,000 MMcf/d, which is roughly the capacity of recently constructed long-distance pipelines from the Permian Basin to the Gulf Coast.

To evaluate the first counterfactual, we use our estimate of the sensitivity of flaring to transmission costs, $\partial f_{it}/\partial r_t$, to calculate what flaring levels would be under a fixed, low r_{it}. We assume that with no congestion, r_{it} is equal to the first decile value of Waha Basis, or about 18 cents. The results are presented in Figure 12. We find that between 2019 and 2023, reducing transmission costs to congestion-free levels would have reduced venting and flaring by 6.4% on average. In periods with the most severe transmission bottlenecks—such as the spring of 2019—eliminating pipeline capacity constraints would have resulted in around a 20% reduction in venting and flaring. In total, our estimates imply alleviating transmission constraints would have reduced methane emissions by approximately 0.18 Tg per year over the period for which we have TROPOMI methane emissions estimates. The combined value of this emissions abatement, including both the environmental benefits

[33] One way this might be achieved in practice is through changes to regulation around pipeline development and expansion. Natural gas pipelines are heavily regulated because they tend to function as natural monopolies. The Federal Energy Regulatory Commission (FERC) oversees interstate pipeline construction approvals, transportation rates, and environmental reviews. Historically, FERC has capped the return on equity for new pipelines at 14%. Increasing this cap or streamlining the approval process could accelerate the development of takeaway capacity, though of course any change may incur other costs.

Figure 11: Waha basis



Notes: The dashed line represents our estimate of the Waha basis at the congestion-free level and is calculated as the first decile of the Waha basis, which is approximately $0.18 per MMBtu.

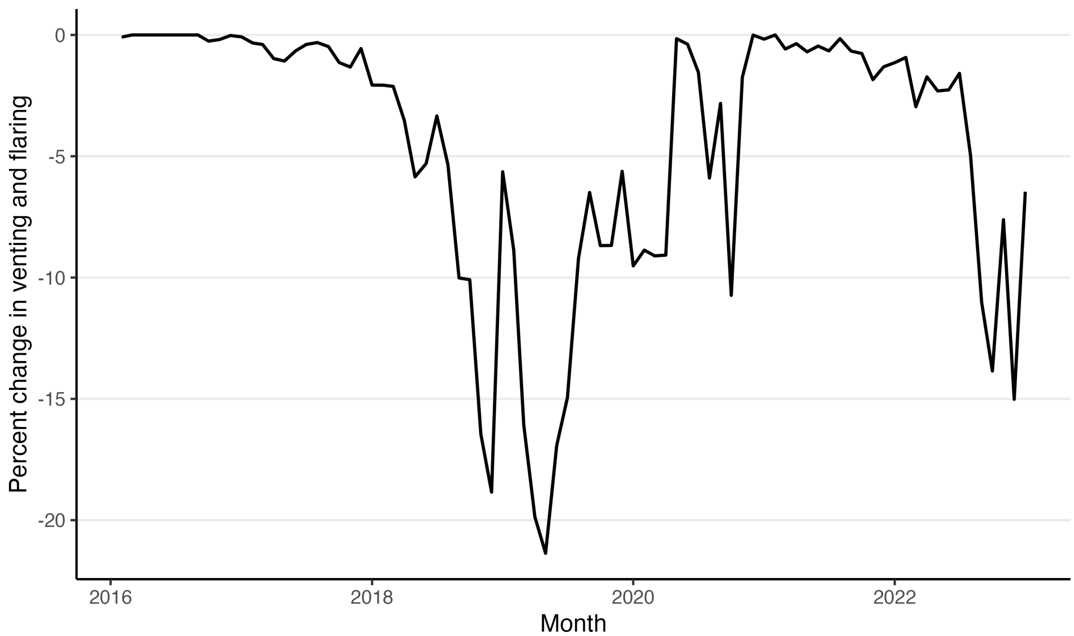
and the market value of the recovered gas, ranges from $309 million to $750 million annually depending on the social cost of methane. For 2019—the year with the highest level of pipeline congestion—the social benefit of relieving this congestion ranges from $518 million to $1.26 billion.

For our second counterfactual, we model the addition of 2,000 MMcf/d in pipeline capacity for the duration of our sample period. Between January 2019 and January 2023, we estimate that adding this incremental egress capacity from the Permian Basin would have reduced methane emissions by 0.10 Tg per year—equivalent to around 55 percent of the emissions reduction that would result from fully eliminating transmission constraints. The social value of this emissions abatement, including both the environmental benefits and the market value of the recovered gas, ranges from $174 million to $424 million annually during this period.

To place the social costs of insufficient pipeline capacity in context, we compare them to the estimated costs of expanding pipeline infrastructure. Using historical reported cost estimates, we calculate a back-of-the-envelope estimate of the cost of building long-distance natural gas pipelines to alleviate Permian egress constraints. This rough calculation is intended only to provide an indicative benchmark and does not account for regulatory and political frictions or other non-pecuniary costs. From the EIA, we obtain data on major U.S. natural gas pipeline projects from 1996 to 2023. The data includes miles, additional capacity (MMcf/d), and—for a subset of projects—cost estimates from companies' press releases and regulatory filings. The sample includes new pipeline construction and expansions of infrastructure, typically carried out through "looping," where a parallel pipe is added alongside an existing line. For each of these project types, we estimate a regression of log project cost on log pipeline length and log capacity. The results are presented in Table C.3.

Since new pipelines serving the Permian Basin have primarily been built to transport natural gas to the Gulf Coast, we focus on the cost of a representative 500-mile pipeline project (the distance between the Permian and the Gulf). Our regressions (Table C.3) indicate that a new 500-mile pipeline with capacity of 2,000 MMcf/d would cost around $1.5 billion, while an expansion project of the same capacity would cost approximately $1.3

Figure 12: Change in vented/flared gas from relieving pipeline congestion



Notes: Results use column (1) parameters from Table 4.

billion (Figure B.16). These figures are broadly consistent with reported costs for recent real-world projects.[34] Assuming this upfront cost captures both social and private costs, a pipeline of this size would generate social benefits sufficient to pay for itself in under eight years, even fully ignoring the non-environmental economic benefits of the pipeline and assuming a low value of the social cost of methane. Thus, even under conservative assumptions, our results indicate that investment in pipeline infrastructure yields substantial social returns.

These findings underscore the significant role of infrastructure limitations in shaping emissions outcomes. Importantly, upstream producers do not fully internalize the costs of venting and flaring when making pipeline capacity purchase decisions, and neither do midstream operators in their pipeline investment decisions.

8 Discussion and Limitations

A key assumption we make in all of our counterfactuals is that flaring and venting will respond to the policies we model, but that new well drilling will not. Based on our estimate of the gas price elasticity for the Permian Basin that is indistinguishable from zero (Section 4.3) , we believe this is a reasonable assumption for our context. However, this assumption may not hold in other basins, particularly those with more gas-focused production. In regions such as the Appalachian Basin, where natural gas production dominates, changes to the profitability of gas production would certainly affect drilling activity: there, other scholars have found the

[34] The Gulf Coast Express Pipeline, completed in 2019, added 1,980 MMcf/d at a cost of $1.75 billion, while the Permian Highway Pipeline, completed in 2019, added 2,100 MMcf/d at a cost of $2 billion (Kinder Morgan, Inc., 2019, 2021). A subsequent expansion of the Permian Highway Pipeline in 2023, which added 550 MMcf/d through compression and looping, cost an estimated $573 million (Kinder Morgan, Inc., 2024).

gas price elasticity of drilling to be significant and positive (Prest, 2025).

