Methane and Markets: Firm Incentives to Emit *

Coly Elhai and Toren Fronsdal
Harvard University

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Abstract

As the primary component of natural gas, methane is both a powerful greenhouse gas and a valuable commodity. We explore the economic factors that influence firms' decisions to emit. Using novel data on methane emissions from the Permian Basin, we provide empirical evidence that emissions respond to high-frequency price variation. In particular, emissions are positively correlated with natural gas transport costs, as captured by the Henry-Waha Hub price spread, but have an ambiguous relationship with natural gas prices. To rationalize these dynamics, we present a dynamic model in which firms make production and emissions decisions in response to oil and gas prices. We find that, while emissions from natural gas flaring and venting decrease with natural gas prices, overall emissions may increase with gas prices due to the extensive margin production response. With the model, we plan to estimate the impact of methane taxes and policies addressing pipeline capacity.

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1 Introduction

Methane is a powerful greenhouse gas, 80 times more potent than CO_2 in its first 20 years. About a quarter of U.S. methane emissions are from the oil and natural gas sector. If a greater share of this methane were captured and sold rather than emitted, the U.S. would be well on its way toward achieving its commitments under the Global Methane Pledge. 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 1). On top of the fluctuations driven by market-wide supply and demand, producers also face price variation coming from changes in the cost of transporting natural gas. Currently, the only cost-effective way for producers to transport their gas to consumers is through pipelines.[1] When pipelines near full capacity, transport costs increase, pushing down the price that producers receive. In the Permian Basin, for instance, transport costs are captured by the gap between the benchmark Henry Hub price and the local Waha Hub price (a gap referred to as "Waha basis"). Several times, high transport costs have caused Waha prices to drop into negative territory, even while Henry Hub trades well above zero (Figure 1).

[1] Liquefaction is an alternative to pipelines for long-distance transport in some cases, but is still very expensive and only economical at scale. With current technology, it is not generally an option for intranational transport. Natural gas storage in the region is also quite limited.

Figure 1: Local and Benchmark Natural Gas Spot Prices

Notes: Daily spot price data from S&P Capital IQ Pro.

The combination of transport costs and demand fluctuations can push producers' net profits on natural gas below zero. Nevertheless, producers may choose to continue producing because in some regions (including the Permian) natural gas and oil are co-produced. For high enough oil prices, it can be profitable for producers to take losses on their gas production in order to continue profiting from oil sales. This is particularly true given the option to dispose of natural gas at low or zero cost by flaring or venting excess product. Flaring is the controlled burning of natural gas to convert the methane to CO_2, while venting is the release of unburned gas into the atmosphere. Both activities are regulated at the state level, but oversight tends to be lax, particularly in Texas. 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.

As oil and natural gas prices fluctuate, producer incentives to abate methane emissions change too. In this project, 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 dynamic investment: given producer expectations over future oil and gas prices and the future stream of production from a new well, 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.[2] We assume there is no natural gas storage, so firms optimize current period profits by selling or disposing of gas depending on the firm's abatement cost curve, the current commodity value of natural gas, and the current cost

[2] As we discuss later, producer decisions tend not to have any 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.

of transporting natural gas to market. We assume that each period, transport costs are subject to a random shock, while commodity values follow AR(1) processes.

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. We further assume that producers have no control over these emissions. Second, emissions result from flaring and venting. We assume that a fixed share of flared/vented gas is released as methane emissions. So, greater flaring and venting activity leads to more emissions.

There are several important implications of our model. The model suggests that, given transitory shocks to gas transport costs, emissions will increase as producers vent and flare a higher share of their product. Furthermore, we find that the effect of a (non-transitory) gas price shock is ambiguous. For instance, consider the case of an exogenous price increase. Because firms rationally expect that a price increase today implies higher prices going forward, well drilling activity today will increase, thus increasing emissions. However, a higher price today also reduces flaring and venting today, reducing emissions. The net effect of the price change on emissions will depend on the shape of firm abatement cost curves and how responsive drilling activity is to the price change.

To test these model implications, we conduct an empirical analysis of the interaction between emissions, venting/flaring, and oil and gas prices. For this part of the paper, 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 make use of recent advances in methane monitoring technology 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.

Using the differential between the Waha Hub price and Henry Hub price as our measure of gas transport costs, we find that Permian methane emissions and gas disposal (through flaring and venting) 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 declines in the price they receive for their gas. Gas disposal is also negatively correlated with Waha Hub prices, which we interpret as an approximation of the net-of-transport price that producers receive. However, emissions have a statistically insignificant relationship with Waha prices. This supports our prediction that price increases have an ambiguous effect on emissions, since they increase emissions from new wells while decreasing emissions from gas disposal.

Reducing methane emissions from oil and gas is a topic of great interest to policymakers today. Our findings suggest that a government intervention to reduce the variance of gas transport costs may be able to reduce methane emissions from venting and flaring. In the future, we plan to estimate the dynamic component of our model as well. With these results, we will be able to estimate the emissions impact of a methane tax, as has been proposed by the U.S. EPA.

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). Thus, producers may be willing to sustain very low profits (or even losses) from the gas side of their operation if it allows them to continue producing oil.

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

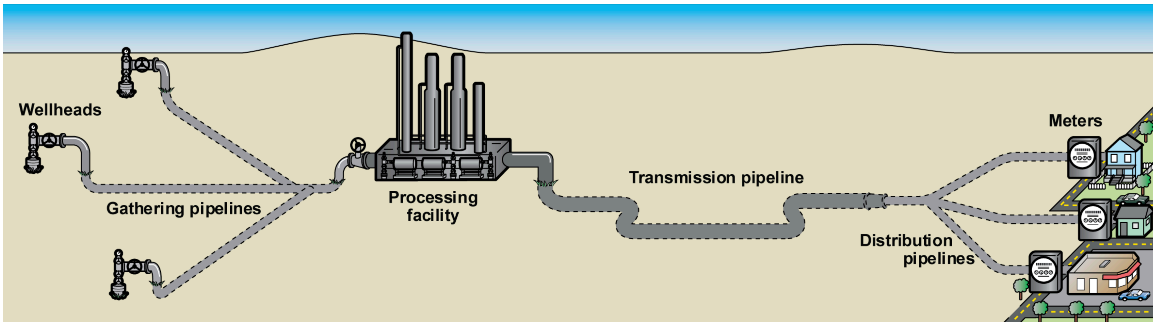
Notes: Lease-level sales data from Enverus. We aggregate sales volumes and values by reported seller name for all observations in 2018. We present here the data for the top 10 gas producers by volume in 2018. We calculate the oil value share to be the ratio of oil sales value to the sum of oil and gas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

Oil is the dominant driver of production across the Permian, but gas-to-oil ratios vary significantly throughout the region. The Delaware and Midland Basins are the most productive sub-basins of the Permian. The Midland Basin occupies the eastern portion of the Permian, while the Delaware Basin is on the western side of the Permian. The Delaware Basin tends to be gassier than the Midland, i.e., it has higher gas-to-oil ratios (Figure A.1). As a result, 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 A.2).

Fueled by the fracking revolution, natural gas and oil production in the Permian has more than quadrupled in the past decade. Pipeline infrastructure has not always kept pace with this rapid expansion in supply. Frequent shortfalls in pipeline capacity have often driven natural gas spot prices at Waha Hub (the main hub serving the Permian Basin) into negative territory.

This points towards an important feature of natural gas: it 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. Despite recurring capacity issues in the Permian, producers have been unable to find a scalable alternative to long-distance transmission pipelines for bringing their gas to market. 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 2). Construction of this upstream infrastructure in the Permian has also failed to keep pace with gas production.

Figure 2: 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 A.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: Lyon et al. (2021) find combustion efficiency in the Permian to be around 93% due to unlit and malfunctioning flares. The remaining gas, which was about 80% methane, was 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. Justifications for exemptions include lack of takeaway capacity and downstream maintenance events. In practice, the RRC approves essentially all flaring requests, as evidenced by permit request data. Texas regulators allow venting during well completion and recompletion, and up to 10 days after well completion. Venting is also permitted for for up to 24 hours at a time, or up to 72 hours in a month. Venting is otherwise prohibited in the state (Texas Administrative Code, n.d.).

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. Lewis, Wang and Ravikumar (2023) uses an RCT at oil and gas production sites in Alberta, Canada, to show that sites with low baseline leakage *increase* emissions when provided with information about on-site leaks, while sites with high baseline leakage *decrease* emissions when informed about their leaks. This is consistent with producers deciding on leak detection and repair in response to perceived losses from leaks.

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 the U.S.' total oil/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.

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. The authors estimate that the other half of methane emissions come from gathering and boosting (38%) and processing (12%).[3] 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 cumulative 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 how many units of activity (e.g., wells) there are. This method is not suited to tracking how carbon intensity varies across units or over

[3] 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.

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 on an entire region's emissions.

