The Economics of Natural Gas Flaring and Methane Emissions in U.S. Shale: An Agenda for Research and Policy*

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February 24, 2022

Abstract

Natural gas flaring and methane emissions (F&M) are linked environmental issues for U.S. shale oil and gas (O&G) operations. In this paper, we lay out an agenda for researchers and policymakers. We describe why F&M are linked, both physically and in terms of policy. We perform an interdisciplinary literature review on measurement of F&M. We marshal granular industry data to identify constraints in the natural gas system correlated with upstream F&M. Motivated by this descriptive analysis, we discuss the economic and physical causes of F&M. We then discuss the external cost of F&M. We calculate that the climate costs of estimated methane emissions are an order of magnitude larger than the climate costs of reported flaring and venting after accounting for hydrocarbon content and flare efficiency. Finally, we discuss both existing policies and economic insights relevant to future policies.

JEL Codes: Q35, Q48, Q53, Q54
Keywords: methane; venting; flaring; natural gas; shale; environmental policy

*We are grateful for feedback from Alan Krupnick and Daniel Raimi (RFF); Robert Kleinberg (Columbia and BU); Marianne Kah (Columbia); Morgan Bazilian, Jim Crompton, Chris Elvidge, and Mikhail Zhizhin (CO School of Mines); Tim Fitzgerald (Texas Tech); Kevin Novan and Jim Sanchirico (UC Davis); Wesley Blundell (Washington State); Ken Medlock and Michael Maher (Rice); Chuck Mason (Wyoming); Colin Leyden, David Lyon, Ben Hmiel, and Maureen Lackner (EDF); Brian Snyder (LSU); and Ted Agerton. Thank you to Jinmahn Jo (UC Davis) for excellent research assistance, and to two anonymous referees.

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1 Introduction

In this paper, we lay out a research and policy agenda around natural gas flaring and methane emissions (F&M). We focus on F&M associated with the extraction of oil and gas (O&G) from U.S. shale plays. Few economic studies address F&M, but the topic has become increasingly salient in climate policy discussions.

The latest Intergovernmental Panel on Climate Change (IPCC) report estimates that anthropogenic methane emissions are "very likely" to have already caused between 0.3°C and 0.8°C of warming, with a central estimate of 0.5°C (IPCC 2021, Figure SPM.2). The IPCC has also concluded with "high confidence" that keeping warming below 1.5°C in any model scenario requires significantly reducing anthropogenic methane emissions (IPCC 2021, Chapter 1, Box 1.2, p.53).[1] The O&G industry is the largest anthropogenic source of methane after agriculture and, according to IEA (2021), provides some of the most cost-effective abatement opportunities.

O&G wells produce a mix of hydrocarbons: methane (CH_4), natural gas liquids (NGLs), and crude oil. When producers cannot economically deliver methane and NGLs to market, they may flare (burn) them instead. Some gas is also intentionally vented (released) directly to the atmosphere, and some is also unintentionally leaked. We refer to natural gas that is intentionally burned as flared gas, while methane emissions can come from incomplete combustion during flaring, intentional venting, or unintentional leaking. We group all three activities under the term "flaring and methane emissions" (F&M).

Geology determines the mix of hydrocarbons that a well produces, but technology and economics determine what share of natural gas is captured and sold. F&M can occur throughout the natural gas system—from upstream wells, midstream processing and pipelines, or downstream refining and distribution systems. Our analysis focuses exclusively on F&M in the upstream segment, where Alvarez et al. (2018) estimate the majority of methane emissions occur.

Despite advances in measuring emissions, the quantity of F&M is still uncertain. We summarize the scientific literature in Section 3. We also discuss what is known about the quantity of F&M in the U.S. and provide some global context. Measuring emissions from F&M is a key area for research. In Section 4, we discuss empirical patterns in flaring. Producers must report most flaring, which is easier to measure than unreported venting and leaking. Understanding the physical causes of flaring can help inform both flaring and methane regulation. Recent scientific evidence suggests that constraints which drive flaring may also drive methane emissions (Lyon et al. 2020). We then turn to the economics of F&M. In Section 5, we describe how market structures could exacerbate constraints and impact the effectiveness of policy.

F&M impose environmental costs on society through GHG emissions and local air pollution. In Section 6, we summarize relevant literature on external costs. We perform a back-of-the-envelope

[1] Interquartile range of about 40 to 60 percent reductions below 2010 levels required by 2050 (IPCC 2018, Figure SPM.3a)

calculation that reported U.S. upstream flaring in 2019, a peak year, generated \$1.7 to \$3.4 billion in climate costs, about half to one percent of the value of U.S. O&G production.[2] The most comprehensive estimate available of U.S. upstream methane emissions is from 2015, although O&G production has since increased (Alvarez et al. 2018). Applying a \$1500/ton social cost of methane (SCM) yields \$16.8 billion in climate costs—an order of magnitude larger than costs from flaring. Thus, policymakers and researchers looking to understand environmental impacts of O&G operations should focus beyond reported flaring.

Finally, we turn to policy in Section 7. The capabilities of measurement technology determine policy options. We discuss how market institutions and emerging monitoring technology lead to new theoretical and applied questions that are relevant beyond F&M.

2 Industry Overview

The O&G supply chain includes three broad components: *upstream*, *midstream*, and *downstream*. Upstream firms extract hydrocarbons from reservoirs underground. Midstream firms transport extracted hydrocarbons to downstream users. The natural gas midstream includes several services. A network of gathering pipelines transports natural gas to gas processing plants that separate out heavier hydrocarbons and other impurities. Then long-haul transmission lines move gas to demand centers. For perspective, the 2019 MapSearch dataset of Texas natural gas infrastructure contains 53,000 miles of gathering pipelines, 111 gas processing plants, and 8,300 miles of transmission lines within the areal extent of the Texas Permian basin. These facilities are owned by 172, 26, and 51 firms, respectively.[3] Finally, downstream firms like oil refiners or natural gas distributors manufacture products from raw hydrocarbons or deliver it to final consumers. Although we focus on upstream F&M, we will provide context and cite relevant literature on upstream emissions relative to midstream and downstream. Appendix A provides a review of the industry and relevant terminology.

3 Quantifying Emissions

Quantifying methane emission presents two challenges. The first has to do with comparing methane to other GHG emissions. Methane's 20-year global warming potential (GWP) is around 85 times that of CO_2 (EPA 2021). However, methane stays in the atmosphere less time than CO_2—12 years on average versus CO_2's 100 years, and methane's 100-year GWP is 28-36 times CO_2's (EPA 2022, Annex 6). A more natural measure of methane emissions for economists may be the social cost of carbon and methane (SCC and SCM). These are estimated using integrated assessment models

[2]This estimate excludes unreported methane emissions and downstream emissions.

[3]We include active natural gas facilities in the Texas Permian only. MapSearch classifications do not differentiate between transmission pipelines that move gas between regions and trunklines which move gas within the region.

that tally the future economic costs of climate change due to an additional unit of emissions. For 2020, the current federal SCC estimate is \$51/mt, and the SCM, \$1500/mt (IAWG 2021).

The second challenge is quantifying the physical amount of methane emissions. In this section, we discuss methane measurement in the context of the upstream O&G industry. Multiple quantification methods are available, but none are comprehensive. This leaves uncertainty about the actual quantity of emissions. Measuring methane is an active area of scientific research, and we review the economic implications of key methods and findings.

The EPA's Greenhouse Gas Inventory (GHGI) estimate of U.S. methane emissions illustrates the challenge of reporting methane emissions. The GHGI estimates that 2020 U.S. methane emissions were 26 million mt (EPA 2022, Table 2-2). As a party to the United Nations Framework Convention on Climate Change (UNFCC), the U.S. must report GHG emissions using GWP values from the IPCC Fourth Assessment Report (AR4). The GWP for methane is 25 in AR4, so the GHGI reports that methane emissions were about 650 million mt CO2e—10 percent of U.S. GHG emissions (EPA 2022, Table 2-1). However, the AR4 GWP is lower than more recent estimates in the Fifth and Sixth IPCC Assessment Reports (EPA 2022, Anex 6). Additionally, as we explain below, results from recent scientific publications suggest that the GHGI underestimates methane emissions from the O&G sector.

3.1 Emissions sources

Upstream F&M occurs for several reasons. Intentional venting and flaring can help maintain stability in the pressurized system of pneumatic devices, valves, compressors, and tanks at the well. Unintentional leaking may occur due to overpressurization, volatile conditions, or malfunctions (Zavala-Araiza et al. 2017). Some normal production activities also emit methane, including well completions, liquids unloading, and workovers.[4] The largest sources of upstream methane emissions are storage tanks, pneumatic devices, unlit or inefficient flares, separators and compressors. A large variety of components may emit small or medium-sized amounts that, when aggregated, comprise a significant share of emissions. Recent studies have measured emissions of individual components. Some have simulated emissions distributions to reconcile these measurements with site-level or regional estimates (Allen et al. 2013; Caulton et al. 2014; Gvakharia et al. 2017; Lyon et al. 2016; Rutherford et al. 2021; Tyner et al. 2021; Zavala-Araiza et al. 2017).

Market conditions are also important. Lyon et al. (2020) find that methane emission rates in the Permian Basin fell from 3.4 to 1.5 percent of gas produced in 2020 when oil prices and production dropped during the Covid-19 pandemic. The authors hypothesize that lower system pressures reduced F&M. Studies also document correlation between production and methane emissions both within and across producing regions (de Gouw et al. 2020; Omara et al. 2018; Schneising et al.

[4] Liquids unloading involves removing liquids trapped in a well. Workovers involve re-stimulating a well to prolong its life.

2020).

3.2 Emissions data and distributions

The three main public data sources on F&M are (1) self-reports, (2) satellite data, and (3) bottom-up inventories. The scientific literature has also gathered remote sensing data from individual site-level surveys (Alvarez et al. 2018; Brandt et al. 2014).

State and federal O&G regulators require that operators report the quantity of gas vented and flared (methane plus NGLs) along with production. However, flaring and venting are usually reported separately,[5] and operators are not required to report all venting and flaring. For example, Texas does not require reporting venting from tank vapors or valves, or flaring and venting associated with drilling and completion[6]. Leaking, even if detected, is not reported.

Satellites are one way to perform top-down measurement of global F&M. The Visible Infrared Imaging Radiometer Suite (VIIRS) satellite instrument has been used to detect the heat signatures of flaring since 2012 (Elvidge et al. 2016, 2013). Beginning in late 2017, the European Space Agency's TROPOspheric Monitoring Instrument (TROPOMI) has provided global measurement of methane concentrations (Hu et al. 2016, 2018). While these two satellites have been useful for estimating aggregate emissions, attributing emissions to individual facilities or firms is harder. More statistical research into attribution of satellite-detected emissions has the potential to improve this ability. Regional estimates can also be made with remote sensors mounted on towers, aircraft, or vehicles, but published surveys have limited temporal and spatial scope.[7]

A third source of data on methane emissions at a national level comes from bottom-up inventories. These typically apply fixed emissions factors to estimated inventories of components and activities at production sites. Bottom-up approaches like those in the US EPA Greenhouse Gas Inventory (GHGI) are often used by policymakers but come with challenges. Top-down methane emission estimates from satellites and aerial surveys have historically exceeded bottom-up estimates. Recent studies have helped resolve these differences (Alvarez et al. 2018; de Gouw et al. 2020; Rutherford et al. 2021; Zavala-Araiza et al. 2015b). There are two major limitations of bottom-up inventories. First, inventories tend to undercount the number of components at each facility. Second, component emissions factors do not account for the right-tailed distribution of emissions. Two changes have helped align bottom-up and top-down estimates: (1) augmenting inventories, satellites, and aerial surveys with facility-scale measurements using ground-based remote sensing, and (2) modeling the right-tailed distribution from individual components (Rutherford et al. 2021).

