The Economics of Natural Gas Venting, Flaring and Leaking in U.S. Shale: An Agenda for Research and Policy*

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Abstract

Natural gas venting, flaring and leaking (VF&L) are closely intertwined environmental policy issues for U.S. shale oil and gas operations. In this paper, we lay out an agenda for researchers and policymakers. We describe why VF&L are closely related, both physically and in terms of policy. We perform an interdisciplinary literature review on measurement of VF&L. We marshal granular industry data to identify constraints in the natural gas system correlated with upstream VF&L. Motivated by this descriptive analysis, we discuss the economic reasons for VF&L and the market distortions that could exacerbate VF&L. We then discuss the external cost of VF&L. We calculate that reported 2015 and 2019 flaring and venting imposed climate damages of \$0.9 to \$1.8 billion and \$1.7 to \$3.4 billion. We calculate that climate damages of 2015 upstream U.S. methane emissions estimated by Alvarez et al.

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(2018) were \$16.8 billion. Finally, we discuss both existing policy and economic insights relevant to future policy.

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1 Introduction

In this paper, we lay out a research and policy agenda around natural gas venting, flaring and leaking (VF&L). We focus on VF&L associated with the extraction of oil and gas from U.S. shale plays. Few economic studies address VF&L, but the topic has become increasingly salient in policy debates around climate change.

Oil and gas wells produce a mix of hydrocarbons: methane (CH_4), natural gas liquids (NGLs), and crude oil. When producers are unable to economically capture and transport methane and NGLs to market, they can choose to *flare* (burn) them. Some gas is also intentionally *vented* (released) directly to the atmosphere (Office of Fossil Energy 2019). *Leaking* is the unintentional release of gas from equipment.[1]

Geological factors determine the mix of hydrocarbons that a well produces, but technology and economics determine what share of methane and NGLs are captured and sold, and what share are not. VF&L can occur throughout the natural gas system—from upstream wells, through midstream processing and pipelines, to downstream refining and distribution systems. Our analysis focuses exclusively on VF&L in the *upstream* segment, where recent studies find the majority of GHG emissions from VF&L occur (Alvarez et al. 2018).

Despite recent advances in measuring emissions, there is still significant uncertainty around the quantity of emissions from VF&L. We summarize the current state of the scientific literature in Section 2. Measuring emissions of methane and NGLs is a key area for research. Accurate measurements

[1] Legal distinctions between venting, flaring and leaking (VF&L) can vary across jurisdiction, but these definitions above are consistent with BLM (2016).

are critical to understand the scale and sources of emissions.

In Section 3, we discuss empirical patterns in reported flaring and venting, which are easier to measure than unreported venting and leaking. Understanding the physical causes of flaring can help inform both flaring *and* methane regulation. Flares release methane, and recent scientific evidence suggests that constraints that drive flaring may also drive venting and leaking (Lyon et al. 2020). Public data based on operator self-reports and satellite-based measurements both show that flaring by U.S. shale producers has increased for several years, at least until the Covid-19 pandemic. We show that flaring behavior is correlated with constraints at multiple points in the natural gas system.

We then turn to the economics of VF&L. In Section 4, we describe how market structures could exacerbate constraints that lead to VF&L and impact the effectiveness of policy. The empirical role of market structure in VF&L is an open question for research.

VF&L impose external environmental costs on society in the form of GHG emissions and local air pollution. In Section 5, we summarize what is known about these external costs and the remaining questions. We make a back-of-the-envelope calculation that reported U.S. upstream flaring and venting in 2019, a peak year, generated \$1.7 to \$3.4 billion in climate damages, about half to one percent of the value of U.S. oil and gas production.[2] In widely cited study, Alvarez et al. (2018) estimate 2015 methane emissions from the U.S. upstream oil and gas industry, which has since increased production. Applying a 2020 social cost of methane (SCM), we find that 2015 methane emissions would generate \$16.8 billion in climate damages—an order of magnitude larger than damages from flaring. Thus, policymakers and researchers looking to understand environmental impacts of oil and gas operations should expand focus beyond reported flaring and venting.

Finally, we turn to policy in Section 6. The capability of measurement technology influences policy options. Where standard market-based instruments are more appropriate for flaring, command-and-control policies and

[2]This estimate excludes unreported venting and leaking and downstream emissions. We explain our calculations in Section 5.

mechanisms for Non-Point-Source (NPS) pollutants may be more appropriate for venting and leaking. We discuss how market institutions and emerging monitoring technology lead to new theoretical and applied policy questions that are relevant outside of VF&L.

Note: we assume readers have a basic understanding of the oil and gas industry, including the *upstream*, *midstream* and *downstream* components as well as the difference between oil, natural gas, and associated gas. Appendix A provides a brief review of the industry and relevant terminology in the context of this paper.

2 Quantifying and Monitoring Emissions

There is uncertainty about the quantity of VF&L in the upstream sector as a whole. Multiple types of data can be used to directly estimate VF&L at a national or regional level. None are comprehensive, and the coverage of each is different. Measurement of methane emissions from oil and gas production is an active area of scientific research, and we review a few key methods and findings.

2.1 National and global estimates

One source of data on venting and flaring is based on operator self-reports. State and federal regulators require operators to report the quantity of gas (methane plus NGLs) vented and flared. Operators generally do not report venting and flaring separately.[3] They are also not required to report all venting and flaring. For example, Texas does not require operators to report venting from tank vapors or valves, or flaring and venting associated with drilling and completion.[4] All are important sources of emissions (Allen et al. 2013; Alvarez et al. 2018; Caulton et al. 2014; Lyon et al. 2016; Zavala-Araiza et al. 2017). Leaking, even if detected, is not typically reported.

For perspective, a global industry association report based on voluntary, self-reported data states that flaring accounted for one quarter of both up-

[3] New Mexico is an exception to this.

[4] 16 Tex. Admin. Code §3.32

stream CO_2 and methane emissions in 2019; venting contributed 51 percent of methane emissions, and leaks, 17 percent (IOGP 2020).[5] These estimates may not be representative of U.S. upstream shale production, but we reference them to give a sense as to the relative importance of venting, flaring, and leaking.