Recent advances in satellite instruments and atmospheric modeling have revolutionized methane measurement. Varon et al. (2022) 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 over the period from May 2018 to October 2020.

2.4 Prior Economic Literature

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 observed distances between wells and pipeline infrastructure, and then linking estimated costs with actual flaring behavior. We expand on this work by linking flaring behavior with methane emissions, which they are unable to measure directly. We also provide a framework to explain how firm incentives to abate could vary not just with the presence of infrastructure but also with the costs associated with its use. In complementary work, Hausman and Muehlenbachs (2019) estimate abatement costs using data on spending to prevent natural gas pipeline leaks. They find that firms spend less on leak prevention than they should, based on the value of the leaked gas. The authors posit that distribution 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 project explores on the production side of the industry.

Closest to our work is 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 work to follow high-frequency variation in both emissions and prices. We build on this work by applying estimates from Varon et al. (2022) to the problem. The availability of more accurate, higher-frequency data gives us a better vantage point from which to examine the decisions that operators make. Furthermore, while Marks uses the spot price of natural gas to infer abatement costs alone, our model allows firms to choose production and emissions intensity separately in response to current and expected prices of both oil and gas. We believe that this is a better fit for an industry characterized by long-term investments and joint production.

There is a substantial literature on optimal emissions regulation. Fowlie, Reguant and Ryan (2016) examines greenhouse gas regulation in the cement industry, and how regulations can increase welfare gains by accounting for market power and emissions leakage. Werner and Qiu (2020) simulates audit-based methane regulation policies, proposing an audit strategy that targets wells based on remotely sensed data on leaks. Cicala, Hémous and Olsen (2022) propose a policy in which firms can voluntarily disclose emissions and pay a tax based on those emissions to avoid paying a tax based on average emissions among non-disclosers. Given this setup, adverse selection leads the market to unravel in favor of disclosure. 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. They rationalize this behavior within a modified Hotelling model, in which producers are constrained by reservoir pressure, and so rarely choose to defer production today to take advantage of higher expected future prices. We encompass these patterns in 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.

3 Data

We use the weekly estimates of Permian Basin methane emissions from Varon et al. (2022), as described in Section 2.3. These estimates cover the period May 2018 to October 2020 and are generated at the level of 25×25 km^2 cells. We primarily use basin-level and subbasin-level aggregates of these estimates.

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. We then merge RRC data with data from Enverus on well drill dates, first production dates, and the number of wells per lease. To do this, we use an Enverus crosswalk linking RRC well IDs with Enverus lease IDs.

Although the RRC dataset does not separate gas that was flared versus vented, we can validate general trends in gas disposal using flaring data from Lyon et al. (2021). This work uses the methodology from Elvidge et al. (2016) to convert observations from the Visible Infrared Imaging Radiometer Suite (VIIRS) satellite instrument into estimates of the number of flares and volume of gas flared each month. Because this methodology is based on VIIRS-derived radiant light and heat, it may not capture malfunctioning or unlit flares.

We use daily natural gas spot price data for Henry Hub and Waha Hub from S&P Capital IQ, along with Cushing WTI spot prices from EIA. We also use EIA data on Cushing forward prices. In most of our analysis, we use weekly averages of daily prices. Oil and gas production data are from Enverus DrillingInfo at the well-month level. This dataset includes information on each well's first production date, as well as features such as well operator and well type that we have not yet integrated into our analysis.

4 Model

4.1 Stylized Facts

With our model, we want to capture several key features of the industry:

1. Production from existing wells declines over time and is not responsive to prices.

2. The drilling of new wells does respond to prices.

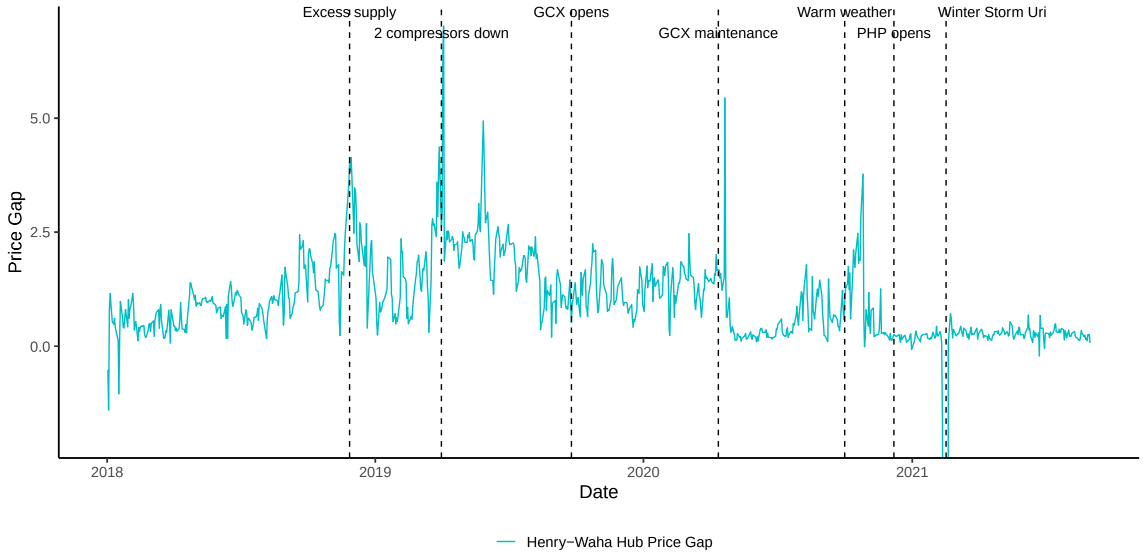
3. Transport costs vary more than commodity values.

We will discuss each in turn. First, it is well-established in petroleum geology and engineering that the production capabilities of gas and oil wells decline over time as reservoir pressure drops. It is common to model production using decline curves that feature exponential decay, or initial hyperbolic decline followed by slower exponential decay. As described and modeled in Anderson, Kellogg and Salant (2018), this production constraint generally binds: oil producers do not adjust production from existing wells in response to price shocks. In Figures A.5 and A.6, we confirm that this same pattern exists for both gas and oil production for the period of our study. Production from existing oil and gas wells declines over time with no apparent correlation with oil or gas prices. The few periods when production and prices appear to co-move correspond to extreme weather that both increased energy demand and interfered with oil and gas production.

In contrast, well drilling does move with prices. We verify this finding from Anderson, Kellogg and Salant (2018) for our context using data on drilling activity. We find that drilling in the Permian Basin tracks oil prices rather than gas prices (Figure A.7, Table 4), an unsurprising pattern given the dominance of oil in Permian producers' revenues (Table 1). Furthermore, producers are forward-looking: higher prices for three-month futures contracts reduce new drilling activity today. These same trends hold for well completions.

Finally, the cost of moving natural gas to market from the Permian Basin 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 1). In contrast, transport costs are quite sensitive to any imbalance of supply and demand, either in gas or in pipeline space (Figure 3). Particularly when pipeline capacity is tight, as it was from 2018 to 2021, maintenance issues or gas oversupply can cause the Waha basis to rise dramatically. Even outside of these major disruptions, day-to-day swings in basis are large.

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.

4.2 A Dynamic Model of Production and Emission

We present a dynamic model of producer production and emissions decisions. Each period, the producer chooses the number of new wells to develop, a_t, and the share of produced gas to dispose of rather than sell, e_t. It chooses a_t and e_t to maximize current profits plus the discounted stream of expected future profits.

Let $\Omega_t = (q_t, w_t, p_t, u_t)$ be a producer's state space in period t, where q_t is the level of oil production from *existing* wells, w_t is the total number of wells the producer operates, $p_t = (p_t^o, p_t^g)$ are the oil and gas prices in the period, and u_t is the utilization rate of gas pipelines. The level of gas production in each period, αq_t, follows deterministically from the level of oil production, according to the gas-to-oil ratio of the wells, α. We assume that each producer is small and so takes u_t and p_t as given.

In any given period, profits are equal to the following (suppressing time subscripts):

$$\pi(e, \Omega) = \underbrace{p^o q - c_o(q)}_{\text{oil profit}} + \underbrace{p^g\left[(1-e)\alpha q\right]}_{\text{gas revenue}} - \underbrace{c_g(e, \alpha q; u)}_{\substack{\text{gas capture/marketing} \\ \text{costs}}} - \underbrace{\tau\left(e\alpha q + \ell w\right)}_{\text{emissions tax}}.$$

Oil profits are the difference between oil revenues $p^o q$ and the marginal cost of oil extraction, $c_o(q)$. Gas revenues are the product of the gas price p^g and the amount of gas sold, which is equal to the sold share $1-e$ of total gas production αq_t. Producers are subject to tax τ on each unit of emissions. Each producer emits a constant amount ℓ from each of its w_t wells, representing leakage and operational venting. Producers also dispose of share e of gas production αq_t. Finally, the producer's choice of e determines how much it must pay in gas capture and marketing costs, which we decompose as follows:

$$c_g(e, \alpha q; u) = \underbrace{c_a(1-e) \cdot \alpha q}_{\text{abatement cost}} + \underbrace{c_m(u) \cdot (1-e)\alpha q}_{\text{marketing cost}}.$$

Abatement costs are a function of disposal rate and must be paid for each unit of gas that is captured. Marketing costs capture the cost of moving gas to market, and depend on the utilization rate of gas pipelines, u. Marketing costs must be paid on each unit of sold gas, $(1-e)\alpha q$.