A significant drilling response would have important implications for a policy's emissions impact, but the direction of this impact depends on the policy under consideration. For example, a methane tax would reduce the returns to gas production, reducing drilling and associated emissions from new wells. These emissions reductions would be on top of the emissions reductions resulting from decreases in flaring and venting. Conversely, expanding pipeline takeaway capacity in order to reduce transmission costs could increase drilling activity by making gas production more profitable. In this case, increased emissions from more well drilling could counteract or even fully negate emissions reductions from reduced flaring and venting. Therefore, the net emissions impact of the policies we discuss above will depend crucially on the policy's impact on effective gas prices as well as the gas price elasticity of drilling in the region of interest. See Appendix A for a more detailed discussion of this issue.

The Permian Basin has the distinction of being the U.S. region with the fastest growing oil and gas production, which has led it to experience the most acute transmission constraints. However, our findings about the importance of transmission congestion are relevant beyond the Permian. In recent years, several other U.S. basins have faced constraints on natural gas takeaway capacity, and some are projected to encounter increasingly tight infrastructure bottlenecks in the near future. This is particularly true in other oil-dominated regions such as the Bakken (Williston Basin), where rising gas-to-oil ratios have increased the strain on gas pipeline infrastructure. Absent new midstream investments, analysts forecast that the Bakken will exceed its existing takeaway capacity within a few years (McDonough, 2025; Dwan, 2024). Unlike the Permian, however, North Dakota enforces significantly more stringent regulations on flaring and venting. North Dakota prohibits venting and imposes tax penalties on flared gas beyond initial exemption periods, while also conditioning well permits on detailed gas capture plans. As a result, drilling activity in the Bakken has been curtailed due to natural gas takeaway limitations, underscoring the importance of the interaction between emissions regulation and transmission constraints.

Although the Permian Basin is by no means representative of oil and gas production in the U.S. or globally, we believe that our findings about the Permian are important for U.S. emissions as a whole. The Permian is not only the largest oil-producing basin and second largest gas-producing region in the U.S., but it is also the region with among the highest methane leak rates (Sherwin et al., 2024). Furthermore, since the Permian has a smaller gas price elasticity than other basins, any tax targeting either gas production or methane emissions directly would likely make Permian methane emissions a larger share of U.S. emissions.[35]

9 Conclusion

Reducing methane emissions quickly will be essential as the world attempts to rein in climate change. Although prior work has explored different methods to regulate methane emissions coming from the oil and gas sector, emissions regulation may not be stringent enough, nor politically palatable enough, to make the necessary

[35] See Prest (2025) for a more in-depth discussion of oil and gas price elasticities across basins and implications for emissions responses to shocks.

impact. In this paper, we explore the market forces driving methane emissions from oil and gas production to better understand policy and non-policy options for emissions abatement.

We find that emissions are strongly increasing in natural gas transport costs, but not significantly correlated with natural gas prices. We explain this pattern with a model of oil and gas producer behavior, in which producers decide how much new drilling to engage in and what share of gas produced to dispose of. Both decisions impact aggregate emissions. Our empirical work shows that in the Permian Basin, new well drilling is not significantly responsive to natural gas prices but is closely linked with oil prices. Natural gas flaring and venting is significantly responsive to natural gas prices and transport costs. Our results allow us to model a range of counterfactual policies, including tax changes and pipeline congestion alleviation. We conclude that congestion alleviation and emissions taxation are complements, but that congestion alleviation alone would likely have the larger impact on emissions in the current capacity-constrained environment.

The question of how broadly these results apply in other regions remains open. A key assumption in our counterfactual modeling is that drilling is inelastic with respect to natural gas prices, which means that increases in the profitability of gas production do not lead to more drilling and thus to more emissions. As a result, our estimates of the emissions reductions from tax changes are likely underestimates, while our estimates of the emissions reductions from pipeline congestion alleviation may be overestimates. Our empirical work is consistent with the zero gas price drilling elasticity assumption in the Permian Basin, but this assumption is not appropriate in all regions, particularly those with more gas-focused production. Future work should explore how our findings extend to places with a different balance of oil and gas production.

We are also not able to address the question of pipeline investment. Given the positive externalities associated with pipeline investment in terms of reduced flaring, we might expect gas pipelines to be undersupplied relative to the social optimum. However, other forces (market power, rate-of-return regulation, technology lock-in, etc.) might push in the opposite direction. On net, it is ambiguous whether pipeline investment is too high or too low, relative to the social optimum. This is an important area for future research.

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10 Appendix

A Counterfactuals with variable drilling

A.1 Methane tax

A methane tax similar to the EPA's proposed Waste Emissions Charge would affect drilling activity through two channels. First, by increasing the cost of flaring and venting, the tax would increase the cost of gas disposal, thus increasing the expected cost of production. Second, the tax would directly increase the cost of new wells because it applies to emissions from drilling activities and operation. Through both channels, the tax would decrease drilling and thus decrease emissions. For all of our calculations, we use statistics from the base year of 2019.

For simplicity, we consider the upper bound of the impact the tax could have on drilling. We model the impact of a $1,500 per metric ton fee with an assumed flaring efficacy of 91%. On the flaring side, we assume that venting and flaring is fixed at 2% of total gas production, which is at the high end of rates observed in the data. In practice the tax would decrease flaring and venting and thus have a smaller impact on drilling than we estimate here. Multiply gas production by 0.02, then by 0.91 to get emissions, multiply by 1500 to get tax burden.

The tax would also be levied on non-flaring activities. We assume that wells emit 1,300 kg per month as part of normal operations, and that emissions from well completion and workover are 5.9 metric tons.[36] In total, we estimate that taxing these emissions at $1,500 per metric ton would lead to an increase in monthly costs of $1,950 and a drilling cost increase of $8,850.

We make the (heroic) assumption that producers respond to changes in operational costs in the same way that they would to price changes. Thus, to translate from the additional tax burden to an impact on drilling, we use our estimate of the upper bound gas price elasticity of drilling applied to the price change equivalents of the tax. For total revenues of [x], the additional costs outlined above amount to [$y]. This loss in revenues would be equivalent to an oil price change of [$z] dollars. Our drilling elasticity estimates imply that this would lead to a [x%] decrease in drilling activity, correspond to a [y%] decrease in emissions.

We do not consider equilibrium impacts on pipeline congestion. If we did, then the tax change would yield even more emissions reductions, as reduced drilling led to reduced pipeline congestion and thus reduced flaring and venting.

A.2 Equal tax treatment for vented and flared gas

Adding a drilling response for the tax treatment change proceeds similarly to the first part of the methane tax case above. This tax change increases the cost of flaring and venting, which increases the cost of production. We again assume that a flat 2% of gas produced is flared or vented. For the Texas tax rate of 7.5% of the value of gas flared, this implies a tax burden of [$x] on a revenues base of [$y]. This is equivalent to a price change of [$z] dollars, which would lead to a [x%] decrease in drilling activity and a [y%] decrease in emissions.

A.3 Relieve pipeline congestion

Unlike in the other two policy counterfactuals, alleviating pipeline congestion would lead to drilling *increases* that would increase total emissions and counteract the emissions savings due to flaring reductions. Pipeline congestion alleviation would reduce gas marketing costs, thus decreasing the expected cost of production and increasing drilling.