Both shale gas production and flaring have increased markedly over the past two decades. Using data compiled from oil and gas regulators, the EIA estimates that upstream producers flared or vented 538 billion cubic feet (bcf) of natural gas in 2019. This represented 1.3 percent of U.S. gas production. If the gas vented or flared in 2019 were instead used to generate electricity, it would have been enough to power 7 million households for a year.[6] The majority of U.S. flaring currently takes place in two oil-directed shale plays: the Bakken Shale and Permian Basin.[7] Figure 1 shows the relationship between oil production and reported flaring and venting in both areas.

Satellites are one way to perform top-down measurement of global VF&L. 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). Using VIIRS, the World Bank estimates that the U.S. flared 611 billion cubic feet in 2019 (World Bank 2019). Over the period 2015–2019, the U.S. flared the third highest volume of any country ($\approx$8.4 percent of global flaring). It should be noted that World Bank estimates include midstream and downstream flaring but exclude venting and leaking. In contrast, EIA estimates come from firm-level self-reports of upstream venting and flaring together. 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). The satellite improves on earlier methane-sensing instruments, but estimates are more reliable when aggregated over space and time. While regional estimates

[5] Venting in these estimates includes emissions from valves, tanks, and other equipment that are not included in self-reported venting to U.S. state regulators.

[6] Calculation based on a heat rate of 7,000 BTU/kWh. Average residential households used 10,968 kWhs in 2018 (EIA).

[7] See map in Figure 6

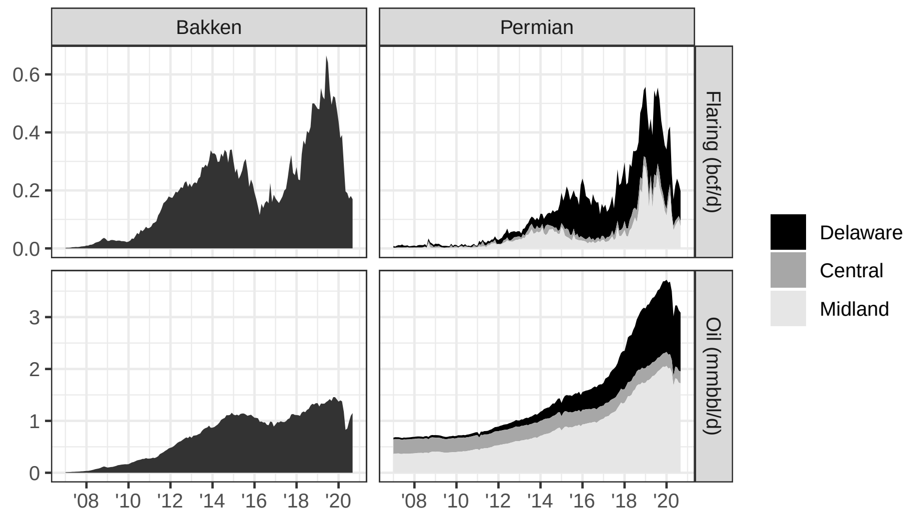


Figure 1: Flaring, venting, and oil production in the Bakken and Permian. The top panels use data reporting flaring and venting together.

can also be made with other remote sensors mounted on towers, aircraft, or vehicles, these surveys tend to be over limited time-spans and areas.

A third source of data on methane emissions at a national level comes from bottom-up studies. These typically apply fixed emissions factors to estimated inventories of component types and processes in operation at production sites in a given year (National Academies of Sciences 2018). Bottom-up approaches like the US EPA Greenhouse Gas Inventory or Greenhouse Gas Reporting Program are often used by policymakers.

Top-down estimates of methane emissions have historically exceeded bottom-up estimates, but recent studies have worked to resolve these differences (Alvarez et al. 2018; de Gouw et al. 2020; Zavala-Araiza et al. 2015b). These studies point to two issues in 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 nature of methane emissions and "super-emitters." Two changes have helped align bottom-up and top-down estimates: augmenting inventories, satellites, and aerial surveys with facility-scale measurements using ground-based remote sensing equipment, and modeling the right-tailed distribution from individual components.

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 to the atmosphere. The authors attribute 60 percent of methane emissions to the upstream sector and another 20 percent of emissions to the gas gathering system. They construct estimates from ground-based, facility-scale measurements in areas accounting for about 30 percent of U.S. gas production, and they validate these with aircraft observations. While Alvarez et al. (2018) do not survey the Permian, Schneising et al. (2020) and Zhang et al. (2020) do in 2018 and 2019. These newer studies calculate that 3.7 percent of Permian methane produced was vented or leaked from production, gathering, or processing.

Studies show that a large share of detected emissions come from a small number of intermittent sources that emit large quantities in absolute terms (Lyon et al. 2015; Omara et al. 2016; Robertson et al. 2017; Tyner 2020). Zavala-Araiza et al. (2017) attribute the majority of methane emissions from the oil and gas industry to absolute “super-emitters”. Super-emitters can also be defined in relative terms because 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, and that policies targeting these “functional” rather than absolute super emitters will lead to greater emissions reductions.

The fact that a smaller number of super-emitters likely account for the majority of emissions does not necessarily imply low methane 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. Also, remote sensing technologies have minimum detection thresholds, so relying on one technology alone can distort measured emissions. There is no one size fits all monitoring solution, and a portfolio of monitoring technologies may be most effective for monitoring emissions (Fox et al. 2019; Harriss et al. 2015; Tyner 2020).

Economic factors are also important to consider in analyzing VF&L. Lyon et al. (2020) find that methane emissions rates in the Permian Basin fell from 3.4 percent to 1.5 percent in 2020 when oil prices and production dropped during the Covid-19 pandemic. The authors hypothesize that higher system pressures lead to VF&L. 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. 2020). Newer producing regions with higher ratios of production to infrastructure capacity also have larger emission rates.

More research is needed to identify systemic causes of right-tailed emissions events and to understand the causal links between capacity constraints, methane emissions, and flaring. Causal inference methods from economics may particularly useful here. Allocating emissions to firms and locations poses an additional statistical challenge for regulation that involves monitoring with satellite data, which are noisy at finer spatial and temporal scales. Finally, statistical work to integrate multi-scale measurements is needed. Recent work in machine learning and machine vision suggests promise in predicting leak probabilities in order to rank sites for inspection (Wang et al. 2020).