Firms choose how many wells to drill in each period, a_t, to maximize the stream of future-discounted expected profits. Wells drilled in period t begin producing in period $t+1$. Drilling costs $c_t(\cdot)$ are a function of number of wells drilled and are allowed to vary by period. Production from a well decays exponentially at rate γ. The process of drilling a well results in emissions that are some multiple f of the well's typical per-period emissions ℓ. These emissions occur in the period that the well is drilled and are also subject to tax τ on methane emissions. The period after a well is drilled, it begins producing at r units of oil.

The value function for the producer is then given by

$$V(\Omega_t) = \max_{a_t, e_t} \pi(e_t, \Omega_t) - c_t(a_t) - \tau f \ell a_t + \beta \mathbb{E}[V(\Omega_{t+1}) | a_t, \Omega_t] \tag{1}$$

$$= \max_{a_t, e_t} \pi(e_t, \Omega_t) - c_t(a_t) - \tau f \ell a_t + \beta \int V(\Omega_{t+1}) \mathbb{P}(\Omega_{t+1} | a_t, \Omega_t) \tag{2}$$

subject to constraints:

$$q_t = \gamma q_{t-1} + r a_{t-1} + \varepsilon_t, \quad \varepsilon_t \sim \mathbb{N}(0, \sigma^2) \qquad \text{Law of motion for production}$$

$$w_t = w_{t-1} + a_{t-1} \qquad \text{Law of motion for number of wells}$$

$$a_t \geq 0 \qquad \text{Zero lower bound for drilling}$$

$$0 \leq e_t \leq 1 \qquad \text{Bounds for emissions rate}$$

Total producer emissions in period t are given by $e\alpha q_t + \ell w_t + f \ell a_t$ and the emissions rate is given by $(e\alpha q_t + \ell w_t + f\ell a_t)/q_t$. Producers expectations are over future production q_t, commodity prices p_t, and utilization u_t. We assume commodity prices p_t follow an AR(1) process:

$$p_t = \beta p_{t-1} + \xi_t, \quad \xi_t \sim \mathbb{N}(0, \sigma_p^2)$$

We assume that utilization is centered around the ratio of total gas production to total built pipeline capacity, which varies over time, but is subject to a random shock each period that captures unforeseen maintenance events and the like. We represent utilization as:

$$u_t = \bar{u}_t + v_t, \quad v_t \sim \mathbb{N}(0, \sigma_u^2)$$

4.3 Predictions

A key feature of this framework is that emissions decisions are static choices that respond only to current prices and costs, whereas production *levels* from existing wells are insensitive to current prices. The optimal emissions rate from existing wells satisfies:

$$c_a'(1 - e^*) = p^g - c_m(u) \tag{3}$$

Suppose that the abatement cost function $c_a(\cdot)$ is increasing and convex in share sold $(1 - e)$ and the marketing cost function $c_m(\cdot)$ is increasing in utilization u. Then, a transitory positive shock to utilization will increase marketing costs, which will increase emissions as producers vent and flare a higher share of their product. However, the same shock should have no effect on wells drilled. Wells drilled today only affect future profits, and a shock to utilization today has no impact on expectations of future utilization or marketing costs.

In contrast, a shock to gas price p_g will affect both emissions rate and well drilling activity. A positive shock increases the marginal return to selling gas today, thus decreasing the optimal emissions rate. The positive shock also increases expectations of future prices, increasing both drilling and drilling-related emissions today. The effect of this gas price shock on total emissions is ambiguous, depending on the shape of firm abatement cost curves and how responsive drilling activity is to the price change.

4.4 Identification

In our data, we directly observe prices p and gas-to-oil ratios α. Using price and production data, we can estimate the variance of lease-level production and commodity prices (σ^2, σ_p^2), as well as the average production from new wells r and the decline rate of well production γ. If we assume a functional form for transport costs, we can estimate the variance of pipeline utilization rate (σ_u^2). With additional data on pipeline capacity and gas outflows, we would also be able to observe $\bar{u}_t$. We need to recover the cost of abatement $c_a(\cdot)$, the marketing cost $c_m(\cdot)$, emissions multipliers on new and existing wells f and ℓ, and time-varying cost of investment in new wells $c_t(\cdot)$.

If we define p_g as the Henry Hub spot price and $c_m(\cdot)$ as the difference between Henry and Waha spot prices, then it is straightforward to estimate $c_a(\cdot)$ in a static framework (equation 3) using our data on prices and observed venting/flaring rates.

We can estimate the emissions multipliers f and ℓ for new wells and existing wells respectively using our data, perhaps combined with an instrument capturing exogenous variation in oil prices. We can validate our estimates by comparing it with numbers from the engineering and atmospheric science literatures.

We can estimate time-varying investment costs within our model using data on new well drilling. Alternately, we could acquire data on rig day rates that allow us to observe the vast majority of the investment cost directly. If neither of these proves possible, we could make a functional form assumption.

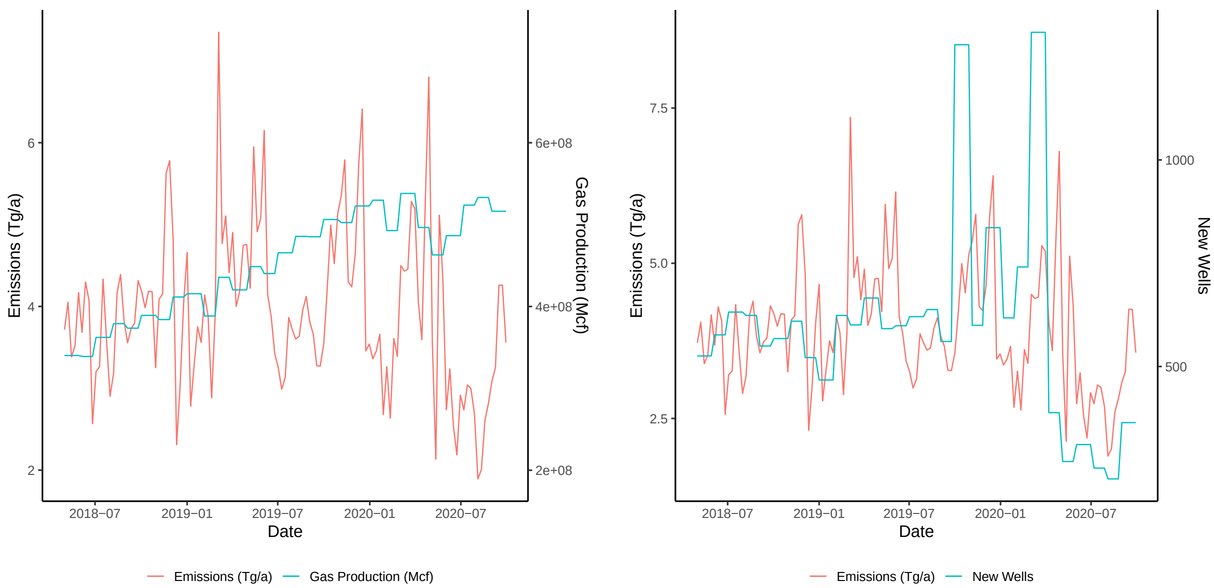
5 Empirics

5.1 Emissions

We begin by examining the raw data on emissions and oil and gas production. Figure 4 shows that methane emissions are highly volatile throughout the study period. There is no apparent trend either upwards or downwards in emissions even as gas production increased (panel a). In panel b, we see that spikes in new wells (i.e., wells that begin producing in a given month) appear to immediately precede jumps in methane emissions. This is likely due to the emissions intensity of the well completion process, as well as the fact that there is often a delay in connecting new wells to gathering pipelines.

