Costs of Inefficient Regulation: Evidence from the Bakken

Gabriel E. Lade, Iowa State University and CARD, gelade@iastate.edu

Ivan Rudik, Cornell University, irudik@cornell.edu

Selected Paper prepared for presentation at the 2018 Agricultural & Applied Economics Association Annual Meeting, Washington, D.C., August 5-August 7

Costs of Inefficient Regulation: Evidence from the Bakken

Gabriel E. Lade and Ivan Rudik*

January 29, 2018

Abstract

Efficient pollution regulation equalizes marginal abatement costs across sources. Here we study a new flaring regulation in North Dakota's oil and gas industry and document its efficiency. Exploiting detailed well-level data, we find that the regulation reduced flaring 4 to 7 percentage points and accounts for up to half of the observed flaring reductions since 2015. We construct firm-level marginal flaring abatement cost curves and find that the observed flaring reductions could have been achieved at 20% lower cost by imposing a tax on flared gas equal to current public lands royalty rates instead of using firm-specific flaring requirements.

JEL Codes: L71, Q3, Q4

Keywords: North Dakota, Bakken, hydraulic fracturing, flaring, efficient regulation, oil and gas

---

*Lade: Iowa State University and the Center for Agricultural and Rural Development. Email: gelade@iastate.edu. Rudik: Cornell University. Email: irudik@cornell.edu. We gratefully acknowledge financial support for this research from the National Science Foundation, Department of Energy, and NBER under the Economics of Energy Markets Grant program, grant number 36269.00.03.00. We thank Dave Keiser, John Rupp, Carly Urban, and seminar participants at Indiana University, Montana State University, East Carolina University, University of Minnesota, and the NBER Economics of Energy Markets meetings for helpful comments. Erix Ruiz-Mondaca and T.J. Rakitan provided excellent research assistance.

1 Introduction

A necessary condition for cost-effective regulation is that marginal compliance costs are equal across all regulated sources. Environmental regulations that achieve this condition include pollution taxes and cap-and-trade programs. Despite the increasing prevalence of market-based environmental policies, many environmental regulations still deviate from this central economic principle. Inefficiencies can arise for two reasons. First, policies may inefficiently allocate pollution abatement across sectors or firms. Second, policies may limit intertemporal arbitrage of abatement costs, requiring firms to meet the same standard in every compliance period.

The gains from moving to more efficient regulation are usually unknown. Estimating efficiency gains requires knowledge of firms' marginal abatement cost (MAC) curves, which are difficult to recover. Those studies that do estimate MAC curves find that gains from trade can be substantial. Carlson et al. (2000) study the SO_2 emissions trading program under Title IV of the Clean Air Act Amendments of 1990 and find that annual compliance costs were \$800 million (43%) lower with trading compared to a uniform standard. Fowlie et al. (2012) document substantial differences in NO_x abatement costs across the electricity and transportation sectors and estimate that equating MACs across the two sectors could reduce total compliance costs by \$1.6 billion (6%).

In this paper, we study the impacts and efficiency of a new natural gas flaring regulation in North Dakota. North Dakota's Bakken shale formation is valued primarily for its vast unconventional oil deposits. However, when firms extract oil, their wells also produce valuable natural gas and natural gas liquid (NGL) co-products. In the absence of pipeline infrastructure, these co-products are flared: burned at the well site (Swanson, 2014). Flaring has become an acute problem in unconventional oil fields in the US because of the explosion in production over the past decade. Despite the rapid growth in production, infrastructure to capture and process the associated natural gas has lagged behind. In July 2014, the North Dakota Industrial Commission (NDIC) passed Commission Order 24665 to reduce gas flaring in the state. The regulation established some of the most aggressive flaring standards in the US, and other regulatory agencies have closely followed its progress (Storrow, 2015).

Order 24665 mandates that every operator in North Dakota captures a minimum percentage of gas produced by all their wells, with an ultimate objective of capturing 91% of produced gas by 2020. Several features of the regulation indicate it is inefficient. First, it is firm-specific. Since 2015, every firm operating in North Dakota must meet the same flaring standard. If operators have different marginal costs of capturing gas, the policy inefficiently allocates abatement across firms. Second, firms must meet the flaring standard every month.

If abatement costs change over time due to expanding pipeline infrastructure or firms drilling new wells, firms may misallocate abatement intertemporally. Gas capture regulations have been identified as among the most difficult and costly regulations for oil-producing firms to comply with (Zirogiannis et al., 2016), suggesting the costs of abatement misallocation may be large.

We begin by characterizing the impact of the NDIC regulation on firms' well operations. We find that the regulation decreased flaring rates at new wells by 4–7 percentage points in the first year of production and that the regulation accounted for between one-third and one-half of the observed year-on-year reduction in flaring rates at new wells in the state. Firms complied with the regulation by accelerating how quickly they connect their wells to gas capture infrastructure, and by taking longer to complete (i.e., begin producing from) new wells after drilling. Consistent with previous literature, we do not find that firms responded to the regulation by curtailing oil or gas production (Kellogg, 2011; Anderson et al., 2016).

We next construct firm MAC curves. The exercise is motivated by our empirical finding that firms' comply with the regulation by connecting wells to pipeline infrastructure. We use detailed pipeline location data to measure the distance between wells and the nearest pipeline infrastructure. We then use engineering estimates to construct estimates of on-site and pipeline infrastructure costs for each well and then aggregate the cost estimates to construct firm-specific and industry MAC curves. We use the estimated cost curves to simulate three counterfactual scenarios that achieve the same aggregate flaring reductions that we observe from January 2015 to June 2016, the first eighteen months of the policy.

We document significant heterogeneity in abatement costs, both across firms and over time. Using our preferred cost estimates, reallocating abatement reduces aggregate compliance costs by \$96 million, or 20%, over the first eighteen months of the regulation. About two-thirds of the reductions result from equating marginal abatement costs across firms, and one-third comes from equating marginal abatement costs within a firm over time. We also calculate counterfactual taxes that could achieve the same observed flaring reductions. We find that the state could achieve the same flaring reductions by taxing flared gases at a rate of \$0.42/mcf. To put the value in perspective, the average public lands royalty rate on gas revenues over this period was around \$0.45/mcf. Alternatively, this amounts to taxing carbon emissions from flared gas at \$7.92/tCO_2, well below current social cost of carbon estimates.

Regulators have several incentives to limit flaring. First, flaring is associated with a number of environmental externalities. Worldwide, flaring results in 300 million tons of CO_2 emissions each year, equivalent to the emissions of 50 million cars (World Bank, 2015). Flaring also emits local pollutants including NO_x, SO_2, and aromatic hydrocarbons that have been linked to cardiovascular disease and increased prevalence of cancer. Second, flaring results in economic losses to lease-owners and the government since flared gases are rarely subject to royalty payments and taxes. In the US, federal and state agencies have passed or considered a number of regulations to reduce gas flaring. For example, the Bureau of Land Management and the EPA recently considered rules to regulate flaring and methane emissions (Bureau of Land Management, 2016), while the Fish and Wildlife Service has considered regulating hydraulically fractured wells drilled on and near protected habitats. Globally, the World Bank has a Zero Routine Flaring initiative seeking to eliminate routine flaring by 2030.