Significant quantities of emissions come from a small number of intermittent sources that are large in absolute terms, sometimes called "super-emitters" (Lyon et al. 2015; Robertson et al. 2017;

[5] New Mexico is an exception.
[6] 16 Tex. Admin. Code §3.32
[7] See Brandt et al. (2016a) for a survey.

Tyner 2020; Zavala-Araiza et al. 2017). Super-emitters can also be defined in relative terms. The right-tailed distribution of emissions is present across the scale of components (Tyner 2020). Zavala-Araiza et al. (2015a) argue that super-emitters should be defined by their proportional emissions rate rather than their absolute magnitude. They calculate that over half of emissions are from medium-scale production sites.

Even if a small number of super-emitters accounts for the majority of emissions, this does not necessarily imply low abatement costs. One might like to imagine using overflights and site-level surveys to find super-emitters and fix them at low cost. However, super-emitters can be characterized by indeterminacy and spatial variability that are difficult to predict (Zavala-Araiza et al. 2017). If surveys are not made with large enough samples or frequently enough, they may not detect many super-emitters. Because remote sensing technologies have limitations like minimum and maximum detection thresholds, they are not comprehensive. This means that relying on one technology alone can distort measured emissions, so a portfolio of technologies may be most effective (Fox et al. 2019; Harriss et al. 2015; Tyner 2020).

Like methane emissions, flaring exhibits a right-skewed distribution. Appendix Figure 10 shows these distributions for both the Bakken and the sub-regions of the Texas Permian Basin. In the Bakken, approximately 75 percent of the reported flaring comes from about 12.5 percent of wells. The distribution is even more skewed in the Permian, and skewness is persistent across years (2016–2020).

More rigorous, causally-identified empirical studies could identify systemic causes of super-emitting events. These could help policymakers understand the causal links between market conditions, capacity constraints, and F&M. Satellite measurements are noisy at finer spatial and temporal scales. This makes attribution of satellite detected F&M to individual firms challenging. Finally, work to statistically integrate multi-scale measurements is needed. Recent work in machine learning and machine vision may be one way to estimate leak probabilities and prioritize sites for inspection (Wang et al. 2020).

3.3 Estimates of U.S. F&M

Shale gas production and U.S. flaring have increased over the past two decades. The majority of U.S. flaring currently takes place in two oil-directed shale plays: the Bakken Shale and Permian Basin.[8] Figure 1 shows the relationship between reported flaring and oil production in these areas. Using data compiled from state regulators, EIA estimates that U.S. upstream producers flared 538 billion cubic feet (bcf) of natural gas in 2019; approximately 1.3 percent of U.S. gas production. Using data from VIIRS, World Bank (2019) estimates that the entire U.S. gas supply supply chain flared or vented 611 billion cubic feet in 2019. The same data show that over the period 2015–2019,

[8] See map in Figure 6 for U.S. shale plays

the U.S. flared the third highest volume of any country, 8.4 percent of global flaring.[9] The U.S. was the largest global producer of natural gas over this period, producing 22 percent of dry natural gas globally.[10] If U.S. gas flared in 2019 were used to generate electricity, it could have powered 7–8 million households for a year.[11]

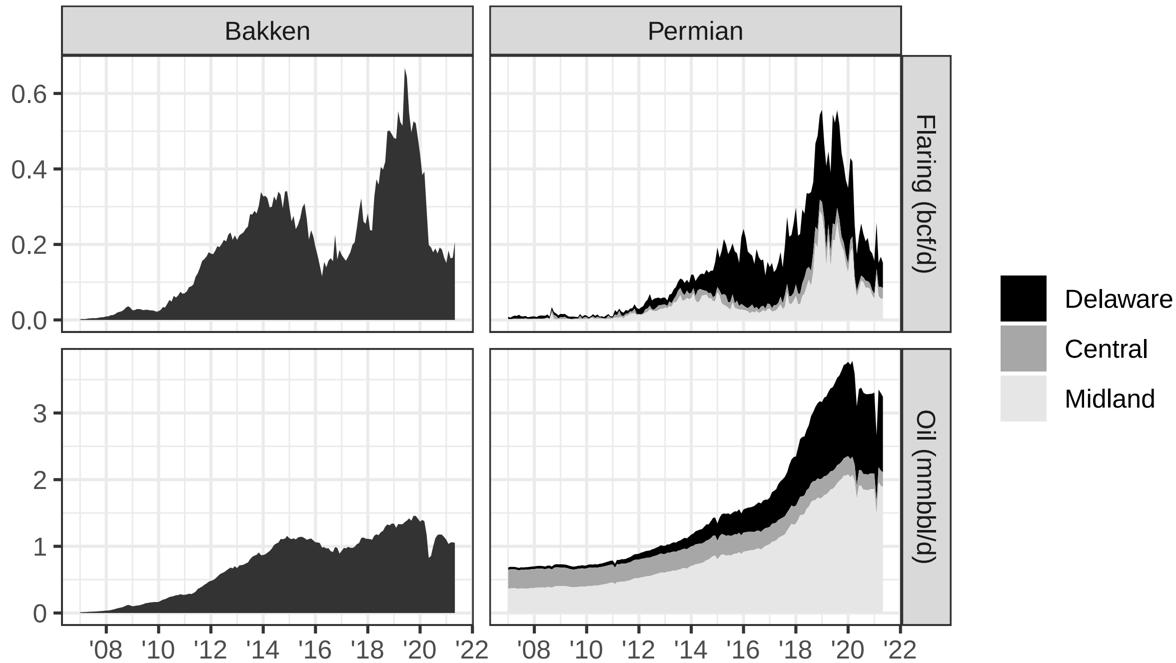

Figure 1: Flaring, venting, and oil production in the Bakken and Permian. The top panels use data reporting flaring and venting together. The Delaware, Central, and Midland are basins within the Permian.

International Energy Agency estimates that the U.S. energy industry has been the second highest global methane emitter behind Russia for several years (IEA 2021).[12] Synthesizing the scientific literature and using several measurement methods, Alvarez et al. (2018) estimate that throughout the entire natural gas system, 2.3 percent of 2015 U.S. gas production was emitted as methane. The authors attribute 60 percent of methane emissions to the upstream sector and another 20 percent to gas gathering systems. A more recent bottom-up study that incorporates uncertainty in component-level emissions generally corroborates these findings (Rutherford et al.

[9]EIA estimates include upstream venting and flaring as reported by operators. VIIRS-based estimates include midstream and downstream flaring but exclude venting and other methane emissions (World Bank 2019).

[10]Source: U.S. EIA. International. Dry Natural Gas Production by Country.

[11]Calculation based on a heat rate of 7,000 BTU/kWh. According to EIA, average U.S. residential households used 10,968 kWh in 2018.

[12]While IEA data has historically been based on bottom-up inventory methods submitted by member countries, the most recent year incorporates global satellite data into country-level estimates.

2021). While neither study extensively surveys the Permian Basin, Schneising et al. (2020) and Zhang et al. (2020) do in 2018 and 2019. These newer studies estimate that 3.7 percent of Permian methane produced was emitted during production, gathering, or processing.

Accounting for F&M can be important when assessing climate trade-offs between fuel sources in electricity generation. For example, coal has more than twice the CO_2 emissions of natural gas when combusted to generate a unit of electricity. However, this does not take into account F&M along the entire supply chain.[13] Alvarez et al. (2012) estimate that coal and natural gas power plants would have equivalent climate impacts at a 3.2 percent life-cycle methane leakage rate from the natural gas system.[14]

4 Physical causes of flaring

In this section, we describe the empirical behavior of reported flaring, and we discuss the market conditions and constraints associated with flaring. We use regulatory data from North Dakota on the Bakken shale and from Texas on the three main areas of the Permian—the Delaware, Central, and Midland basins.[15] For ease of exposition, we use the term "flaring" to refer to venting and flaring. These are reported as a single number in monthly production reports. We, like Lade et al. (2020), assume that most self-reported vented and flared volumes are flared. We focus on reported flaring for three reasons. First, comprehensive data on methane emissions at a well level do not exist. Second, inefficient and unlit flares emit methane, so flaring reductions are relevant for methane abatement. Third, venting and leaking may be exacerbated by the same conditions that lead to flaring (Lyon et al. 2020).

Flaring has sometimes been cast as the result of physical constraints imposed on producers. That characterization is incomplete. Flaring is the result of producers' economic decisions given physical and regulatory constraints. There are (at least) two economic decisions at play. First, producers decide when and where to extract oil. Second, they decide whether to flare or capture the associated gas. Producers can reduce flaring by changing either of these two decisions: they can delay extraction, or they can invest in infrastructure and services to capture the gas. Delivering gas to market requires a suite of infrastructure and services beyond what is required for oil: onsite equipment, local gathering lines, processing plants to strip out heavier hydrocarbons, and long-haul transmission to carry the gas to market.

Data on Bakken and Permian flaring suggest that congestion—not absence of connection to gathering—has been the primary physical cause of flaring for several years. Moreover, there are

[13] According to EIA, in 2020 0.91 and 2.23 pounds of CO_2 were emitted per kWh of electricity generated from natural gas and coal respectively in the U.S. Source: EIA website. Frequently Asked Questions (FAQS). *How much carbon dioxide is produced per kwh of U.S. electricity generation?* Accessed February 2022.

[14] Break-even estimates vary. Howarth et al. 2011 argues for between 2 and 3 percent while Farquharson et al. 2017 argues for closer to 4 percent.

[15] See Appendix B for a description of data sources.

multiple points in the natural gas supply chain that appear to experience congestion.

Flaring comes from two groups of locations: those that both sell *and* flare gas in the same quarter, and those that flare all of the gas produced in a quarter.[16] Of the locations that flare all gas, some have always flared everything; others have previously sold gas. Locations which have previously sold gas are likely connected to gathering infrastructure. Those that have never sold gas before are likely not connected.[17]

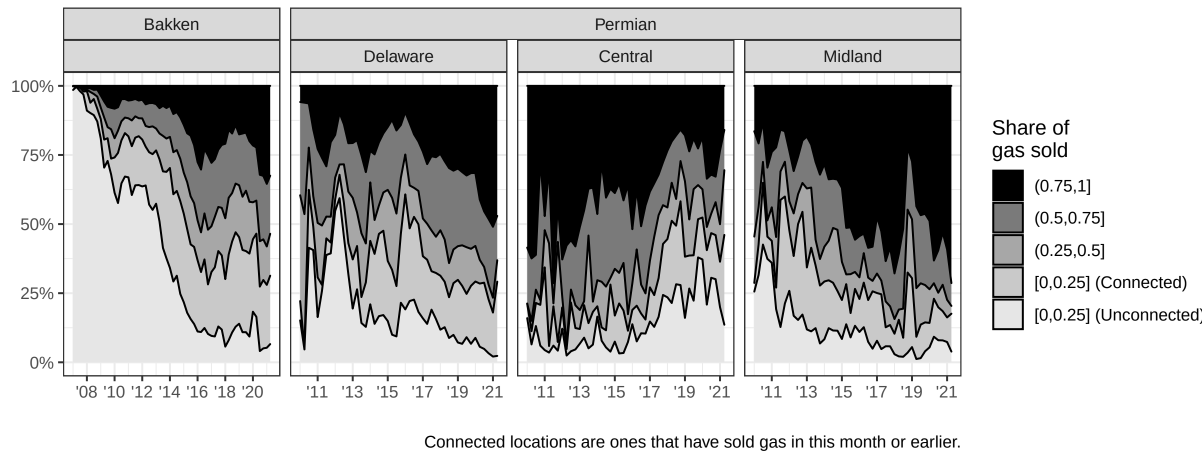

Figure 2: Share of total gas flared by share of gas location sells that quarter

Figure 2 shows that locations which flare most or all gas contribute less than half of all flaring for most quarters. The majority of flaring in the first half of 2021 comes from locations which also sell at least 25 percent of their gas. By mid-2021, flaring by unconnected locations made up less than one quarter of flaring in the Bakken or Permian, even though unconnected locations accounted for majority of flaring during early development of the Bakken and Delaware.[18]

The fact that most flaring comes from connected locations that sell their gas suggests that intermittent congestion, not connection delays, explains most flaring. When gas production exceeds midstream capacity, some oil wells must flare associated gas in order to keep producing oil. Additional evidence also supports this hypothesis. As shown in Appendix Figure 11 the probability of a location flaring *some* gas (versus all or none) has increased over time. This is consistent with a 2019 Federal Reserve survey of producers: 49 percent of respondents cited capacity constraints in gathering and processing as a reason for flaring (Federal Reserve Bank of Dallas 2019).