Figure 4: Production and emissions

(a) Gas production　　　　(b) New wells

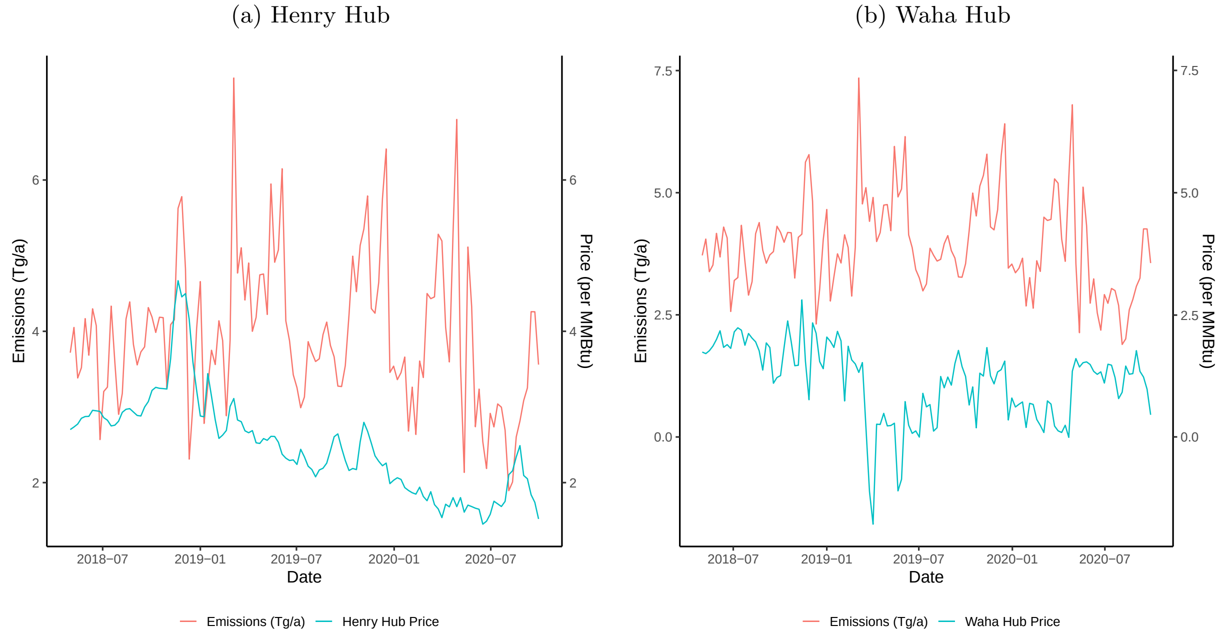


Notes: In a), we plot methane emissions and total monthly gas production over time. In b), we plot methane emissions and new wells, which we measure as the number of wells that begin producing in the given month.

In Figure 5, we plot emissions against the Henry and Waha Hub natural gas spot prices. Henry Hub is located in coastal Louisiana, and serves as the industry benchmark price because it is connected to many of the country's most important natural gas markets. Waha Hub is the main hub serving the Permian Basin. Upon visual inspection, it appears that there might be a slight positive correlation between emissions and Henry Hub prices, and a negative correlation between emissions and Waha Hub prices, but this relationship does not appear consistent throughout the period.

However, when we plot the difference between the Henry and Waha Hub spot prices (termed "Waha basis"), a clearer pattern emerges. Henry Hub spot prices almost always exceed Waha Hub spot prices, but a larger Waha basis appears to coincide with or slightly lag emissions spikes. This trend is clearest when we use the maximum price gap for each week (Figure 6), rather than the mean price gap (Figure A.8). Industry sources

Figure 5: Emissions and the Hub Prices



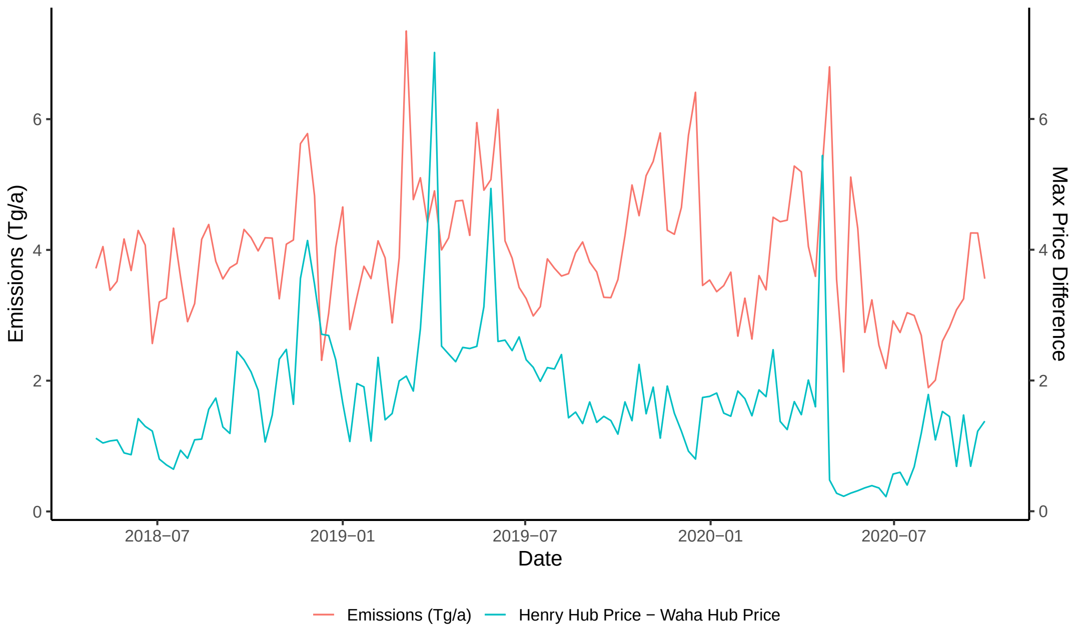
Notes: In a), we plot the raw data for emissions and the Henry Hub spot price, averaged within each week. In b), we do the same for the Waha Hub spot price.

identify the Waha basis as the most important component of natural gas transport costs, both in terms of magnitude and variance. Thus, the story that emerges from Figure 6 is one of increased emissions when transport costs are higher. Producers choose between selling their natural gas and disposing of it, but are more likely to dispose of their gas when transport costs are high. Since both flaring and venting result in methane emissions, this increase in gas disposal increases total emissions. The fact that the maximum price gap for each week better matches the emissions series than the mean price gap could imply that the marginal abatement cost curve is convex.

To test the relationships we observe in the raw data, we run regressions of emissions on prices and production variables (Table 2). We estimate these regressions for the entire Permian, and then separately by sub-basin. Our regression results are in accordance with our observations from Figure 6, and with our proposed story of increased gas disposal when transport costs increase. For all geographies, the Waha basis is positively correlated with emissions. The relationship is significant for the entire Permian, and for the Midland and Central basins. The coefficient is largest for the Midland, which is the most oil-concentrated sub-basin, but insignificant for the Delaware Basin, which has the highest gas-to-oil ratio of all three sub-basins (Figure A.2). This pattern suggests that producers that rely more on gas sales may be less sensitive to transport costs. These producers may restrict new well drilling when gas is less lucrative, rather than continuing to expand production and disposing of unsellable gas.

In contrast, the coefficient on Waha prices is generally positive but insignificant for all geographies. Our model suggests an explanation for this: high Waha prices could reflect either high commodity values or low transport costs, which have opposite influences on emissions. High commodity values drive drilling and increase

Figure 6: Emissions and the Max Weekly Henry-Waha Price Gap

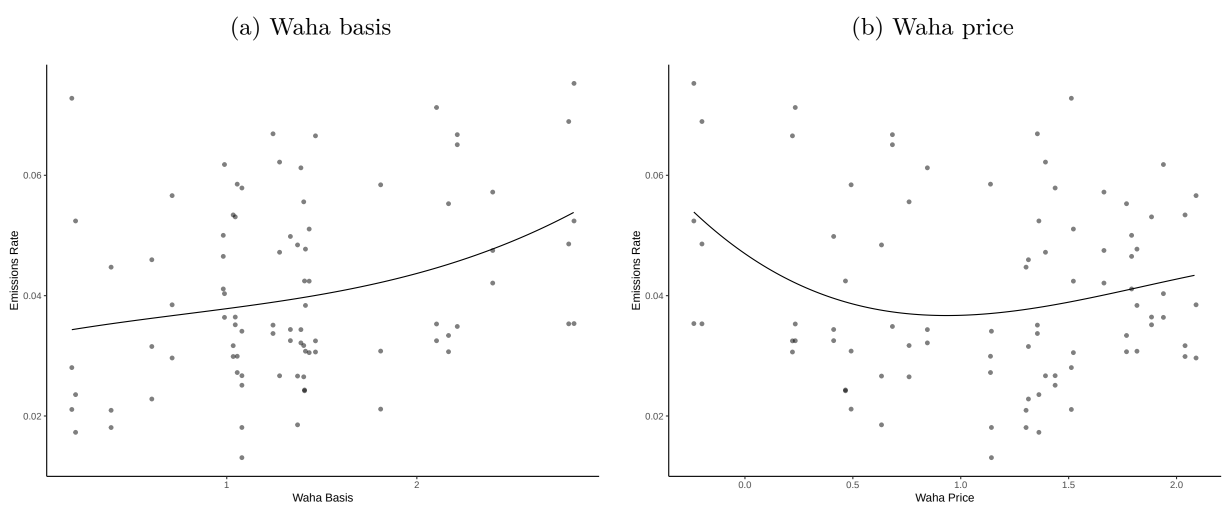


Notes: We plot raw, weekly methane emissions data (as estimated by Varon et al. (2022)) and the maximum Henry-Waha price gap within each week.

emissions, while low transport costs discourage gas disposal, decreasing emissions.