Our work contributes to a growing literature studying the economic impacts of the fracking revolution. Previous work has documented the health and pollution impacts of fracking (Olmstead et al., 2013; Hill, 2015); how nearby drilling is capitalized into housing values (Gopalakrishnan and Klaiber, 2014; Muehlenbachs et al., 2015; Bartik et al., 2017); the efficiency of landowner-firm leases (Vissing, 2016); the supply elasticity of fracked versus conventional wells (Newell et al., 2016); and the economic and welfare impacts of these newly reachable resources (Hausman and Kellogg, 2015; Feyrer et al., 2017). Only recently have others begun to analyze firm decision-making, specifically learning, in this setting (Covert, 2015). To date, little work has studied the effects of environmental regulations on oil and gas firms' decision-making. One contribution of our paper is to take advantage of a rich dataset to develop novel identification strategies to study the impact of policies on well operations.

This paper contributes more generally to an extensive literature studying efficient regulation. Environmental economists have long advocated for moving from command-and-control to market-based policies. The theoretical efficiency of market-based instruments is well established (Montgomery, 1972; Baumol and Oates, 1988) but little work has been able to empirically validate these results (Carlson et al., 2000; Kerr and Newell, 2003; Fowlie et al., 2012).

The paper proceeds as follows. In Section 2, we describe oil production in the Bakken, the institutional and regulatory setting in the state, and the North Dakota flaring regulation. In Section 3, we develop a model of a firm's production and gas connection decisions to clarify the margins through which firms may respond to the regulation and motivate our subsequent simulations. In Section 4 we describe our data and provide summary statistics, and in Section 5 we discuss our empirical strategy and present our results of the effects of the regulation on firms' flaring and production decisions. In Section 6 we estimate firm-specific marginal abatement cost curves and construct counterfactual flaring scenarios. Section 7 concludes. The appendix contains more details on how we perform the counterfactuals, as well as a set of sensitivity and robustness checks.

2 Background

2.1 The Bakken Shale Formation

Much of North Dakota's geology is characterized by "tight" formations where oil is locked into the structure of shale rock. Two advances have drastically improved the economic viability of extracting oil in the region. First, drilling operations have become more efficient at drilling horizontal wells. Since shale formations are found in horizontal layers in the earth, drilling horizontally exposes the well to more oil-rich rock than vertically drilled wells. Second, firms have become more efficient at fracturing shale rock. Fracturing involves injecting fluids into wells at extremely high pressures to fracture the surrounding rock so that oil can flow out of the well.

These innovations have transformed the oil and gas industry. Oil production from fracked wells now accounts for nearly half of US production (Energy Information Administration, 2015), and oil production in North Dakota has increased tenfold from 90,000 barrels per day (bpd) in 2005 to over 1.2 million bpd in 2015 (North Dakota Industrial Commission, 2016). Firms have also dramatically reduced their costs of extraction – break-even oil prices in the state have been recently estimated to be as low as \$35 per barrel (bbl) (Bailey, 2015). North Dakota is likely to continue producing substantial quantities of oil into the future. The US Geological Survey estimates that the Bakken and Three Forks shale formations contain 7.4 billion bbls of oil, accounting for nearly 20% of proven recoverable reserves in the United States (Gaswirth et al., 2013; Energy Information Administration, 2016a).[1]

In addition to oil, the Bakken formation contains 6.7 trillion cubic feet of associated natural gas and 530 million barrels of NGLs (Gaswirth et al., 2013). When oil is produced by a fracked well, these gas co-products come along with it. Historically, much of this gas has been flared. This comes at a significant cost to landowners and the state government because flared gas is rarely subject to royalty and tax payments. The lost value of the gas is non-negligible. Flared gas constituted about 14% of the energy content of the produced crude oil from 2006 to 2013 (Brandt et al., 2016), and the commercial value of NGLs flared by North Dakota well operators in May 2013 alone was estimated to be \$3.6 million (Salmon and Logan, 2013).[2]

[1] Three Forks is a smaller formation adjacent to the Bakken. We address both of them as the Bakken.

[2] Flaring is much preferred to venting, or releasing gases directly into the atmosphere. Vented gases contain compounds like hydrogen sulfide that are hazardous to human health. Flaring converts methane and other pollutants to CO_2 and reduces the quantity of other harmful by-products. Venting is also prohibited in North Dakota.

2.2 The North Dakota Flaring Regulation and Firm Compliance

The NDIC passed Order 24665 in 2014 to reduce flaring in the state (North Dakota Industrial Commission, 2015).[3,4] Order 24665 created ambitious gas capture goals. The regulation requires that every firm operating in the Bakken capture 77% of the gas produced at their wells from January 2015 to March 2016; 80% from April 2016 through October 2018; 85% from November 2016 through October 2018; 88% from November 2018 through October 2020; and 91% after November 2020. The gas capture requirements are applied uniformly across firms and firms must comply with the regulation every month.[5] Thus, the policy is akin to a within-firm cap-and-trade program, where firms can efficiently allocate abatement among all the wells they own, but cannot trade flaring rights with other firms. The regulation allows firms to bank excess gas captured for up to three months, but does it not allow for borrowing. The NDIC has indicated that to date, few firms have taken advantage of the banking provisions. Firms that violate the regulation can have wells ordered to curtail production to as low as 100 bpd.[6] If a firm is out of compliance for more than three months, it may incur civil penalties of up to $12,500 per day for each well that is below the firm-level capture target.

Firms must comply with the NDIC regulation every month. Each month, the NDIC calculates each firm's capture rate as[7]

$$(\%\ \text{Capture})_i = \frac{\sum_j \left(\mathrm{g}^s_{i,j} + \mathrm{g}^u_{i,j} + \mathrm{g}^p_{i,j}\right)}{\sum_j \mathrm{g}^i_j}$$

where j indexes the wells owned by firm i; $\mathrm{g}^s_{i,j}$ is gas sales from well j; $\mathrm{g}^u_{i,j}$ is gas used on site; $\mathrm{g}^p_{i,j}$ is the gas processed in an approved manner; and g^i_j is total gas produced by well j.[8] Firms' primary compliance mechanism is to connect wells to existing gas pipeline infrastructure. This involves installing smaller pipelines, called gathering lines, that connect

[3] A task force was first organized to develop a plan to reduce flaring in North Dakota in September 2013. In March 2014 the task force released its report and the ruling was subsequently adopted.

[4] Before its passage, the only existing flaring regulation was a requirement that operators pay taxes and royalties on flared gas after the first year of production (Energy Information Administration, 2016b). This was not particularly burdensome since wells produce most of their total oil and gas in the first year.

[5] The NDIC was cognizant of cost-effectiveness. Order 24665 explicitly states that it is firm-specific instead of well-specific to give firms "maximum flexibility" in complying with the policy (North Dakota Industrial Commission, 2015).

[6] Average production at new wells from 2015 to 2016 was 633 bpd in the first three months of production and 378 bpd in the first year of production. A substantial portion of industry stakeholders commented during the regulation's hearing on how the curtailments would negatively affect well economics, firm cash flow, and profitability.

[7] Firm compliance is determined with some delay due to reporting lags from industry. For example, the NDIC did not discuss aggregate flaring rates for January 2015 until its March 2015 monthly webinar.

[8] Gas may be used on site to power an electric generator or processed using a natural gas stripping unit.

the well site to larger product pipelines that transport the captured gas to processing plants.