Congestion in midstream infrastructure can happen downstream of gathering. Before natu-

[16] In North Dakota, firms report well-level flaring. In Texas, firms report flaring for each gas well and each oil lease. A lease can involve multiple wells. See Appendix B for additional discussion.

[17] In Texas, we are unable to identify whether the individual wells on a lease are physically connected to gathering—just whether gas produced on a lease has been sold.

[18] Lade et al. (2020) cast Bakken flaring as an issue of connecting wells to gathering, presumably because their analysis is restricted to 2007–2016 when connection to gathering was a more important driver of flaring.

ral gas enters a transmission pipeline, it must be separated from heavier hydrocarbons at a gas processing plant. Insufficient processing capacity, like insufficient gathering capacity, has likely caused some flaring, especially in the Bakken (Blundell et al. 2022; DOE 2014). Figure 3 plots gas processing capacity versus gas production in the Bakken. Although processing has increased with production, production has exceeded processing capacity several times. Because production and processing are spatially differentiated, spare capacity in one area may not be accessible to constrained producers in another. This means aggregate utilization rates can understate congestion at specific locations.

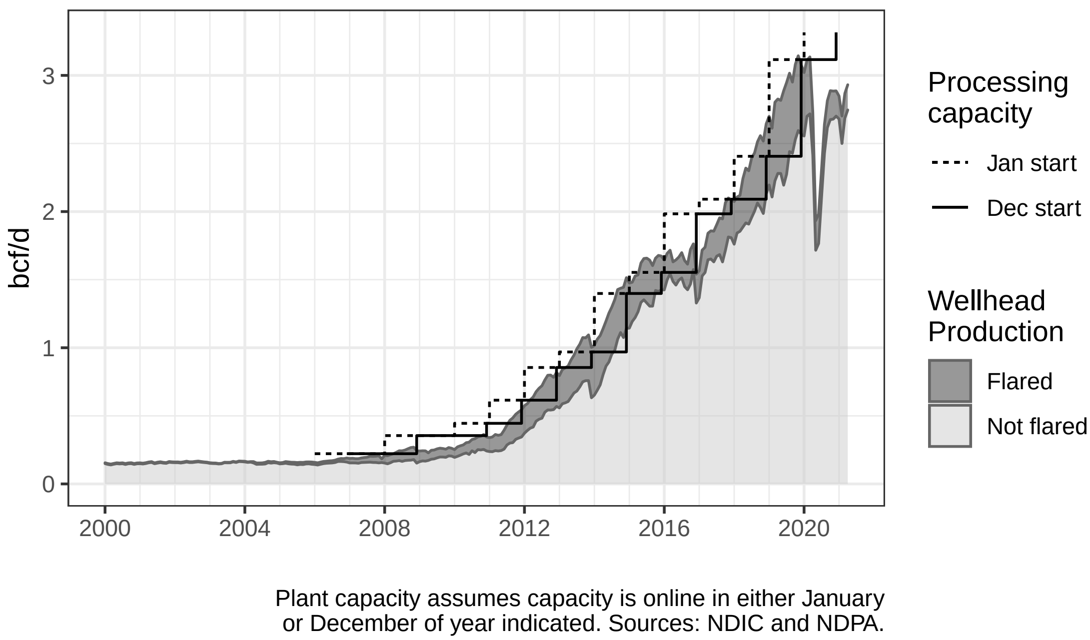

Figure 3: ND gas processing capacity barely kept pace with ND gas production

Long-haul transmission pipelines carry gas from processing plants to market. We present descriptive evidence consistent with transmission constraints causing flaring, particularly in the Midland region of the Permian. The bottom pane of Figure 4 shows the difference between the nationally representative spot price for natural gas (Henry Hub) and the spot price in the Midland gas hub (Waha). The difference reflects the scarcity rent associated with transmission out of the Permian. Scarcity rents rose so much in 2019 and 2020 that Waha gas prices were negative. While persistent scarcity rents incentivize pipeline investment (Agerton et al. 2019; Oliver et al. 2014), building pipelines takes time. The top pane of Figure 4 shows Permian flaring over time by region. There is a clear correlation between transmission scarcity rents and Midland flaring: both appear to rise to balance demand and supply for transmission. In contrast, Delaware flaring started increasing in 2015, well before the emergence of a Waha–Henry Hub differential.

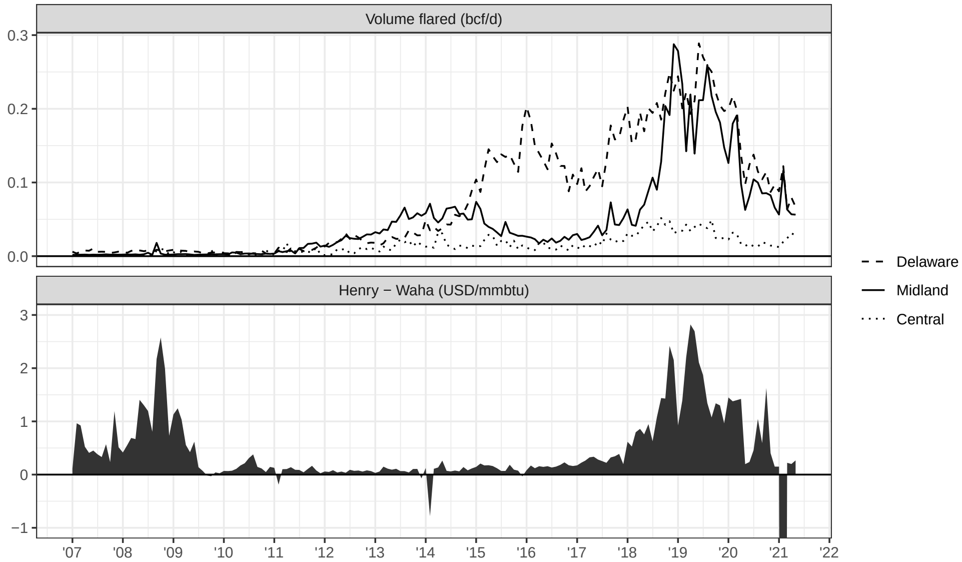

Figure 4: Flaring in the Permian and natural gas basis differentials

5 Private incentives and F&M

Some of the physical constraints highlighted in Section 4 may be transitory, but others may persist absent market or policy changes. In this section, we describe reasons why gas production might exceed infrastructure capacity and then be flared.

Natural gas has economic value. Profit-maximizing firms will only dispose of gas in a flare if the cost of not flaring is greater than the market value of the gas. The cost of not flaring may include delaying production; installing new equipment; or gathering, processing, and transporting the gas. Industry think tank reports suggest that much F&M can be abated at negative marginal cost (IEA 2021; Rystad Energy 2021). However, revealed preferences suggest that foregone abatement options are unprofitable. Difficulties in detecting methane emissions and opportunity costs to prevent F&M could help explain this apparent inconsistency.

Some flaring likely makes economic sense when developing a new area. In a new area, producers face uncertainty about the area's geologic and economic potential, and how much infrastructure they will need. It can be valuable to flare associated gas, delay midstream investment, and maintain the real option to build infrastructure later with more information. Additionally, production from new shale wells declines quickly. It may not make economic sense to build capacity sufficient to handle peak initial production if production declines rapidly. Instead it might be more profitable to flare a share of the gas initially. Both uncertainty and rapid production declines are acute in the short-run. As a play matures and production stabilizes, these economic rationales for flaring should dissipate.

Midstream companies generally recover their fixed investment costs through variable charges on the volume of gas shipped. As with pricing in utilities, this presents a tension between revenue adequacy and pricing services efficiently so that they reflect marginal cost (Borenstein 2016; Braeutigam 1989). Two observations suggest that midstream prices might not reflect the marginal cost of midstream services. First, 45 percent of respondents to a Federal Reserve Bank of Dallas (2019) survey cited excessive fees in gathering and processing capacity as causes of flaring. Second, wellhead gas prices reported by Permian producers for tax purposes exhibit large variation around national benchmarks, even within a small spatial area.[19] In contrast, wellhead oil prices display little dispersion: they are tightly clustered around the national benchmark. (See Appendix Figure 12.) While some of the variation in wellhead gas prices is probably due to differences in composition of the gas, some could also be due to variation in the price of midstream services.

There are two kinds of long-haul natural gas transmission lines: interstate and intrastate lines. The Federal Energy Regulatory Commission (FERC) regulates interstate pipelines and transmission rates to ensure pipeline owners achieve revenue adequacy but do not earn monopoly rents.[20] A firm regulated under a standard cost-of-service framework solves a different profit maximization problem than a firm in a competitive market. Averch et al. (1962) predict that if the rate of return on the firm's capital investment is less than the cost of capital, the firm will exit the market. In the context of F&M, if the regulator sets the rate of return for transmission too low, midstream firms will not build enough capacity, and producers will flare production in excess of capacity. If the allowed rate of return is greater than the cost of capital, transmission owners have an incentive to over-capitalize, and possibly overbuild.

As with transmission, gathering infrastructure requires upfront, fixed investments, and gathering services are usually priced with volumetric charges. Unlike transmission, however, gathering agreements are private, bilateral contracts. To reduce the risk of hold-up, midstream firms often require an *acreage dedication*—a long-term commitment by the producer to ship all gas produced in an area through a midstream firm's gathering system. The agreement limits the risk to the midstream firm that the producer ships (or threatens to ship) gas with a competitor. Despite acreage dedications, midstream companies still face uncertainty about the quantity of gathering services producers will demand. In the event of a downturn in hydrocarbon prices, lower production and demand for gathering can lead to a revenue shortfall.[21] Consequently, risk-averse midstream firms may raise prices above expected long-run average cost to ensure they can recoup their investment. Long-term contracts may help reduce risk for gas processors, but the lumpiness of processing investment and uncertainty can lead to a mismatch between natural gas production and infrastructure capacity, especially in areas with new production growth.

[19] This data is collected by Enverus from the Texas Comptroller and merged with Enverus production data derived from the Texas Railroad Commission.

[20] Appendix A provides additional discussion midstream market structure.

[21] Long-term take or pay contracts can ameliorate this issue, but do not appear to be used as much for gathering and processing.

5.1 Flaring, Bargaining, and Competition

Spatial differentiation can limit competition between gathering companies at a specific location. Congestion can exacerbate this, creating isolated sub-markets as is the case in electricity markets (Borenstein et al. 2000). Because gathering prices are market based, limited competition may enable midstream firms to mark up prices. The option to flare serves as an additional midstream competitor: should negotiations with a midstream provider break down, producers can flare instead of curtailing production. This option may reduce midstream firms' bargaining power.