When we plot our observations in price-emissions space, we again find that the Waha basis captures more of the variance in emissions rates than does the Waha price (Figure 7). Emissions are increasing in transport costs, but have a more ambiguous, nonlinear relationship with Waha prices.

Figure 7: Emissions vs. Waha Basis, Waha Price



Notes: We plot subbasin-week-level emissions rates against the mean Waha basis (panel a) or Waha price (panel b) for each week. Emissions rates are calculated by dividing emissions (converted to mcf) by total gas production for a given subbasin-week. Over the raw data, we plot a line representing the third degree polynomial of best fit.

Several of the other variables in Table 2 have significant coefficients, though none are robust across geographies. This could be due to confounding relationships between control variables (see Table B.2 for a correlation matrix). For instance, we know that production (in particular, new well drilling) increases with oil prices and leads to more emissions. To disentangle these relationships, we plan to instrument for drilling activity and capacity constraints. For the former, we can gather data on global oil price shocks. For the latter, we plan to acquire data on unforeseen pipeline disruptions that caused reductions in capacity. Without these instruments, we caution that our regression results are suggestive rather than causal.

Table 2: Methane Emissions, Prices, and Production

	Dependent variable:			
	log(emissions)			
	All	Midland	Central	Delaware
	(1)	(2)	(3)	(4)
Waha Hub Price	0.036	−0.003	0.007	0.055
	(0.049)	(0.059)	(0.035)	(0.058)
Henry - Waha Hub Price	0.084^{*}	0.137^{**}	0.096^{**}	0.012
	(0.049)	(0.056)	(0.039)	(0.059)
Cushing Spot Oil Price	-0.004^{**}	−0.003	0.001	-0.009^{***}
	(0.002)	(0.002)	(0.002)	(0.003)
log(Oil Production)	0.985	-1.552^{*}	−0.423	3.620^{**}
	(1.195)	(0.801)	(0.755)	(1.400)
log(Gas Production)	−0.994	1.132	1.388	-3.405^{***}
	(1.014)	(0.757)	(0.908)	(1.286)
log(New Wells)	0.215	0.136	0.013	0.550^{**}
	(0.159)	(0.340)	(0.069)	(0.268)
log(Lagged New Wells)	0.040	0.299	−0.048	−0.182
	(0.161)	(0.347)	(0.070)	(0.270)
Constant	1.150	4.507	-16.274^{**}	−0.710
	(4.859)	(5.247)	(7.502)	(4.480)
Observations	127	127	127	127
R^2	0.316	0.277	0.238	0.325
Adjusted R^2	0.275	0.235	0.194	0.286
Residual Std. Error (df = 119)	0.211	0.242	0.184	0.268
F Statistic (df = 7; 119)	7.841^{***}	6.517^{***}	5.323^{***}	8.200^{***}

Notes: An observation is a week. Sample covers May 2018 through October 2020. Emissions are in log teragrams per year (Tg/a). Prices reflect the average of prices over the week. 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.
$^{*}p < 0.1, ^{**} p < 0.05, ^{***} p < 0.01$

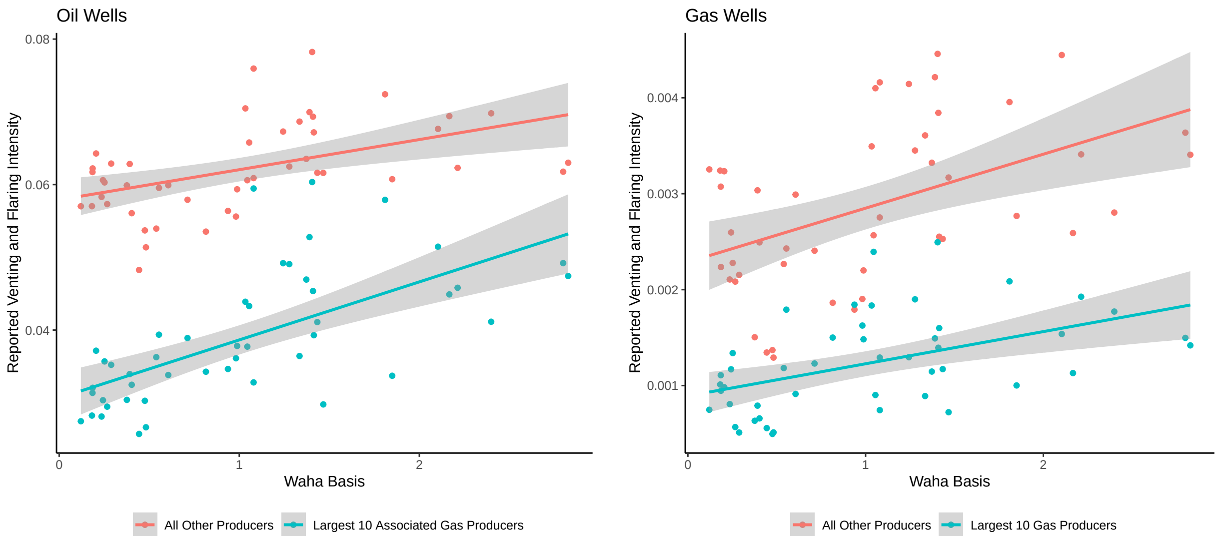
5.2 Flaring and Venting

To validate the relationship we propose between gas disposal and transport costs, we look directly at flaring and venting behavior. First, we use monthly producer reports to the Texas Railroad Commission of produced and flared and vented gas volumes. We divide flared and vented volumes by total gas produced to calculate a lease-month level measure of disposal intensity. In Figure 8, we show that disposal rates are generally increasing in the Waha basis, which captures transport costs.

Because this dataset is at the lease level, we are able to separate observations by well type and producer size to determine how these factors affect disposal rates. We identify leases that are owned by the largest 10 gas producers based on observed gas production. The largest producers have lower disposal rates than other producers at all levels of the Waha basis. We also find that disposal rates are far higher for oil wells than for gas wells, again supporting the notion that gas-focused operators are more incentivized to sell their gas even when transport costs are high.

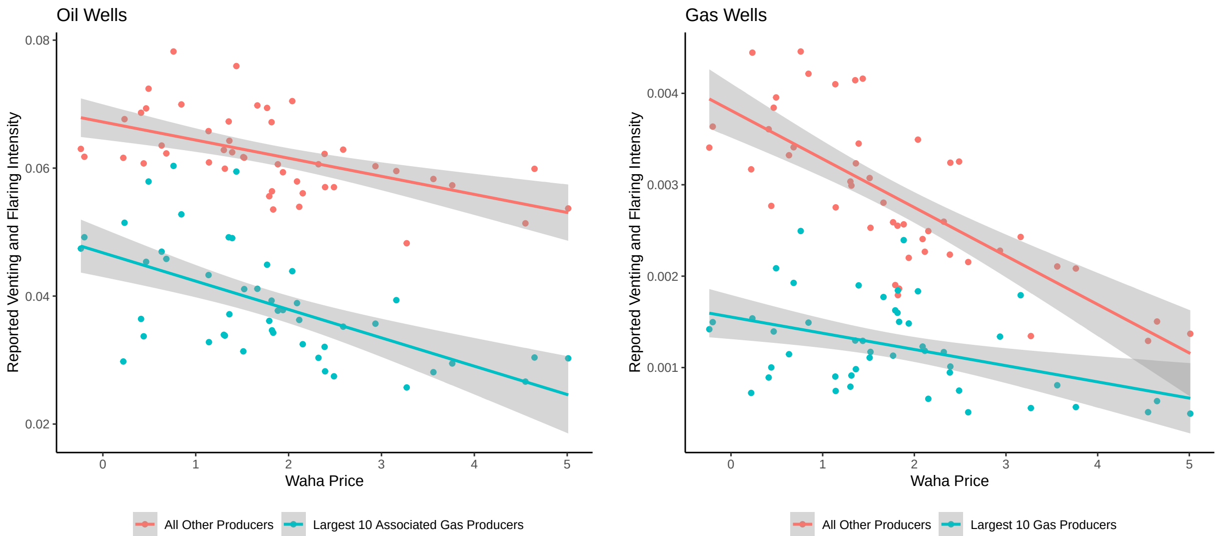
In contrast to our emissions analysis, gas disposal has a clear relationship with Waha price levels as well as Waha basis (Figure 9). As our model suggests, the disposal decision is a static one. Increases in effective price, whether due to transport costs or commodity value, always decrease gas disposal rates. At all price levels, disposal rates are lower for larger producers and for gas wells.