3 Physical causes of flaring

In this section, we describe the empirical behavior of reported flaring and venting to explain the market conditions and constraints that lead to flaring. We use 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. Most recent flaring activity has occurred in these two areas. See

Appendix B for a description of data sources.

For ease of exposition, in this section we use the term "flaring" to refer to jointly reported venting and flaring. We, like Lade et al. (2020), assume that most self-reported vented and flared volumes are intended to be flared. We focus our empirical discussion on reported flaring for three reasons. First, as discussed above, comprehensive data on methane emissions at a well level simply do not exist. Second, inefficient and unlit flares emit methane, so flaring reductions are relevant for methane abatement. Third, venting and leaking are likely to 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 *economic decisions* that profit-maximizing firms make given physical and regulatory constraints. There are (at least) two economic decisions driving flaring as described below. First, firms 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 in a location, or they can invest in capacity to capture the gas instead of flaring it. Capturing the gas requires investment in a suite of infrastructure and services beyond what is required for oil: onsite equipment, local gathering lines to collect gas from wells, processing plants to strip out heavier hydrocarbons, and long-haul transmission to carry the gas to market. Our empirical observations in this section suggest that eliminating flaring requires addressing multiple issues in the upstream and midstream.

3.1 Unconnected wells

Flaring comes from two groups of locations:[8] locations that sell *and* flare gas in the same quarter, and locations that flare *all* of the gas produced in a quarter. Of the locations that flare *all* gas, some have *always* flared every-

[8]In North Dakota, firms report flaring for each well. 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.

thing; others have previously sold gas. We assume that locations which have never sold gas flare for lack for gathering infrastructure. Locations which have previously sold any gas are almost certainly connected to gathering infrastructure.[9] These producers have chosen to build gathering infrastructure and pay for midstream services. They flare because either gas production is greater than the midstream capacity these producers have secured, or it is not profitable to capture all the gas.

Figure 2 shows that locations which flare most or all gas actually contribute less than half of all flaring for most quarters. Instead, the majority of flaring today comes from wells which also *sell* much of their gas. In fact, the majority of flaring in recent years happens at leases which sell at least 25 percent of their gas.

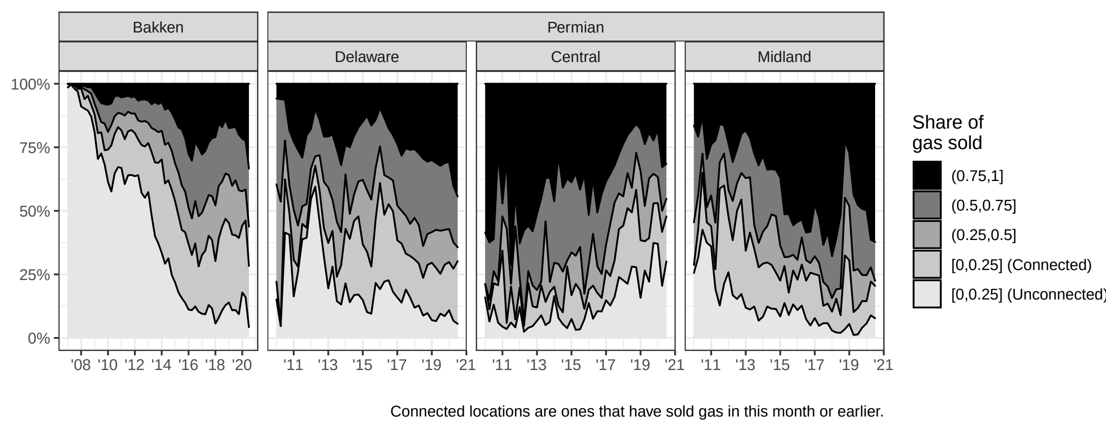


Figure 2: Share of total gas flared by how much production the well or lease sells in the same quarter

Conclusion 1: The majority of recent flaring happens at wells that also *capture* much of their gas. The time lag between first production and installation of gathering infrastructure does not explain most flaring. VF&L

[9]That said, we are unable to identify whether the individual wells on a each lease are physically connected to gathering.

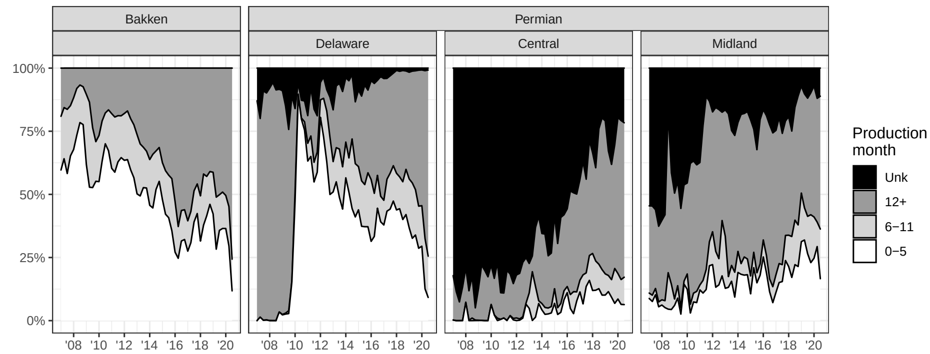


Figure 3: Share of total flaring by number of months location has produced

is not simply an issue of connecting wells to gathering.[10]

3.2 Older Leases Connected to Gathering

Shorter lags in connecting new wells to gathering, especially in the Bakken and Delaware region of the Permian, correspond to a another trend shown in Figure 3. The plot shows that over time, an increasing share of flaring occurs at older locations that have produced for more than a year. Production from shale wells declines quickly over time, so we surmise that despite efforts to connect new wells to gathering faster, investment in midstream infrastructure further down the value chain has been insufficient to relieve constraints.

Periodic congestion along different segments of the midstream can cause connected locations to sell *and* flare gas in the same month. If production exceeds gathering, processing, or transmission capacity, some oil wells must flare associated gas in order to keep producing. Congestion and, therefore flaring, would then be intermittent. As shown in Figure 7 in the Appendix, we find the probability of a location flaring *some* gas (versus all or none) has increased over time—even if the well flared all or no gas in the previous

[10]While Lade et al. (2020) do cast Bakken flaring as an issue of connecting wells to gathering, their analysis is restricted to 2007–2016 when connection to gathering was a more important factor in causing flaring.

month. This is consistent with a Q4 2019 survey of oil and gas producers by the Federal Reserve Bank of Dallas: 49 percent of respondents cited capacity constraints in gathering and processing as a reason for flaring (Federal Reserve Bank of Dallas 2019).

