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

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Abstract

Flaring of natural gas associated with U.S. unconventional tight oil production is a significant environmental and policy issue for the sector. We marshal granular data to identify the bottlenecks in the oil and gas value chain that physically cause upstream flaring at the well. Motivated by this descriptive analysis, we further analyze the economic reasons for flaring, market distortions that could exacerbate it, and the cost to society of flaring. We lay out an agenda for researchers and policymakers charged with understanding and regulating flaring.

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1 Introduction

When and why do companies flare natural gas? In this paper, we lay out a research and policy agenda around natural gas flaring by U.S. onshore oil wells. Few economic studies address flaring, but the topic has become increasingly important as U.S. shale oil and gas production has boomed over the last two decades. Our analysis focuses on two of the most prolific oil basins in the U.S.: the Permian Basin and Bakken Shale.

Flaring happens when companies burn natural gas (methane, CH_4) as a waste product. Both oil and natural gas are hydrocarbons, and they are often produced out of the same underground reservoirs. *Associated gas* is a byproduct of the production of crude oil. It consists of methane, as well as other light hydrocarbons. If producers are unable to economically transport associated gas to market, they often flare it. Flaring emits carbon dioxide, and can also emit methane and EPA-designated criteria pollutants such as nitrogen dioxide, sulfur dioxide, carbon monoxide, and volatile organic compounds (VOCs).[1] Although these criteria pollutants have known health effects, further study is required to quantify the extent to which emissions from associated gas flaring contribute to these health effects.[2]

Today, most flaring in the U.S. is happening in two of the most prolific shale basins: the Permian Basin, located in Texas and New Mexico, and the Bakken shale, located in North Dakota (see map in Figure 13 in Appendix A). According to the U.S. Energy Information Administration (EIA), in 2018 468 billion cubic feet of natural gas was flared or vented in the United States.[3] To put this into perspective, that represented about 1.2 percent of U.S. gas production. If the flared natural gas was instead used to generate electricity, it would have been enough to power 6.1 million households for a

[1] `https://www.energy.gov/sites/prod/files/2019/08/f65/NaturalGasFlaringandVentingReport.pdf`

[2] Criteria pollutants are those for which the U.S. Environmental Protection Agency has established National Ambient Air Quality Standards. `https://www.epa.gov/sites/production/files/2015-10/documents/ace3_criteria_air_pollutants.pdf`

[3] The World Bank's Global Gas Flaring Reduction Partnership (GFFR) uses detailed satellite data to estimate flaring globally and estimates the U.S. flared about 13.1 billion cubic meters, or about 478 billion cubic feet.

year.[4] From 2014–2018, the United States flared the fourth highest volume of any country worldwide, accounting for about 8 percent of world flaring (World Bank 2019).

Burning a flare to convert CH_4 into CO_2 is preferable to simply *venting* the CH_4 (releasing it into the atmosphere) for a number of reasons. First, CH_4 is combustible, while CO_2 is not, so CH_4 can be an immediate safety hazard. Further, the climate impact of methane is 28–36 times that of CO_2 over 100 years, with even more severe near term warming effects.[5] Flares are not fully efficient under real-world conditions, so they do not combust 100% of the hydrocarbons into CO_2 and water. Further, they can become inadvertently unlit and release methane directly into the atmosphere. As will be discussed further, operators typically are not required to report flaring and venting separately, nor are they always aware of when a flare became unlit. Combined, these factors imply that flaring and venting may be a significant source of both carbon dioxide and methane emissions from the oil and gas sector.

The effect of flaring on local air pollution depends on a variety of factors that vary over time and space. Many harmful local pollutants have been detected in flared gas but the presence and amount of a given pollutant depends on the composition of the gas that comes out of the ground, the combustion efficiency of the flare, local weather conditions, and other site-specific factors (Buzcu-Guven and Harriss 2012). Although many studies have sampled a small number of test sites within a basin or modeled pollution dispersion from flares in a single area (e.g., Fawole, Cai, and MacKenzie (2016), Fawole, Cai, Abiye, et al. (2019), Kostiuk, Johnson, and Thomas (2004), Strosher (1996), and Strosher (2000)), we know of no study that undertakes a systematic basin-wide inventory of flaring-based pollutants for any major producing basin. Moreover, the *social cost* of these local pollutants depends on the amount and severity of impacts on health in nearby communities, and there are few studies from which reliable causal inference

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

[5] `https://www.epa.gov/ghgemissions/understanding-global-warming-potentials`

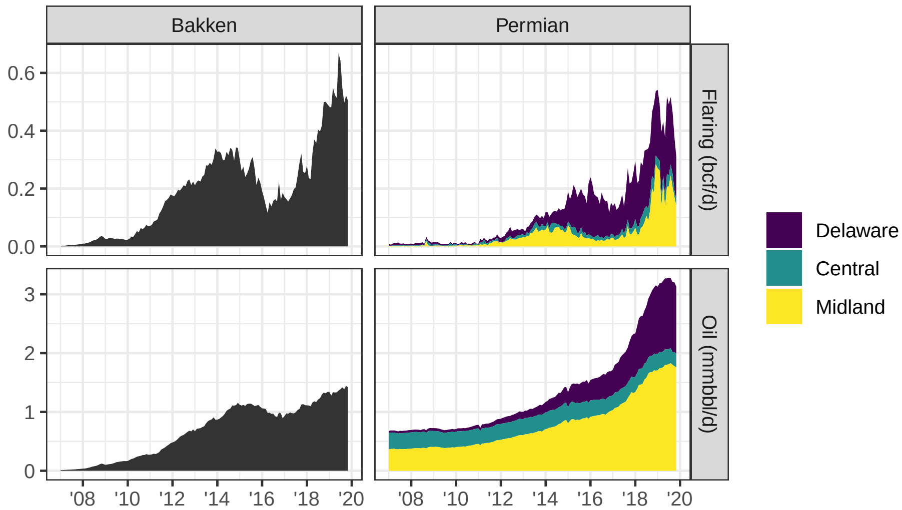


Figure 1: Flaring and oil production in the Bakken and Permian

can be made.

Major U.S. oil producers say that they are making concerted efforts to avoid flaring, and some even incur economic costs to do so (Addison 2019; Crowley 2020). However, flaring has continued to grow in the U.S., especially in the Bakken and Permian basins as Figure 1 shows. According to recent estimates from the World Bank, flaring increased by 48 percent in the U.S. between 2017 and 2018 (The World Bank 2019). Oil producers have said that they are hemmed in by a lack of pipeline capacity to transport gas out of producing regions, and that the arrival of new pipelines will allow them to capture and sell gas instead of flaring it. With oil demand and oil prices having fallen amidst the Covid-19 pandemic, U.S. oil production has been falling, and flaring with it.[6] As demand recovers, however, flaring may rise again.

This paper lays out a research and policy agenda around the practice of flaring associated gas. First, we discuss the datasets we use in our

[6]According to EIA, U.S. Field Production of Crude Oil in April of 2020 (the most recent data at the time of this writing) was down 6% relative to its peak in November 2019.

analysis. Second, we utilize detailed data to illustrate that flaring is happening because of constraints at several points along the midstream value chain—not just because firms fail to connect their wells to pipeline networks. Third, we consider whether current market structures—even if flaring did not cause environmental externalities—would deliver optimal amounts of flaring. Fourth, we examine the external costs of flaring associated with pollution. We review the economic efficiency of standard policy options that regulators could implement to address flaring. Accurate and timely monitoring of flaring is important for effective regulation, but we outline why this is a challenge. We discuss how emerging remote-sensing technologies could allow for more efficient flaring monitoring and regulation. While we motivate our analysis with data and theory, our discussions should be viewed as a launching point for further research that can answer the questions we raise.

1.1 Industry Background

Before proceeding, we present some basic terminology commonly used in the oil and natural gas industry that is needed to discuss natural gas flaring. Readers familiar with the oil and gas value chain might skip ahead to Section 2.

Leases and wells The difference between a *lease* and a *well* is key distinction. In the context of this discussion, a well is a hole drilled into the ground for the purpose of extracting hydrocarbons. 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 (fracking). After completion, the well can produce hydrocarbons. We call the month that the well begins producing commercial quantities the *first production date*.

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 both types of leases may coincide but do not have to.

Oil, natural gas, and associated gas An oil well produces multiple types of hydrocarbons. The shortest hydrocarbon that an oil well can produce is methane, CH_4 (natural gas). With additional carbon and hydrogen atoms, the molecule becomes longer and heavier.[7] At atmospheric pressure and temperatures, shorter hydrocarbons remain 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 at the wellhead. Gases, on the other hand, are transported via pipeline from the wellhead all the way to the downstream purchaser. Because a pipeline is required to move gas, firms have less flexibility in transporting gas relative to oil.

A well must be designated as an oil well or natural 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. As we discuss later, 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.

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 several uses: (1) residences or commercial businesses use

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

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.[8]

The midstream segment consists of several services that connect upstream wells to downstream demand. We focus primarily on midstream services for natural gas. After gas exits the well, a network of gathering pipelines transport it to a natural gas processing plant. If it is not consumed locally, the gas then gets on a long-haul transmission line to go from a producing region to a demanding region. Produced gas (especially associated gas from oil wells) often contains heavier hydrocarbons or other impurities. A portion of these heavier molecules must be stripped out of the gas stream at a natural gas processing plant before the gas enters long-haul transmission pipelines. At the end of 2017, there were 510 natural gas processing plants in the United States.[9] The *natural gas liquids (NGLs)* like ethane, propane, and butane are stripped out during gas processing. NGLs are important inputs for petrochemicals and can be more valuable than methane. Stripped of NGLs and other impurities, the natural gas can be shipped over long-haul transmission lines.