Figure 8: Producer-reported venting and flaring vs. Waha basis



Notes: Each observation is a lease-month. Data span 2018 through 2021. The Waha basis is the difference between Henry and Waha spot prices, averaged within month. We calculate reported venting and flaring intensity to be the ratio of vented/flared gas to total gas produced. We define the largest 10 producers as the operators that accounted for the most gas produced during this period.

Figure 9: Producer-reported venting and flaring vs. Waha prices



Notes: Each observation is a lease-month. Data span 2018 through 2021. Waha prices are spot prices, averaged within month. We calculate reported venting and flaring intensity to be the ratio of vented/flared gas to total gas produced. We define the largest 10 producers as the operators that accounted for the most gas produced during this period.

There is some concern that producers do not accurately report flaring behavior (see for instance McDonald and Wilson (2021)). Therefore, we supplement our analysis using remote-sensed measures of flaring activity. In Table 3, we present estimates of the relationship between the prices and the volume of flared gas, as estimated by Lyon et al. (2021) using VIIRS data. We find a significant, positive coefficient on the Waha basis: a dollar increase in transport costs corresponds to a 16 percent increase in flared gas volumes in Permian as a whole, and a 30 percent increase the Midland Basin. Table B.1 presents the same regressions, but using number of flares (again, remote-sensed) as the outcome rather than flared volume.

Table 3: Flared Gas, Prices, and Production

	Dependent variable:		
	log(flared gas)		
	All	Midland	Delaware
	(1)	(2)	(3)
Waha Hub Price	0.006^{*}	0.013^{***}	0.001
	(0.003)	(0.004)	(0.003)
Henry - Waha Hub Price	0.162^{***}	0.295^{***}	0.178^{***}
	(0.031)	(0.038)	(0.033)
Cushing Spot Oil Price	−0.001	0.002	-0.009^{***}
	(0.002)	(0.002)	(0.002)
log(Oil Production)	6.658^{***}	7.435^{***}	1.729
	(1.014)	(0.713)	(1.141)
log(Gas Production)	-5.290^{***}	-4.605^{***}	-2.351^{**}
	(0.781)	(0.530)	(1.020)
log(New Wells)	0.277^{*}	−0.325	0.667^{***}
	(0.167)	(0.312)	(0.228)
log(Lagged New Wells)	-0.342^{**}	−0.241	−0.227
	(0.168)	(0.310)	(0.234)
Constant	-17.729^{***}	-41.084^{***}	11.849^{***}
	(3.889)	(3.637)	(1.996)
Observations	190	199	199
R^2	0.631	0.648	0.580
Adjusted R^2	0.617	0.636	0.564
Residual Std. Error	0.251 (df = 182)	0.331 (df = 191)	0.282 (df = 191)
F Statistic	44.553^{***} (df = 7; 182)	50.320^{***} (df = 7; 191)	37.660^{***} (df = 7; 191)

Notes: An observation is a week. Outcome variable is the volume of flared gas, based on VIIRS observations and calibrated to match administrative data. Prices reflect the average of prices over the week. 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.
$^{*}p < 0.1, ^{**}p < 0.05, ^{***}p < 0.01$

5.3 Drilling

In our model, producers respond to price changes through drilling decisions, as well as through gas disposal decisions. To confirm our theory that drilling decisions are affected by both oil prices and natural gas prices, we regress new wells on prices. Similar to Anderson, Kellogg and Salant (2018), we construct regressions in first differences:

$$\Delta \log(\text{New wells}_t) = \alpha + \beta_0 \Delta \log(\text{Oil Price}_t) + \beta_1 \Delta \log(\text{Oil Futures}_t) + \beta_2 \Delta \log(\text{Gas Price}_t) + \text{error}_t$$

We use two different measures of new wells, each of which we observe at the subbasin-month level using data from Enverus. First, we use the number of spuds, which is defined as the number of wells for which drilling began in the given month. Second, we use the number of wells that began producing in each month. It can take as little as a month for a well to start producing after drilling begins, but producers can also choose to drill a well and then wait before completing it.

Results are presented in Table 4. We see that both drilling and well completions are significantly and positively associated with front-month oil prices, but significantly negatively associated with three-month oil futures. Gas prices are positively correlated with drilling, but negatively correlated with newly producing wells, perhaps because having more new wells come online pushes gas prices down. Coefficients on gas prices are much smaller in magnitude than those on oil prices, which supports the idea that oil prices are a more important driver of production activity (see also Figure A.7). Results are similar when we add lagged versions of the price variables.

Ideally, we would also be able to test how transport costs affect drilling behavior. However, transport costs are likely sensitive to production from new wells, so regression coefficients would not necessarily be informative about producer decision-making. To circumvent this issue, we hope to construct an instrument for transport costs using data on unexpected pipeline maintenance events.

Table 4: Oil prices, drilling, and production

	Dependent variable:	
	Log(Spuds)	Log(First Prod)
	(1)	(2)
Δ Log Cushing, Front-month	1.987^{***}	1.678^{***}
	(0.404)	(0.335)
Δ Log Cushing, 3-month	-2.324^{***}	-1.638^{***}
	(0.615)	(0.512)
Δ Log Henry Spot	0.279^{*}	-0.259^{**}
	(0.145)	(0.122)
Basin = Delaware	−0.074	−0.012
	(0.063)	(0.053)
Basin = Midland	0.026	−0.033
	(0.064)	(0.053)
Time trend	0.026^{**}	0.008
	(0.011)	(0.009)
Constant	-53.311^{**}	−16.513
	(21.760)	(18.486)
Observations	300	295
R^2	0.114	0.113
Adjusted R^2	0.095	0.094
Residual Std. Error	0.450 (df = 293)	0.373 (df = 288)
F Statistic	6.258^{***} (df = 6; 293)	6.091^{***} (df = 6; 288)

Notes: An observation is a month-subbasin. Prices are averaged within month and then differenced. "Spuds" represents the number of wells that begin the drilling process each month. "First Prod" captures the number of wells that begin to produce each month. Drilling data from Enverus. Oil price data from EIA. Gas spot prices from S&P Capital IQ.
$^{*}p < 0.1,^{**} p < 0.05,^{***} p < 0.01$

6 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 impact. In this project, we seek to understand the market forces driving methane emissions due to oil and gas production. A greater understanding of producer incentives will make possible more effective emissions-abatement policy.

We find that emissions are increasing in natural gas transport costs, but not necessarily in local natural gas prices. We explain this pattern using a dynamic model of producer behaviors, 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. In our model and in the evidence we have so far collected, emissions from flaring and venting are increasing in transport costs and decreasing in natural gas prices, while emissions from well drilling have a positive relationship with natural gas prices.

Our next steps involve estimating our model of producer drilling and emissions decisions. With the parameters we estimate, we hope to simulate the emissions impact of a range of policies. Of course, the most salient policy is putting a price on methane emissions. We will calculate the impact of methane taxes and fees on drilling, gas disposal rates, and overall emissions. Our framework will also allow us to assess the effectiveness of more creative policy solutions. For instance, our results so far suggest that transport costs drive methane emissions from venting and flaring. Better regulations regarding pipeline maintenance could reduce the variance of pipeline capacity, thus smoothing the transport costs that producers face and reducing the need for venting and flaring.

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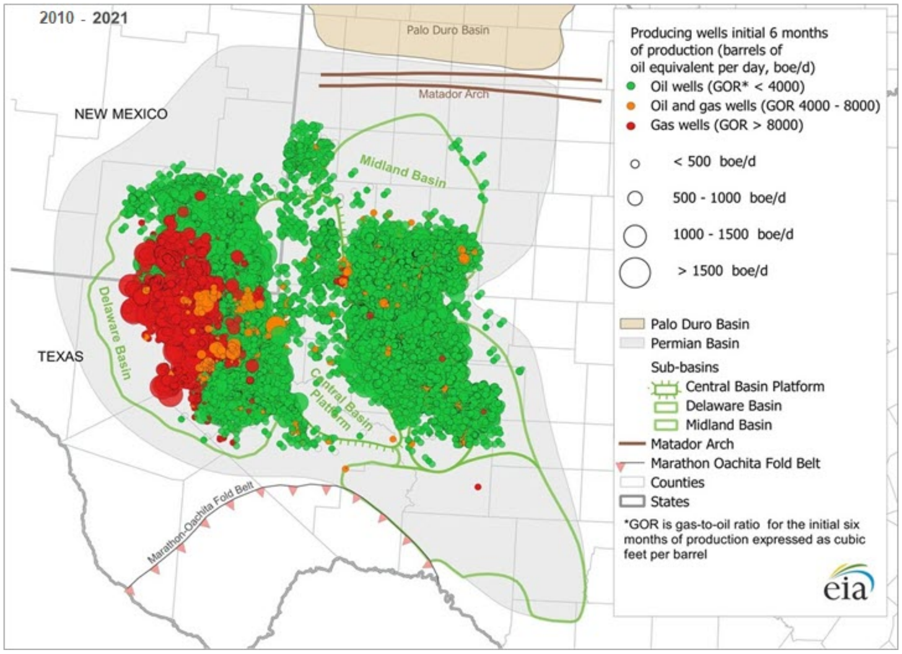
7 Appendix