Conclusion 2: The share of flaring from wells producing for at least one year has increased, and the probability of flaring some gas (versus all or nothing) has increased over time. This is consistent with intermittent congestion in the midstream sector—gathering, processing, and transmission.

3.3 Processing constraints

Before natural gas is shipped along a transmission pipeline, it must be separated from heavier hydrocarbons at a gas processing plant. Insufficient processing capacity, like insufficient gathering capacity, can cause connected wells to flare. This has been especially important in the Bakken (DOE 2014).

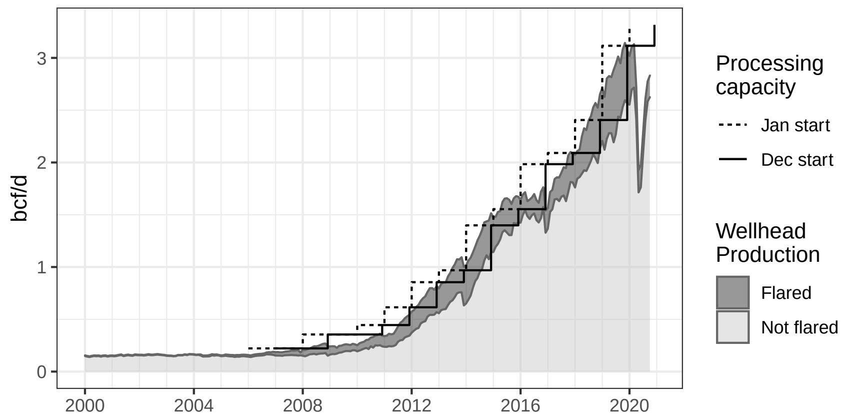
Figure 4 plots gas processing capacity and utilization in the Bakken. Gas processing has barely kept up with production. In fact, production has exceeded processing capacity several times. Because production and processing are spatially differentiated, spare capacity in one area may not be accessible to constrained producers in another.

Conclusion 3: Insufficient natural gas processing has likely contributed to flaring.

3.4 Transmission constraints

Once processed, natural gas enters on long-haul transmission pipelines that go to market. Insufficient transmission capacity has likely caused some flaring, particularly in the Midland region of the Permian.

The bottom pane of Figure 5 shows the difference between the nationally representative spot price for natural gas (Henry Hub) and the spot price in



Plant capacity assumes capacity is online in either January
or December of year indicated. Sources: NDIC and NDPA.

Figure 4: ND gas processing capacity barely kept pace with ND gas production

the Midland gas hub (Waha). The difference reflects the scarcity rent associated with transmission out of the Permian. When demand for transmission threatens to outstrip supply, scarcity rents rise to clear the market (Agerton et al. 2019). While not shown in this figure, scarcity rents actually rose so much in 2019 and 2020 that Waha gas prices were negative. The top pane of Figure 5 shows Permian flaring over time, broken down by region. There is a clear correlation between transmission scarcity rents and Midland flaring. Flaring appears to function as a "relief valve" for excess transmission demand. In contrast, Delaware flaring started increasing in 2015, well before transmission constraints emerged.

Conclusion 4: Insufficient long haul transmission capacity has likely caused some amount of flaring.

4 The economic choices in VF&L

Section 3 highlighted physical constraints that cause reported venting and flaring, and likely also unreported venting and leaking. Some of these con-

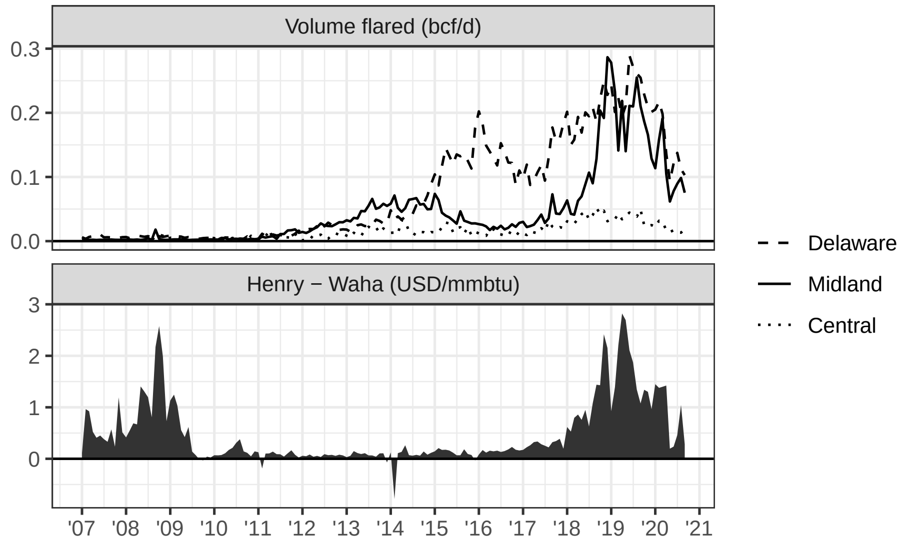


Figure 5: Flaring in the Permian and natural gas basis differentials

straints may be transitory issues, but some may be the result of persistent economic incentives. In this section, we describe the incentives that could lead gas production to exceed infrastructure capacity and then be intentionally vented or flared. As in Section 3, we use “flaring” to refer to reported venting and flaring.

Natural gas is a valuable good. Firms only flare or vent it if the cost of not doing so is greater than its market value. The cost of not flaring or venting gas may include delaying production; installing new equipment; and gathering, processing, and transporting the gas.

Flaring likely makes more economic sense during the initial years that a play is developed. Firms face significant uncertainty when they make initial investments in new wells and midstream infrastructure. With new geology or new technology, firms do not know how much they will produce or what size infrastructure they will need. It can be valuable to flare associated gas, delay midstream investmentment, and maintain the real option to build infrastructure once more information has been revealed. Additionally, production from new shale wells declines quickly. It may not make economic sense to build capacity sufficient to handle peak initial production because this large capacity will not be fully utilized once production declines. 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.