A recent dispute in Texas between producer EXCO and midstream firm Williams illustrates how the option to flare can limit midstream pricing power (RRC 2019). The dispute centered on whether the regulator would permit EXCO to flare, even though EXCO's wells were physically connected to Williams' infrastructure. Williams argued that allowing EXCO to flare would violate flaring regulations. It asked that EXCO be required to stop flaring and instead use its oil profits to pay for gas gathering services. Williams priced gathering at $198 million, over four times the market value of the gas—$45 million. A competitor to Williams would be unlikely to build alternative gathering infrastructure: Williams' infrastructure was a sunk cost, and Williams could undercut any new entrant. In its decision, the RRC framed Williams' suit as an attempt to use flaring regulations to gain leverage in a commercial dispute and preserved EXCO's option to flare (RRC 2019, p. 22).

Contracting frictions and midstream market power can, in theory, lead to inefficiently low gas capture rates and excess flaring. The extent to which these factors matter in practice is an open question for economic research. As suggested by the EXCO–Williams dispute, midstream market structure and regulation could interact with F&M in important ways.

6 External costs of F&M

F&M generate two types of pollution: GHGs and local air pollutants. Quantifying the external health and environmental costs of pollution from F&M is a key question for researchers and policymakers.

Producers can reduce F&M by capturing gas. However, if the alternative use of the gas, such as power generation or residential heating, emits equivalent GHGs, flaring reductions especially might have limited net climate benefits.[22] This is unlikely.

As discussed earlier, the climate costs of one ton of methane are larger than those of CO_2. This holds true for NGLs: the 100-year GWP of NGLs butane, ethane and propane are 7 to 10 times larger than CO_2 (Hodnebrog et al. 2018). Emitting these hydrocarbons to the atmosphere imposes higher climate costs than combusting them, whether combustion is through flaring or

[22] In reality, this is more nuanced as there are several margins of adjustment. For instance, some wells might not be drilled, reducing the O&G production. Upward pressure on prices would reduce consumption. On the other hand, if F&M reductions increase gas supply as firms sell gas instead of flaring it, this could theoretically reduce gas prices and impact power dispatch decisions. Evaluating these effects is beyond the scope of this discussion.

Table 1: Climate costs from flaring ($/mcf)

Flare Efficiency	Bakken Mix	Pure methane
100%	$5.00	$2.70
98%	$5.38	$3.23
93%	$6.31	$4.54
0%	$23.76	$28.89

See Appendix D for calculations.

another productive use.

Even if flaring reductions increase natural gas consumption one-for-one, the fact that flares are not fully efficient suggests flaring reductions will have net climate benefits. Environmental conditions can reduce flare efficiency (Gvakharia et al. 2017; Leahey et al. 2001; Strosher 2000), and flares can fail to light. Inefficient and unlit flares release hydrocarbons directly into the atmosphere. An aerial survey in the Permian by the Environmental Defense Fund (EDF) found that more than 10 percent of flares had incomplete combustion. EDF estimates that on average, flares vent seven percent of their gas (EDF 2020). This is higher than the two percent estimate used in government GHG inventories (EPA 1996). Much of the flared gas associated with oil production contains NGLs, which generate more CO_2 in combustion than methane does. NGLs are petrochemical feedstocks and could be converted into plastics and other materials instead of being flared or vented. Flaring can also release black carbon, itself a contributor to climate change (Johnson et al. 2002; Stohl et al. 2013). As discussed in Section 3, recent measurements of U.S. upstream methane emissions tend to be limited to a particular time and place, so it is difficult to compare them or form precise annual estimates of the associated climate costs. Nevertheless, we believe it is important to communicate the general scale of these damages. Quantifying a more comprehensive external cost of U.S. F&M is an important topic for future (likely multidisciplinary) research.

We address the climate costs of reported flaring and venting first. Table 1 shows how NGL content and flare efficiency affect the climate cost of flaring, a point made by Kleinberg (2019). Using the federal SCC and SCM, we calculate that flaring pure methane at the EPA-assumed 98 percent efficiency generates climate costs of $3.23/mcf (see Appendix D for details). This is greater than the average spot price of U.S. natural gas in 2020, which was $2.03/mcf. Because of the NGLs present, flaring the Bakken associated gas mixture analyzed in Brandt et al. (2016b) results in higher climate costs than flaring pure methane. Flaring the Bakken gas mixture at 93 percent efficiency—the average efficiency estimated by EDF (2020) in the Permian—results in higher climate costs of $6.31/mcf.

Using these marginal climate cost estimates as lower and upper bounds, we calculate that reported U.S. flaring and venting generated between $0.9 and $1.8 billion in climate costs in 2015. This figure rises to between $1.7 and $3.4 billion in climate costs in 2019, or about half to one percent of the value of U.S. O&G production that year.[23] These calculations exclude unreported venting and leaking as well as downstream emissions, and they assume that all of the reported flaring and venting was, in fact, flaring. We note that reported flaring and venting fell in 2020.

We next address methane. Alvarez et al. (2018) estimate that in 2015, the O&G sector emitted approximately 11 million tons of methane. Applying the latest federal SCM of $1500/ton yields climate costs of $16.8 billion. This is an order of magnitude larger than our estimate of the climate costs of reported 2015 flaring. Updated methane estimates comparable to Alvarez et al. (2018) are not currently available. However, 2019 emissions were likely to have been higher than 2015 emissions. First, U.S. oil and gas production increased by 30 percent and 24 percent, respectively, from 2015 to 2019. Second, the Permian produced a larger share of O&G in 2019 relative to 2015. Zhang et al. (2020) and Schneising et al. (2020) estimate that methane emission rates in the Permian basin during 2018–2019 were approximately 60 percent higher than the national estimate in Alvarez et al. (2018).

Flaring, venting, or leaking associated gas also emits EPA-designated criteria pollutants such as nitrogen dioxide, sulfur dioxide, carbon monoxide, particulate matter, and volatile organic compounds (VOCs) (Buzcu-Guven et al. 2012; EPA 2018, 2019). Actual emissions of each pollutant depend on many localized factors, and existing studies on flaring and emissions use relatively small samples (Fawole et al. 2019; Kostiuk et al. 2004; Strosher 2000). Blundell et al. (2022) empirically estimate the causal impacts of Bakken flaring on respiratory health. While flaring has caused increased hospital visits associated with respiratory ailments, the low population density of North Dakota has limited the scale of external health costs. More work can be done to construct inventories of local air pollutants for major producing basins. As Blundell et al. (2022) find, the external costs of emissions depend on localized health and ecosystem impacts.

Quantifying and valuing F&M externalities remains a policy-relevant research frontier. Uncertainty around the quantity of emissions will hopefully improve as measurement technology advances. Flare composition and efficiency varies across wells, and both factors affect climate costs. Potential health impacts from F&M depend on the composition of flared gas, as well as weather conditions and proximity to population centers. Finally, the benefits of F&M abatement policies depend on the external costs of the alternative use of the gas. The external cost of the alternative could be zero if the gas is left in the ground. If the gas is captured instead, it could include emissions during transportation and consumption.

[23] To compute the value of O&G production, we use EIA estimates for monthly total U.S. field production of crude oil and U.S. Natural Gas Gross Withdrawals. We multiply these by the monthly average WTI spot price and Henry Hub spot price. The value of 2015 U.S. oil production was $182 billion in 2020 USD, and gas production, $94 billion. The value of O&G production in 2019 rise to $257 and $106 billion.

7 Policy options for F&M

We now review current policies and discuss an agenda for F&M policy research. We direct the interested reader to Rabe et al. (2020) for a detailed review of state-level F&M policies and DOE (2019) for a review of state and federal flaring policy.

7.1 Current F&M policies

Texas and North Dakota require firms to obtain flaring permits and report most flared volumes. While permits in Texas specify how much a well is allowed to flare, there are no statutory limits on upstream flaring. Producers are also allowed to vent for 24 hours at a time during specified events such as upset conditions or liquids unloading. They are not required to report venting from exempt categories such as drilling, completion, or tank releases.[24]

The North Dakota Industrial Commission (NDIC) implemented new flaring and venting regulations in 2014. NDIC Order 24665 established annual gas capture targets as a percentage of gas production (NDIC 2014). Targets were to increase each year until 2020, when they would reach 91 percent. Operators that did not meet targets would be required to curtail production. The order allowed the first well in a Bakken spacing unit to flare unlimited quantities. Subsequent infill wells are allowed to flare unlimited quantities for 90 days, at which point they become subject to gas capture targets. The NDIC relaxed flaring regulations once in 2015 and twice in 2018 (NDIC 2015, 2018, 2020). We estimate that during 2019, Bakken wells captured 81 percent of their gas, while Permian oil leases captured 95 percent of their gas (see Table 3 in Appendix C).

Both Texas and North Dakota impose severance taxes on oil and natural gas production. However, Texas exempts associated gas volumes flared upstream (Texas Comptroller 2021). North Dakota has a similar exemption, but only for the first year of a well's production (ND HB 1134 2013). When gas flared in the upstream is exempted from severance taxes, this lowers the opportunity cost of flaring relative to capturing the gas. One policy consideration would be to equalize the tax treatment of flared versus captured gas.

Most attempts to regulate methane emissions have focused on command and control policies such as Leak Detection and Repair (LDAR) or technology standards. At a federal level, the EPA developed a rule in 2016 with prescriptive LDAR and emissions control technology standards.[25] However, the rule was never fully implemented before it was challenged in court and replaced with a less stringent policy.[26] EPA proposed an updated, more stringent rule in November 2021.[27] At the time of this writing, the rule is undergoing public comment. Colorado and Pennsylvania also have specific upstream and midstream requirements for LDAR and methane emissions reporting.

[24] 16 Tex. Admin. Code §3.32
[25] 40 CFR 60 OOOOa
[26] 85 FR 57018, 85 FR 57398
[27] 86 FR 63110

These LDAR standards focus on leaking, but not flaring, and do not provide continuous monitoring or emissions quantification.

7.2 Future policy options

Marks (2022) estimates that initial methane abatement would generate net social benefits, but costs increase steeply after about two-thirds of abated emissions. He estimates that a \$3.17/mcf methane tax would decrease emissions by 60 percent, achieving \$1.8 billion in annually avoided climate costs. Taxing methane at \$28/mcf (the SCM) would reduce emissions by almost 75 percent (Marks 2022, Table 3). Both Lade et al. (2020) and Johnson et al. (2012) similarly find that moderate flaring taxes could reduce flaring significantly.

Alternative market-based instruments might also be considered. North Dakota uses a portfolio standard for flaring. Portfolio standards are used in automobiles, motor fuels, and electricity markets (Austin et al. 2005; Holland et al. 2009; Upton et al. 2017). Markets for "responsibly sourced" or "green" gas are also developing (Krupnick et al. 2020). These markets allow producers with environmentally responsible practices to differentiate their gas with the goal of selling their "green" gas for a premium.

Environmental economics theory shows that efficient policy will account for differences in the external costs of bads, such as flaring and methane emissions. In theory, the stringency of efficient F&M policies would even vary by location and gas composition if the external costs also vary. However, in practice F&M policies will need to make trade-offs between simplicity, monitoring costs, and efficiency. These tradeoffs can be stark. For example, flaring is easier to monitor than methane and could be a target of stringent regulations. However, if venting is a substitute for flaring, then stringent flaring limits could lead to more venting. Absent curbs on harder-to-monitor methane, this might limit or even reverse the climate benefits of a flaring policy. Calel et al. (2020) raises this concern at an international level. Another example is the tradeoff between taxing methane using inventory-based estimates versus measured emissions. Inventory-based taxes incentivize firms to optimize inventories of emission sources—not emissions themselves. Directly targeting reductions in measured emissions may lead to lower abatement costs but higher monitoring costs. Inventory-based policies become less efficient when emissions factors differ from actual average emissions as they currently do (Alvarez et al. 2018; Rutherford et al. 2021).