Connecting a well to gas capture infrastructure does not eliminate flaring. Flaring at connected wells may still occur due to insufficient capacity of downstream gathering pipelines, product pipelines, or gas processing facilities. Firms have some margins to reduce flaring by changing practices on the well site. For example, a firm can temporarily curtail oil and gas production or use gas for other purposes on site. Alternatively, firms can build "looping" lines to circulate and store gas in case of insufficient downstream capacity.

The NDIC began enforcing the regulation in January 2015, and all active wells in the state were included in firms' gas capture calculations at that time. However, a well is not subject to the regulation for the well's first 90 production days. As a result, firms have substantial flexibility with regards to their flaring rates at new wells until the fourth month of production.

2.3 Oil Production in the Bakken

Understanding the impacts of Order 24665 on firm behavior requires knowledge of firms' decision-making and oil and gas production functions. After firms determine a suitable location and obtain the mineral rights, firms drill or "spud" a well. Most producers hire independent drilling companies for this. Drilling is completed in multiple stages, including: (i) drilling the vertical segment of the well; (ii) drilling one or more "laterals" or horizontal segments through the oil-rich shale layer; and (iii) inserting and securing production casing to protect surface water and ensure the structural integrity of the well. After drilling, firms hydraulically fracture the well. Fracking involves perforating the well casing and injecting large amounts of water, sand, and other additives at high pressure to create and prop open fissures in the surrounding shale rock. A well is "completed" and ready to produce oil and natural gas after it has been fractured. At this stage, firms install a permanent wellhead and other on-site infrastructure. Oil, gas, and water flow from the wellhead through the flow lines to tanks that separate oil from water and lighter hydrocarbon products. After separation, oil is stored in large containers until it is picked up to be delivered to the nearest pipeline or refinery. If the well is connected to gas gathering infrastructure, the separated gas is transported to nearby gas plants through pipelines. If the well does not have gathering lines installed, separated gas is flared at the well site.

The amount of oil and gas that a well produces is determined by two factors: (i) the amount of hydrocarbons in the underlying shale; and (ii) the length of the well and the intensity with which firms frack the well. Firms can affect the former by drilling in more productive areas. However, firms are not perfectly informed, and they do not always drill into the most productive shale (Covert, 2015). After a well is producing, the amount of oil and gas that comes out of the well is largely determined by the underlying pressure. While operators can curtail production or plug a well, they are unable to make the well more productive unless they re-fracture it.[9]

3 A Model of Gas Capture

We develop a model of an oil and gas producer to better understand the economic incentives of the NDIC's regulation and to identify factors that contribute to the inefficiency of the policy. We model a single firm facing the flaring regulation in a two-stage, static setting. In the first stage, the firm selects the number of wells to drill, J, the location of these wells, the length of the horizontal segment of the well, and how much of each input (e.g., water and sand) to use when fracking the wells. Between the first and second stages, the wells are fracked and completed. At the beginning of the second stage, the oil and gas productivity of each well is realized, and the firm decides whether to connect each well to gas capture infrastructure. At the end of the second stage, oil is sold at price P^o and, if the well is connected to gas capture infrastructure, gas is sold at price P^g. Here we will focus on the second stage.

We make two additional assumptions. First, the firm's connection decision is independent of its oil production (i.e., connecting a well has a negligible effect on oil-related profits). This assumption allows us to abstract from wells' oil production when considering the firm's gas connection decision. Second, we assume that the firm knows the total amount of gas a well will produce when it makes the connection decision. Neither assumption is overly restrictive in our setting. We are unaware of literature documenting production losses from installing gas capture infrastructure. After completion, oil and gas production follows a relatively stable, well-understood decline curve. A common characterization is the 'ARPS' model (Fetkovich, 1980). The model specifies well j's oil and gas production in any period t as

$$
\begin{aligned}
\mathrm{o}_{jt} &= \mathrm{O}_{j0} t^{\beta_{\mathrm{o}}} \exp(\epsilon_{jt}) \\
\mathrm{g}_{jt} &= \mathrm{G}_{j0} t^{\beta_{\mathrm{g}}} \exp(e_{jt})
\end{aligned}
\tag{1}
$$

[9] Kellogg (2011) and Anderson et al. (2016) study conventional oil wells in Texas and argue that oil prices impact well drilling rather than production from existing wells. They show that along an equilibrium path, firms always keep wells producing at their maximum possible level regardless of the prevailing oil price. This result has one caveat in unconventional oil setting: firms may re-pressurize unconventional wells by re-fracking.

where o_{jt} and g_{jt} are the well's oil and gas production at time t; O_{j0} and G_{j0} are the initial levels of oil and gas production from the well; β_o and β_g are the oil and gas decline rates; and ϵ_{jt} and e_{jt} are noise terms. In the first stage, the firm's input choices and the underlying geology determine O_{j0} and G_{j0}. So long as ϵ_{jt} and e_{jt} are small and mean zero, firms can estimate the total oil and gas that a well will produce with a fair degree of confidence after observing a well's initial production and decline rates at similar wells.[10]

Consider the second stage of the firm's problem. Wells are heterogeneous in the amount of gas they produce and their connection costs. Well j produces g_j units of gas over its lifetime, which can be calculated by summing equation (1) over the lifetime of the well. We denote the connection costs for well j as $C_j(h_j)$, where $h_j \in \{0, 1\}$ and 1 indicates that the well is connected to a gathering line while 0 indicates that it is left unconnected. We assume that $C_j(0) = 0,\ \ C_j(1) > 0$.[11] We model the NDIC flaring restriction as a minimum fraction of gas that must be captured by the firm across all its wells, $\bar{F} \in (\alpha, 1]$ where $\alpha > 0$ is sufficiently high so that the flaring constraint binds.

The firm's problem is

$$\max_{h_1,\ldots,h_J} \sum_{j=1}^{J} P^g\, g_j\, h_j - C_j(h_j)$$

$$\text{subject to:} \quad \frac{\sum_{j=1}^{J} g_j\, h_j}{\sum_{j=1}^{J} g_j} \geq \bar{F} \quad \text{and} \quad h_j \in \{0,1\}\ \ \forall j = 1, ..., J$$

Let λ denote the Lagrange multiplier on the flaring constraint. The firm connects well j if

$$P^g + \lambda \geq \frac{C_j(1)}{g_j}, \qquad j = 1, ..., J. \tag{2}$$

The firm connects well j if the marginal benefit of selling gas, the market price plus the firm's shadow price of the constraint, is greater than the cost of connecting the well per unit of gas produced.

The first-order condition yields key insights that allow us to empirically evaluate the efficiency of the regulation. A cost-effective policy equalizes shadow prices across all firms, and in a dynamic model, a cost-effective policy equalizes a firm's shadow price over all compliance periods. If $\bar{F}$ is applied uniformly across different firms, then λ will differ across firms if they own portfolios of wells with heterogeneous connection costs or gas productivity.

[10] While unconventional drilling remains a relatively new technique, there is evidence that unconventional wells have less variability in realized production than conventional wells (Newell et al., 2016).

[11] Gathering line costs vary along two important dimensions: (i) distance to the nearest product pipeline; and (ii) the diameter of the line.