In this paper, we use the term *upstream* to mean drilling, completion, and production of hydrocarbons at the wellhead. We use *midstream* to indicate the suite of gathering, processing, and transportation services that move hydrocarbons from a producing property to intermediate and final *downstream* demand.

2 Data

We assembled a comprehensive dataset on well-level production and flaring and midstream infrastructure. Using this data, we computed a number of descriptive statistics to investigate the constraints along the value chain

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

[9]Triennial EIA Natural Gas Processing Plant Survey, EIA-757 Schedule A.

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 two commercial vendors, Enverus and MapSearch.

In North Dakota, oil and gas production are reported to the North Dakota Industrial Commission (NDIC) at the well level. For each well, we downloaded 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. Flaring and venting are reported as a single number, and because of this, for purposes of describing the data analysis, we simply use the term flaring to describe both. North Dakota bans the practice of venting altogether.[10] We then merged NDIC data to drilling and production records from Enverus and excluded wells outside of the Bakken.[11]

In Texas, oil and gas producers report production to the Texas Railroad Commission (RRC), and reporting is more complicated. Natural gas wells report production 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, flaring and venting 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.[12] Again, for purposes of discussing results of the data analysis we use the term flaring to describe both processes. 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 production to the most recent well completion on the lease to get a sense of the evolution of

[10]ND Administrative Code 43-02-03-45. Vented Casinghead Gas. `https://www.legis.nd.gov/information/acdata/pdf/43-02-03.pdf`

[11]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.

[12]16 Tex Admin. Code §3.32 (Gas Releases to be Burned in a Flare) `https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=16&pt=1&ch=3&rl=32`

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 a well location. 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.

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.[13] We merged this with annual, plant-level capacity data provided by the North Dakota Pipeline Authority (NDPA).[14] 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.[15] We then calculated the distance from each Texas well to the nearest natural gas gathering pipeline for both years. For both Texas and North Dakota wells, we also calculated the distance from each well to all gas processing plants within 50 km.

[13] Gas plant volumes are available at `https://www.dmr.nd.gov/oilgas/feeservices/gasplants.asp`, and locations at `https://www.dmr.nd.gov/OaGIMSSub/downLoadShapeFiles.asp`

[14] `https://northdakotapipelines.com/datastatistics/`

[15] 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.

3 Why are firms flaring?

The usual narrative about flaring casts flaring as the result of a *physical* constraint imposed on producers. That is incomplete. Flaring is an *economic decision* that profit-maximizing firms make given physical and regulatory constraints. There are actually (at least) two decisions. 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 capture the gas instead of flaring it. Capturing the gas requires investment in a suite of midstream infrastructure and services beyond what is required for oil: 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.

In this section, we muster descriptive evidence from North Dakota's Bakken shale and the three main areas of the Permian—the Delaware, Central, and Midland basins—to understand the physical constraints that lead to flaring. Firms appear to be routinely flaring for two reasons. Some flaring occurs because the producer simply has not built gathering pipelines and field compression to capture and transport the gas to market. Surprisingly enough, we find that this first reason—the complete absence of gathering pipelines—is *not* the main reason why firms are flaring. Instead, we find that the majority of flaring is happening because the existing midstream infrastructure—while in place—appears to be too small to handle all of the gas firms are producing. We show evidence that constraints in midstream infrastructure happen in multiple places: gathering, processing, and transmission. The lack of capacity may have been intentional, or it may have resulted from uncertainty about future production and limits to how quickly infrastructure can be built.

3.1 Unconnected wells

Flaring comes from two groups of locations: locations that sell gas *and* flare gas in the same quarter, and locations that flare *all* of the gas produced.

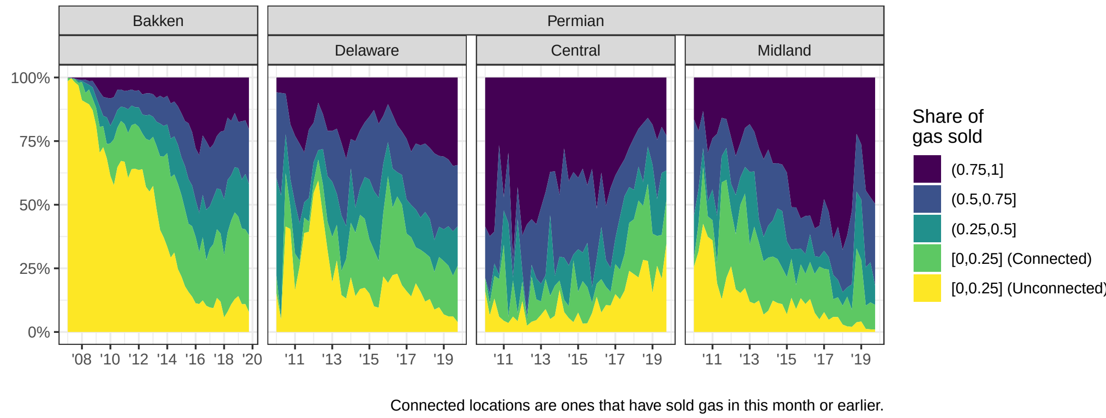


Figure 2: Share of total gas flared by how much production the well or lease sells in the same quarter

(Recall that North Dakota reporting locations are wells, and Texas reporting locations are oil leases and gas wells.) Of the locations that flare *all* of the gas produced, there are some locations which have *always* flared all of their gas, and there are others that have sold gas in prior quarters. Most likely, locations that have never sold any gas flare because there is no gathering infrastructure. North Dakota wells which have previously sold any gas are almost certainly connected to gathering infrastructure. Similarly, Texas oil leases which have sold gas are also connected to gathering. That said, we are unable to identify whether the individual wells on a each lease are physically connected to gathering.[16]

Figure 2 shows that locations which sell no gas but instead flare all of it 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. Wells and leases that both sell and flare gas are connected to gathering infrastructure. The producers that own these wells have chosen to build gathering infrastructure and pay for midstream services; however, they are producing more gas than the capacity they have secured in the midstream

[16]Based on discussions with industry, transporting gas from the wellhead via other modes (truck or rail) is uneconomic.

sector, or are choosing not to sell the gas. Even more interesting is the fact that the majority of flaring in recent years happens at wells which sell at least 25% of their gas.

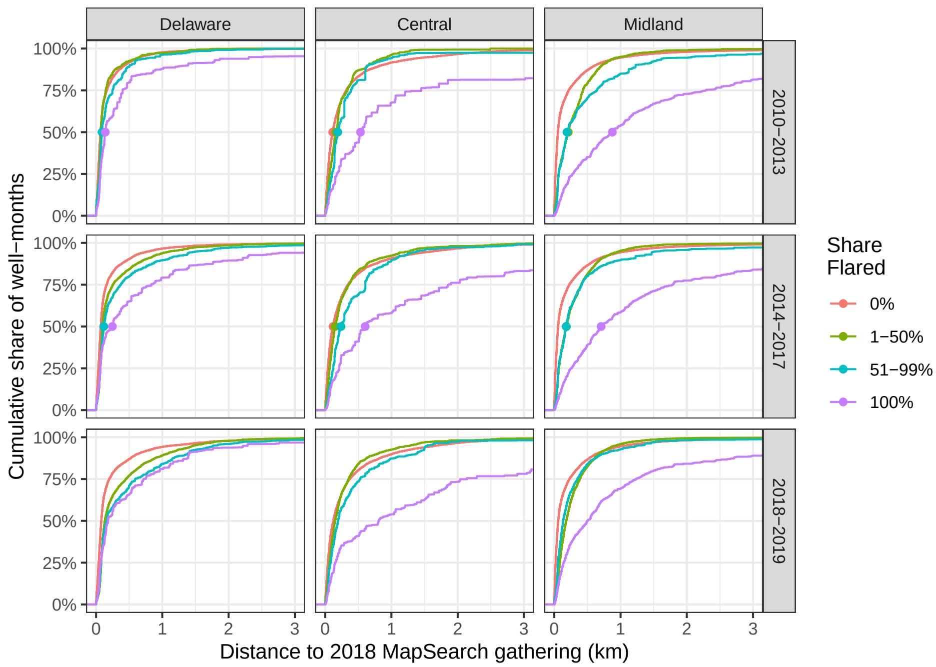


Figure 3: Leases that flare all gas are far away from gathering

To further investigate the set of unconnected wells which flare 100% of their gas, in Figure 3 we plot the cumulative distribution of the distance from each Permian gas well or oil lease to the nearest gathering pipeline as of December 2018.[17] We classify monthly production records by whether the location flares no gas, some gas, or all gas in a month. Figure 3 shows that locations that flare no gas are about as far away from gathering infrastructure as wells that flare some (but not all) gas. Locations that flare all of their gas are qualitatively different. They are much further away from gathering. Reducing flaring at this group of unconnected locations requires either halting production (*shutting in*) or building gathering infrastructure

[17] We define the location of an oil lease as the location of the well Enverus uses as the lease's location.

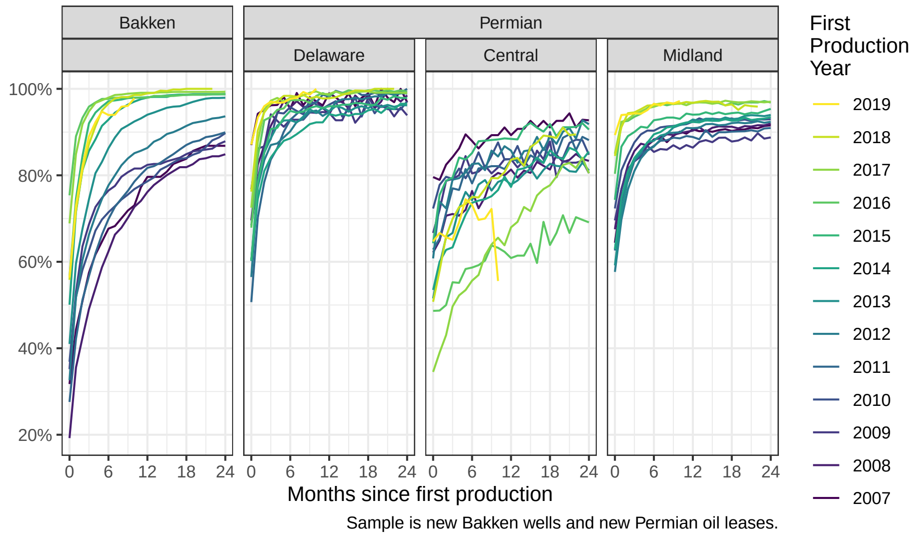


Figure 4: Months until location connected to gathering

and purchasing midstream services. In remote areas, building gathering might not be sufficient to halt flaring, as there might not be gas processing or transmission services nearby.