Several features of F&M lend themselves to considering policies like targeted inspections alongside specific requirements or technology standards. Monitoring and attribution of F&M pose significant challenges for emissions pricing, whereas a few salient component types (tanks, flares, pneumatic devices) are responsible for a large share of emissions (Rutherford et al. 2021). Engineering simulations suggest that finding and repairing many of these sources is cost effective even in the absence of policy, although these simulations produce considerable heterogeneity in costs and benefits across sites (Kemp et al. 2016).

7.3 Monitoring and measurement

As highlighted in Section 3, measurement of F&M is challenging. Firms currently self-report flaring to regulators. Self-reporting can economize on auditing expenses and reduce the firm's risk by replacing large, uncertain fines with certain smaller fines when violations are reported (Kaplow et al. 1994). However, self-reporting also enables mismeasurement and misreporting. The accuracy of self reports can depend on the enforcement costs of auditing and administering fines, policy stringency, and monitoring technology accuracy (Malik 1993). Further, leaked volumes are often either not known or not reported.

Remote sensing may be able to help monitor F&M at scale and detect misreporting. However, each remote sensing technology has its own temporal and spatial limitations and detection thresholds (Fox et al. 2019; National Academies of Sciences 2018). For example, handheld cameras have lower detection limits that enable finding many small leaks that may be large in aggregate, but their upper detection limits miss super-emitters. Satellites with daily global coverage become more accurate when aggregated, but atmospheric conditions and limited spatial resolution prevent them from identifying individual emitters—particularly when wells from multiple operators are close together.[28]

Accommodating limitations in measurement requires new research. Estimating localized emissions from coarse spatial and temporal measurements will require advances in statistical methods, as will integrating measurements from multiple technologies. Incorporating noisy emission measurements into the design and enforcement of F&M policies will require advances in economic theory.

The economic literature on non-point-source (NPS) pollution may contain lessons on how to integrate remote sensing technology into policy. The NPS literature studies regulatory mechanisms when monitoring and attribution are costly (Kotchen et al. 2020; Xepapadeas 2011). NPS mechanisms for F&M could involve taxing observable inputs or outputs, setting taxes based on regional ambient emissions measured through remote sensing, or hybrid schemes with differential fees based on the precision of the remote sensing or leak detection technology in use. The precision and accuracy with which firms can be linked to remotely-sensed emissions is an applied question. A F&M NPS mechanism would depend on the technical capabilities of sensors; the spatial and temporal distribution of firms and emissions; and the development of statistical and machine-learning techniques to quantify emissions.

[28] The spatial resolution of VIIRS is approximately 0.75 km^2 (Elvidge et al. 2013), and of TROPOMI is 3.5 by 7 km (Hu et al. 2018), both large enough to cover multiple producing locations.

8 Conclusion

Flaring and methane emissions (F&M) are significant, linked environmental policy issues for U.S. shale O&G operations and the O&G value chain more broadly. In this paper, we provide an interdisciplinary literature review and marshal granular data to identify constraints in the O&G supply chain to explain upstream F&M. Our empirical observations suggest that constraints at multiple points in the natural gas supply chain can cause emissions from upstream operations. Our back-of-the-envelope calculations suggest that the climate cost of upstream methane emissions is an order of magnitude larger than the climate cost of just upstream flaring. Using the IAWG (2021) SCC and SCM for 2020, we calculate that reported 2015 flaring imposed climate costs of \$0.9 to \$1.8 billion based on EIA data, while U.S. upstream methane emissions imposed a cost of \$16.8 billion that year based on Alvarez et al. (2018) emission estimates.

We highlight several areas where economists can contribute to F&M research. First, causal inference methods can help identify why F&M occurs and evaluate F&M policies. Second, interdisciplinary research can improve understanding of both the external cost of F&M and the abatement cost. Third, economic research can help inform the effectiveness and efficiency of proposed policies, particularly under imperfect monitoring. Researchers should be aware of how the existing market structure in the O&G industry, such as contracting for midstream services, impact F&M and potentially interact with policy in unexpected ways. Similarly, just as economists are attuned to issues of economic structure and uncertainty, they should also be aware of the complex engineering systems at work and the scientific uncertainties around the quantities, costs, and physical causes of F&M. Particularly in forward-looking analyses, accounting for these factors may require collaboration with other disciplines in the engineering and natural sciences.

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A Industry Background

We present some basic terminology commonly used in the oil and natural gas industry. We recommend a review of this terminology, especially for readers not already familiar with the supply chain in the oil and natural gas (O&G) industry.

A.1 Oil, natural gas, and associated gas

O&G wells produce different types of hydrocarbons. The shortest hydrocarbon is methane, CH_4 (natural gas). With additional carbon and hydrogen atoms, the molecule becomes longer and heavier.[29] At atmospheric pressure and temperatures, shorter hydrocarbons are in a gaseous state, while longer hydrocarbon chains, including crude oil, remain in a liquid state. Liquids can be transported via several modes: pipeline, tanker vessel, barge, or truck. They can also be stored in a tank near the wellhead. Gases, on the other hand, are transported via a series of smaller gathering pipelines and long-haul transmission pipelines to market. Because moving large quantities of gas onshore is uneconomic without pipelines, firms have less flexibility in transporting gas relative to oil.

A well is typically designated as an "oil well" or "gas well" for legal and tax purposes. While the precise definitions can change across states, generally speaking oil wells are drilled for the economic purpose of extracting oil, and gas wells, for extracting natural gas. Nevertheless, oil wells, particularly in unconventional shale plays like the Permian or the Bakken, also produce *associated gas* along with crude oil. The associated gas is a byproduct. It includes methane and other NGLs like ethane, propane, butane, etc. Because natural gas can be costlier to transport relative to crude oil, there may be valid economic reasons to flare some amount of associated gas at the well rather than capturing it.

A.2 Leases and wells

The difference between a *lease* and a *well* is key distinction for understanding upstream O&G data available from the Texas regulator (Texas Railroad Commission, or RRC). In the context of this discussion, a well is a hole drilled into the ground for the purpose of extracting hydrocarbons (i.e. crude oil, condensate, natural gas liquids, and natural gas). The date a producer starts drilling a well is the *spud date*. After a firm drills a well, the well must be *completed*, which can involve hydraulic fracturing (commonly referred to as "fracking"). After completion, a successful well will begin to produce economic quantities of hydrocarbons.

In the context of O&G data, when we refer to a *lease*, we do not refer to the contract whereby a lessor assigns a lessee the right to extract hydrocarbons in a particular area. Instead, we refer to a group of wells whose production is reported in aggregate to the regulator. The spatial extent of mineral lease contracts and leases in reported production may coincide but do not have to.

In North Dakota, producers report production at the well-level. In Texas, producers report production from gas wells at the well-level, but they report the aggregated lease-level production for oil wells. When comparing analysis from Texas and North Dakota, it is important to be aware of this difference in reporting.

[29] Ethane (C_2H_6); propane (C_3H_8); butane (C_4H_{10}), etc.

A.3 Upstream, midstream and downstream

Like all industries, the O&G industry is a supply chain. The supply chain starts with oil and natural gas production in areas with hydrocarbon-rich geology—the *upstream* part of the business. Once hydrocarbons are produced, the *midstream* segment transports them to the *downstream* segment where they are combusted to produce energy or transformed into final products. Oil is used as an input to a refinery that transforms it into gasoline, diesel, jet fuel, or other products. Natural gas has many uses: (1) residences or commercial businesses use it in heating or cooking; (2) chemical and fertilizer plants use gas to create plastics, chemicals, and fertilizers; (3) power power plants burn it to generate electricity; and (4) Liquefied Natural Gas (LNG) plants liquefy the gas and prepare it for export.[30]

The midstream segment consists of several services that connect upstream wells to downstream demand. After gas exits the well, a network of gathering pipelines transport it to a natural gas processing plant that separates out heavier hydrocarbons and other impurities. Once processed, natural gas is transported on a long-haul transmission line to carry it from the producing region to demand centers.

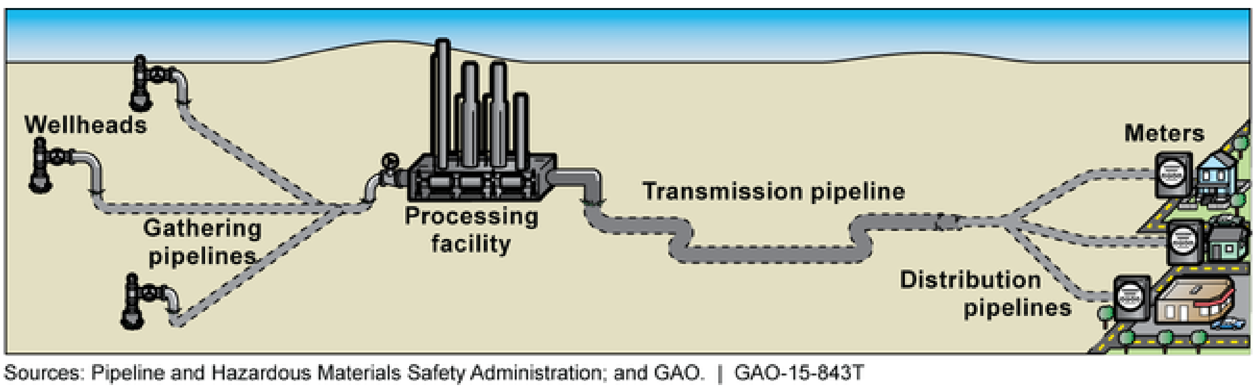

Figure 5: Natural Gas Supply Chain Schematic

Figure 5 shows a schematic of the natural gas supply chain, sourced from the Pipeline and Hazardous Safety Administration and the Government Accountability Office. Figure 6 shows a map of shale producing areas in the United States. The focus of this analysis is on two shale plays that produce oil but also have significant quantities of associated natural gas, namely the Bakken and Permian.

A.4 Market Structure of Midstream Services

Midstream services for natural gas can be separated into three main segments. First, gathering pipelines transport natural gas from the wellhead to a natural gas processing plant. Because gathering lines are so localized, there are many more miles of gathering lines relative to transmission. Second, natural gas processing plants separate out heavier hydrocarbons and other impurities. Typically, natural gas must be greater than 95 percent methane before entering into a long-haul transmission pipeline. The prices of both gathering and natural gas processing are determined

[30] Once seaborne LNG cargoes reach their destination, they are re-gasified and enter into the supply chain within the country of import.