In the *long run*, if the prices of midstream services exceed the marginal cost of supplying them, then producers may VF&L too much, even absent external costs. In this case, marginal producers will underinvest in infrastructure. They will capture too little gas, even though the value of the gas is less than the marginal cost of capturing. Conversely, if midstream services are priced too low, midstream firms will lack underinvest in capacity, leading to more VF&L. A key question for economic policy is, *are prices for midstream services low enough to encourage capturing gas, and high enough to incentivize investment?*

Two observations are consistent with the possibility 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[11] exhibit large variation around national benchmarks, even within a small spatial area. In contrast, wellhead oil prices display little dispersion: they are tightly clustered around the national benchmark. While some of the variation in wellhead gas prices across wells is probably due to differences in the NGL content of the gas, some could also be due to variation in the price of midstream services.

4.1 Pipeline cost-of-service regulation

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

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

Energy Regulatory Commission (FERC) regulates interstate pipelines and transmission rates to ensure pipeline owners achieve revenue adequacy but do not earn monopoly rents. States regulate intrastate transmission and generally follow the same regulatory methodology as FERC.

A firm regulated under a the 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 VF&L, 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 vent or 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.

4.2 Fixed costs and uncertainty about the future

In contrast to transmission, gathering is priced based on private agreements. As with transmission, building gathering infrastructure requires an upfront fixed costs. Firms hope to recover these plus a rate of return over time. Upfront fixed costs can present difficulties in pricing midstream services. Prices must provide sufficient revenues for midstream services to cover long run average costs, but they should not discourage marginal producers from gathering.

The challenge of recovering long-term fixed costs with per-unit charges is endemic to regulated utilities (Borenstein 2016; Braeutigam 1989). Unlike utilities, the economics of a specific oil field can change quickly. Uncertainty in prices and gas volumes exacerbates the difficulty of pricing midstream services to achieve both efficiency—transporting all gas with a value higher than the marginal cost of transportation—and revenue adequacy.

In general, midstream firms build infrastructure and charge the producer per unit of gas shipped. To reduce risk, midstream firms often require that producers dedicate their acreage to a firm's gathering system. An *acreage dedication* is a long-term commitment by the producer to ship all gas produced in an area through a firm's gathering system. The agreement limits the risk to the midstream firm that the gas producer ships (or threatens to ship) gas with a competitor.

Even with acreage dedications, midstream companies still face uncertainty about the quantity of gathering services that producers will demand. Should the price of oil fall relative to what midstream firms forecast, lower demand for gathering can lead to a revenue shortfall.[12] Thus, risk-averse midstream firms may raise prices above expected long-run average cost to ensure they can recoup their investment should oil prices and gathering demand drop.

Similar contractual arrangements also attempt to reduce risk for gas processing, but the fundamental issue of lumpy investments and uncertainty can lead to a mismatch between natural gas production and infrastructure capacity, especially in the short-to-medium term as a new area is developed.

4.3 Flaring, Bargaining, and Competition

Because gathering is spatially differentiated, competition between gathering companies at a specific location may be limited. Gathering prices are not regulated as transmission rates are. Congestion can create isolated submarkets and exacerbate lack of spatial competition, as is the case in electricity markets (Borenstein et al. 2000). Under limited competition, midstream firms may be able to mark up prices for their services. In this case, flaring acts like an additional midstream competitor: should negotiations with a midstream provider break down, producers can flare for a minimal cost instead of shutting in their wells. The option to flare reduces midstream firms' bargaining power.

A recent dispute in Texas between producer EXCO Resources, Inc. and midstream firm Williams Companies suggests that midstream firms can in

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

some cases have significant pricing power (*Proposal for Decision: EXCO vs Williams* 2019). The dispute centered on whether the regulator would permit EXCO to flare gas worth $45 million, even though EXCO's wells were physically connected to Williams' infrastructure. Williams advocated that EXCO be forced 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 value of the gas. Logically, a competitor to Williams would be unlikely to build alternative gathering infrastructure: Williams' infrastructure is a sunk cost, and Williams would likely undercut any new entrant. In its ruling, the regulator sided with EXCO, preserving producers' option to flare and avoiding enhancement of midstream pricing power.

Contracting frictions and midstream market power can, in theory, lead to inefficiently low gas capture rates and excess VF&L. 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 VF&L in important ways.

5 External costs of VF&L

VF&L generate two types of pollution: global greenhouse gases and local air pollutants. While the previous section focused on distortion of *private* incentives in the midstream sector, we now focus on health and environmental damages from VF&L emissions. These damages are non-market, *external* costs. A key question for researchers and policy-makers is, *what is the external cost of pollution from VF&L?*

We first focus on the associated climate damages caused by VF&L. Producers can reduce VF&L by capturing gas. However, if the alternative use of the gas, such as power generation or residential heating, emits equivalent GHGs, VF&L reductions might have limited net climate benefits.[13] This is

[13]In reality, this is more nuanced as there are several other margins of adjustment. For instance, some wells simply might not be drilled, reducing the supply of oil and natural gas nationally. Upward pressure on prices would reduce usage. On the other hand, if reductions in VF&L on net increases the natural gas supply as firms are incentivized to bring that gas to market, this could in theoretically reduce natural gas prices therefore

unlikely for three reasons.

First, when vented or leaked into the atmosphere, methane and other NGLs are more powerful greenhouse gases than the CO_2 generated by combusting them. The 2020 federal social cost of carbon is \$51/ton under a 3 percent discount rate, but the social cost of methane is much higher: \$1500/ton (Interagency Working Group on Social Cost of Greenhouse Gases 2021). The 100-year global warming potentials of NGLs butane, ethane and propane are also 7 to 10 times greater than CO_2 (Hodnebrog et al. 2018), so their associated climate damages are higher than those of CO_2.

The second and third reasons apply specifically to flaring. Flares in the wild are not fully efficient. Environmental conditions can reduce flare efficiency (Johnson et al. 2002; Leahey et al. 2001; Strosher 2000), and flares can fail to light. 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 (Environmental Defense Fund 2020). This is higher than the two percent estimate used in government GHG inventories (US Environmental Protection Agency 1996). Finally, much of the flared gas associated with oil production contains NGLs. When combusted, NGLs generate more CO_2 than an equivalent volume of methane. NGLs are key feedstocks in the petrochemical industry and could be converted into plastics and other materials instead of being flared or vented.