To determine the degree to which pipeline congestion alleviation would reduce flaring and venting, we need to estimate how much producer expectations of marketing costs would change with an increase in pipeline capacity. We assume that producers have accurate expectations, so that their expectations are equal to the mean of marketing costs (as estimated in section 6.1) under the pre- or post-policy regime. We estimate that mean realized marketing costs during our sample period were [x$]. In the no-congestion scenario, these marketing costs would be [y$] and with an additional 2,000 MMcf/d of pipeline capacity, they would be [z$]. This implies a reduction in marketing costs of [x%] or [y$] per MMBtu.

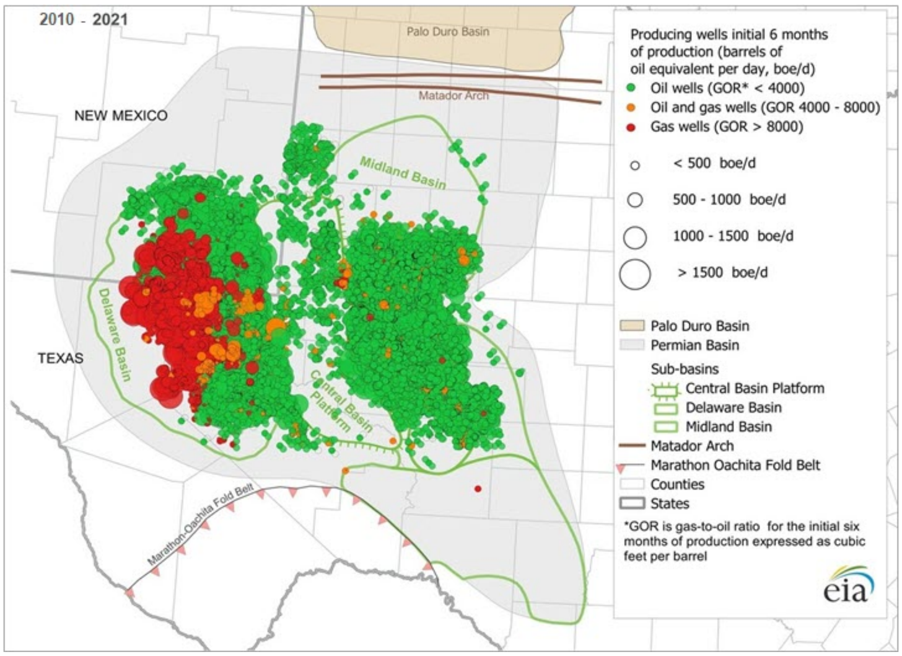
[36] This is the assumed by the EPA in their 2014 greenhouse gas inventory (EPA, 2015) for workovers and completions in which emissions controls are in place and gas is flared. See Cardoso-Saldaña and Allen (2020) for more discussion of this and other estimates.

Again, we assume that changes in expected marketing costs enter drilling decisions in the same way that changes in prices do. Our upper bound gas price drilling elasticity estimate (0.26) implies that the marketing cost decreases outlined above would lead to an increase in drilling of [y%] and an increase in emissions of [z%].

We do not account here for feedback effects: increased drilling would lead to increased production and thus more pipeline congestion, thus attenuating drilling and flaring effects. However, given the small magnitude of the expected change in drilling, we do not expect this feedback to be significant.

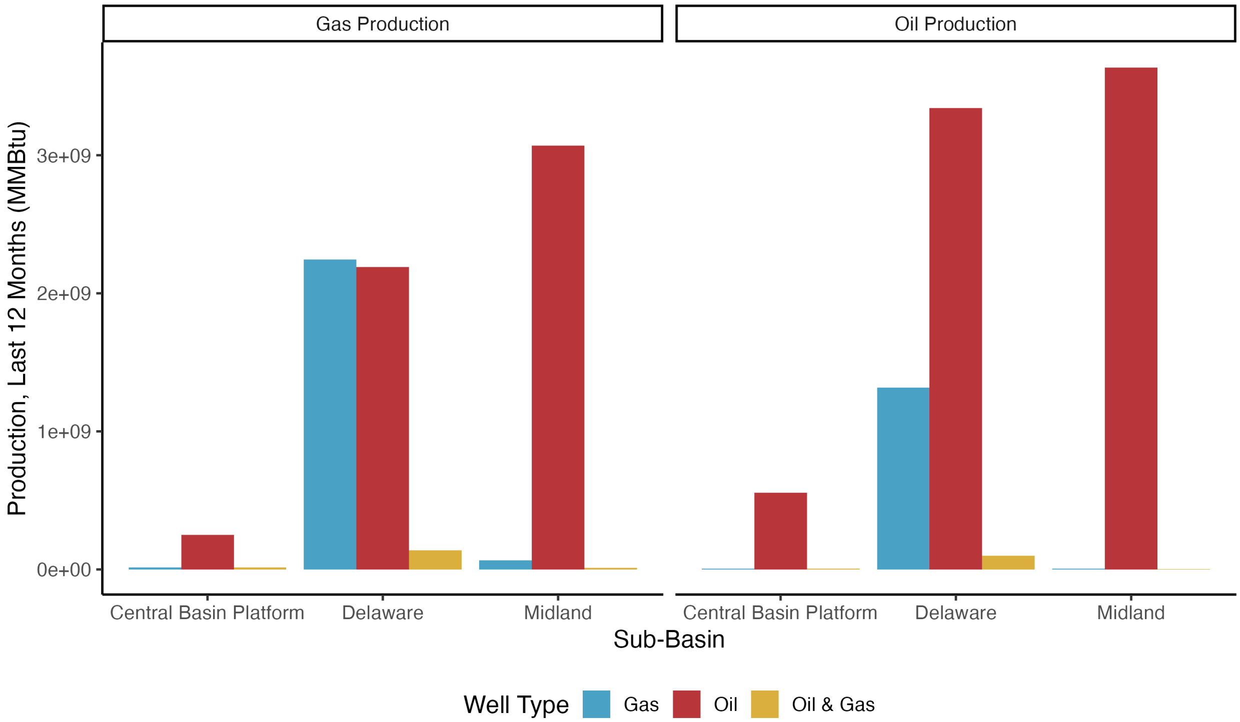
B Figures

Figure B.1: Oil and gas production



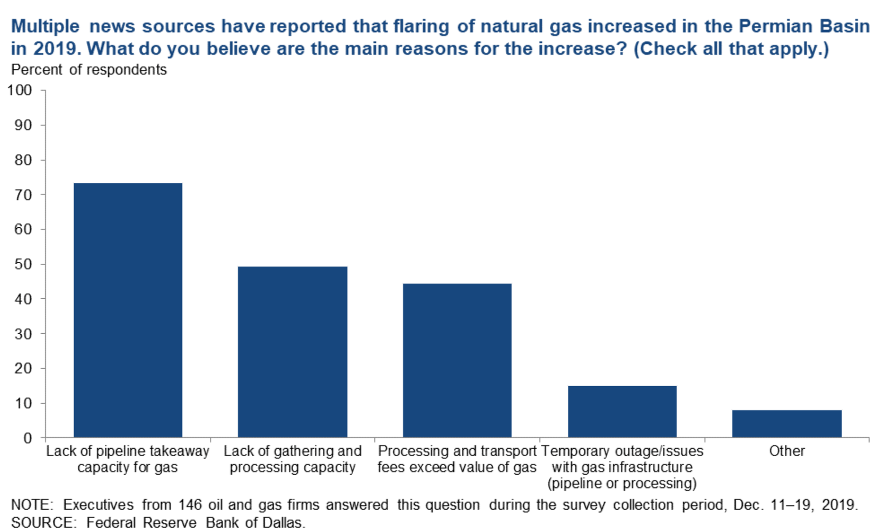
Notes: This figure was produced by the Energy Information Administration (EIA) and summarizes first 6 months production from wells drilled in the Permian between 2010 and 2021.