A Figures

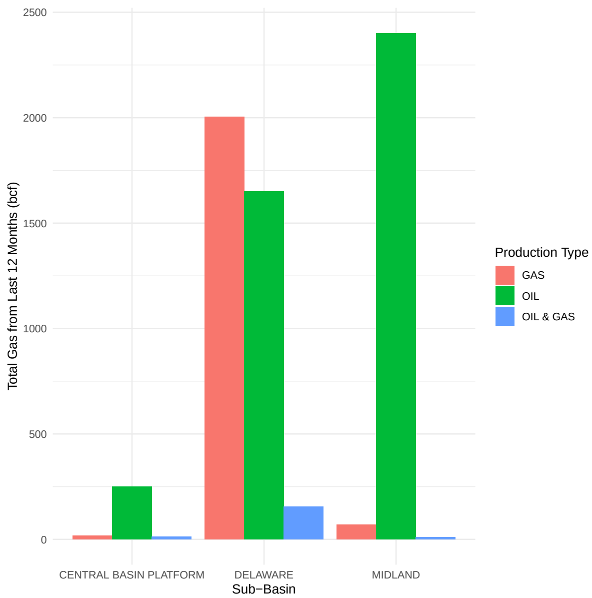
Figure A.1: Oil and Gas production



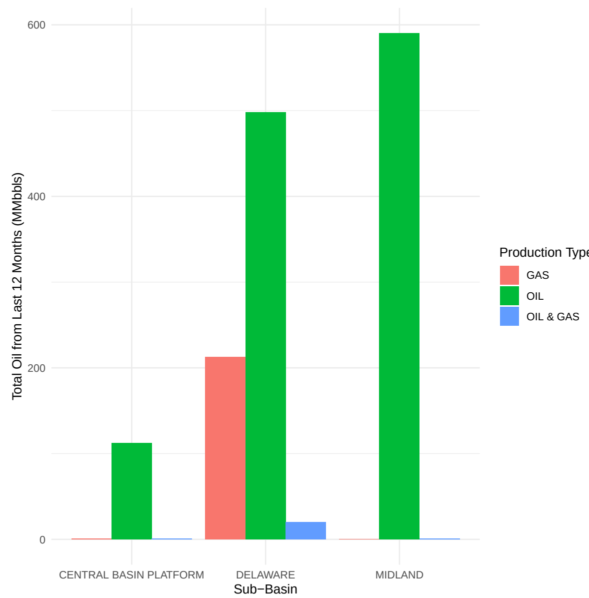
Notes: This figure was produced by the Energy Information Administration (EIA) and summarizes first 6 months production from wells drilled in the Permian between 2010 and 2021.

Figure A.2: Production by basin

(a) Gas production

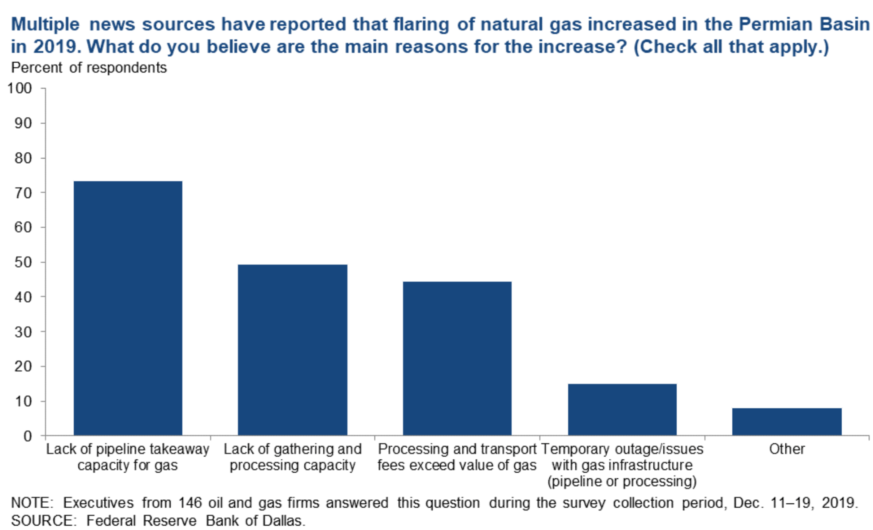


(b) Oil production



Notes: Production data from Enverus. We aggregate gas (panel a) and oil (panel b) produced by different categories of wells in each of the major Permian subbasins. Wells are categorized based on gas-to-oil ratios.

Figure A.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 A.4: Mitigation decisions and firm size

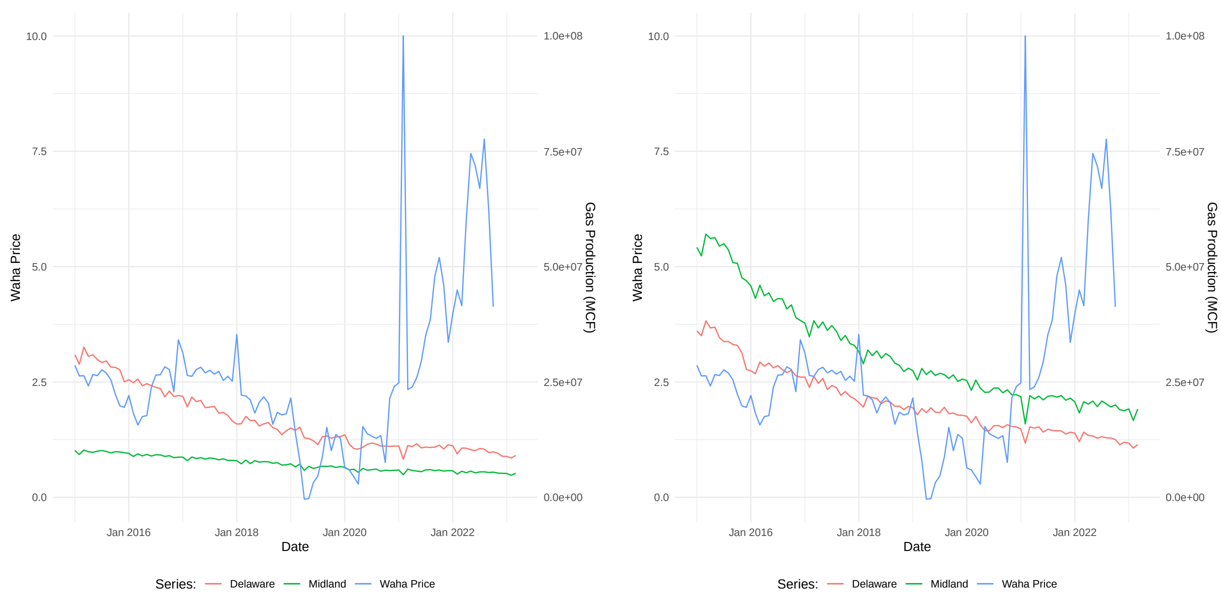
Response	Percent of respondents (among each group)		
	Small firms	Large firms	All firms
Plan to reduce CO_2 emissions	22	65	34
Plan to reduce methane emissions	38	65	46
Plan to reduce flaring	43	61	48
Plan to recycle/reuse water	25	48	31
Plan to invest in renewables	2	17	6
None of the above	35	17	30

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 A.5: Gas production at existing wells