As discussed in Section 2, recent scientific measurements of U.S. upstream methane emissions tend to be limited to a particular time and place, so it is difficult for us to compare them or form precise annual estimates of the associated climate damages of VF&L. Nevertheless, we believe it is important to communicate the general scale of these damages. Quantifying a more comprehensive external cost of VF&L is an important topic for future research and policy proposals.

We tackle reported flaring and venting first. Table 1 shows how NGL content and flare efficiency affect the external cost of flaring, a point made by Kleinberg (2019). Using the latest Federal social cost of GHG estimates, we

impacting power dispatch decisions. These effects are beyond the scope of this discussion.

Table 1: Climate damages 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.

calculate that flaring pure methane at the EPA-assumed 98 percent efficiency generates climate damages 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 a representative associated gas mixture in the Bakken results in higher climate damages than flaring pure methane. Under the real-world Permian flare efficiency of 93 percent found by EDF, flaring Bakken gas imposes climate damages of $6.31/mcf.

Using these marginal climate damage 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 damages in 2015. This figure rises to between $1.7 and $3.4 billion in climate damages in 2019, or about half to one percent of the value of U.S. oil and gas production that year.[14] These damages exclude unreported venting and leaking and downstream emissions. We note that reported flaring and venting fell in 2020.

Methane's potency as a GHG makes climate damages from upstream methane emissions larger than damages due to flaring. Alvarez et al. (2018) estimate that in 2015 the sector emitted approximately 11 million tons of methane. Applying the latest Federal SCM of $1500/ton, this yields climate damages of $16.8 billion—an order of magnitude larger than our estimate of climate damages from reported flaring and venting that year. Updated estimates comparable to Alvarez et al. (2018) are not available for 2019,

[14] To compute the value of oil and gas 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 oil and gas production in 2019 rise to $257 and $106 billion.

and we note that supply conditions differed between years. U.S. oil and gas production in increased by 30 percent and 24 percent from 2015 to 2019. The Permian and Bakken produced a larger share of oil and gas and have higher flaring rates. Zhang et al. (2020) and Schneising et al. (2020) find that methane emission rates in the Permian basin during 2018–2019 are approximately 60 percent higher than the national estimate reported by Alvarez et al. (2018).

In addition to GHGs, VF&L emit EPA-designated criteria pollutants such as nitrogen dioxide, sulfur dioxide, carbon monoxide, and volatile organic compounds (VOCs) (EPA 2019; Office of Fossil Energy 2019). The effect of VF&L on local air quality depends on a variety of factors that vary over time and space. Local pollutants have been detected in flared gas (Johnson et al. 2000; Johnson et al. 2011; Kindzierski 2000; McEwen et al. 2012; Stohl et al. 2013; US Environmental Protection Agency 2018), but the presence and amount of a given pollutant depends on many factors (Buzcu-Guven et al. 2012). Existing studies on flaring and local air pollution focus on smaller samples (Fawole et al. 2016, 2019; Kostiuk et al. 2004; Strosher 1996; Strosher 2000). More work can be done to construct inventories of emissions for major producing basins. Moreover, the *external cost* of these emissions depends on health impacts in nearby communities, another topic that warrants further study.

There is still much to be done in order to value VF&L externalities. This is challenging for several reasons. At a basic level, there is uncertainty about the quantity of VF&L. Flare efficiencies and the composition of flared gas vary across wells; both factors affect the climate damages from flaring. Health damages from VF&L depend on the composition of flared gas, as well as weather conditions and proximity to population centers. Finally, when evaluating the benefits of VF&L abatement, it is important to consider the external costs of the alternative use of the gas. If the alternative is simply not extracting the gas, the external damages are zero. However, if the gas is captured, it is likely to be combusted and could be leaked.

6 Policy options for VF&L

While Section 5 provides a sense of the magnitude of the external costs of VF&L and the challenges in quantifying them, we now give an overview of current policies and discuss an agenda for future VF&L policy research.

6.1 Current VF&L policies

Texas and North Dakota require firms to obtain flaring permits and report most volumes. While flaring permits in Texas specify how much a well is allowed to flare, there are no statutory limits on statewide flaring volumes. Firms are also allowed to vent for 24 hours at a time during specified events such as upset conditions or liquids unloading, and are not required to report venting from exempt categories such as drilling, completion, or tank releases.[15]

The North Dakota Industrial Commission (NDIC) implemented new flaring and venting regulations in 2014. NDIC Order 24665 required firms to submit a gas capture plan and established a series of 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. North Dakota operators that did not meet gas capture targets would be required to curtail production. The order allows the first well in a Bakken spacing unit to flare unlimited quantities. Subsequent infill wells can flare unlimited quantities for 90 days, and are then subject to the gas capture targets. Bakken oil production and flaring both increased after 2014. In September 2015 the NDIC revised the 2016 target downward (NDIC 2015). In April and November of 2018, the NDIC amended the order again to exempt more wells, and it created further allowances for flaring (NDIC 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 2 in Appendix C).

Both Texas (Texas Comptroller 2021) and North Dakota impose severance taxes on oil and natural gas brought to market, but not on gas released

[15] 16 Tex. Admin. Code §3.32

through VF&L. In North Dakota, producers pay no severance taxes or royalties on the first year of captured or flared gas, with non-Bakken wells allowed to flare for up to one year (ND HB 1134 2013). Taxes and royalties lower the profitability of capturing gas, and may tip marginal wells to flare instead. One policy consideration would be to equalize the tax treatment of VF&L versus captured gas.

Most existing 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 highly prescriptive LDAR and emissions control technology standards[16]. However, the rule was never fully implemented before it was challenged in court and ultimately replaced with a less stringent policy[17]. Colorado and Pennsylvania also have stringent upstream and midstream requirements for LDAR and methane emissions reporting. While LDAR can decrease the amount of leaking, it may not reduce emissions from flaring or venting and does not provide continuous monitoring or emissions quantification.

6.2 Market-based policies

We now discuss how some standard economic policy instruments could apply or have applied to VF&L. A standard economic solution for the external costs of VF&L would be to give firms a market signal of the external costs through either a Pigouvian tax or a tradeable permits program. Both Lade et al. (2020), writing on North Dakota's Bakken shale, and Johnson et al. (2012), writing on oil production in Alberta, Canada, find that moderate flaring prices could reduce flaring by an economically significant amount.