In the next graphs, we focus on the decision to connect new Bakken wells and new Permian oil leases to gathering infrastructure.[18] We define the time to connection as the number of months between when production starts and gas is sold for the first time. Figure 4 shows how quickly new wells in the Bakken and new oil leases in the Permian get connected to gathering. The time it takes Bakken wells to connect has greatly improved since 2007, when less than 80% of wells were connected by 12 months. In recent years, it has taken less than 3 months to connect 80% of new wells. Connection times for new leases in the main Delaware and Midland basins of the Permian have been better than for the Bakken, and have generally improved over time. The Permian's Central platform has gotten worse over time, but it represents a small share of production.

Figure 5 shows a similar story—the share of gas flared in the first six

[18]Permian gas wells are excluded as these clearly will be connected to gathering infrastructure.

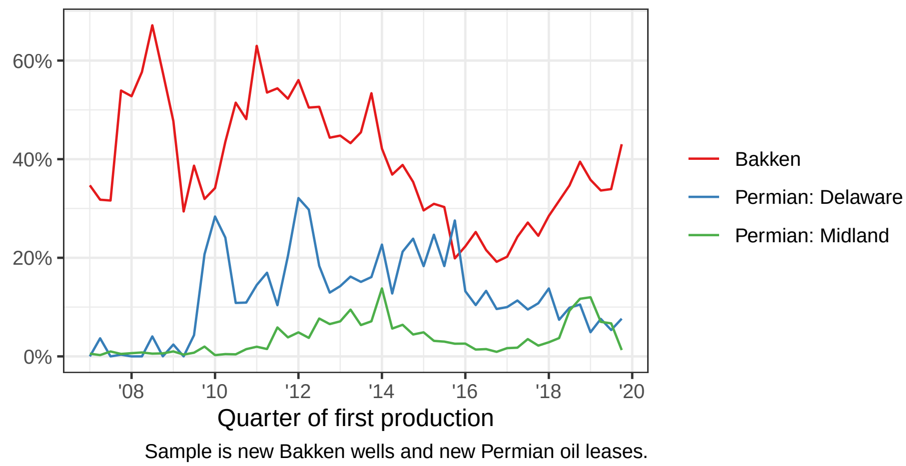


Figure 5: Share of gas flared in first six months for new locations

months of a new Bakken well's production marched downward between 2011 and 2016, but has risen sharply since. Shale activity in both the Midland and Delaware basins of the Permian began in roughly 2010.[19] While the Midland Basin improved its flaring rate on new locations from 2014–17, the trend reversed during 2017–19. In contrast, flaring rates in the Delaware Basin have steadily trended down since 2016 as the industry plumbed the basin with new gathering.

3.2 Older Leases Connected to Gathering

Improving connection times for Bakken and Delaware wells correspond to a another trend shown in Figure 6. The plot shows that as flaring has increased, the share of flaring from locations (Bakken wells, Permian gas wells, and Permian oil leases) that have been producing for more than a year has climbed. Production from shale wells declines quickly over time, so we surmise that despite the efforts of producers to quickly connect new wells with gathering infrastructure, investment in midstream infrastructure further down the value chain has been insufficient to relieve constraints.

[19] The smaller number of new locations in the Central Platform introduce large sampling variation, so we exclude them from Figure 5.

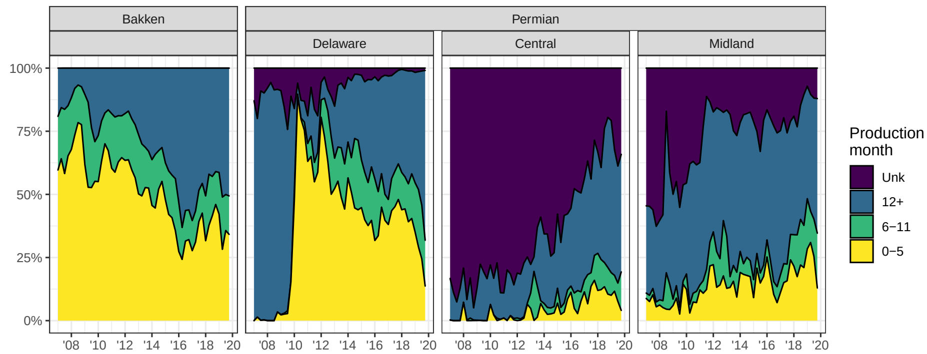


Figure 6: Share of total flaring by number of months location has produced

Constraints along different segments of the midstream value chain can cause connected locations to sell *and* flare gas in the same month. Some constraints may be related to undersized gathering infrastructure that cannot handle all of the gas associated with oil production. Descriptive evidence suggests that physical constraints are indeed arising. If a location has to flare because of constraints further downstream—not the absence of gathering—these constraints may not bind in every month. The location may flare in some months but not others.

Figure 7 provides statistical evidence that such intermittent flaring, which is most plausibly associated with constraints further downstream, can explain a sizable share of flaring. The figure represents a set of *Markov transition matrices* for the states of flaring None, Some, or All gas in a given month. Each pane represents a particular region and time period. The panes show the probability that a location flares None, Some, or All of gas produced this month conditional on what it did last month. The large numbers on the diagonal indicate persistence: if a well flared everything, something, or nothing last month, it will tend to do the same this month. Over time, all of the Permian sub-basins and the Bakken share the same trend: wells seem increasingly likely to revert to flaring *something* instead of everything or nothing. This suggests that *congestion* has increasingly been an issue: connected wells are having to flare a bit each month, whether they flared

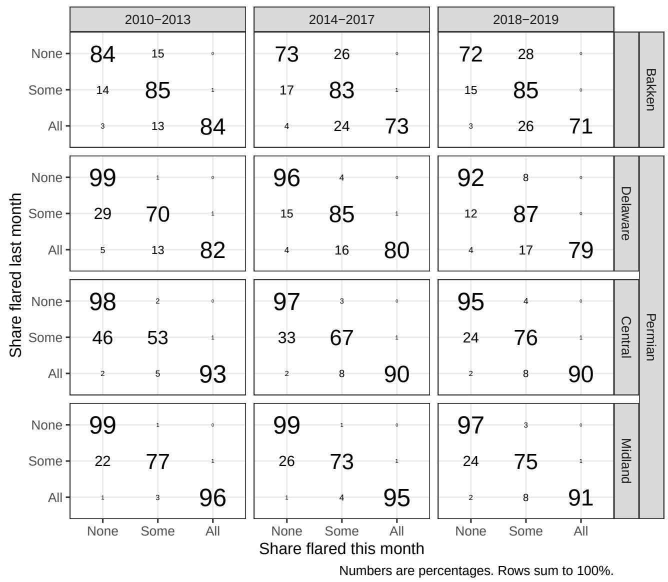


Figure 7: Probability of flaring given last month's flaring

something or not last month. During recent years, intermittent flaring appears to be more prevalent in the Bakken compared to the Permian; over a quarter of Bakken wells that flared nothing this month will revert to flaring next month. By comparison, in the Permian, only three to eight percent of non-flaring wells revert to flaring.

3.3 Transmission constraints

Our data do not allow us to directly observe the role that undersized gathering pipelines play in causing constraints and flaring. However, our data do allow us to associate constraints in Bakken gas processing and Permian transmission capacity with flaring. The top pane of Figure 8 shows flaring by the sub-regions of the Permian (the Midland, Delaware, and Central Basins). The bottom pane shows the difference between the nationally representative spot price for natural gas (Henry Hub) and the spot price in the Midland basin's gas hub (Waha). This difference reflects the scarcity rent associated with transmission out of the Permian. When demand for trans-