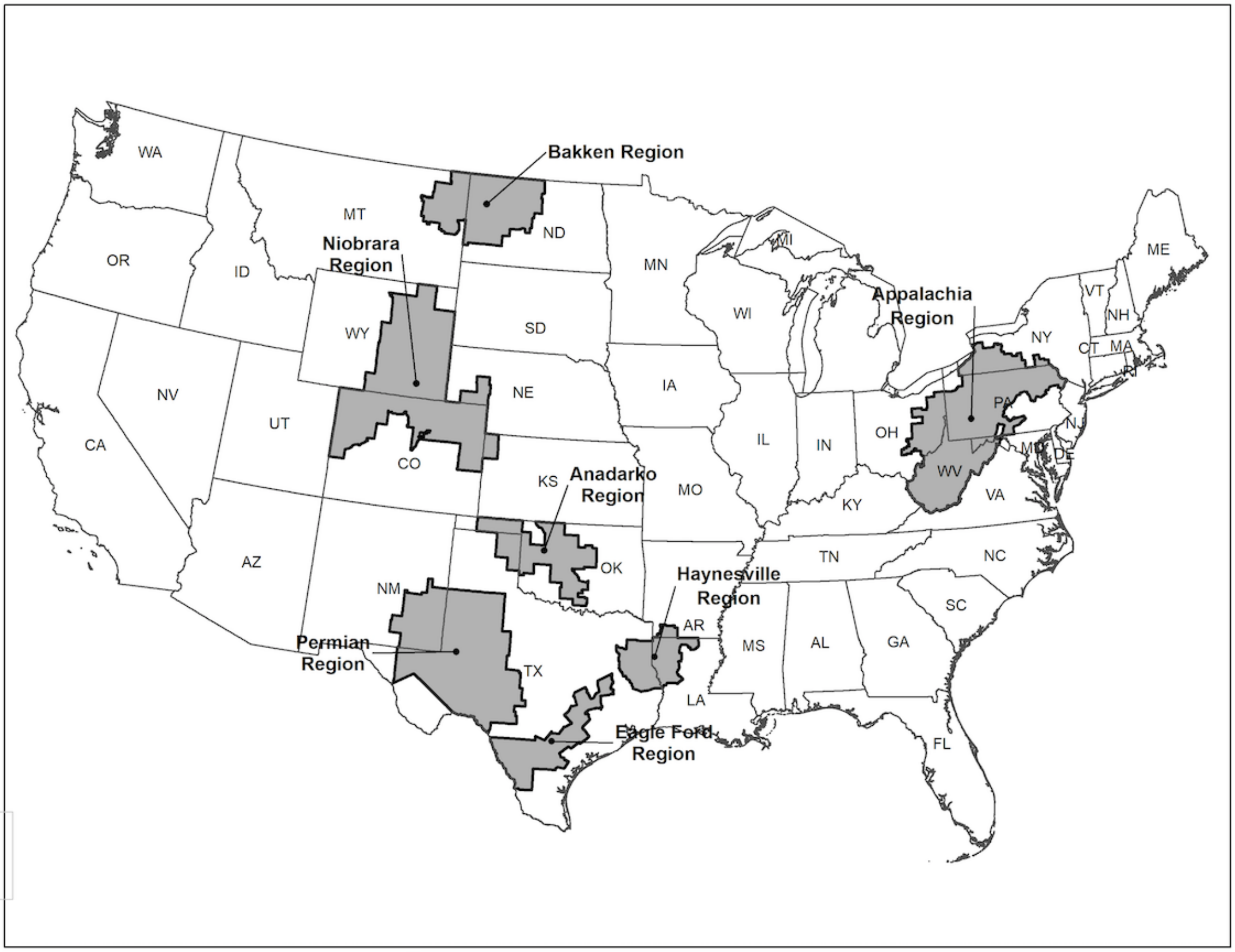

Figure 6: Map of all U.S. shale plays as defined by EIA's Drilling Productivity Reports

by the market; regulators do not set their prices. Because gathering and processing are spatially differentiated, there is potential for market power in localized areas. Market power could, in theory, be exercised by large upstream producers or midstream service providers.

The third and final piece of the midstream segment is long-haul transmission pipelines that transport large quantities of natural gas to demand centers hundreds, and even thousands, of miles away. There are two kinds of long-haul natural gas transmission lines that carry natural gas around the U.S.: interstate and intrastate lines. The Federal Energy Regulatory Commission (FERC) regulates interstate pipelines and transmission rates to ensure pipeline owners achieve revenue adequacy but do not earn monopoly rents.

While pipelines can deviate from rates set by a cost-of-service (COS) methodology, COS provides a baseline and fallback for alternative rate-setting frameworks (American Gas Association 2007). Typically rates are established using one of three methodologies (American Gas Association 2007). First, the *cost-of-service* (COS) method determines prices based on the capital expenditures of the project, ongoing operational costs, plus a rate of return. Prices are set such that the pipeline operator owner can recover its costs plus a reasonable rate of return on the capital investment. Second, the *negotiated rate* method allows the owner to charge the shipper an agreed-upon rate. However, the shipper must have the option to select a *recourse rate* based on a cost of service methodology. Thus, the negotiated rate method sets a maximum rate for pipeline service and allows shippers to negotiate a lower rate. Third, a *market-based rate* method can be used when the pipeline operator can demonstrate that it lacks market power. In this case, the operator is authorized to charge rates that are consistent with market conditions. In all three circumstances, the FERC has oversight of the rates charged. States regulate intrastate transmission and generally follow the same regulatory methodology as FERC.

A firm regulated under a standard cost-of-service framework solves a different profit maximization problem than a firm in a competitive market. The standard Averch et al. (1962) model predicts that if the rate of return on the firm's capital investment is less than the cost of capital, the firm will exit the market. In the context of F&M, if the regulator sets the rate of return for transmission too low, firms will not build enough capacity. Should production exceed transmission capacity, producers will flare. If the allowed rate of return is greater than the cost of capital, transmission owners have an incentive to over-capitalize, and possibly overbuild. Faced with high pipeline tariffs, some producers could then choose to flare instead of capture gas.

A.5 The Evolution of Shale Oil & Gas in the U.S.

Figures 6, 7, 8, and 9 illustrate the variation in the expansions and contractions of the seven largest shale plays in the U.S. First, Figure 6 shows that the seven largest shale plays are geographically dispersed throughout the country. The locations and extent of these areas corresponds to geological formations thousands of feet below the earth's surface. Each formation has its own distinct composition of oil and natural gas. For example, the Haynesville and Appalachia areas are overwhelmingly "dry" natural gas, as opposed to the Bakken, which is overwhelmingly oil. The Eagle Ford has a mix of both oil and natural gas, and the ratio of oil and natural gas changes throughout the play. This paper focuses on the Bakken and Permian. Though extraction in these two areas is driven by oil, they also produce significant amounts of associated natural gas.

Figure 7 shows the variation in the timing of oil and natural gas price changes. In the early part of the sample, oil and natural gas prices move in tandem with one another. In 2009, the price of oil and natural gas began to diverge. This divergence continued until 2014, when prices converged

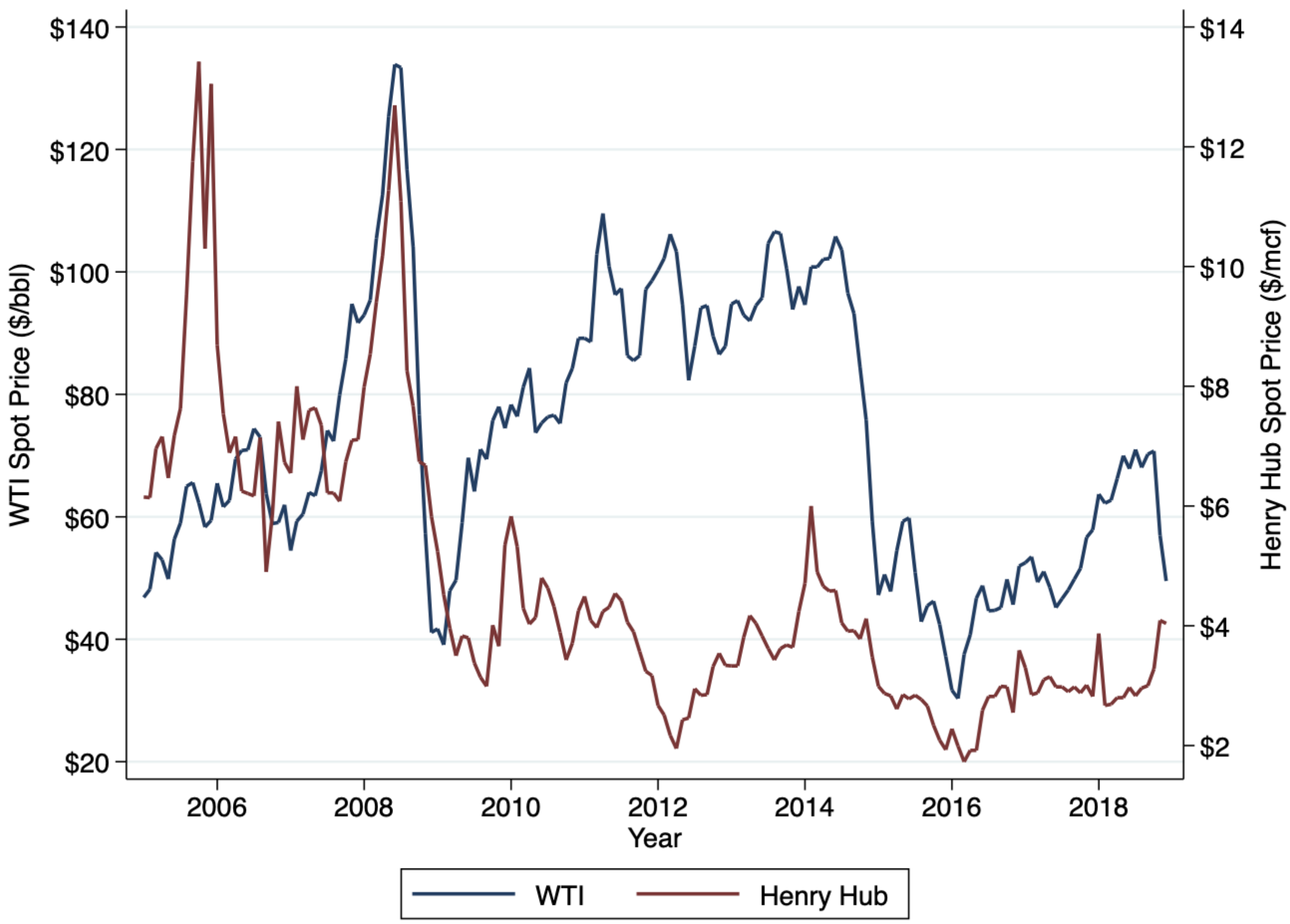

Figure 7: Oil and Natural Gas Prices

once again with the oil price drop. The timing of oil and natural gas price shocks impacted different plays in different ways.

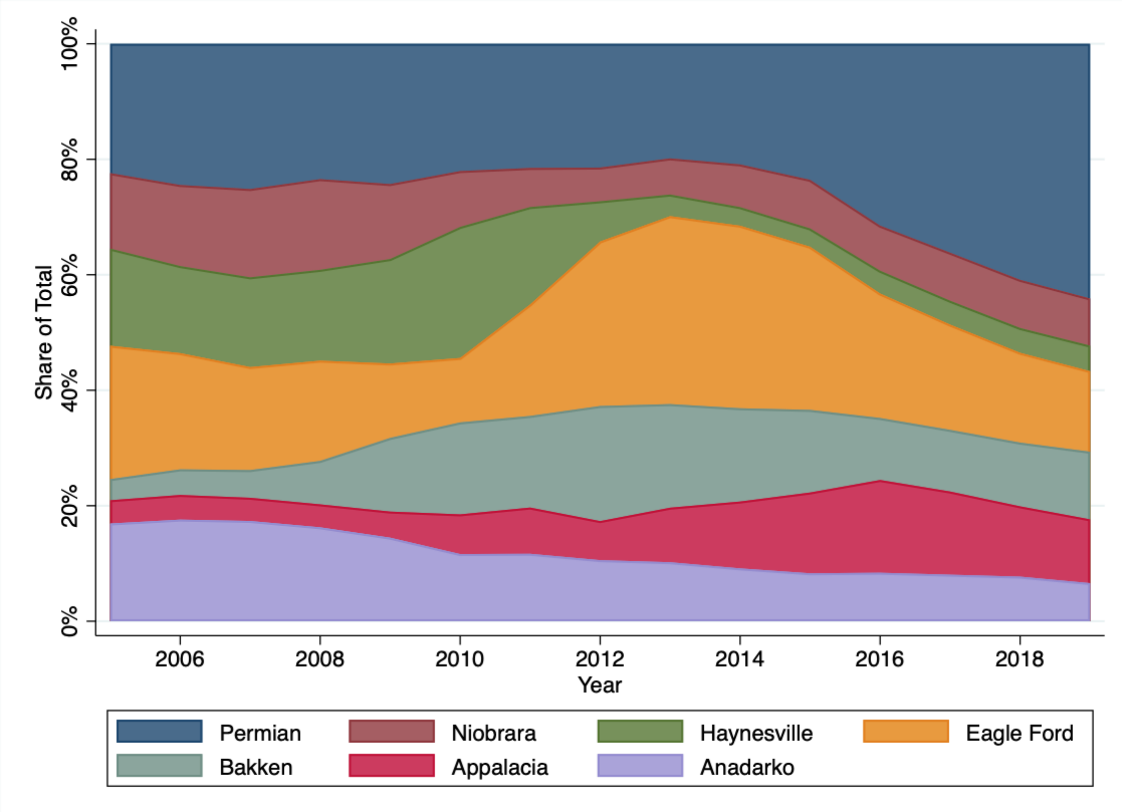

Figure 8: Share of Value of O&G Production by Shale Play Area from Wells Less than 1 Year From First Production

Figure 8 dispalys the share of new production (in dollar terms) from the seven major U.S. shale plays. We define "new" production as the quantity of oil or natural gas produced from wells that are less than one year old. We multiply monthly production from these wells by the corresponding commodity price—WTI or Henry Hub—to calculate the value of new production. Figure 8 shows that early in the sample period, the Haynesville shale accounted for a relatively large share of the value of new production. In contrast, the share of the value of new production from the Bakken was small. Its share peaked in 2013 before the oil price crash in 2014.