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). Finally, markets for "responsibly sourced" or "green" gas are being discussed (Krupnick et al. 2020). These

[16] 40 CFR 60 OOOOa
[17] 85 FR 57018, 85 FR 57398

markets would allow producers with minimal VF&L and environmentally responsible practices to differentiate their gas and receive a price premium.

Monitoring and attribution of VF&L could pose significant challenges for market-based instruments. Instruments would need to differentiate between flaring and methane emissions since the external costs of each are different. In principle, a fully efficient policy would account for how external costs differ by location and gas composition.

6.3 Monitoring

Pigouvian taxes, tradeable permits, and portfolio standards would all require that regulators accurately monitor VF&L by each firm. As highlighted in Section 2, measurement is challenging. Firms currently self-report venting and flaring to regulators. Self-reporting schemes can economize on government auditing resources and reduce the firm's risk by replacing large, uncertain fines for noncompliance with certain smaller fines when violations are reported (Kaplow et al. 1994). However, self-reporting schemes also enable mismeasurement and misreporting. Whether self-reporting results in an accurate account of venting and flaring can depend on the costs of auditing and imposing fines, the stringency of the policies in place, and the accuracy of monitoring technology (Malik 1993). Further, leaked volumes are often not known, and even if known are not typically reported.

Remote sensing is a promising avenue for monitoring VF&L at scale. However, each remote sensing technology has its own temporal and spatial sampling capabilities and minimum detection thresholds, so different technologies are needed for different applications (Fox et al. 2019; National Academies of Sciences 2018). There are additional limits to current remote sensing technology. Over-flights are expensive. Satellite measurements become more accurate when aggregated over space and time, but atmospheric noise and ground-level conditions limit their ability to attribute emissions to individual firms. This is particularly true when wells from multiple operators are relatively close together as they are in the Permian and the Bakken. More research is needed to understand how remotely sensed VF&L measurements can be optimally incorporated into the design and enforcement of VF&L policies.

The rich economic literature on *non-point-source* (NPS) pollution is a promising source of VF&L policy ideas that integrate remote sensing technology. This literature studies regulatory mechanisms when monitoring and attribution are costly (Kotchen et al. 2020; Xepapadeas 2011), as is the case with VF&L. For example, NPS mechanisms would suggest VF&L could be regulated by taxing observable inputs or outputs, by fees on regional ambient emissions detected through remote sensing, or by 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 that could inform NPS mechanism design. The answer depends 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 firms' emissions.

7 Conclusion

Venting, flaring and leaking (VF&L) are significant and closely intertwined environmental policy issues for U.S. shale oil and gas operations. In this paper, we provide an interdisciplinary literature review and marshal granular data to identify constraints in the oil and gas value chain that cause upstream VF&L. Our empirical observations suggest that constraints at multiple points in the natural gas value chain can all cause emissions from upstream operations. Thus, policies aimed at mitigating VF&L should consider the entire system, not just upstream producers.

We highlight several areas where economists can contribute to VF&L research. First, causal inference methods can help identify why VF&L occurs. Second, interdisciplinary research is needed to understand the external cost of VF&L. Third, economic research can help inform what regulation and policy will be effective, particularly under imperfect monitoring. Researchers should be aware of how existing market distortions in the oil and gas industry, such as contracting frictions for midstream services, can exacerbate VF&L and potentially interact with VF&L policy in unexpected ways.

We conclude with a call for future work in this area to be interdisciplinary. In understanding VF&L, it is necessary to understand the physical infrastructure that moves hydrocarbons from underground reservoirs to final consumers, scientific efforts to quantify emissions, and the economic incentives created by market and regulatory structures.

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A Industry Background

We present some basic terminology commonly used in the oil and natural gas industry that is needed to understand flaring and venting (VF&L). We recommend a review of this terminology, especially for readers not already familiar with the supply chain in the oil and natural gas industry.

Oil, natural gas, and associated gas Oil and gas wells can both produce multiple of hydrocarbons. The shortest hydrocarbon is methane, CH_4 (natural gas). With additional carbon and hydrogen atoms, the molecule becomes longer and heavier.[18] At atmospheric pressure and temperatures, shorter hydrocarbons are in a gaseous state, while longer hydrocarbon chains, including crude oil, 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 usually 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 technical designations can change across state lines, generally speaking oil wells are drilled for the economic purpose of extracting oil, while the opposite is true for 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. 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.

Leases and wells The difference between a *lease* and a *well* is key distinction for understanding upstream oil and gas reporting data. 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 physically 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.

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

In the context of oil and gas reporting 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 state 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.

Upstream, midstream and downstream Like all industries, the oil and gas industry is a value chain. The value 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.[19]

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. There are approximately 500 natural gas processing plants in the United States (EIA 2019). Once processed, natural gas is transported on a long-haul transmission line to carry it from the producing region to demand centers.

Flaring, Venting and Leaking Emissions occur from both production processes and equipment types, and can be intentional or unintentional. Examples of equipment sources of methane are storage tanks, compressors, and a vast number of small sources such as valves and controllers, from which many small or medium-sized leaks might comprise a significant share of aggregate emissions.

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

Unlike leaking equipment, some emitting activities—*venting*—are intentional and part of normal operations. "Liquids unloading" is an occasional procedure to remove liquids that are trapped in the well, and 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 facturing 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, but as a consequence a mix of methane and other hydrocarbons escape.

Reduced emissions completions (RECs) or "green completions" describe a process for separating gas during completion flowback using specific equipment to capture and sell the gas. 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, VF&L, and midstream infrastructure. We compute a number of descriptive statistics to investigate the constraints along the value chain that may cause VF&L at the well. We obtain data from state regulatory agencies' websites and public records requests in North Dakota and Texas, as well as two commercial vendors, Enverus and MapSearch.

Bakken In North Dakota, oil and gas production are reported to the North Dakota Industrial Commission (NDIC) at the well level. For each well, information about the well's location, date of drilling, date of completion, and monthly production are observed. 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 causing venting (NDAC 2000).

We then merge NDIC data to drilling and production records from Enverus and excluded 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 Bakken play area as defined by Enverus.