Letting m denote the marginal well that a firm connects to gas capture infrastructure, differences in $C_m(1)/g_m$ across firms indicates differences in λ across firms and that the flaring regulation inefficiently allocated gas capture. Alternatively we can think of different firms in this static model as the same firm but at different points in time, assuming the firm is not forward-looking. A cost-effective policy would require that the per unit connection cost of the marginal well be equal in all compliance periods. We take advantage of these insights in Section 6.1 when we construct firm marginal abatement costs curves.

4 Data Description and Summary Graphs

Our data consist of monthly, well-level production, flaring, and sales data reported by the NDIC for over 9,300 horizontal wells owned and operated by 54 firms in North Dakota between 2007 and 2016. For most of our analysis, we focus on the roughly 6,800 wells completed between January 2012 and June 2016. We process the data from the NDIC in a few ways. First, we focus on oil and gas wells in the Bakken or Three Forks shale formation since the NDIC regulation applies only to these wells. Second, we drop wells where we observe the maximum level of oil production occurring more than five months after we observe their first production. These wells have likely been re-fracked and are not comparable to other wells.[12]

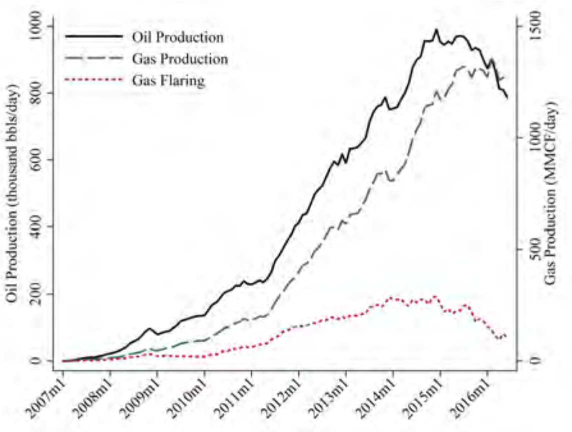
We observe a number of well-level characteristics including the year and month of spudding and completion; wells' latitude/longitude; well depth and horizontal length; and the current and original owner of all wells.[13] We merge the data with well characteristics from a number of other sources. First, we obtained GIS data for all natural gas and oil pipelines in 2016 from Rextag. We use the data to calculate the distance between every well and the nearest gas gathering or transmission pipeline.[14] Second, we merge data on the volume of the wells' fracking inputs from the FracFocus Chemical Disclosure Registry. We obtain weather data from the nearest weather monitoring station provided by the North Dakota Agricultural Weather Network, and snowfall data from the NOAA National Operational Hydrologic Remote Sensing Center. Last, we control for historical oil and gas price data using futures prices for Henry Hub (HH) natural gas and West Texas Intermediate (WTI) oil prices from

[12]We drop just over 1,000 wells as a result of these restrictions.

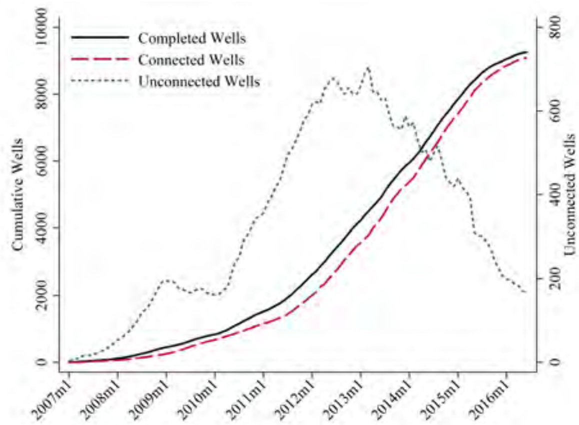
[13]Only the most recent operator and initial operator are provided. We do not observe the sales date of any wells and thus cannot determine when any well purchases may have occured.

[14]A disadvantage of the Rextag data is that we only observe a cross-section of North Dakota's pipeline network. We do not observe when each pipeline became active. We have also explored distance to the nearest well connected to gas capture infrastructure as an alternative distance measure that is time-variant to proxy for the roll-out of the gas pipeline network. Using this alternative measure does not affect our primary results.

Figure 1: Oil and gas production, gas flaring, and well completions in the Bakken.



(a) Aggregate Oil & Gas Production and Flaring



(b) Completed and Connected Wells

Notes: Figure 1a graphs total production and flaring from all horizontal wells in our sample from January 2007 to June 2016. Figure 1b graphs the cumulative number of completed and connected wells (left axis), and the number of unconnected wells (right axis) over the same period.

Quandl.[15,16]

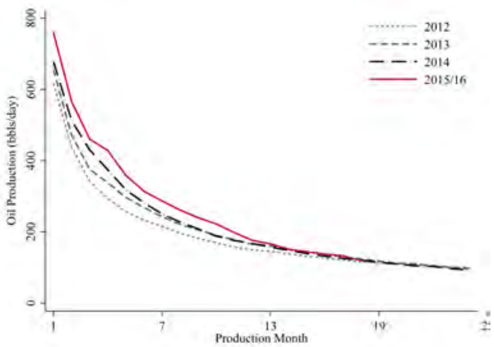
Figures 1a and 1b graph monthly oil and gas production, gas flaring, the number of completed and connected wells, and the number of unconnected wells from January 2007 to June 2016 for all wells in our sample. Oil and gas production grew exponentially until mid-2014 when oil prices began to fall, and operators flared a substantial volume of the gas produced in the state over this period. It was not uncommon to observe months where flaring rates exceeded 40% from 2008 to 2009, and monthly flaring rates regularly exceeded 30% until early 2014. Both the volume and rate of gas flaring has decreased since around the beginning of 2015 when the flaring regulation kicked in. Figure 1b highlights one of the main mechanisms through which firms have reduced flaring – the number of unconnected wells in the state has declined rapidly, particularly around January 2015.

Figures 2a to 2d graph average oil production, gas production, flaring rates, and the

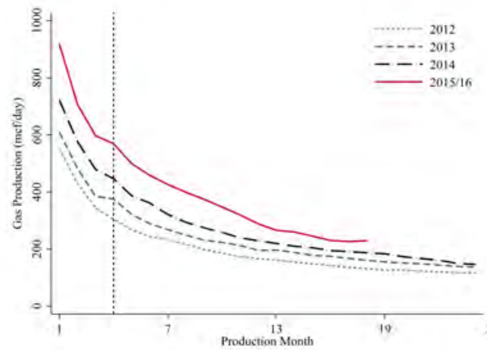
[15]Oil and gas prices for North Dakota crude oil are not publicly available at the frequency we require over the full sample period. In a monthly online webinar, the director of the NDIC stated that while there is no traded Bakken oil price, it is typically paid as a basis off of the WTI and that a reasonable estimate of the price received by Bakken producers is 85% of the WTI price. We are unaware of posted prices for natural gas in the state. However, recent work by Avalos et al. (2016) suggests that natural gas prices are integrated even in distant markets across the US.

[16]In our main specifications, we control for the average of all concurrently traded futures prices up to twelve months ahead. Results are not sensitive to using spot prices, the 6 month ahead futures price, or the 12 month ahead futures price.