Figure B.2: Oil and gas production by basin



Notes: Production data from Enverus. We aggregate the last 12 months of oil and gas production as of the last reported month of operation in 2023. Wells types are categorized based on gas-to-oil ratios, as defined by the operator on the filing.

Figure B.3: Self-reported reasons to flare



Notes: This chart was produced by the Dallas Federal Reserve as part of their report on their 2019 survey.

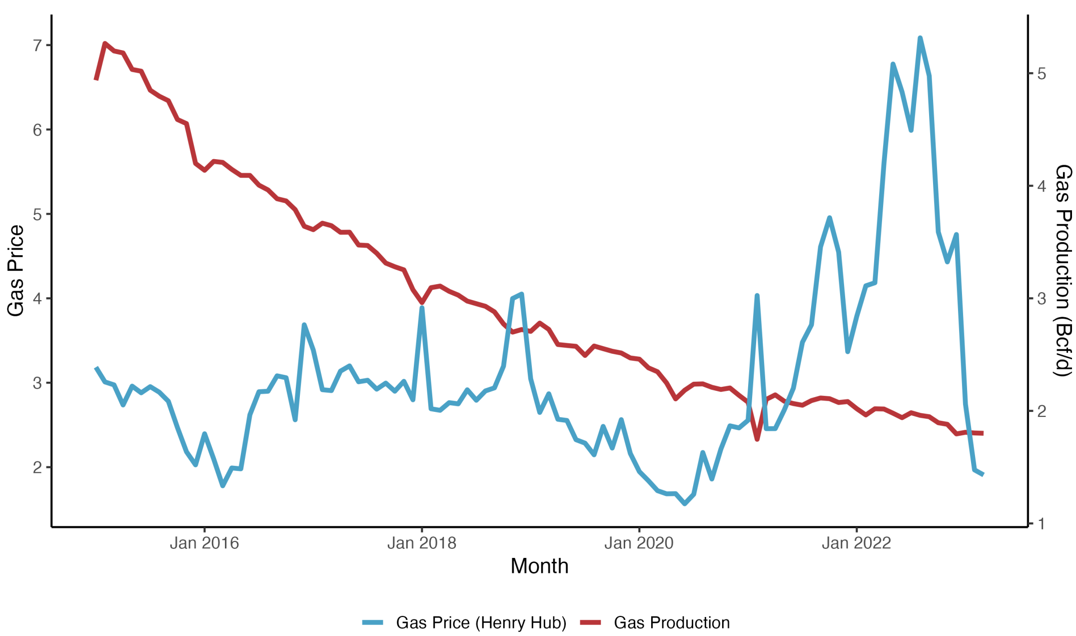
Figure B.4: Mitigation decisions and firm size

Response	Percent of respondents (among each group)		
	Small firms	Large firms	All firms
Plan to reduce CO_2 emissions	22	65	34
Plan to reduce methane emissions	38	65	46
Plan to reduce flaring	43	61	48
Plan to recycle/reuse water	25	48	31
Plan to invest in renewables	2	17	6
None of the above	35	17	30

NOTES: Executives from 83 exploration and production firms answered this question during the survey collection period, Dec. 7–15, 2022. Small firms produced less than 10,000 barrels per day (b/d) in fourth quarter 2022, while large firms produced 10,000 b/d or more. Responses came from 60 small firms and 23 large firms.
SOURCE: Federal Reserve Bank of Dallas.

Notes: This chart was produced by the Dallas Federal Reserve as part of their report on their 2022 survey.

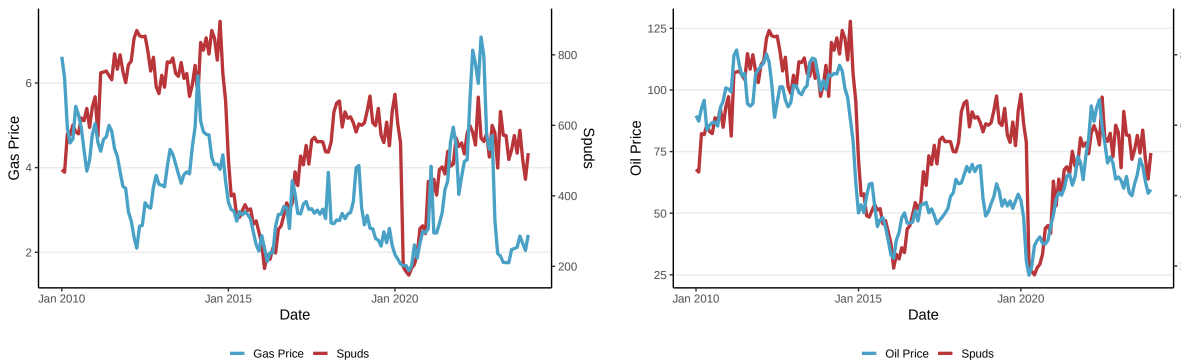
Figure B.5: Permian gas production from wells drilled before 2015



Notes: We depict production data covering January 2015 through March 2023 for Permian Basin wells that were completed in or before January 2015. We plot this against Waha spot prices to show that production from existing wells does not respond to price variation. We derive production data from Enverus. Spot prices are from S&P Capital IQ Pro.