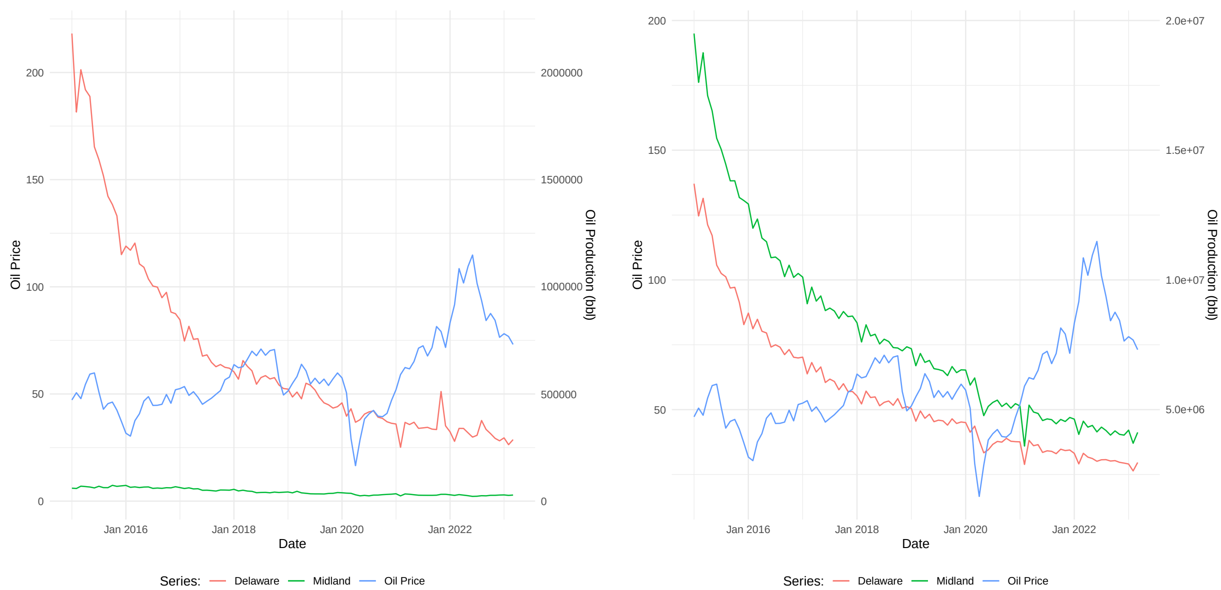
(a) Gas wells (b) Oil wells



Notes: In both panels, we depict production data covering 2015-2023 for Permian Basin wells that were completed before January 2015. We plot this against Waha spot prices to show that production from existing wells does not respond to price variation. Gas production is separated by the subbasin in which wells are located, either Midland or Delaware, and the type of the producing well, either oil or gas. We derive production data from Enverus. Spot prices are from S&P Capital IQ Pro.

Figure A.6: Oil production at existing wells

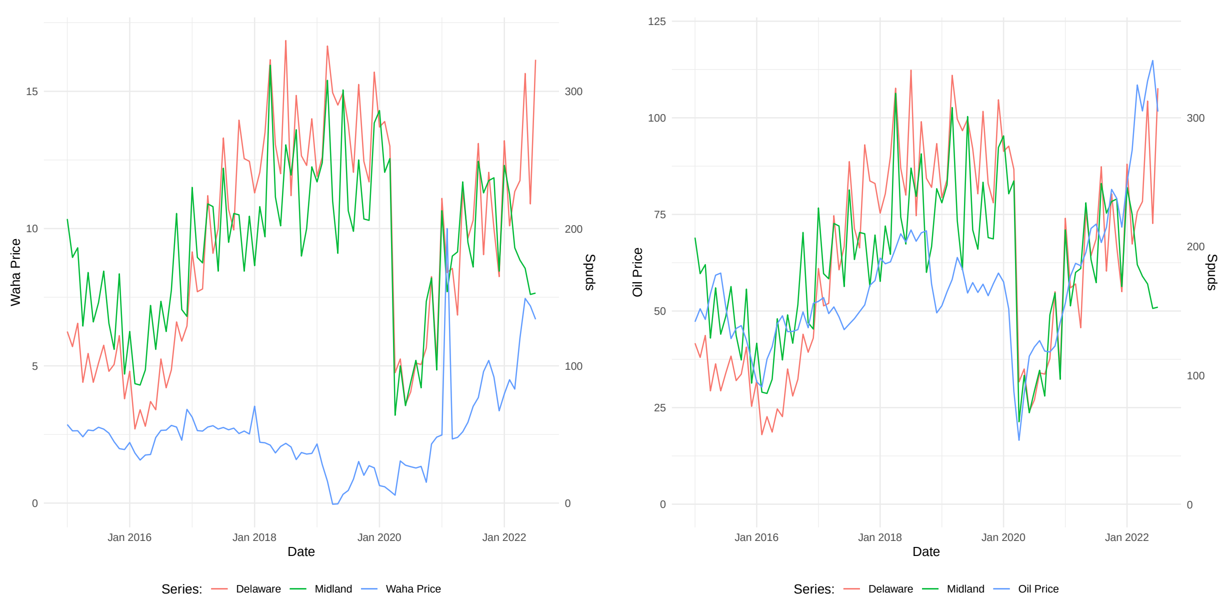
(a) Gas wells (b) Oil wells



Notes: In both panels, we depict production data covering 2015-2023 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. Oil production is separated by the subbasin in which wells are located, either Midland or Delaware, and the type of the producing well, either oil or gas. We derive production data from Enverus. Spot prices are from S&P Capital IQ Pro.

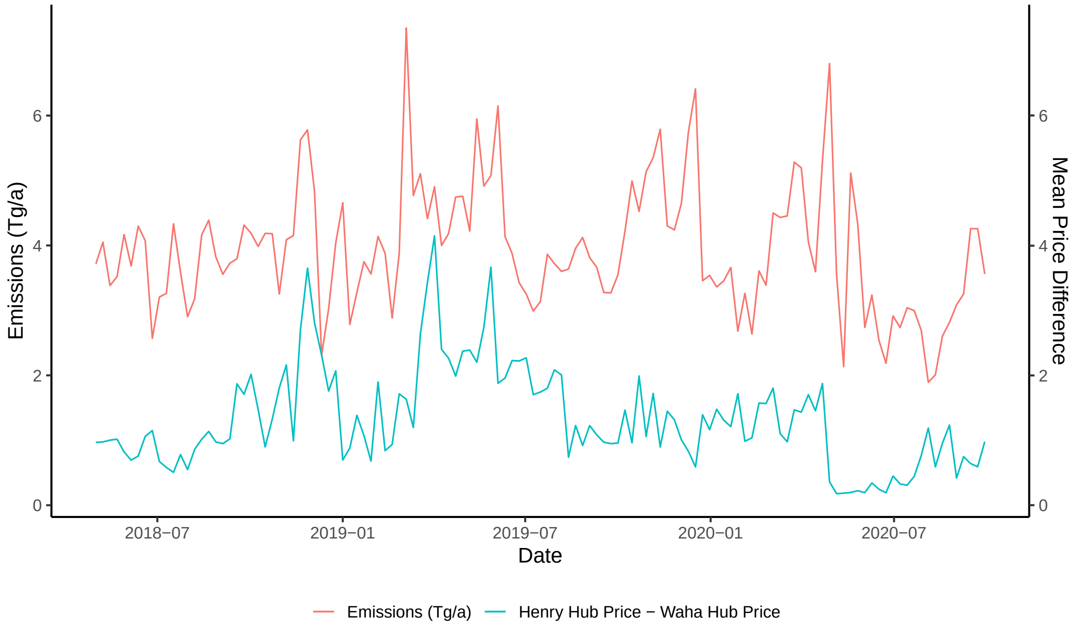
Figure A.7: Well drilling and prices

(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 2015 and 2023. We plot this against Cushing spot oil prices and Waha spot prices. Production data are from Enverus. Spot prices are from S&P Capital IQ Pro.

Figure A.8: 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. (2022)) and the mean Henry-Waha price gap within each week.

B Tables

Table B.1: Methane Flares, Prices, and Production

	Dependent variable:		
	log(num_flares)		
	All	Midland	Delaware
	(1)	(2)	(3)
Waha Hub Price	0.004^{***}	0.008^{***}	0.002
	(0.001)	(0.002)	(0.001)
Henry - Waha Hub Price	0.056^{***}	0.068^{***}	0.074^{***}
	(0.013)	(0.016)	(0.014)
Cushing Spot Oil Price	−0.0003	0.001	-0.004^{***}
	(0.001)	(0.001)	(0.001)
log(Oil Production)	2.410^{***}	2.711^{***}	0.545
	(0.431)	(0.305)	(0.493)
log(Gas Production)	-1.798^{***}	-1.484^{***}	−0.652
	(0.332)	(0.227)	(0.440)
log(New Wells)	0.050	−0.191	0.197^{**}
	(0.071)	(0.133)	(0.099)
log(Lagged New Wells)	−0.105	−0.027	−0.063
	(0.071)	(0.132)	(0.101)
Constant	-3.461^{**}	-14.317^{***}	6.885^{***}
	(1.653)	(1.555)	(0.862)
Observations	190	199	199
R^2	0.493	0.528	0.444
Adjusted R^2	0.474	0.511	0.424
Residual Std. Error	0.107 (df = 182)	0.141 (df = 191)	0.122 (df = 191)
F Statistic	25.310^{***} (df = 7; 182)	30.566^{***} (df = 7; 191)	21.789^{***} (df = 7; 191)

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 B.2: Correlation matrix

	Waha price	Henry - Waha price	Gas prod.	New wells	Lag new wells	Flared volume	# Flares
Waha price	1	-0.210	-0.045	-0.149	-0.151	-0.113	-0.010
Henry - Waha price	-0.210	1	-0.158	0.367	0.388	0.656	0.582
Gas prod.	-0.045	-0.158	1	-0.070	-0.066	-0.158	-0.059
New wells	-0.149	0.367	-0.070	1	0.933	0.497	0.399
Lag new wells	-0.151	0.388	-0.066	0.933	1	0.476	0.387
Flared volume	-0.113	0.656	-0.158	0.497	0.476	1	0.927
# Flares	-0.010	0.582	-0.059	0.399	0.387	0.927	1