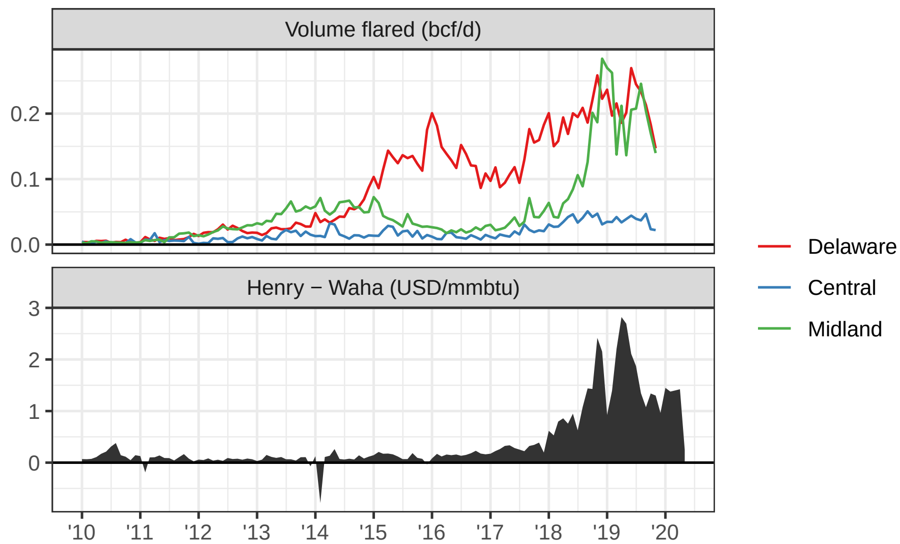
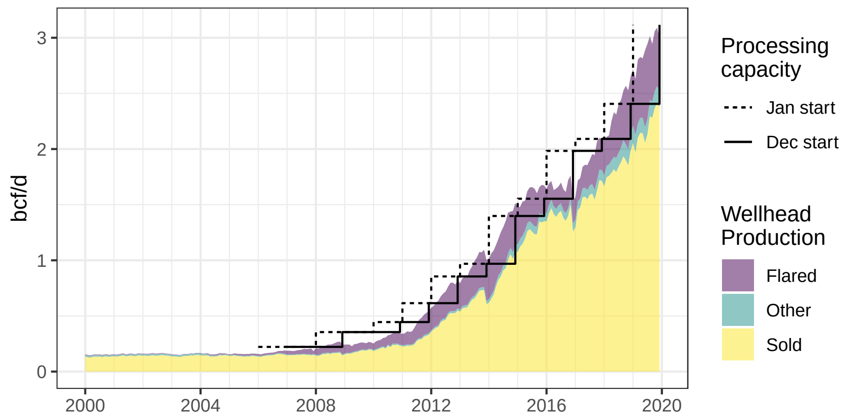


Figure 8: Flaring in the Permian and natural gas basis differentials

mission threatens to outstrip supply, scarcity rents rise to clear the market (Agerton and Upton 2019). In fact, while not shown in this figure, for a few weeks in both 2019 and 2020, the scarcity rent had gotten so big as to drive Waha gas prices below zero. The top pane of Figure 8 shows that flaring in the Permian's Midland basin is correlated with the wedge between Henry Hub and Waha. Flaring appears to be working like a "relief valve" that relieves excess demand for transportation out of the Permian, especially in the Midland basin. In contrast, flaring in the Delaware basin ramped up starting in 2015, well before transmission constraints emerged.

3.4 Processing constraints

Lack of processing capacity can also be a constraint on moving gas from wells to market. Both Blundell and Kokoza (2019) and Quadrennial Energy Review Task Force Secretariat and Energy Policy and Systems Analysis Staff (2014) tie lack of processing capacity in North Dakota to flaring further upstream at the wellhead. Figure 9 plots total capacity and utilization



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

Figure 9: ND gas processing capacity barely kept pace with ND gas production

of natural gas processing in North Dakota's Bakken shale. Gas processing has barely kept up with production. In fact, production has exceeded processing capacity several times. While the plot shows that the total amount of gas sold never approaches the aggregate capacity of processing plants, production and processing are not all in the same place. That means spare processing capacity may not be accessible to constrained producers.

4 The economic choice to flare

Natural gas is a valuable good. Firms will only dispose of it through flaring if the cost of gathering, processing, and transporting it is greater than its market value. In this section, we discuss the private tradeoffs firms face when flaring, and how the unique features of the oil and gas industry—particularly contracting for midstream services—may affect how much flaring occurs. We address the environmental externalities associated with flaring in the subsequent section.

There are a number of economic reasons that it may be profit-maximizing for producers to flare during the initial years that a play is developed. These are *short term* reasons that flaring may be privately optimal. First, producers flare to maintain operational safety when gas pressures on pipelines rise (Office of Fossil Energy 2019). Second, firms make the decisions to invest in new wells and midstream infrastructure in an environment of operational and market uncertainty. When producers drill exploratory wells in a new area, they may not know how much infrastructure will eventually be needed. With further uncertainty about eventual well productivity and market demand for oil and gas, it can be valuable to maintain the real option to build infrastructure later, once more is known. Rather than build the wrong amount of infrastructure right away, it may make economic sense to flare initial wells and build the right amount later. Third, high initial production rates and rapid declines may lead to flaring, even if there is no operational or market uncertainty. If a producer builds infrastructure to handle peak production, much of that infrastructure will not be utilized after a short time. It may make economic sense, then, to build a smaller gathering capacity which will be fully utilized for a longer period of time, even though this will necessitate flaring in the early stages of development.

In the *long run*, if the prices of midstream services—gathering, processing, and transporting gas—do not reflect the private marginal cost of supplying these services, then we can also get too much flaring, even if flaring causes no pollution. Suppose that the price of midstream services paid by the producer is higher than the actual opportunity cost that the midstream firm incurs to provide them. Marginal producers deciding whether to flare or gather their gas will find it more profitable to flare, even though the cost to society of gathering is less than the value of the gas. Conversely, if the price of midstream services is too low, midstream firms will lack the incentive to invest in capacity.

Mispricing of midstream services may be occurring. In a Q4 2019 survey of oil and gas producers by the Federal Reserve Bank of Dallas, 45% of respondents cited excessive fees in gathering and processing capacity as causes of flaring (Federal Reserve Bank of Dallas 2019). In fact, 49% of respondents to the same survey by the Federal Reserve Bank of Dallas cited capacity constraints in gathering and processing as a reason for flaring. Thus, the key question is, *Are prices for midstream services low enough to encourage capturing gas, and high enough to incentivize investment?*

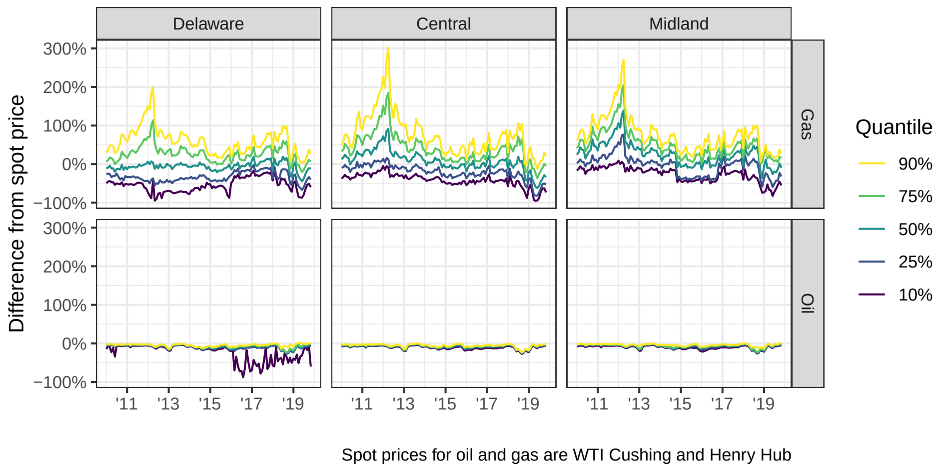


Figure 10: Difference between Permian wellhead prices and national spot prices

Empirical evidence suggests that over-pricing and under-pricing of midstream services could both be occurring. Figure 10 shows that wellhead gas prices in the Permian exhibit very large variation around national benchmarks, even within a sub-play and a month. While not shown here, we verified that wellhead gas prices are highly variable even at much finer spatial scales. In contrast to wellhead gas prices, 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 energy content of the gas, some could also be due to variation in the price of midstream services. We are unable to empirically test this.

There are at least three possible reasons that the price of midstream services might not reflect the actual cost. First, some portions of the natural gas midstream system are priced by regulators, who could err in ratemaking. Second, *market power* might allow midstream companies to raise prices above costs in instances where there is little competition. Third, mid-

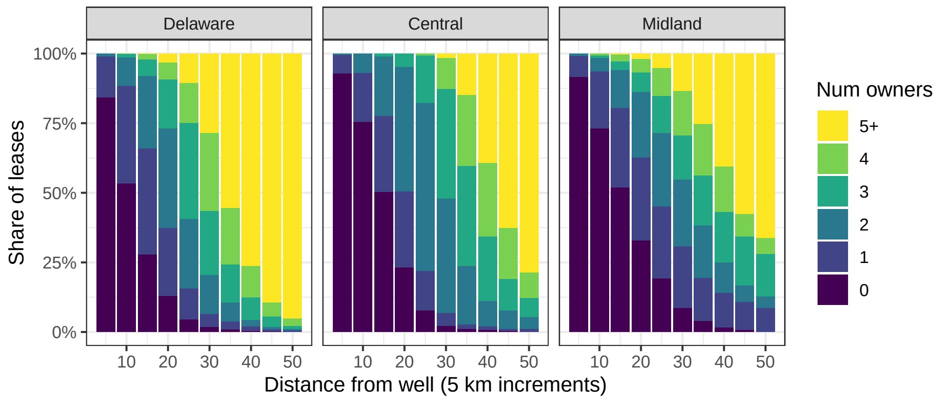


Figure 11: Number of different processing companies within a given distance of each Permian oil lease

stream infrastructure involves lumpy fixed investment costs and relatively low marginal costs, which can cause short-run prices to diverge from long-run average costs. Even if flaring did not pollute or firms internalized the external cost of flaring pollution, these three market distortions could lead to flaring above or below what is optimal. Resolving these market distortions might require a separate policy instruments that could complement, not substitute environmental policies to reduce flaring.

4.1 Flaring and 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 Energy Regulatory Commission (FERC) regulates interstate pipelines. Interstate pipeline transportation prices are typically established using one of the 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 can recover its costs plus a reasonable rate of return on the capital investment. Second, the *negotiated rate* method allows the operator 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. Intrastate natural gas pipeline are regulated by individual states, but generally follow the same cost-of-service based principles as FERC.[20]

A firm regulated in a COS framework will solve a different profit maximization problem than a firm in a competitive market. Averch and Johnson (1962) present the standard economic model of firm behavior under COS-based rates. The model predicts that if the allowed 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 flaring, if the regulator sets the rate of return for pipeline infrastructure *too low*, firms will not build enough capacity. Should production exceed transmission capacity, producers will flare. If the rate of return allowed by the regulator is greater than the cost of capital, the pipeline operator will have an incentive to over-capitalize, and possibly overbuild. Faced with high pipeline tariffs, some producers may choose to flare instead of capture gas.