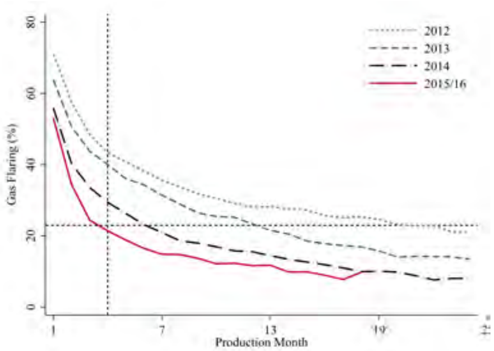
Figure 2: Well production, flaring and connection rates by production month.



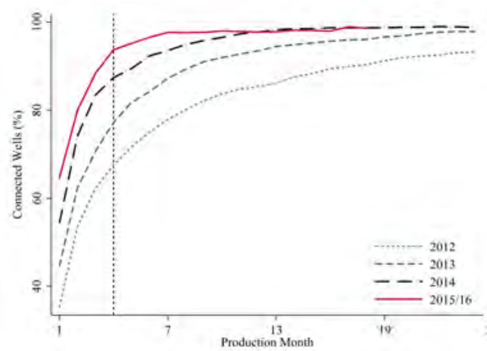
(a) Average Oil Production



(b) Average Gas Production



(c) Average Flaring Rate



(d) Average Connection Rate

Notes: The subfigures graph average oil and gas production, flaring rates, and connection rates in production time at wells completed in 2012, 2013, 2014, and 2015/16. The dotted lines in subfigure (c) indicate the January 2015 flaring target and the fourth month in production time.

fraction of wells connected to gas capture infrastructure in well 'production time.' Production time is defined as the months since the first month of observed oil production from a well. The figures document the substantial gains in productivity over time. Initial oil and gas production averaged 600 bpd and 600 thousand cubic feet per day (mcf/day) in 2012. By 2015–2016, initial oil production increased by 25% to 750 bpd and gas production increased by 50% to nearly 900 mcf/day. The figures also illustrate the approximately exponential decline rate in oil and gas production over the first year of production.

Flaring rates decline slowly over wells' productive lifetimes. In 2012 and 2013, firms flared around 40% of the gas that wells produced in their fourth production month, and flaring rates remained above 20% even after a full year of production. Wells completed in 2014 and 2015-2016 display nearly identical flaring rates in the first two production months. However, beginning in month three, wells completed in 2015–2016 show a rapid decline in flaring relative to 2014 until around the eighth production month. In the fourth month, when wells are subject to the flaring regulation, average flaring at wells completed in 2015–2016 is about 23% – the flaring limit set by the NDIC for 2015. Figure 2d graphs the fraction of wells that connected in a given production month. In 2012 and 2013, just around 40% of wells connected to gas infrastructure in their first production month, but by 2014–2016 this increased to about 60%.[17]

5 Effects of the NDIC Flaring Order

In this section, we describe our empirical strategy to estimate the impact of the NDIC regulation on flaring rates at new wells in North Dakota. We then describe our methods to disentangle the mechanisms by which firms respond to the regulation. We focus on: (i) time to complete wells; (ii) time to connect wells to gas capture infrastructure; and (iii) oil and gas production.[18] Last, we present our results.

5.1 Empirical Strategy: Flaring

We begin with a reduced form description of the regulation's effects. Our main empirical strategies use difference and difference-in-differences estimation frameworks. Because the majority of gas production, and therefore flaring, occurs in the first few months after firms

[17]Table A.1 in the appendix presents other relevant summary statistics, comparing wells completed in 2012–2014 to those completed after 2015.

[18]We do not consider other margins such as well location, well length, or fracking input choice. Conversations with regulators and operators in North Dakota suggest that drilling and location decisions are primarily determined by oil prices.

complete a well, we limit our analysis to the impact of the regulation on wells completed after January 2015 and focus on wells' first year of production.

We define our treatment group as North Dakota wells that were completed and began production in 2015–2016. Ideally we would observe wells drilled in similar locations over the same period that happened to be exempt from the regulation. While there are some unconventional oil wells in nearby Montana and Saskatchewan, the number of wells outside North Dakota is small, and data are not available at the same spatial or temporal resolution. We instead take advantage of the fact that wells drilled in North Dakota before the regulation have very similar production patterns over their lifetimes.

In our main specifications, we define our control wells as those that were completed in 2014 and define time in our estimation as production time. Wells completed in 2014 are eventually subject to the regulation. For example, flaring from a well completed in July 2014 is included in the firm's flaring calculations beginning in January 2015. Thus, we drop control well observations from calendar year 2015, and focus on the impacts of the regulation in wells' first year of production.[19] We include a number of covariates and fixed effects in our regressions to control for important factors that may differentially affect flaring at wells completed after 2015 versus those completed in 2014.

Our first empirical strategy is a differences strategy that compares flaring rates at wells completed in 2014 versus those completed after 2015 over their first year of production. We estimate the following regression:

$$Y_{ift\tau} = \rho \mathbf{1}[\text{Completed 2015}] + g(t;\Theta) + \mathbf{X}'_{if\tau}\beta + \varepsilon_{ift\tau}, \tag{3}$$

where $Y_{ift\tau}$ is the flaring rate at well i owned by firm f in production month t and calendar month τ.[20] $\mathbf{X}_{if\tau}$ includes the log of the well's gas production; the log of changes in HH and WTI prices; the log distance to nearest pipeline; and local weather conditions.[21] The function $g(t;\theta)$ is a flexible function in production time that controls for common practices across wells in each production month. In our main specification, we specify $g(t;\Theta)$ as production time fixed effects. Last, in $\mathbf{X}_{if\tau}$ we include township fixed effects to control for fixed characteristics of the well's location, firm fixed effects to control for fixed owner

[19]We perform a suite of sensitivity and robustness checks in the appendix, including using alternative control groups. We also conduct a number of placebo tests to validate our empirical strategy. Results are generally robust to all specifications, and placebo tests support the validity of our design.

[20]For example, $Y_{if,1,\tau}$ is the percent of the produced gas that is flared at well i in its first month of production, and $Y_{if,12,\tau}$ is the percent of produced gas flared in the twelfth month of production.

[21]We cannot reject the null hypothesis that log WTI and Henry Hub prices contain a unit root over our sample and the two series are highly collinear in levels. We, therefore, first difference the series in all regressions, controlling for whether the average twelve month ahead futures strip of each variable is increasing or decreasing in any given month. Weather controls include total precipitation and temperature.

characteristics, and month fixed effects to control for seasonality in production, drilling, and prices.[22]

Our second empirical strategy leverages the fact that wells are not included in firms' aggregate flaring calculations until their fourth production month. For this, we estimate the following difference-in-differences regression:

$$Y_{ift\tau} = \rho \mathbf{1}[\text{Completed 2015}, t \geq 4] + g(t; \Theta) + \mathbf{X}'_{if\tau}\beta + \varepsilon_{ift\tau}. \tag{4}$$

The controls are the same as the prior specification, with the exception that well fixed effects are now in $\mathbf{X}_{if\tau}$ and absorb the township fixed effects, firm fixed effects, and distance to a pipeline.