Figure 9 shows the value of production from all wells (both oil and natural gas) in these largest seven shale plays relative to the rest of the United States. Figure 9 illustrates how during the early part of the sample, the value of production in shale and non-shale regions moved in tandem. Beginning around 2009, the two diverge considerably, with the majority production (in dollar terms) coming from shale regions. The figure shows the 2014 price drop and then a rebound through 2019.

A.6 Flaring, Venting, and Leaking

Upstream O&G methane emissions occur from both production processes and equipment sources. Emissions can be intentional or unintentional. Examples of equipment sources are storage tanks,

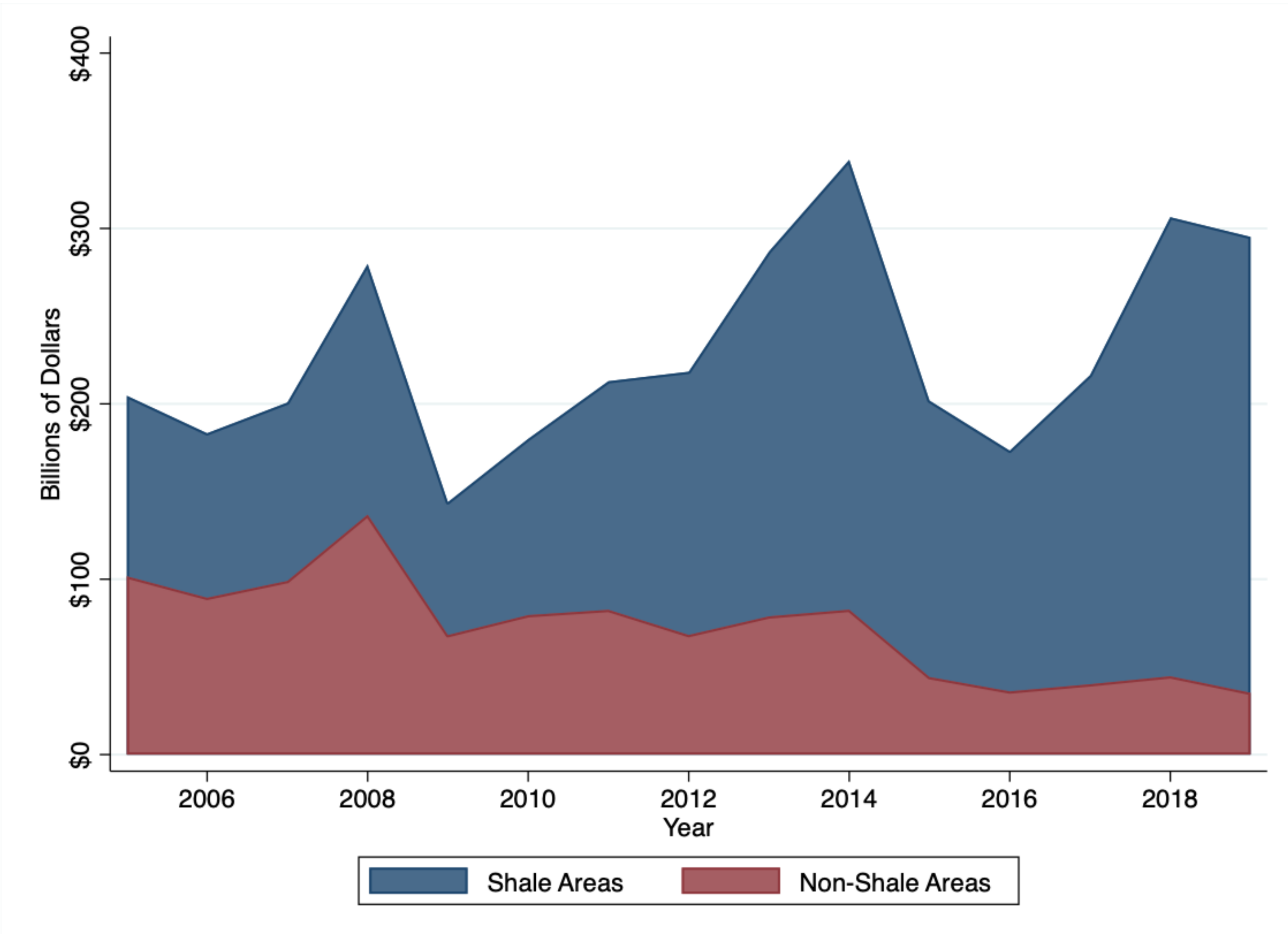

Figure 9: Total Value of U.S. O&G Production in Shale and Non-Shale Areas

compressors, and a vast number of small sources such as valves and controllers. Leaks from small sources may not be large individually, but may comprise a significant share of aggregate emissions.

Unlike leaking equipment, some emitting activities are intentional (e.g., venting) and part of normal operations. “Liquids unloading” is an occasional procedure to remove liquids that are trapped in the well. The procedure may purposefully vent methane in order to change pressure in the well and allow liquids to rise. “Well workovers” occur when producers re-stimulate an existing well to prolong its life. Just after hydraulically fracturing a new well or completing a workover on an existing well, “completion flowbacks” occur. This is a high-velocity flowback to push the hydraulic fracturing fluids back out of the well. As a consequence, a mix of methane and other hydrocarbons escape.

Reduced emissions completions (RECs) or “green completions” involve processes and equipment for separating gas during completion flowback. Separated gas can be captured and sold. Because this equipment can handle the high-velocity, high-pressure conditions at well completion, the procedure reduces methane emissions as well as the need to flare. Green completions were a component of the proposed BLM (2016) rule.

B Data Construction

We assemble a comprehensive dataset on well-level production, flaring, and midstream infrastructure. We compute a number of descriptive statistics to investigate the constraints along the value chain that may cause flaring at the well. We obtained data from state regulatory agencies' websites and public records requests in North Dakota and Texas, as well as three commercial vendors, Enverus, Genscape, and MapSearch.

Bakken In North Dakota, O&G production are reported to the North Dakota Industrial Commission (NDIC) at the well level. For each well, NDIC reports information about the well's location, date of drilling, date of completion, and monthly production. Production is broken down into oil, associated gas sold, and associated gas either flared or vented. Vented and flared gas are reported as a single number. Although North Dakota bans the practice of venting altogether, flares can unintentionally become unlit and release methane (NDAC 2000).

We merge NDIC data to drilling and production records from Enverus and exclude wells outside of the Bakken. We defined “Bakken” wells as any well that extracts from the Bakken, Sanish, or Three Forks pools and is also located spatially within the areal extent of the Bakken as defined by Enverus.

Permian In Texas, O&G producers report production as well as venting and flaring to the Texas Railroad Commission (RRC). Natural gas wells report at the well level, while oil wells report at the lease level. Leases often contain multiple oil wells of different ages, but the wells are located within the same geographic area. As in North Dakota, venting and flaring are not reported separately in Texas. Texas' Statewide Rule 32 allows firms to vent gas for less than 24 hours, but requires longer releases to be burned in a flare.[31]

We merge RRC production records to data from commercial provider Enverus to obtain information on the wells, locations, and completions associated with each production record. Because

[31] 16 Tex. Admin. Code §3.32

Table 2: Table of Data Sources

Source	Data
Texas Railroad Commission	Lease/well production and flaring
Enverus	Well characteristics Lease/well level production Map of shale plays
NDIC	Well characteristics and production Monthly natural gas processing volumes
NDPA	Natural gas processing capacity
Bloomberg	Spot prices
Genscape	Permian natural gas processing plant locations Transmission capacity
MapSearch	Texas natural gas gathering and transmission pipelines Texas gas processing plant locations

Texas oil leases may involve several wells, we match each month of lease-level production to the most recent well completion on the lease to get a sense of the evolution of flaring from the month that production begins. (North Dakota's well-level reporting means we do not have to do this.) For oil leases with multiple wells, Enverus picks a specific well to represent the location of the lease. We use this as the location of the lease. We restrict analysis to Texas wells spatially located within the areal extent of the Permian Basin as defined by Enverus. The Texas Comptroller's office requires firms to report well or lease-level information on the monthly volume and value of O&G sold. Enverus matches Texas Comptroller sales data at the well or lease level to RRC data on the production. We merge this information to our Texas production information. Sales data measure the value of O&G at the wellhead net of transportation costs.

Midstream We gathered data on midstream infrastructure for both North Dakota and Texas. In North Dakota, we assembled a dataset of gas processing plants. The NDIC provides data on the location and monthly intake of plants. We merged this with annual, plant-level capacity data provided by the North Dakota Pipeline Authority (NDPA). We merged the two datasets and verified that monthly gas processing plant volumes closely track aggregate monthly gas sales by wells.

For Texas, we purchased data from MapSearch on the locations of natural gas gathering pipelines, transmission pipelines, and gas processing plants as of the end of 2009 and January 2018.[32] We also purchased data on gas processing and transmission from Genscape.

C Extra figures

[32] According to MapSearch, their April 2010 vintage data represent 2009 infrastructure, and the April 2019 vintage data represent January 2018 data. While the RRC does provide data on pipeline locations, they do not maintain any historical records of infrastructure as it appeared in prior years.