4.2 Market Power

In contrast to natural gas transmission, localized gathering is priced based on private agreements. Gathering does not face the same degree of regulatory scrutiny as transmission does. Thus, while specific safeguards are in place to ensure that transmission pipelines do not exert market power, these safeguards are not in place for local gathering.

While there are many midstream companies, their infrastructure is not all located in the same place. Thus, a producer's wells may only have access to the gathering and processing infrastructure of one or two midstream

[20] Pipeline transmission rates also distinguish between "firm" and "interruptible" transportation service. These details are beyond the scope of this discussion.

firms. Studies of electricity and coal markets confirm that network congestion can create isolated sub-markets that limit competition (Borenstein, Bushnell, and Stoft 2000; Preonas 2018; Woerman 2019). 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. Put more simply, producers' option to flare reduces midstream firms' bargaining power.

Current litigation in Texas between producer EXCO Resources, Inc. and midstream firm Williams Companies suggests that midstream companies may indeed be able to exert market power to increase the price of their services (*Proposal for Decision: EXCO vs Williams* 2019).[21] The litigation centers on the question of whether EXCO should be allowed to flare gas worth $45 million or, as Williams advocated, be forced to stop flaring and use oil profits to pay for gathering in exchange for $198 million. A competitor to Williams is unlikely to build out alternative infrastructure since Williams, which has already paid to build pipelines, can always undercut the competitor. In its ruling, the RRC sided with EXCO. The ruling reduced midstream operators' bargaining power by preserving oil producers' ability to flare.

Figure 11 shows the number of different processing companies Permian oil leases can access within a given as-the-crow-flies distance.[22] In each basin, a majority of wells have access to two or fewer different processing firms within 20 km. As the distance increases, wells have access to additional processing companies. The degree to which far processors compete with near processors is a function of the cost to transport natural gas and the availability of spare transportation capacity in the network. Ironically, while producers ramped up unconventional oil extraction first in the Midland Basin compared to the Delaware Basin, Figure 11 shows that Delaware leases are, in general, close to a larger number of gas processing competitors

[21] See TX RRC Oil & Gas Docket No. 01-0308609 `https://www.rrc.state.tx.us/media/53466/01-0308609-pfd-exco.pdf`

[22] Plot excludes Permian gas wells.

than are Midland leases. Reduced competition in the Midland basin relative to the Delaware is consistent with the previous discussion of Figure 5: the figure shows that Midland flaring rates for new wells have trended upward, while Delaware flaring rates have dropped quickly.

4.3 Fixed costs and uncertainty about the future

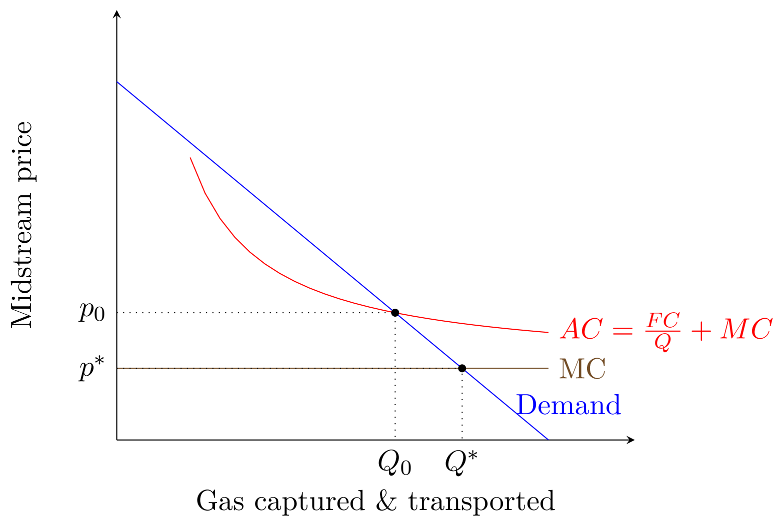


Figure 12: Recovery of fixed costs implies midstream price is above marginal cost

Even if market power in gathering and processing is not an issue, the large fixed costs of long-lived midstream infrastructure still 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 instead of flaring.

Figure 12 illustrates this pricing quandary when there is no uncertainty. Suppose that providing midstream services involves a constant marginal cost MC plus a large fixed cost FC. In order stay profitable, midstream providers must spread the fixed cost out over all units of gas ever transported Q. The price that does this is the average cost $AC = FC/Q + MC$. At price AC, only Q_0 units of gas will be captured. However, marginal units of gas from

Q_0 to Q^* could be profitably transported at price MC. These marginal units of gas will end up being flared when they should be gathered. If the price of midstream services is equal to marginal cost, MC, midstream companies won't have enough revenue to pay their fixed costs. This quandary is endemic to regulated utilities like electricity generation and transmission (Borenstein 2016; Braeutigam 1989). One way to overcome this challenge in pricing is for midstream firms to charge different units of gas different prices (*price discrimination*). For example, inframarginal units of gas up to Q_0 could be charged AC, the units from Q_0 to Q^* could be charged MC.

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, a midstream firm will build gathering infrastructure and charge the producer per unit of gas shipped. To reduce risk, midstream firms often require that producers sign an *acreage dedication* contract. An acreage dedication is a long-term producer commitments to ship all gas produced in a particular area through that midstream firm's infrastructure. The agreement limits the risk to the midstream firm that the gas producer ships (or threatens to ship) gas with another midstream firm. However, 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 the midstream firm forecast, the associated gas volumes shipped by oil producers can lead to a revenue shortfall for the midstream firm.[23] 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, hence, gathering utilization drop.

Pricing in gas processing can introduce revenue risk for midstream firms beyond what gathering faces. Like gathering, future gas processing volumes are uncertain. In addition, two of the three typical pricing arrangements tie processing prices to the volatile prices of natural gas and natural gas liquids (NGLs). This introduces price risk, which can be positively corre-

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

lated with volume risk. There are three typical pricing structures for gas processing. A *fee* basis involves a set price per unit of gas. *Percent of proceeds* allows processors to keep part of the revenues from sales of the gas and its constituent NGL components. *Keep whole* pricing allows the processor to extract and sell high-value liquids and return an equivalent volume of lower-value methane to the producers (Followill, Pursell, and Williams 2008; Kafka and Strawn 2017). Percent of proceeds and keep whole contracts expose midstream companies to price risk. When there are high levels of risk, real options theory explains that it is economically rational for midstream firms to delay investment in processing (Dixit and Pindyck 1994).

Gas processing contracts and the price risk they create can also incentivize producers to flare. For example, when natural gas prices fell relative to NGL prices, the incentives for producers on percent of proceeds contracts diverged from producers on keep whole contracts. Those with percent of proceeds could reap the benefits of high NGL prices by gathering their gas. Those on keep whole contracts could not. Further, if gas prices fell in absolute terms, some producers on keep whole contracts might have, on the margin, found flaring to be economically justified when it was not previously.

5 Social costs of flaring

The question of how much flaring is "too much" depends on the environmental and health costs of flaring pollution to society at large. These costs are *external* to private firms and are not factored into the market prices that drive economic decision making.[24] While the prior section focused on issues that distort private incentives in the midstream sector and ignored environmental externalities, here we focus squarely on flaring pollution and policies.

First we describe the two types of pollutants flaring generates—local air pollution and greenhouse gases. Second, we review existing policies to

[24]Many companies also claim to consider "Environmental, Social, and Governance (ESG)" explicitly in their decision making. This section is referring only to the private costs and benefits a company faced that are built into market prices.

address flaring in Texas and North Dakota. Third, we discuss standard *market-based policies* that put a price on flaring. We compare the relative economic efficiency of these benchmark policies and discuss some of the possible challenges to their implementation. Fourth, we address the likely possibility that regulators are unable to perfectly monitor flaring by each firm, and alternative policies that do not require this and but instead leverage improvements in remote sensing technologies.

5.1 How much flaring is socially optimal?

The environmental and health damages caused by pollution from flaring associated gas are non-market external social costs. Firms receive the market value of gas when they choose to capture instead of flare it, but they do not incur external social costs if they choose to flare. Thus, pollution generated by flaring is an *externality*—a cost that flaring firms impose on society but do not themselves bear. Because a non-market externality is present when flaring occurs, market prices do not reflect the full cost of flaring to society. If the cost of the externality were to be incurred by the profit maximizing firm, it is plausible that flaring would be reduced in aggregate. A key question for researchers and policy-makers is, *what is the external cost of pollution created by flaring?* Understanding the magnitude of external costs of flaring is necessary to determine whether new flaring regulations are justified and, if so, how stringent they should be.

Flaring generates two types of pollutants: global greenhouse gas emissions and local air pollution. If the greenhouse gases emitted by flaring are the same as those that would be emitted by an alternative use of the gas, such as power generation or residential heating, incentivizing firms to gather instead of flare may have limited net climate benefits.[25]

[25]In reality, this is more nuanced as there are several other margins of adjustment that would need to be considered. 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 flaring in net increases the natural gas supply to market as firms are incentivized to bring that gas to market in lieu of flaring, this could in theory reduce natural gas prices therefore impacting power dispatch decisions. These effects are beyond the scope of this discussion.