Our last empirical strategy is a matching estimator that compares flaring at wells completed in 2015 versus those completed in 2014. We use nearest-neighbor matching for every well completed after 2015 to its five closest matches from wells completed in 2014. We match wells based on their initial gas production, well depth, distance to a pipeline, average log difference in WTI and HH prices, and the number of months that we observe the well.[23] The simplest representation of our estimated treatment effect is given by:

$$\hat{\rho} = \frac{1}{N} \sum_{i=1}^{N} \left[\hat{Y}_i(1) - \hat{Y}_i(0) \right], \tag{5}$$

where $\hat{Y}_i(1)$ and $\hat{Y}_i(0)$ are the appropriately adjusted average flaring rates at wells that are subject to the regulation and not subject to the regulation.

Our identifying assumption is that, absent the NDIC regulation and conditional on our full set of controls, flaring rates for wells completed in 2015 would have the same level over the first year of the production as at wells completed in 2014 for the differences and matching strategies, and that flaring rates for wells completed in 2015 would follow parallel trends to wells completed in 2014. All strategies defined above identify changes in average flaring rates over either the entire first year of well production or the over fourth to twelfth production months. We explore heterogeneity in the regulation's effect throughout a well's lifetime by estimating difference-in-differences regressions of the form:

$$Y_{ift\tau} = \sum_{s=1}^{12} \rho_s \mathbf{1}[\text{Treated, t=s}] + g(t; \Theta) + \mathbf{X}'_{if\tau}\beta + \alpha_i + \varepsilon_{ift}. \tag{6}$$

[22] A township is a 6-by-6 mile square defined by the US Geological Survey.

[23] We use a Mahalanobis scaling matrix to determine our matched sample. We match wells exactly on the number of production months. Following Abadie and Imbens (2011), we adjust the estimates for bias resulting from matching on more than one continuous covariate.

Equation (6) allows for separate coefficients ρ_s for each of the first twelve production months.

5.2 Empirical Strategy: Mechanisms

We use similar empirical strategies to disentangle how firms comply with the regulation. We consider three margins of behavior. First, we test whether firms take longer to complete wells after spudding (drilling). This may indicate that firms install more on-site infrastructure, including gas capture infrastructure. Second, we test whether firms connect to gas capture infrastructure more quickly. Because gas output is highest in the first production months, reducing time to connection can increase the total amount of gas captured. Last, we test whether firms curtail oil and gas production at wells subject to the regulation.

Spud-to-completion and first production-to-connection duration: We estimate survival (hazard) models for the spud-to-completion time and first production-to-connection time. In the former, wells "survive" if they are not completed (i.e., not producing) t months after spudding, and "die" if they are completed. In the latter, firms "survive" if they remain unconnected to gas capture infrastructure t months after initial production and "die" if they connect. We define control and treatment groups as before, consider only the first twelve production months, and throw out data for wells completed in 2014 after January 2015.

We first estimate a non-parametric Kaplan-Meier (KM) survivor function for each outcome. Let $\bar{t}_j$ denote the production month a well is completed or connected to gas capture infrastructure, i_j denote the number of wells not completed or connected before production month $\bar{t}_j$, and c_j be the number of wells that are completed or connected in production month $\bar{t}_j$. The KM function is given by:

$$\hat{S}(t) = \prod\nolimits_{j|\bar{t}_j \leq t} \left(\frac{i_j - c_j}{i_j} \right). \tag{7}$$

We estimate equation (7) separately for wells completed in 2014 and those completed after 2015.

Equation (7) does not control for differences in the economic environment, gas capture infrastructure, or weather between the treatment and control groups. We therefore also estimate a parametric survival model with time-varying controls. Specifically, we estimate a hazard function for wells that are either completed or connected in period t as:

$$h(t, 1[\text{Treated}], \mathbf{X}_{it}; \Theta) = \frac{f(t, 1[\text{Treated}], \mathbf{X}_{it}; \Theta)}{1 - F(t, 1[\text{Treated}], \mathbf{X}_{it}; \Theta)}, \tag{8}$$

where $f(\cdot)$ and $F(\cdot)$ are Weibull density and cumulative density functions of the spud-to-completion time or first production-to-connection time.[24] For our spud-to-completion regressions, the covariates $\mathbf{X}_{it}$ include fracking inputs, well depth, oil and gas prices, and distance to nearest pipeline. For time to connection regressions, we control for initial gas production, distance to pipeline, and oil and gas prices. Our coefficient of interest in both cases is on the indicator function for whether the well was completed after 2015.

To facilitate interpretation we also estimate regression-adjusted average treatment effects (ATE) of the regulation on the spud-to-completion time and first production-to-connection time. We first estimate separate Weibull survival models for wells completed in 2014 and those completed after 2015. To ensure we have one predicted survival time for each well, we estimate a time-invariant version of equation (8). We then predict and compare the average survival times for each group to estimate an ATE of the regulation on time to completion and connection.[25]

Oil and gas production: Last, we test whether the regulation affects wells' oil and gas production. We estimate regression equations (3) and (4), where we replace $Y_{ift\tau}$ with the logarithm of oil or gas production. In these regressions, the function $g(t;\Theta)$ controls for the average oil and gas decline curve. Similar to Newell et al. (2016), we use three forms of $g(\cdot)$: (i) an ARPS model where $g(\cdot)$ is the logarithm of production time; (ii) a cubic spline in production time;[26] and (iii) production time fixed effects. Controls include oil or gas prices, initial oil or gas production, local weather conditions, and township fixed effects. As above, we also use a matching estimator comparing wells' oil and gas production for wells completed in 2014 versus those completed after 2015.

5.3 Results: Flaring Treatment Effects

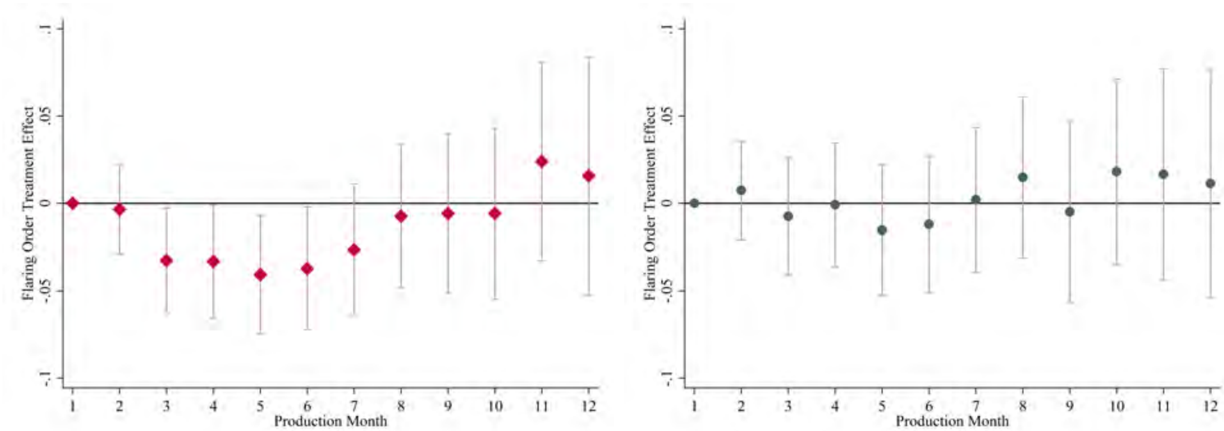
Table 1 presents our estimates of the effect of the regulation on flaring. Columns (1) to (3) show estimates of the treatment effects over the first year of production, and columns (4) to (6) show estimates of the treatment effects over the fourth to twelfth production months. Panel A includes all wells, and Panel B includes only wells that were connected by their second production month. The latter is meant to test whether the regulation impacts routine flaring that occurs after a well is connected to gas gathering infrastructure.