Permian In Texas, oil and gas producers report production to the Texas Railroad Commission (RRC). Natural gas wells report production, and venting and flaring, at the well level. Production from oil wells is reported at the lease level. While leases often contain multiple oil wells of different ages, the wells are located within the same geographic area. As with 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.[20]

We merged RRC production records to data from commercial provider Enverus to obtain information on the wells, locations, and completions associated with each production record. Because 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 wells spatially located within the Permian Basin as defined by Enverus. The Texas Comptroller's office also requires firms to report well or lease-level information on the monthly volume and value of oil and gas sold. Enverus matches Comptroller sales data at the well or lease level to RRC data on the production, and we also merge this information to our Texas production information. Sales data measure the value of oil and gas 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.[21] We then calculated the distance from each Texas well to the nearest natural gas gathering pipeline for both years. For both

[20] 16 Tex. Admin. Code §3.32

[21] 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.

Texas and North Dakota wells, we also calculated the distance from each well to all gas processing plants within 50 km.

C Extra figures

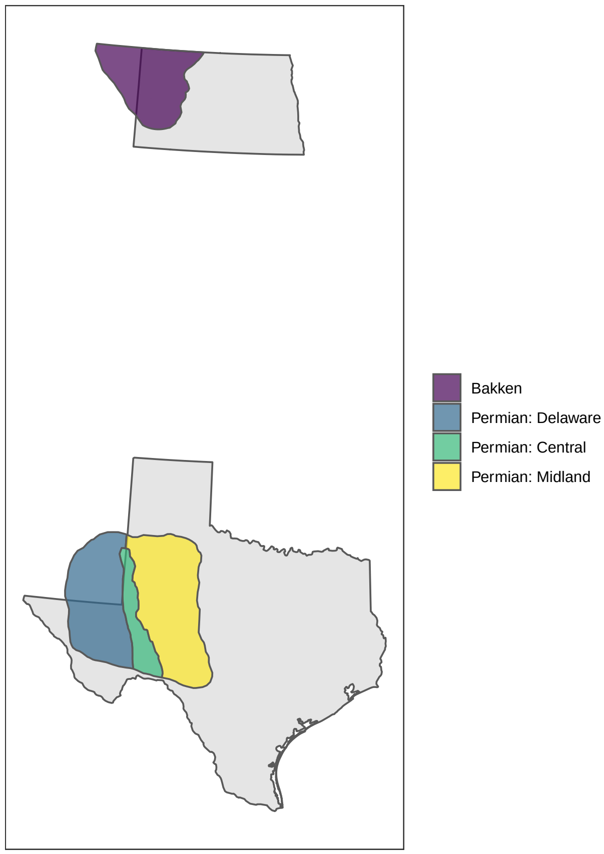

Figure 6: Map of Bakken and Permian shale plays as defined by Enverus

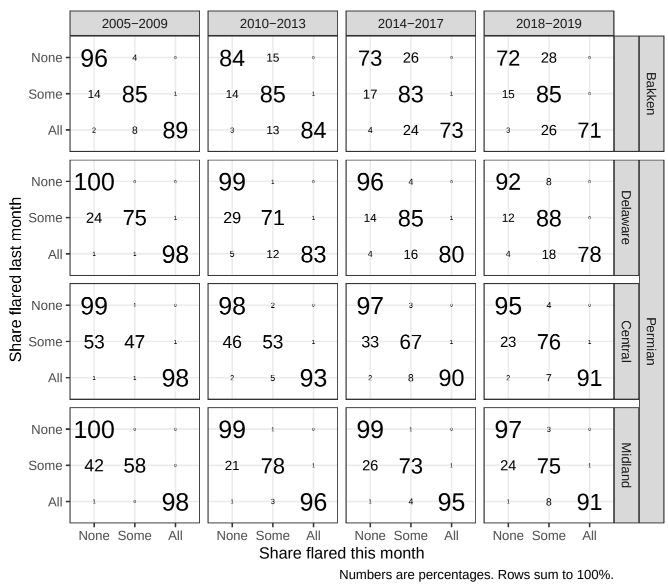

Figure 7: Probability of flaring all/some/no gas given last month's flaring

	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	0.23	0.22
2008	0.07	0.05	0.02	0.42	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	0.85	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	2.28	0.38	0.17	0.31
2019	1.38	2.84	0.54	0.19	0.39
			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	0.29
2012	0.01	1.25	0.00	0.00	0.33
2013	0.02	1.21	0.01	0.01	0.42
2014	0.05	1.34	0.02	0.01	0.33
2015	0.10	1.59	0.07	0.04	0.69
2016	0.13	1.72	0.09	0.05	0.68
2017	0.19	2.19	0.07	0.03	0.39
2018	0.33	3.30	0.11	0.03	0.32
2019	0.45	4.41	0.12	0.03	0.27
			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	0.63	0.01	0.01	0.02
2011	0.33	0.80	0.02	0.02	0.05
2012	0.43	1.11	0.04	0.03	0.08
2013	0.53	1.40	0.06	0.04	0.11
2014	0.66	1.85	0.08	0.05	0.13
2015	0.79	2.22	0.09	0.04	0.12
2016	0.92	2.55	0.07	0.03	0.08
2017	1.26	3.24	0.09	0.03	0.07
2018	1.92	4.52	0.21	0.05	0.11
2019	2.46	6.14	0.31	0.05	0.13

Flaring rate is mcf flared per mcf gas produced.

Flaring intensity is mcf flared per bbl oil produced.

D Climate damage calculations

Our flaring climate damage 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 Interagency Working Group on Social Cost of Greenhouse Gases (2021) does not provide social costs of ethane, propane, or butane, we multiply the SCC by the 100-year greenhouse warming potentials (GWP) of these gases Hodnebrog et al. (2018). We assume that pentanes and hexane do not have any greenhouse gas effect. 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_1$0	4	0.2121	$10.82	6.5		$23.79
Normal $C_4H_1$0	4	0.2121	$10.82	6.5		$23.89
Iso $C_5H_1$2	5	0.2651	$13.52	-	-	-
Normal $C_5H_1$2	5	0.2651	$13.52	-	-	-
$C_6H_1$4	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_1$0	0.0168	$0.18	$0.40
Normal $C_4H_1$0	0.0506	$0.55	$1.21
Iso $C_5H_1$2	0.009	$0.12	$0.00
Normal $C_5H_1$2	0.0126	$0.17	$0.00
$C_6H_1$4	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