If flares do not achieve efficient combustion, they may vent methane and have a greater climate impact relative to capturing the gas. Engineering studies have found that cross-winds and other factors reduce the percentage of methane fully combusted in flares below theoretical efficiencies (Johnson and Kostiuk 2002; Johnson 2008; Leahey, Preston, and Strosher 2001; McDaniel 1983; Pohl et al. 1986; Strosher 2000). Flares can also fail to light. A recent, non-peer reviewed satellite-based methane inventory from a private firm, GHGSat, found that unlit flares are the oil and gas might be the industry's biggest source of methane emissions (Anchondo 2019; Malik 2019). US Environmental Protection Agency (1996) estimates that upstream flares vent 2% of their methane due to incomplete combustion. A survey done by the Environmental Defense Fund (EDF) suggests that two percent may be too low. EDF sampled 300 Permian flares using remote sensing equipment and found that more than 10 percent of flares either had incomplete combustion or the flare became unlit. Based on this data, the EDF estimates that on average, flares release seven percent of their methane into the atmosphere. Methane has a global warming potential of 28–36 times that of CO_2 over 100 years.[26] Inefficient combustion of methane under real-world conditions could have 2.9–3.5 times the warming impact of burning gas at 100% efficiency. Thus, capturing associated gas instead of flaring it may have significant climate benefits.

When firms flare associated gas, they also create local air pollution—volatile organic compounds (VOCs), soot, carbon monoxide (CO), nitrogen oxides (NOx), and others (Ajugwo 2013; Gobo and Richard 2009; Ite and Ibok 2013; Johnson and Kostiuk 2000; Johnson, Devillers, and Thomson 2011; Kindzierski 2000; McEwen and Johnson 2012; Stohl et al. 2013; US Environmental Protection Agency 2018). A large literature has exploited plausibly exogenous variation in localized air pollution in other contexts to study the causal effect on human health outcomes (Currie et al. 2014;

[26]Over 20 years, the global warming potential of methane is even higher: 84–87 times that of CO_2. United States Environmental Protection Agency. Understanding Global Worming Potentials. `https://www.epa.gov/ghgemissions/understanding-global-warming-potentials`

Heutel and Ruhm 2016; Knittel, Miller, and Sanders 2015; Moeltner et al. 2013; Schlenker and Walker 2016). So far, the empirical literature investigating the causal link between pollution from flaring and localized health outcomes has been scant. Cushing et al. (2020) find a significant association between flaring and preterm birth after controlling for the number of nearby wells and other factors, but their methods do not establish causality. While empirically distinguishing between local air pollution caused by flaring versus other drilling and completion activities is challenging, one recent economic study has causally linked flaring in North Dakota's Bakken to respiratory-related hospital visits (Blundell and Kokoza 2019). The authors find evidence that flaring leads to statistically significant increases in nitrogen dioxide (NO_2) concentrations 0–60 miles away and lead to increased hospital visits for respiratory ailments. Damages associated with local air pollution caused by flaring depend on the population density in the area: flaring in a city around many people is worse than flaring in a sparsely populated area. The Permian and Bakken regions are not densely populated, so local air pollution from flaring may have relatively low social costs. More empirical research can improve our understanding of how flaring impacts local air quality and human health.

Environmental economic theory tells us that society can improve welfare by reducing any externality until the costs of reducing it a little more (*marginal abatement costs*) exceed the benefits (*marginal social benefits*). In the context of flaring, abatement costs may include purchasing additional units of midstream services; expanding midstream infrastructure; drilling in less productive areas with less associated gas; shutting in existing wells; or drilling fewer wells altogether. Given the issues with pricing of midstream services described in the previous section, many of these abatement costs are not well measured. Abatement benefits include reduced emissions of greenhouse gases and local air pollutants, in addition to the reduced waste of a valuable resource.

There are circumstances when the marginal abatement costs of reducing flaring are likely to exceed the social benefits of doing so. Consider the question of whether society should build gathering infrastructure to an existing well in order to halt flaring there. The marginal social benefit of capturing gas instead of flaring includes the final consumer's marginal willingness to pay for a unit of flared gas, which is less than \$2/mcf if valued at current Henry Hub prices.[27] It also includes the external benefits from reducing flaring. Using EIA emissions factors, we can estimate that reducing flaring by one mcf creates \$2.19/mcf in external climate benefits.[28] As discussed earlier, this estimated climate benefit may be too low due to methane releases from flaring. Reductions in flaring will also provide external benefits in the form of reduced local air pollution. The full marginal social benefit of abatement is the sum of the market value of the gas, plus the external climate and local air quality benefits. The marginal abatement costs involve building gathering infrastructure and using midstream services. Lade and Rudik (2018) estimate that gathering costs in North Dakota's Bakken shale are highly dependent on location of wells, ranging from less than \$0.45/mcf to well over \$100/mcf. The marginal abatement cost must also include the cost of processing the gas to commercial standards and transporting it to final markets. When building gathering costs \$100/mcf, the marginal cost of abatement by connecting to the gathering network is likely to exceed the marginal social benefit, so we should not expect society will benefit by connecting such a well to gathering in order to stop flaring.[29] Appropriate market signals or policy incentives can encourage firms with flaring wells that can capture gas at low cost to do so. They may also induce firms to shift production to areas with lower gathering costs, or drill fewer wells overall. Further work on appropriately quantifying social costs and benefits of flaring will improve the ability of policy makers to set policies in a way that improve social welfare.

[27] Current as of June 2020.

[28] Assumes a \$40/ton social cost of carbon and the EIA's flaring emission factor of 54.75 kg CO_2/mcf of gas flared. See `https://www.eia.gov/environment/emissions/co2_vol_mass.php`.

[29] If the present value of environmental damages from flaring from this well exceeds the present value of oil from that well (net of environmental damages from burning oil), it may be in society's best interest to shut in the well permanently. This would require that the value of oil remains very low, and also that the social cost of carbon is very high.

5.2 Current policies in Texas and North Dakota

State regulators in Texas and North Dakota require firms to obtain permits for flaring and report most volumes. Reporting and permitting involves some cost to the firm, but at least in Texas, of the 27,000 permit applications over the period 2012–19, none were denied (Elliott 2018, 2019).[30] While Texas flaring permits specify how much a well is allowed to flare, the state has no statutory limit on statewide flaring volumes.

North Dakota—the other major source of U.S. wellhead flaring[31]—implemented new flaring regulations in 2014 motivated by increased flaring during the shale boom but later loosened these requirements starting the following year. Specifically, North Dakota Industrial Commission (NDIC) Order 24665, issued in July 2014, established a series of annual gas capture targets. The targets require producers to capture a certain percentage of their gas each year.[32] This percentage increases each year until 2020, when firms must capture 91% of their gas. For perspective, during January–November 2019, Bakken wells captured 81% of their gas while Permian oil leases captured 95% percent of their gas (see Table 1 in Appendix A). North Dakota operators that fail to meet gas capture targets are required to curtail production.

Oil production and flaring both climbed rapidly in the Bakken, and the NDIC loosened its regulations. In September 2015, the NDIC revised the 2016 target downward (Scheyder 2015). In April and November of 2018, the NDIC amended the order again to exempt additional wells from the flaring targets and created further allowances for flaring.[33] The U.S. DOE fact sheet on North Dakota suggests that the regulations were loosened to

[30] According to RRC commissioner Ryan Sitton, companies withdraw permit applications before they are rejected (*Texas Oil Regulator Defends Flaring Exceptions Amid Williams' Lawsuit - Bloomberg* 2019).

[31] According to the EIA, North Dakota and Texas together account for more than 80 percent of U.S. flared volumes and including New Mexico brings that share to 90 percent `http://www.eia.gov/dnav/ng/ng_prod_sum_a_epg0_vgv_mmcf_a.htm`

[32] NDIC Order 24665: `https://www.dmr.nd.gov/oilgas/or24665.pdf`

[33] NDIC Order 24655 Guidance from April 18, 2018 `https://www.dmr.nd.gov/oilgas/041718GuidancePolicyNorthDakotaIndustrialCommissionorder24665_2.pdf` and November 20, 2018 `https://www.dmr.nd.gov/oilgas/112018GuidancePolicyNorthDakotaIndustrialCommissionorder24665_2.pdf`

accommodate firms' failure to meet them:

> *In November 2018, the NDIC made additional changes due to the high rate of growth in gas production. The NDIC revised the goals of the gas capture policy to focus on increasing the volume of captured gas, rather than reducing the flared volume.*[34]

Both Texas and North Dakota impose severance taxes on oil and natural gas brought to market, but this severance tax is not imposed on flared gas.[35] According to North Dakota HB 1134, producers pay no severance taxes or royalties on the first year of flared gas (or captured gas).[36] Taxes and royalties lower the profitability of capturing gas compared to flaring it, and may tip marginal wells to flare instead of capture gas. One simple policy change would be to equalize the tax treatment of flared and captured gas.

5.3 Market-based policy benchmarks

We now turn to discuss the options that regulators have to reduce flaring. An extreme policy would be an outright *ban* on flaring. If it is socially optimal for some gas to be flared, a ban would lead to overinvestment in costly midstream infrastructure and under-production of oil. A ban would be particularly onerous for future exploration, as firms would need to build costly midstream infrastructure before fully understanding the potential of the area. A ban would also give midstream firms greater leverage in pricing their services, potentially creating additional market power as appears to be the case in the EXCO vs Williams conflict.

[34] `https://www.energy.gov/sites/prod/files/2019/08/f66/North%20Dakota.pdf`

[35] The Texas Comptroller website reports that flared gas is exempt from severance taxes. The Texas RRC describes an additional severance tax exemption for gas that was previously flared for 12 months but is now being captured.

[36] HB 1134, passed in the Sixty-third Legislative Assembly of North Dakota In Regular Session in 2013, allows non-Bakken wells to flare for up to one year. Order 24665 allows the first well in a Bakken spacing unit to flare unlimited quantities. Subsequent infill wells in the Bakken spacing units can flare unlimited quantities for 90 days, and are then subject to the operator performance standard. `https://www.legis.nd.gov/assembly/63-2013/documents/13-0257-08000.pdf`

The standard economic solution for the disconnect between the opportunity cost of flaring faced by firms and the full social cost of flaring is to give firms a market signal of the social costs of flaring. Implementing a *market-based policy instrument* would give firms the flexibility to flare while allowing the market to allocate flaring reductions to the least costly means. When producers make decisions, market-based instruments allow them to incorporate the social cost of flaring into their profit calculations. The regulator does not have to make judgment calls about which wells should flare and which should not. The policy would be less stringent than an outright ban on flaring and more flexible than firm- or well-specific limits.