[24]Results are similar using an exponential and Gompertz survival distribution. Newell et al. (2016) use a generalized gamma distribution to estimate spud-to-completion times for conventional and unconventional oil wells in Texas. Results using a generalized gamma model are also similar to our Weibull results when we do not include covariates. However, including controls in the model leads to convergence issues.

[25]Coefficients for the time-invariant survival function are similar to the time-varying parameter survival model. We also estimate a linear probability model in the appendix.

[26]We estimate a four-knot restricted cubic spline with knots at 1.1, 1.4, 2, and 2.4 months. Knots are clustered early in the production lifetime since this is where the most curvature is in the production path.

Figure 3: Treatment effects of the regulation on flaring rates by production month.



(a) All Wells

(b) Connected Wells

Notes: Figure 3 graphs the point estimates and 95% confidence intervals from estimating equation (6). Time is specified in production time, and the effects are relative to the regulation's effect in the first production month. Figure 3a includes all wells, and Figure 3b includes wells that were connected in the first two production months. Both regressions include the same controls as in column (5) of Table 1. Standard errors are clustered at the well level.

After controlling for observable differences between wells completed in 2014 versus those completed after 2015, we find that all wells flared 4%–7% less over the first production year. The results differ between the difference-in-differences estimates and the matching estimators for months four to twelve. The former finds no impact while the latter finds substantive decreases. Panel B presents results for connected wells. We find no systematic reduction in flaring across these wells, suggesting that the regulation has little discernible impact on routine flaring. The point estimates for other covariates have intuitive signs. Firms flare more at wells if they produce more gas and if they are further from pipeline infrastructure, and firms flare less when natural gas prices are improving.

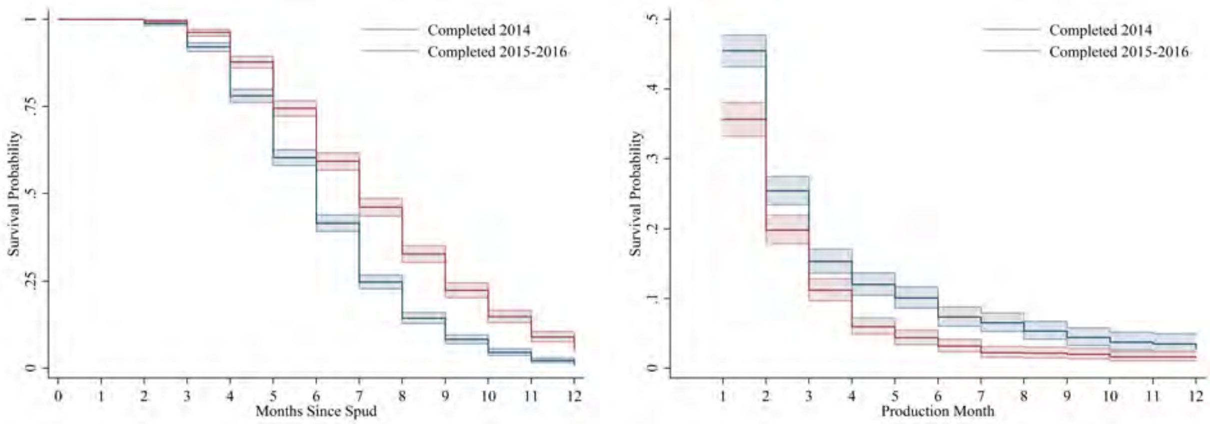
Figure 3 graphs the estimates and 95% confidence intervals from equation (6). The regression includes the same controls as in column (5) of Table 1, and we present estimates for all wells and those that were connected in their first two production months. All estimates are relative to the omitted first production month. When we consider all wells, the treatment effects are concentrated between the third and seventh production months, where we find a 3%–4% reduction in flaring rates relative to control wells. As before, we find no impact of the regulation on flaring at connected wells.

Table 1: Average effect of the regulation on flaring rates.

	(1) Dif	(2) Dif	(3) NN Match	(4) D-in-D	(5) D-in-D	(6) NN Match
Panel A: All Wells						
Post-2015 (M1-M12)	-0.112***	-0.043***	-0.072***			
	(0.008)	(0.011)	(0.011)			
Post-2015 (M4-M12)				-0.234***	-0.017	-0.089***
				(0.007)	(0.011)	(0.011)
Log Gas Production		0.034***			0.044***	
		(0.002)			(0.002)	
Log Dist. to Gathering Line		0.027***				
		(0.003)				
Δ Log HH Price		-0.447***			-0.185***	
		(0.063)			(0.056)	
Δ Log WTI Price		-0.313***			-0.114**	
		(0.050)			(0.048)	
Observations	26,610	26,610	3,292	26,423	26,423	2,747
Wells	3,358	3,358	3,292	3,171	3,171	2,747
Panel B: Wells Connected by Second Production Month						
Post-2015 (M1-M12)	-0.034***	0.003	0.030***			
	(0.008)	(0.010)	(0.010)			
Post-2015 (M4-M12)				-0.124***	-0.004	0.015
				(0.007)	(0.012)	(0.009)
Log Gas Production		0.012***			0.016***	
		(0.003)			(0.003)	
Log Dist. to Gathering Line		0.012***				
		(0.003)				
Δ Log WTI Price		-0.272***			-0.136**	
		(0.054)			(0.056)	
Δ Log HH Price		-0.235***			-0.133*	
		(0.065)			(0.068)	
Observations	15,527	15,527	1,980	15,414	15,414	1,631
Wells	1,980	1,980	1,980	1,867	1,867	1,631
Well FE	No	No	No	Yes	Yes	No
Firm FE	No	Yes	No	No	No	No
Township FE	No	Yes	No	No	No	No
Production Month FE	No	Yes	No	No	Yes	No
Calendar Month FE	No	Yes	No	No	Yes	No
Weather Controls	No	Yes	No	No	Yes	No

Notes: The dependent variable is the well-level flaring rate. The coefficients of interest are Post-2015 (M1-M12), which equals 1 if the well was completed after 2015, and Post-2015 (M4-M12), which equals one if the well was completed after 2015 and it is after the well's fourth production month. Dif, D-in-D, and NN Match denote our differences, difference-in-differences, and nearest neighbor matching estimators. Regression standard errors are clustered at the well level, and NN match standard errors are robust to arbitrary heteroskedasticity. *, **, and *** denote significance at the 10%, 5%, and 1% level.

Figure 4: Kaplan-Meier survival estimates.



(a) Spud-to-Completion Time (b) First Production-to-Connection Time

Notes: Figure 4 graphs KM survival probabilities and 95% confidence intervals for wells completed in 2014 and after 2015. Figure 4a graphs KM survival probabilities for spud-to-completion time. Figure 4b graphs KM survival probabilities for first production-to-connection time.