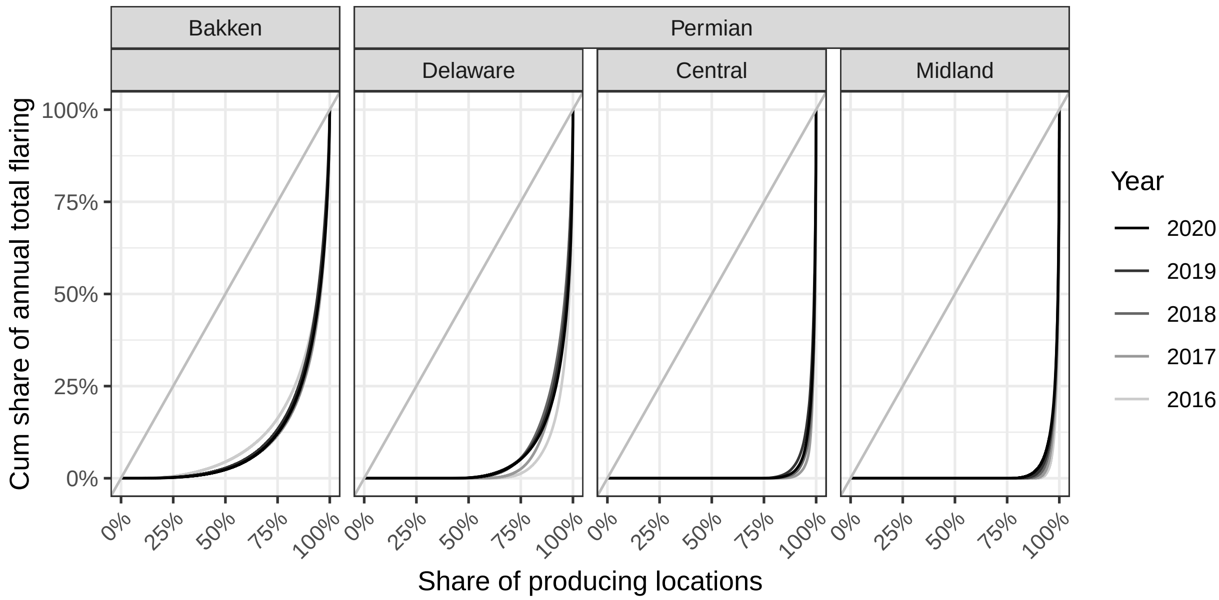

Figure 10: Lorenz curve of annual flaring totals by play

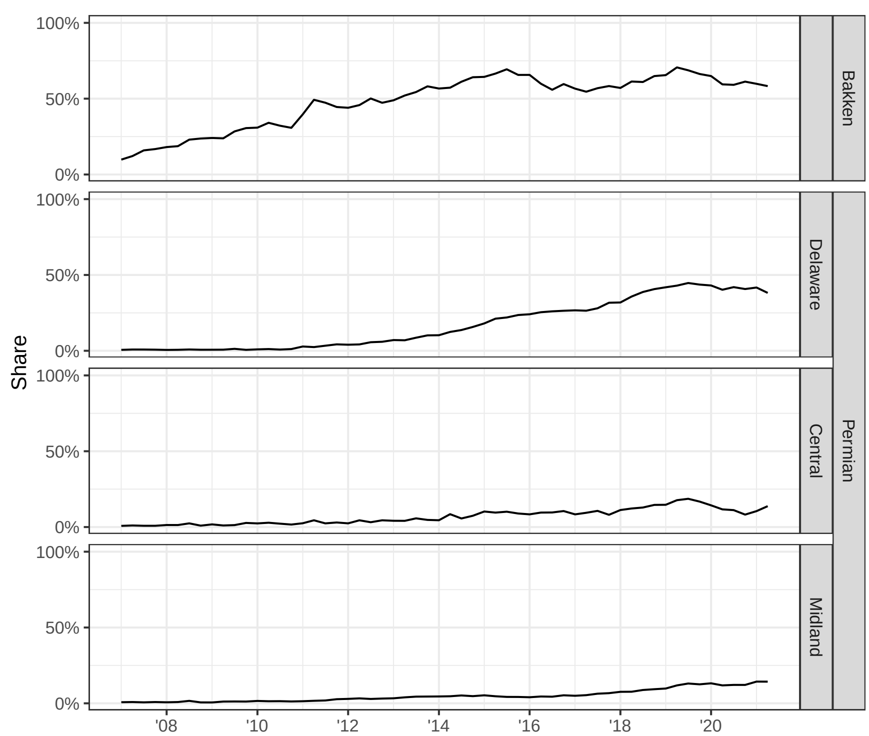

Figure 11: Probability a location flares something (vs all or nothing) each month

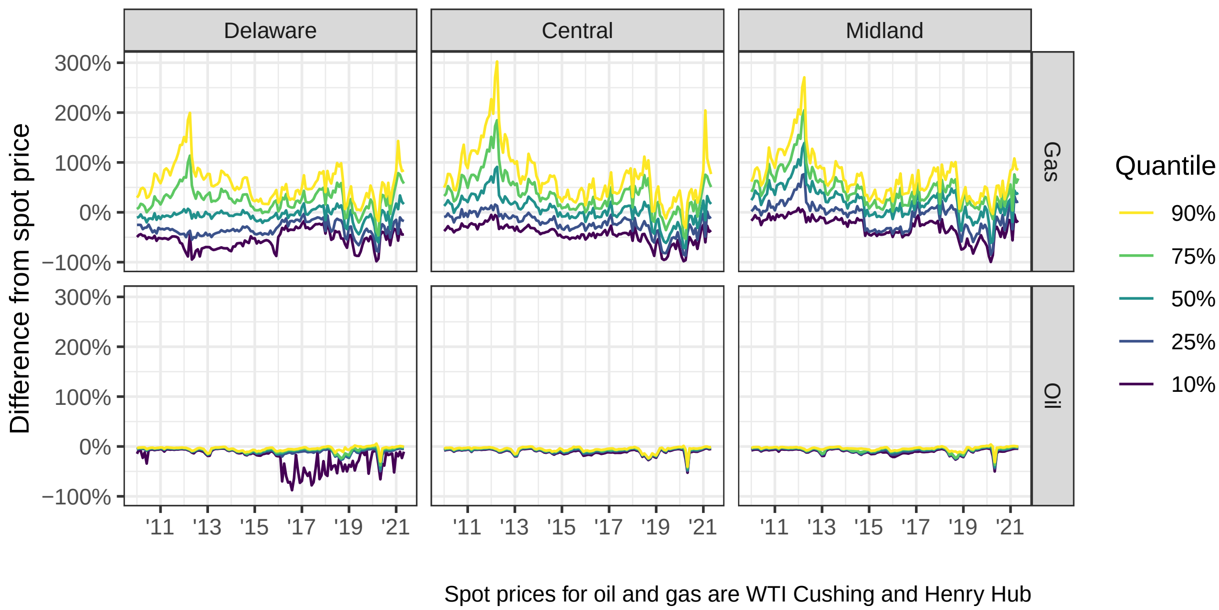

Figure 12: Distribution of difference between average monthly wellhead price and national benchmark

	Oil	Gas	Flaring		
	Quantity mmbbl/d	Quantity bcf/d	Quantity bcf/d	Rate %	Intensity mcf/bbl
			Bakken wells		
2007	0.02	0.02	0.00	0.22	0.22
2008	0.07	0.05	0.02	0.41	0.28
2009	0.14	0.10	0.03	0.27	0.19
2010	0.23	0.18	0.05	0.28	0.21
2011	0.35	0.32	0.12	0.38	0.35
2012	0.60	0.61	0.20	0.33	0.34
2013	0.79	0.86	0.26	0.31	0.33
2014	1.01	1.17	0.32	0.28	0.32
2015	1.12	1.50	0.26	0.17	0.23
2016	0.98	1.58	0.16	0.10	0.17
2017	1.02	1.81	0.22	0.12	0.21
2018	1.21	2.27	0.38	0.17	0.31
2019	1.38	2.83	0.54	0.19	0.39
2020	1.15	2.64	0.25	0.09	0.22
			Permian gas wells		
2007	0.01	2.04	0.01	0.00	0.78
2008	0.01	2.07	0.01	0.00	0.90
2009	0.01	2.00	0.01	0.00	0.70
2010	0.01	1.75	0.00	0.00	0.20
2011	0.01	1.46	0.00	0.00	0.31
2012	0.01	1.25	0.00	0.00	0.33
2013	0.02	1.21	0.01	0.01	0.44
2014	0.05	1.35	0.02	0.02	0.42
2015	0.10	1.60	0.07	0.04	0.69
2016	0.13	1.73	0.09	0.05	0.67
2017	0.19	2.21	0.07	0.03	0.38
2018	0.33	3.31	0.11	0.03	0.32
2019	0.47	4.51	0.12	0.03	0.27
2020	0.49	4.77	0.07	0.02	0.15
			Permian oil leases		
2007	0.18	0.47	0.00	0.00	0.00
2008	0.21	0.50	0.00	0.01	0.01
2009	0.21	0.55	0.00	0.00	0.01
2010	0.25	0.64	0.01	0.01	0.02
2011	0.33	0.81	0.01	0.02	0.05
2012	0.44	1.11	0.04	0.03	0.08
2013	0.53	1.41	0.06	0.04	0.10
2014	0.66	1.85	0.08	0.04	0.12
2015	0.79	2.23	0.09	0.04	0.12
2016	0.93	2.57	0.07	0.03	0.08
2017	1.27	3.25	0.09	0.03	0.07
2018	1.93	4.52	0.21	0.05	0.11
2019	2.47	6.11	0.31	0.05	0.13
2020	2.50	7.07	0.17	0.02	0.07

Flaring rate is mcf flared per mcf gas produced (e.g., share flared).

Flaring intensity is mcf flared per bbl oil produced.

Table 3: Annual oil production, gas production, and flaring for 2007–2020

D Climate cost calculations

Our flaring climate cost calculations follow Kleinberg (2019) closely. We obtain fluid densities and all conversions from open-source fluid properties library CoolProp (Bell et al. 2014). We take representative associated gas composition for the Bakken from Table S4 of the Supplemental Information of Brandt et al. (2016). Because the IAWG (2021) does not provide social costs of ethane, propane, or butane, we multiply the SCC by the 100-year GWP of these gases estimated in Hodnebrog et al. (2018). We assume that pentanes and hexane do not have any climate warming impacts. We assume that all gas volumes are measured at oil industry Standard Temperature and Pressure (STP), which is 60°F and 14.73psi (288.7K and 101.56 kPa). There are 28.32 m^3 per mcf.

Converting gas densities to social cost per mscf

	Density (kg/m^3)	Density (t/mscf)	100 yr GWP	CH_4e	SC Venting ($/mscf)
CO_2	1.873	0.0530	1		$2.70
CH_4	0.680	0.0193		1	$28.89
C_2H_6	1.283	0.0363	10.2		$18.90
C_3H_8	1.900	0.0538	9.5		$26.06
Iso C_4H_{10}	2.534	0.0718	6.5		$23.79
Normal C_4H_{10}	2.545	0.0721	6.5		$23.89

Social cost of combustion and venting

	Social Cost of Perfect Combustion			Social Cost of Venting		
	Carbon atoms	CO_2 generated (t/mscf)	Cost ($/mscf)	CO_2e (100 yr GWP)	CH_4e	Cost ($/mscf)
CO_2	1	0.0530	$2.70	1		$2.70
CH_4	1	0.0530	$2.70		1	$28.89
C_2H_6	2	0.1060	$5.41	10.2		$18.90
C_3H_8	3	0.1591	$8.11	9.5		$26.06
Iso C_4H_{10}	4	0.2121	$10.82	6.5		$23.79
Normal C_4H_{10}	4	0.2121	$10.82	6.5		$23.89
Iso C_5H_{12}	5	0.2651	$13.52	-	-	-
Normal C_5H_{12}	5	0.2651	$13.52	-	-	-
C_6H_{14}	6	0.3181	$16.23	-	-	-

Social cost of flaring and venting typical Bakken associated gas

	Mole fraction	SC Flaring ($/mscf)	SC Venting ($/mscf)
CO_2	0.007	$0.02	$0.02
CH_4	0.4924	$1.33	$14.22
C_2H_6	0.2103	$1.14	$3.97
C_3H_8	0.1509	$1.22	$3.93
Iso C_4H_{10}	0.0168	$0.18	$0.40
Normal C_4H_{10}	0.0506	$0.55	$1.21
Iso C_5H_{12}	0.009	$0.12	$0.00
Normal C_5H_{12}	0.0126	$0.17	$0.00
C_6H_{14}	0.0165	$0.27	$0.00
TOTAL	0.9661	$5.00	$23.76

Social cost of flaring and venting pure methane

	Mole fraction	SC Flaring (\$/mscf)	SC Venting (\$/mscf)
CH_4	1	\$2.70	\$28.89

Social cost of flaring given flare efficiencies and gas composition (\$/mcf)

Flare Efficiency	Bakken Mix	Pure methane
100%	\$5.00	\$2.70
98%	\$5.38	\$3.23
93%	\$6.31	\$4.54
0%	\$23.76	\$28.89

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