One way to do this is for the regulator to charge a "flaring fee" (*Pigouvian tax*) for each unit of gas flared. The fee should be set equal to the marginal external cost of pollution created by flaring. With such a fee, firms considering whether to flare will explicitly incorporate the external cost of flaring in their investment decision. Both Lade and Rudik (2018), writing on North Dakota's Bakken shale, and Johnson and Coderre (2012), writing on oil production in Alberta, Canada, find that moderate prices for flaring can reduce flaring by an economically significant amount.

Another way of pricing flaring is for the regulator to issue a limited number of permits specifying the amount of flaring allowed in a given time frame. The regulator would allow firms to buy and sell these permits from each other (a *cap and trade* program). The RRC does currently allocate flaring permits to firms. However, permitting does not appear to constrain flaring, and the permits are not tradable.

Market-based instruments have been applied in many other contexts. These include cap and trade programs for sulfur dioxide allowances to control acid rain through the bipartisan Clean Air Act Amendments of 1990 (Carlson et al. 2000); for nitrogen dioxide (NOx) through the NOx Budget Trading Program in the northeastern U.S. (Fowlie 2010) and California's Regional Clean Air Incentives Market (Fowlie, Holland, and Mansur 2012); and for greenhouse gases through the Regional Greenhouse Gas Initiative (Fell and Maniloff 2018; Murray and Maniloff 2015) and California's AB32 program (Caron, Rausch, and Winchester 2015).

A flaring fee is likely to be preferable to a cap and trade scheme from an *economic efficiency* standpoint, as others have argued with respect to greenhouse gas regulation more generally (Goulder and Schein 2013; Hoel and Karp 2002; Karp and Zhang 2005; Newell and Pizer 2003; Pizer 2002). The reasoning is based on the well known framework in (Weitzman 1974).[37] Consistent with Weitzman's model, the marginal benefits of flaring abatement are likely to be flat over the relevant range of possible abatement. The climate damages associated with greenhouse gas emissions from any source, including those from flaring, are fairly constant over the short run. Climate damages are caused by the total atmospheric stock of carbon, not as much incremental emissions (Hoel and Karp 2002). Although the slope of the marginal external damages caused by local air pollution from flaring is less well understood, the marginal abatement benefits also include the opportunity cost of the foregone natural gas commodity value. This can be valued at the market price, which is not likely to change much if flared volumes are instead captured. A constant, per-unit tax on flaring should approximate climate and local air pollution costs. The marginal cost of reducing flaring is likely increasing: reducing flaring from some wells will be relatively inexpensive, but the cost rises for wells that are far from gathering infrastructure, as Lade and Rudik (2018) have shown. It is difficult to predict what the "right" amount of permitted flaring (the cap) should be in the future. Baseline production will change with global oil shocks, and new infrastructure will be built and change the cost of midstream services. These uncertainties make it difficult for a regulator to know what the right quantity of flaring is and accurately predict flaring abatement costs. With uncertain and steep marginal abatement costs, and fairly constant marginal abatement benefits, taxes generally minimize the economic losses of any errors in policy stringency (Weitzman 1974).

[37] According to Weitzman (1974), when the marginal costs of abatement are uncertain, the regulator has to guess the optimal level of the tax or the cap. If the regulator sets policies that are too stringent or not stringent enough, this implies an economic loss. If the marginal benefits of abatement are relatively constant but the marginal costs of abatement increase rapidly with additional abatement, then the economic losses from deviating from the optimal tax are smaller than deviations from the optimal cap.

A flaring fee may also be easier to administer for the regulator. There are bureaucratic costs associated with setting up and running a cap and trade market, and choosing rules for allocating permits can be contentious. In addition, the difficulties in predicting the "right" amount of flaring mentioned above in order to calculate and allocate the appropriate quantity of permits may be unpalatable and administratively costly to regulators. Permit trading also creates a new source of price volatility. In contrast, however, taxes and fees tend to be unpopular. If the regulator's objective is to achieve a given predetermined limit on the amount of flaring at least cost, then cap and trade is a cost effective approach.

There are other alternative regulations that could be implemented. North Dakota is using a *portfolio standard*, also known as a *performance standard* or a *rate standard*. Other examples of a portfolio standard in practice are the U.S. Corporate Average Fuel Economy (CAFE) standards for automotive manufacturers (Austin and Dinan 2005); the low carbon fuel standard for light-duty vehicles in California (Holland, Hughes, and Knittel 2009); and state renewable portfolio standards (RPSs) that require firms to generate a certain share of electricity from renewable sources (Upton and Snyder 2017). A tradable performance standard for CO2 emissions in the power sector was included in the U.S. Environmental Protection Agency's Clean Power Plan but was never enacted (Bushnell et al. 2017).

A common critique of performance standards is that they can implicitly subsidize production in areas that fall below the standard. This can distort economic decision-making as firms have an incentive to inflate whatever quantity is in the denominator of the emissions rate calculation (Fischer 2001; Helfand 1991).[38] For instance, North Dakota's flaring portfolio standard is based on the flared gas per unit of gas produced, rather than flared gas per barrel of oil (what some term *flaring intensity*). This type of stan-

[38] In the context of the CAFE standards, this effect has lead to large disparities in the size of cars on the road (Jacobsen 2011). Holland, Hughes, and Knittel (2009) show that a nationwide low carbon fuel standard for vehicles could actually increase net carbon emissions. In the electricity sector a carbon emissions standard would subsidize natural gas-fired power generation, which may come at the expense of renewable power (Becker 2020).

dard could incentivize producers to drill more low-value, gassy wells with low gathering costs. The credits from these low-value wells could then offset flaring from high-value oil wells with high gathering costs. A standard based on flared gas per barrel of oil (flaring intensity) would incentivize producers to drill more low-value, low-gas oil wells in order to generate credits to offset flaring from high-value, high-gas oil wells. In that case, the standard could inefficiently subsidize oil production rather than captured gas production. Standard economic theory says that both types of portfolio standards sacrifice economic efficiency for industry flexibility.

The North Dakota flaring portfolio standard does not allow firms to trade the right to flare (Lade and Rudik 2018). One possible improvement would be for regulators to allow trade. This would allow firms with high gathering costs to purchase the right to flare from firms with low gathering costs. The industry would achieve its flaring target, but at a lower cost. Two studies of *tradable portfolio standards* for power generation emissions estimate that allowing trade offers significant cost savings (Burtraw, Fraas, and Richardson 2012; Burtraw, Woerman, and Paul 2012). While tradable performance standards are not as economically efficient as a flaring fee or cap-and-trade program, they are likely to be more cost effective than technical restrictions on when firms can flare or an outright flaring ban.

5.4 Monitoring

All of the regulations discussed in the previous subsection require that state regulators can accurately monitor flaring by each firm. Regulators, however, do not proactively monitor flaring at each well. Instead, firms self-report 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 and Shavell 1994). Self reporting schemes may also lead to intentional misreporting. Whether the the benefits of self reporting exceed the social costs of underreported pollution depends on the costs of auditing and imposing fines, the stringency of the policies in place, and the accuracy of monitoring technology (Malik 1993).

Comparisons of state regulatory data and satellite-based flaring estimates suggest that producers are flaring significantly more than they report (Collins 2018; Lee 2019; Leyden 2019). More investigation is needed to resolve the discrepancy, understand producers' incentives to misreport flaring, and find ways to modify flaring regulation in light of misreporting.

Misreporting may or may not be intentional. Firms have an incentive to misreport or violate regulations when the cost of compliance is greater than the payoff to violation. Lee (2019) finds that misreporting of flaring in the Bakken increased significantly after the portfolio standard was imposed in 2014, especially in areas with more historical oilfield incidents. Misreporting due to simple mismeasurement is also possible. Flaring happens at high temperatures and pressures. These are most severe during peak production from the well, and accurate measurement requires costly instrumentation (Buzcu-Guven and Harriss 2012; Emam 2015; Marshall 2012; Olin 2014). Misreporting may be greatest earlier in a well's life when flared volumes are highest: flaring is hardest to measure, and production may exceed available gathering capacity. In Texas, incentives to misreport could also be highest when flaring permits expire, potentially after peak production.

Differences in firm size and capital structure may also affect compliance. One market intelligence report notes that smaller producers tend to flare more of their production than larger producers in the Permian. The note further explains that the smallest producers fall into two groups: they either report significant flaring or none at all. The author writes that discrepancy could indicate that a number of these small firms are under-reporting (Rystad Energy 2020). Large, well-capitalized producers likely find compliance to be less costly since they can spread fixed reporting and compliance costs over more wells. Publicly traded firms may also face higher public pressure to meet environmental goals that involve less flaring.

If caught misreporting, large firms in strong financial positions are liable for the full cost of noncompliance. Smaller firms in tenuous financial positions can limit their liability by declaring bankruptcy. Limited liability may reduce the incentive to comply with regulations (Shavell 1986). This *judgment-proof problem* is often associated with large accidents like major oil spills, but it applies to any *ex-post* financial liability, including fines for misreporting and unpaid prior flaring fees.