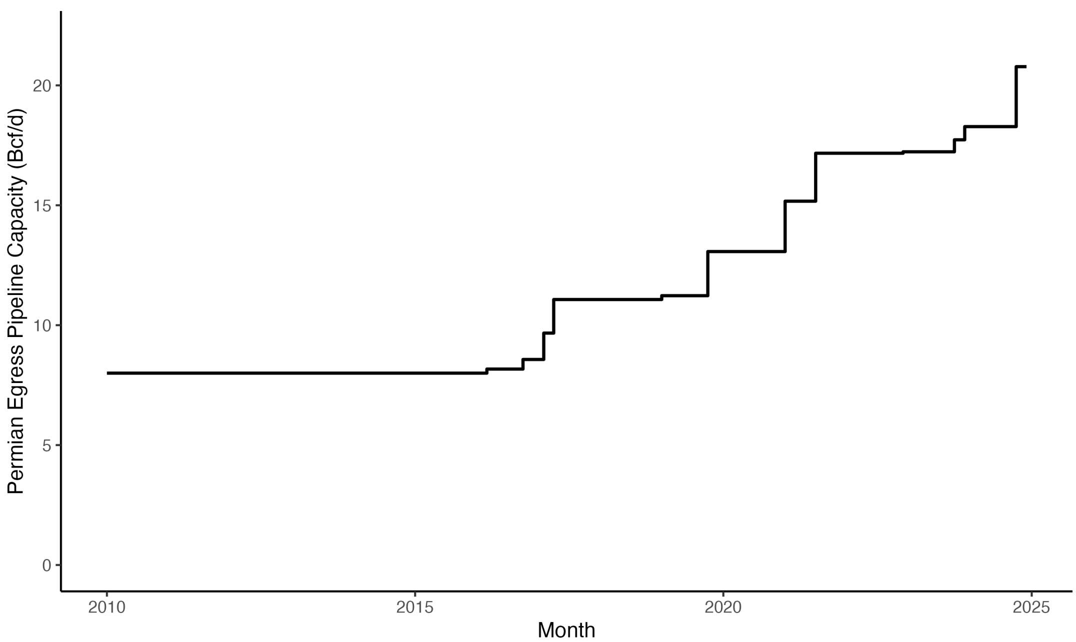
Figure B.6: Well drilling and prices

(a) Gas prices (b) Oil prices



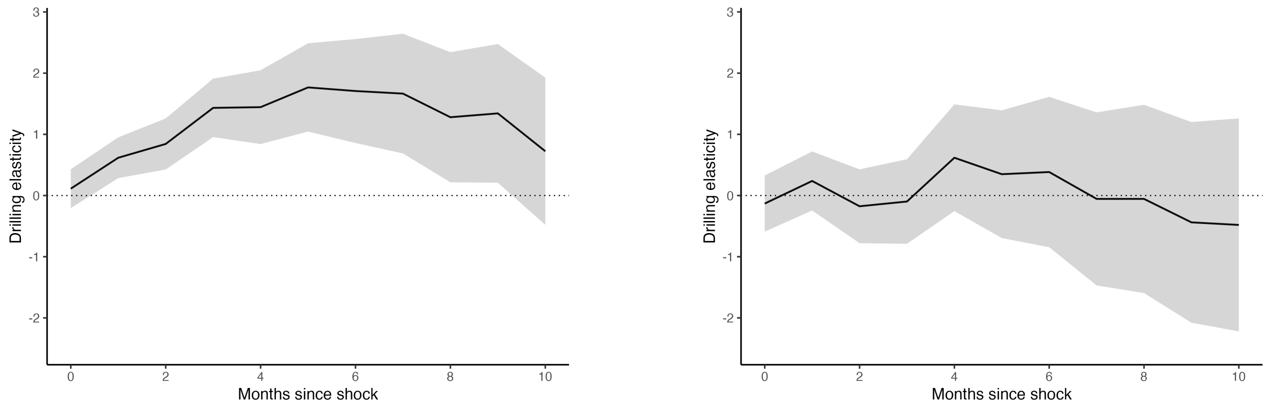
Notes: In both panels, we depict number of spuds (the beginning of drilling operations) by sub-basin of the Permian Basin between 2010 and 2023. We plot this against Cushing WTI spot oil prices and Henry spot prices. Production data are from Enverus. Spot prices are from S&P Capital IQ Pro.

Figure B.7: Permian natural gas egress pipeline capacity, 2010-2024



Notes: Permian gas takeaway capacity collected by authors from industry reports and press releases on pipeline completions.

Figure B.8: Drilling elasticities, oil and gas futures, 2010-2015

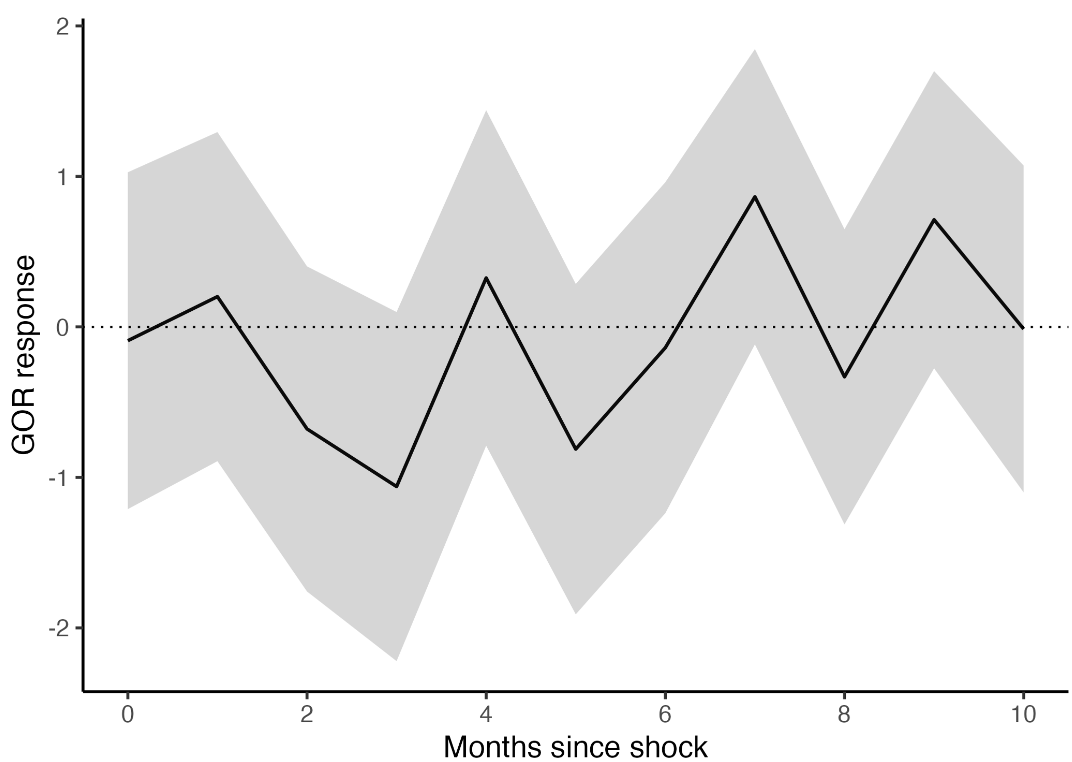


(a) Oil futures

(b) Gas futures

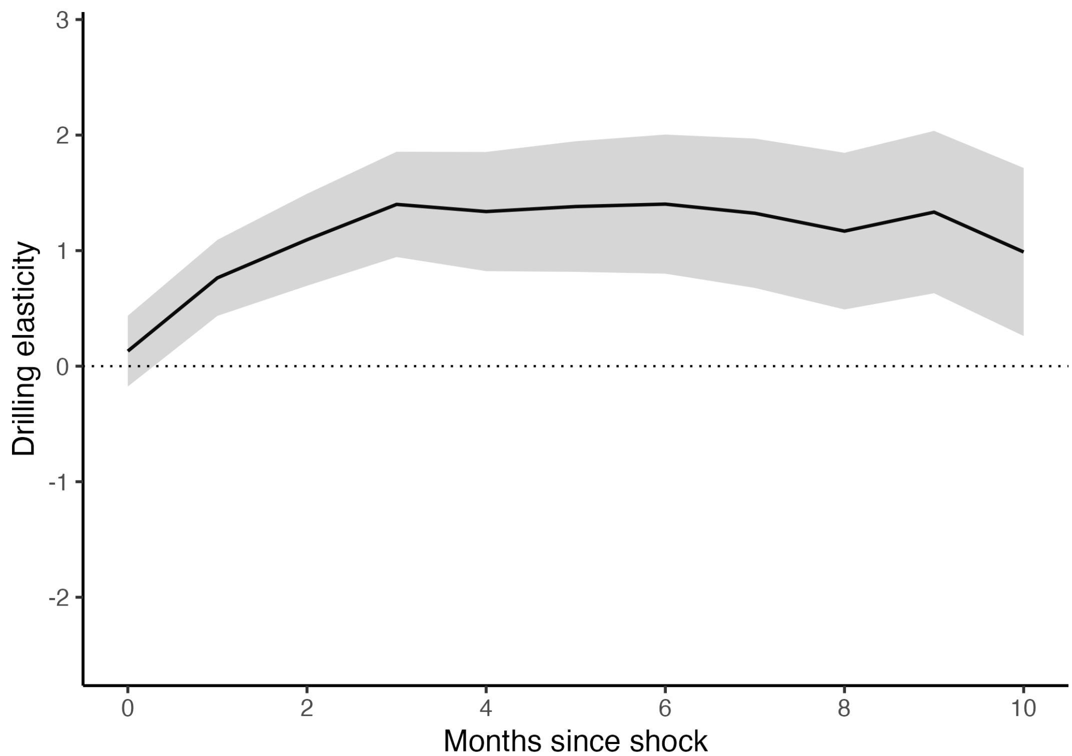
Notes: Local projection results from equation 1 for 2010 to 2015, before the U.S. natural gas market became integrated with the global market.

Figure B.9: Gas-to-oil ratio (GOR) response to gas futures



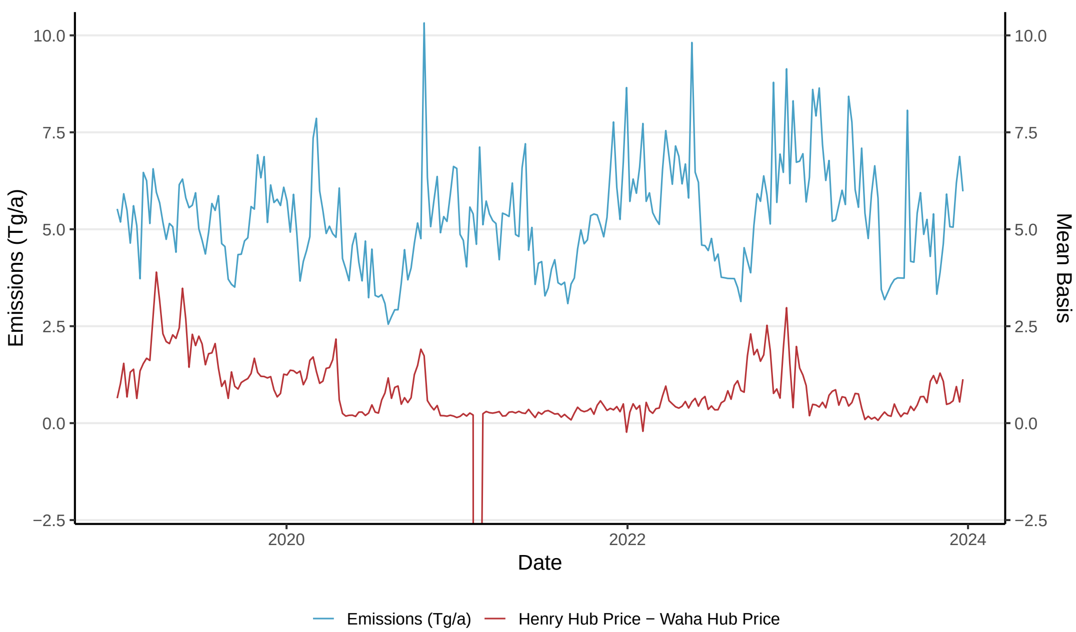
Notes: Local projection results from equation 1, where the outcome is the gas-to-oil ratio for first six months of production.

Figure B.10: Drilling elasticities, composite futures price index



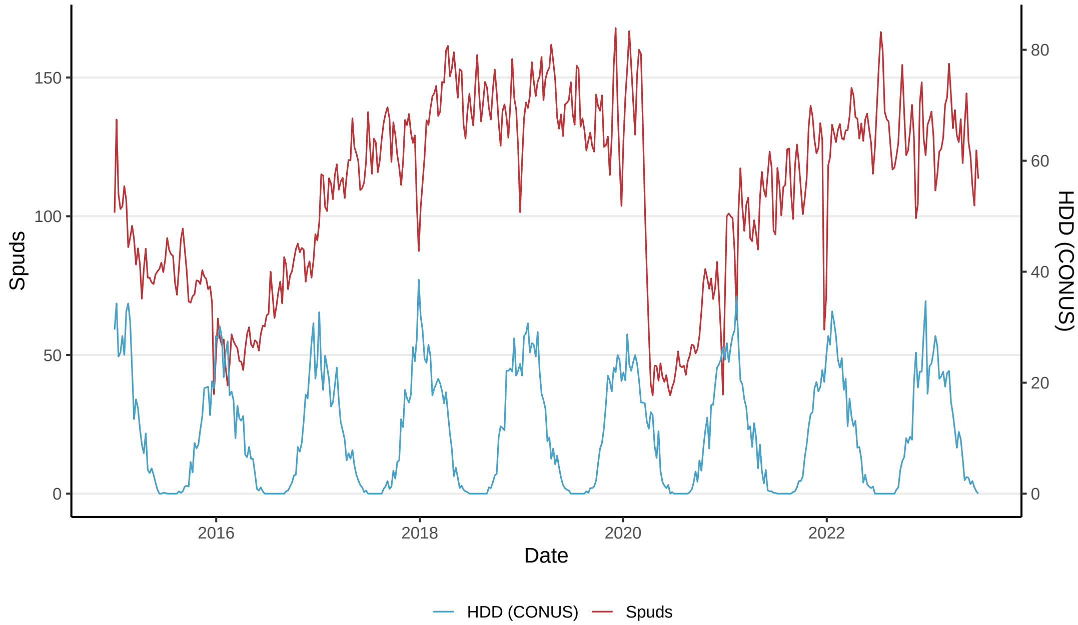
Notes: Local projection results from equation 1, replacing the separate oil and gas price variables with the composite energy futures price index.

Figure B.11: Emissions and the Mean Weekly Henry-Waha Price Gap



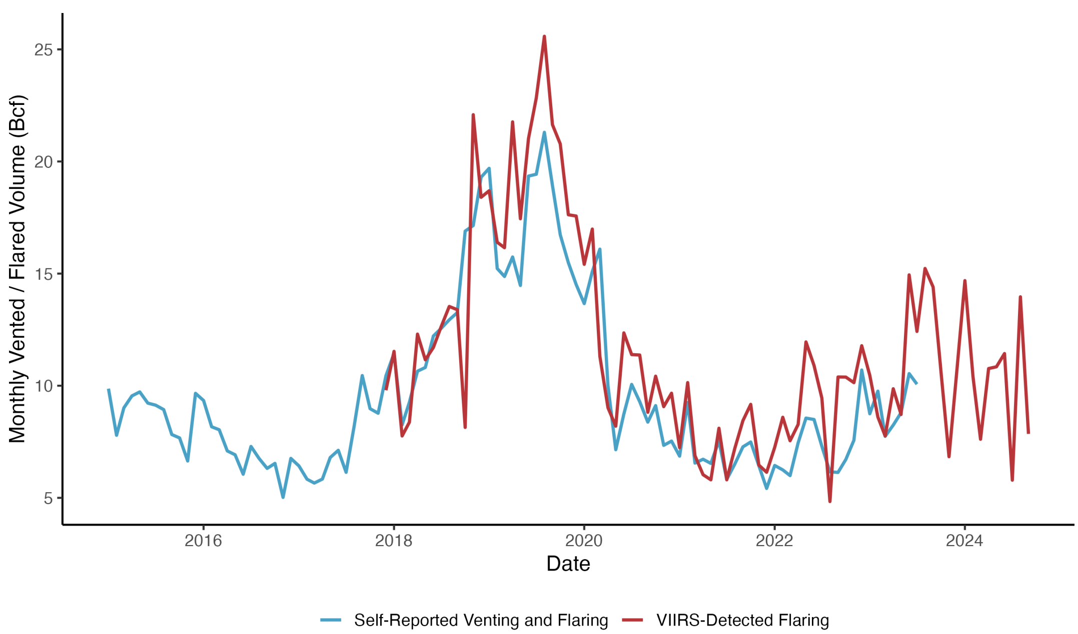
Notes: We plot the raw, weekly data for Permian methane emissions (as estimated by Varon et al. (forthcoming)) and the mean Henry-Waha price gap within each week.