Liabilities associated with flaring may not be large under current rules, but with a flaring fee or cap and trade program in place, firms could be made to pay for their flaring in arrears if a pattern of misreporting was discovered. Bankruptcy would limit costs to the firm should this occur. Flaring violations may also affect how investors, banks, and bonding agencies assess the risk of a particular producer. In the context of oil spills, Boomhower (2019) shows that increasing small firms' liability for environmental damages from Texas oil production by requiring surety bonds caused significant reductions in environmental impacts, while also driving consolidation. Incorporating flaring limits into surety bonds in combination with a market-based flaring fee would ensure that firms are in a financial position to pay these fees, but could also create perverse incentives for misreporting and detection avoidance as firms have a larger financial incentive to hide their flaring in order to recoup their bond and avoid the fees.

Remote sensing offers a possible remedy for regulators' current inability to perfectly monitor flaring. Government satellites like NOAA's VIIRS instrument[39] or commercial satellites, such as the Claire satellite operated by GHGSat Inc or those operated by Satelytics, and over-flights can be used to monitor flaring at scale. Unfortunately, there are limits to current remote sensing technology. Over-flights are expensive. Satellite-based methods are good at detecting aggregate flaring over a wide region and longer time. However, atmospheric noise and ground-level conditions limit their ability to attribute individual infrared anomalies to flaring at a particular well and time. This is particularly true when wells from multiple operators are relatively close together as they are in the Permian and the Bakken.

While these remote sensing approaches can be effective at improving measurement of actual flaring and misreporting in aggregate, more theo-

[39] The Earth Observation Group at Colorado School of Mines' Payne Institute uses data from VIIRS to create a dataset of flares from around the world. `https://payneinstitute.mines.edu/eog-1`

retical and applied research is needed to determine how this information can be optimally incorporated into the design and enforcement of flaring regulations. Lessons from regulating regional air and water quality may be useful in this regard. Often air and water pollution emissions by individuals are not observable but ambient pollution levels across a broad area such as a county or a body of water can be measured. Such emissions are often called "Non-Point-Source" (NPS) pollution. Flaring represents an intermediate case in which remote sensing can detect flaring in a local area, but accurately measuring the location and volume depends on the cost of deploying the technology, the time horizon, and the atmospheric conditions. Policy options for NPS pollution have historically included regulating inputs (which are more easily observed than pollution), regulating all firms based on the ambient level of detected emissions in a region, or creating hybrid schemes to incentivize investment in more accurate monitoring technology and emissions reductions (Xepapadeas 2011).

Input-based schemes work by regulating unobservable emissions indirectly through an observable part of the production process. In the context of flaring, this can include oil production itself in addition to production inputs. Because oil and gas are jointly produced from individual wells, most uniform, input-based schemes may result in a proportionate reduction in oil production regardless of whether they target inputs or oil output. For example, the regulator could impose taxes on drilling permits, rigs, well completions, or oil output. Each of these options may reduce flaring at the expense of significant reductions in oil production.

Input-based schemes need not be applied uniformly if the regulator can estimate each firm's contribution to emissions based on activity they can observe (Dosi and Tomasi 1994; Shortle, Abler, and Horan 1998; Shortle and Dunn 1986). Regulators could use satellite data to identify localized flaring clusters, estimate each nearby lease's contribution to localized flaring based on their input use, oil production profile, and proximity to the center of the cluster, and use these estimated contributions to levy firm-specific flaring fees. Drawbacks to this approach are that the complexity of these calculations may seem non-transparent to regulated firms, and uncertainty in the calculations means that the tax burden will not always be fairly allocated. The practical issues of applying such a scheme to flaring and its economic efficiency relative to alternative policies would require further study.

Ambient schemes are an alternative to input-based regulations. Under ambient schemes, all producers in a given region or zone pay a fee equal to the marginal external cost of emissions when the aggregate pollution level in the area exceeds the limit. In some ambient scheme designs, the fees can be rebated back to firms when ambient levels fall below the limit in order to provide a collective incentive to keep emissions low (Holmstrom 1982; Horan, Shortle, and Abler 1998; Segerson 1988). Under an ambient scheme applied to flaring regulators could set local or zonal limits on aggregate flared volumes detected by satellites. Given the current state of remote sensing technology, the zones could be fairly small – on the scale of a few square miles. Although these schemes can be economically efficient, they often suffer from challenges of budget balance and collusion among the regulated firms (Xepapadeas 2011). Budget balance may be easier to achieve with many small zones because in any given reporting period some zones may be above and others below the allowable limit. With few operators per zone, however, collusion becomes more of a concern.

Some of the problems with ambient schemes can be resolved with *hybrid schemes* that involve differential taxation depending on how firms report their emissions and whether they install monitoring technology that the regulator can use to verify emissions (Xepapadeas 1995). The accuracy of onsite instruments for measuring flared volumes continues to improve, although some producers report estimates from engineering calculations rather than direct measurements from monitoring instruments (Buzcu-Guven and Harriss 2012; Emam 2015; Marshall 2012; Olin 2014). Improved instrumentation and adoption incentives could be part of a hybrid scheme. Millock, Sunding, and Zilberman (2002) and Millock, Xabadia, and Zilberman (2012) propose a differential taxation scheme that allows firms to choose between two options. Firms can choose option one: to pay a large fixed fee. They can also choose option two: receive a small, lump-sum subsidy to install monitoring equipment and pay the Pigouvian fee equal to their own (now verified) marginal external costs. It may be possible to adapt a hybrid scheme to spur additional investment in improved remote-sensing that could be used by many firms.

6 Conclusion

Flaring is an important environmental issue for the U.S. oil and gas industry. Additional economic and engineering research is particularly needed in at least five areas. First, our analysis of flaring is not able to attribute a specific percentage of total flaring to each of the constraints that exists along different points in the midstream value chain. Detailed upstream and midstream data from Texas and North Dakota should enable this kind of analysis. Second, more work can be done to understand the external costs of upstream flaring in terms of climate damages from GHG emissions and the health damages from local air pollution. Third, further research can help regulators understand whether the market structure of midstream services leads to inefficient capacity constraints and excess flaring. For instance, if the price of midstream services lies significantly above the cost of those services, market regulators at both the state and federal level can take this into account while setting cost of service based rates. If some of these wedges are associated with market power, policies to promote competition may also have positive environmental benefits. Fourth, further research on specific policies aimed at flaring reductions can guide flaring policy decisions. An important element of such research is to account for the possible unintended consequences of policy. Finally, further research on remote sensing to detect flaring can improve measurement of flaring and provide policy-makers new options.

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A Extra figures

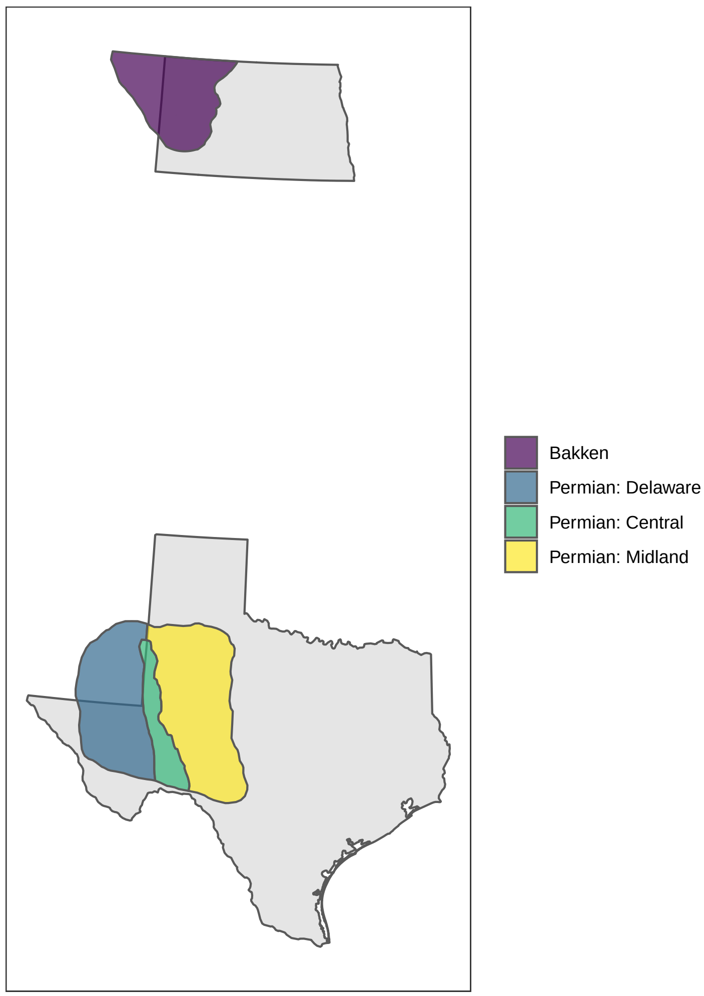

Figure 13: Map of Bakken and Permian shale plays as defined by Enverus

	Oil	Gas	Flaring		
	mmbbl/d	bcf/d	bcf/d	Share	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	0.85	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	1.37	2.82	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	1.45	0.00	0.00	0.26
2012	0.01	1.24	0.00	0.00	0.32
2013	0.02	1.21	0.01	0.01	0.41
2014	0.05	1.33	0.01	0.01	0.29
2015	0.09	1.55	0.06	0.04	0.66
2016	0.12	1.67	0.08	0.05	0.71
2017	0.18	2.14	0.07	0.03	0.40
2018	0.31	3.19	0.10	0.03	0.34
2019	0.40	4.06	0.11	0.03	0.27
		Permian oil leases			
2007	0.18	0.46	0.00	0.00	0.00
2008	0.20	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	0.32	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	0.09	0.05	0.13
2015	0.79	2.25	0.10	0.04	0.12
2016	0.93	2.59	0.07	0.03	0.08
2017	1.27	3.27	0.09	0.03	0.07
2018	1.93	4.58	0.22	0.05	0.11
2019	2.32	5.98	0.30	0.05	0.13

Flaring share is mcf flared per mcf gas produced.

Flaring intensity is mcf flared per bbl oil produced.

Table 1: Average production rates for January 2007–November 2019