Figure B.12: Well Drilling and Heating Degree Days



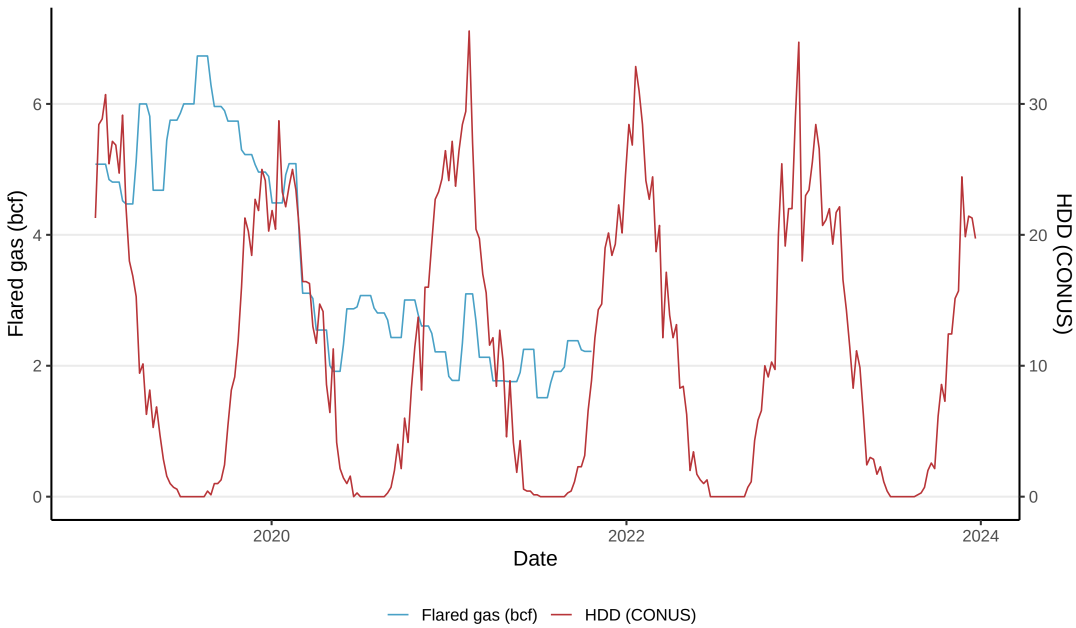
Notes: We plot heating degree days for the continental U.S. alongside the number of spuds in the Permian.

Figure B.14: Self-reported and remote-sensed venting and flaring volumes



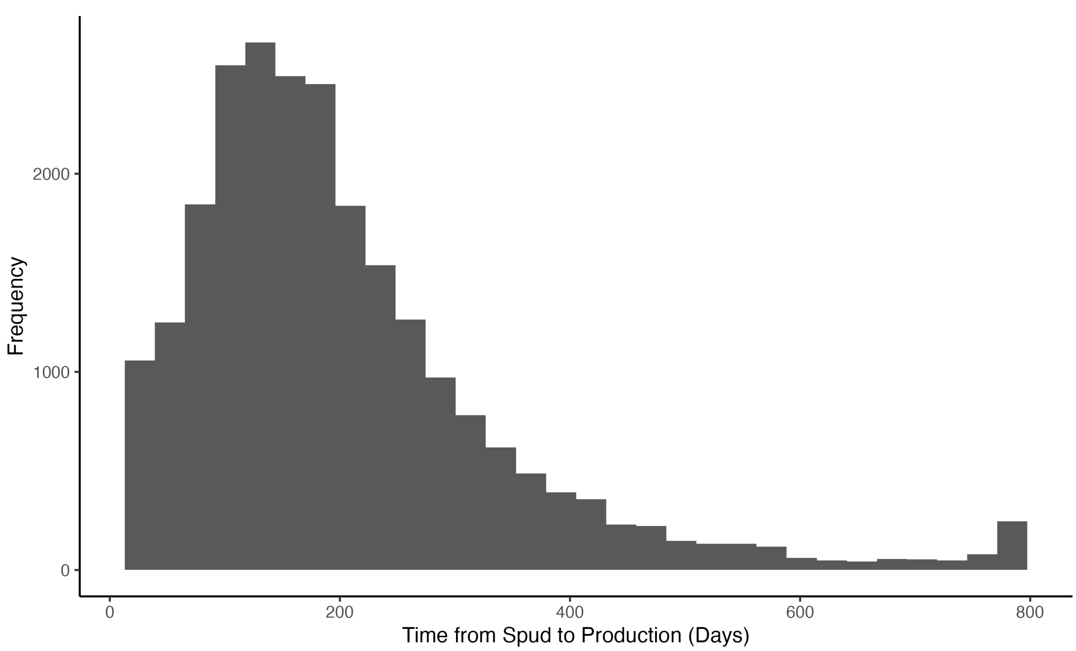
Notes: VIIRS series represents estimates of flared gas calculated by the authors using data from Elvidge et al. (2013) and methodology from Lyon et al. (2021). Self-reported series represents data reported by producers to the RRC and includes both flared and vented gas. Both series capture totals for the Texas Permian Basin.

Figure B.13: Flaring and Heating Degree Days



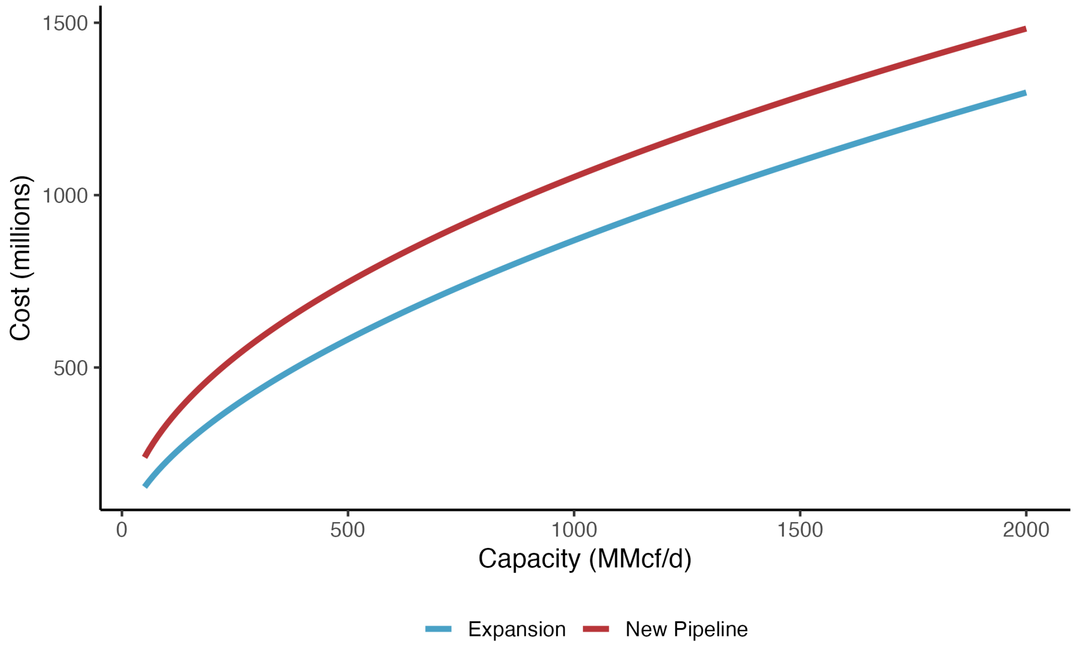
Notes: We plot heating degree days for the continental U.S. alongside VIIRS-based estimates of flared gas volumes for the Permian.

Figure B.15: Time between drilling and first production



Notes: Using data from Enverus, we present the time between a well's spudding (when drilling begins) and its first production. The sample is limited to Permian gas and oil wells drilled in or after 2018 that have been productive at least as recently as 2023. We winsorize at the 1% level.

Figure B.16: Estimated cost of a representative 500-mile pipeline project



Notes: ...

C Tables

Table C.1: Permian Basin natural gas egress pipeline expansions

Date	Pipeline Name	Operator	Capacity Increase (Bcf/d)	Total Capacity (Bcf/d)
2016-03-10	Roadrunner	ONEOK Partners	0.17	8.17
2016-10-01	Roadrunner	ONEOK Partners	0.40	8.57
2017-01-30	Comanche Trail	ETP	1.10	9.67
2017-03-31	Trans-Pecos	ETP	1.40	11.07
2019-01-01	Old Ocean Pipeline	Enterprise/ETP	0.16	11.23
2019-09-25	Gulf Coast Express (GCX)	Kinder Morgan	2.00	13.07
2021-01-01	Permian Highway Pipeline (PHP)	Kinder Morgan	2.10	15.17
2021-07-01	Whistler Pipeline	WhiteWater, MPLX	2.00	17.17
2022-12-01	Oasis	Energy Transfer	0.06	17.23
2023-09-30	Whistler Pipeline	WhiteWater, MPLX	0.50	17.73
2023-12-12	Permian Highway Pipeline (PHP)	Kinder Morgan	0.55	18.28
2024-10-01	Matterhorn	WhiteWater, EnLink Midstream, Devon Energy Corp, and MPLX	2.50	20.78

Table C.2: Methane flares, prices, and production

	Dependent variable:		
	log(Num. Flares)		
	All	Midland	Delaware
	(1)	(2)	(3)
Henry Hub Price	-0.019	0.080^{*}	-0.061^{*}
	(0.031)	(0.041)	(0.033)
Waha Basis	0.110^{**}	0.093^{*}	0.115^{**}
	(0.041)	(0.052)	(0.045)
Cushing Spot Oil Price	0.001	-0.002	-0.001
	(0.003)	(0.004)	(0.003)
log(Oil Production)	1.136	1.831^{***}	0.579
	(0.769)	(0.645)	(0.995)
log(Gas Production)	-0.825	-0.838^{*}	-0.611
	(0.582)	(0.462)	(0.856)
log(New Wells)	-0.089	-0.254^{*}	0.018
	(0.118)	(0.137)	(0.094)
log(Lagged New Wells)	0.039	0.113	0.040
	(0.104)	(0.126)	(0.096)
Constant	2.241	-10.716^{***}	7.533^{***}
	(3.178)	(3.621)	(2.040)
Observations	46	46	46
R^2	0.520	0.533	0.551
Adjusted R^2	0.432	0.447	0.468
Residual Std. Error (df = 38)	0.114	0.156	0.120
F Statistic (df = 7; 38)	5.887^{***}	6.200^{***}	6.652^{***}

Notes: An observation is a week. Outcome variable is the number of clustered VIIRS flaring object detections. Prices reflect the average of prices over the week. Oil and gas production and new wells are measured monthly. Oil and gas production are in sbarrels and thousands of cubic feet (Mcf), respectively.
$^{*}p < 0.1, ^{**}p < 0.05, ^{***}p < 0.01$

Table C.3: Estimated pipeline costs

	Dependent variable:	
	Log cost (millions)	
	New pipeline	Expansion
	(1)	(2)
Log length (miles)	0.761^{***}	0.480^{***}
	(0.068)	(0.040)
Log capacity (MMcf/d)	0.495^{***}	0.579^{***}
	(0.067)	(0.046)
Constant	-1.185^{***}	-0.213
	(0.394)	(0.222)
Observations	133	338
R^2	0.690	0.565
Adjusted R^2	0.685	0.562
Residual Std. Error	0.959 (df = 130)	1.103 (df = 335)
F Statistic	144.580^{***} (df = 2; 130)	217.402^{***} (df = 2; 335)

Notes: OLS results ... A unit of observation is a pipeline project. From EIA data, compiled for projects from 1996 to 2023.
$^{*}p < 0.1, ^{**}p < 0.05, ^{***}p < 0.01$

Table C.4: Correlation matrix

	Waha price	Waha basis	Gas prod.	New wells	Lag new wells	Flared Gas	# Flares
Waha price	1	-0.701	0.116	-0.085	-0.105	-0.533	-0.509
Henry - Waha price	-0.701	1	-0.272	0.409	0.428	0.713	0.634
Gas prod.	0.116	-0.272	1	-0.283	-0.287	-0.266	-0.189
New wells	-0.085	0.409	-0.283	1	0.957	0.519	0.373
Lag new wells	-0.105	0.428	-0.287	0.957	1	0.521	0.386
Flared Gas	-0.533	0.713	-0.266	0.519	0.521	1	0.930
# Flares	-0.509	0.634	-0.189	0.373	0.386	0.930	1

Notes: Prices reflect the average of prices over each month. Gas production, new wells, and flaring variables are observed monthly. Gas production is in thousands of cubic feet (Mcf). Flared volume is measured in billions of cubic feet. Data cover the period January 2018 through October 2021.

Table C.5: Gas-to-oil ratio and futures prices

Dependent Variable:	log(GOR at t+3)			
Sample	Full sample		2010-2015	
	6-mo GOR	12-mo GOR	6-mo GOR	12-mo GOR
Model:	(1)	(2)	(3)	(4)
Variables				
log(18-month Henry Hub gas futures)	0.0686	0.0686	0.2588	0.2588
	(0.0648)	(0.0648)	(0.1579)	(0.1579)
log(18-month WTI oil futures)	0.0049	0.0049	-0.2315**	-0.2315**
	(0.0727)	(0.0727)	(0.1101)	(0.1101)
Fixed-effects				
Firm	Yes	Yes	Yes	Yes
Fit statistics				
Observations	65,583	65,583	22,010	22,010
R^2	0.75414	0.75414	0.71185	0.71185
Within R^2	0.00040	0.00040	0.00161	0.00161

Clustered (Firm) standard-errors in parentheses
*Signif. Codes: ***: 0.01, **: 0.05, *: 0.1*

The unit of observation is a spudded well. Gas-to-oil ratios (GORs) winsorized at 1st and 99th percentiles. All models include operator fixed effects. The full sample includes wells spudded from January 2010 to January 2023. Models for 2010-2015 include only wells spudded before January 2016.