5.4 Results: Mechanisms

Figure 4 graphs the KM survival functions and corresponding 95% confidence intervals for wells' spud-to-completion and first production-to-connection times. Figure 4a graphs the survival probabilities for each month since initial spudding. In all months, the survival probability (non-completion probability) is higher for wells spudded after 2015 than those spudded in 2014. Six months after spudding, only 42% of 2014 wells remained incomplete, while over 55% of 2015–2016 wells remained incomplete. Figure 4b graphs survival probabilities for the time-to-connection duration models. Wells completed after 2015 have lower survival rates in all months. In the first production month, 45% of wells completed in 2014 remained unconnected while 35% of wells completed in 2015 were unconnected. We observe smaller differences in survival probabilities in the second and third production months. However, in the fourth month when new wells become subject to the regulation, the survival probability for wells completed after 2015 falls sharply, and the survival function remains lower through the ninth production month.

Tables 2 and 3 present the estimates from our structural survival models. Coefficients from the survival model in columns (1) to (3) are specified in accelerated failure-time so that a one unit change in explanatory variable x_j increases the failure time by $\exp(\beta_j)$. Columns (4) and (5) present the regression-adjusted mean completion time for 2014 wells and the difference in completion time (measured in months) between wells completed in 2014 and

Table 2: Effect of the regulation on spud-to-completion duration.

	(1) AFT	(2) AFT	(3) AFT	(4) ATE	(5) ATE
Completed Post-2015	0.197***	0.197***	0.206***	1.215***	1.101***
	(0.014)	(0.015)	(0.015)	(0.094)	(0.096)
Log Water Inputs		0.024**	0.024**		
		(0.010)	(0.011)		
Log Non-Water Inputs		-0.004	-0.003		
		(0.004)	(0.004)		
Log Well Depth		0.181**	0.246***		
		(0.089)	(0.089)		
Δ Log HH Price		0.431***	0.512***		
		(0.099)	(0.116)		
Δ Log WTI Price		0.040	0.264***		
		(0.077)	(0.094)		
Log Distance to Pipeline		-0.015**	-0.016***		
		(0.006)	(0.006)		
Mean Completion Time				6.281***	6.299***
(2014 Wells)				(0.056)	(0.060)
Observations	22,844	21,895	21,605	3,185	3,182
Density	Weibull	Weibull	Weibull	Weibull	Weibull
Weather Control	No	No	Yes	No	Yes

Notes: The dependent variable is the spud-to-completion duration. Columns (1)-(3) present estimates from the parametric survival functions which are specified in accelerated failure time (AFT). Columns (4) and (5) present estimated average treatment effects of the regulation measured in months. Standard errors are clustered at the well level. *, **, *** denotes significance at the 10%, 5%, and 1% level.

those completed after 2015. Consistent with the KM estimates, wells spudded after 2015 have longer spud-to-completion times and quicker connection times than those completed in 2014. In our specification with the full set of controls, we find that wells completed after 2015 have over 20% longer completion times, taking around 1 month longer to be completed on average. Conditional on producing, wells completed after 2015 have 12% shorter non-connection times, and connect to gas capture infrastructure 0.7 months sooner than wells completed in 2014, on average.

Table 4 presents our results for the effects of the regulation on firms' oil and gas production. We find no consistent differences in oil or gas production across specifications at wells completed after 2015 compared to those completed in 2014. Thus, on average, we find no evidence that firms curtail production in response to the regulation. This is consistent with previous work – conditional on drilling a well it is optimal for firms to produce at maximum capacity (Kellogg, 2011; Anderson et al., 2016).

Table 3: Effect of the regulation on first production-to-connection duration.

	(1) AFT	(2) AFT	(3) AFT	(4) ATE	(5) ATE
Completed Post-2015	-0.140***	-0.087***	-0.128***	-0.541***	-0.697***
	(0.040)	(0.032)	(0.032)	(0.077)	(0.083)
Log Gas Production		-0.249***	-0.249***		
		(0.011)	(0.011)		
Δ Log HH Price		-0.688***	-0.037		
		(0.162)	(0.198)		
Log Distance to Pipeline		0.114***	0.115***		
		(0.011)	(0.011)		
Mean Connection Time				2.321***	2.405***
(2014 Wells)				(0.065)	(0.074)
Observations	6,523	6,523	6,503	3,131	3,128
Model	AFT	AFT	AFT	ATE	ATE
Density	Weibull	Weibull	Weibull	Weibull	Weibull
Weather Control	No	No	Yes	No	Yes

Notes: The dependent variable is first production-to-connection duration. Columns (1)-(3) present estimates from the parametric survival functions which are specified in accelerated failure time (AFT). Columns (4) and (5) present estimated average treatment effects of the regulation measured in months. Standard errors are clustered at the well level. *, **, *** denotes significance at the 10%, 5%, and 1% level.

6 Heterogeneous Costs and Gains from Trade

In this section, we make use of our theoretical model and empirical results to construct firm MAC curves. We use the estimated MAC curves to study the efficiency of the NDIC regulation, and quantify potential gains from instituting more flexible flaring standards in the state. We explore three counterfactual policies. The first allows for inter-firm trading but continues to enforce the same flaring standard in every month. The second allows for inter-temporal trading but leaves in place the firm-specific standard. The third combines the two forms of trade.

6.1 Firm Abatement Costs

Section 3 showed that a firm connects a well if the cost of doing so is below some threshold. We use this insight to study the efficiency of the NDIC flaring regulation. In a static setting with continuous abatement cost functions, the regulation achieves a given aggregate flaring reduction at minimum total cost if and only if marginal abatement costs are equalized across firms.[27] In our setting, firms have discrete connection decisions so equality across firms may not hold. Thus, we require a slight modification to this rule. The regulation is cost-effective if and only if all connected wells were connected at a lower cost per unit of gas captured than wells left unconnected.

[27]This condition need not hold in a dynamic setting. For example, a firm may connect a well that statically has connection costs that are 'too high' because the firm is forward-looking and anticipates connecting more wells to newly developed infrastructure in the future. We do not study forward-looking behavior here.

Table 4: Average effect of the regulation on oil and gas production.

(4.A) Oil Production

	(1) Dif	(2) Dif	(3) Dif	(4) NN Match
Post-2015 (M1-M12)	-0.012	-0.004	-0.004	0.007
	(0.022)	(0.022)	(0.022)	(0.032)
Log Initial Oil Production	0.288***	0.288***	0.288***	
	(0.017)	(0.017)	(0.017)	
Δ Log WTI Price	-0.107	-0.005	-0.009	
	(0.093)	(0.095)	(0.095)	
Observations	26,610	26,610	26,610	3,358
Wells	3,358	3,358	3,358	3,358
Prod Time Controls	ARPS	Cubic Spline	Prod FEs	N/A
Firm FE	Yes	Yes	Yes	No
Township FE	Yes	Yes	Yes	No
Weather Controls	Yes	Yes	Yes	No

(4.B) Gas Production

	(1) Dif	(2) Dif	(3) Dif	(4) NN Match
Post-2015 (M1-M12)	0.042	0.050*	0.050*	0.027
	(0.026)	(0.027)	(0.027)	(0.036)
Log Initial Gas Production (mcf/day)	0.261***	0.261***	0.261***	
	(0.016)	(0.016)	(0.016)	
Δ Log HH Price	0.117	0.179	0.182	
	(0.124)	(0.126)	(0.126)	
Observations	26,140	26,140	26,140	3,292
Wells	3,292	3,292	3,292	3,292
Prod Time Controls	ARPS	Cubic Spline	Prod FEs	N/A
Firm FE	Yes	Yes	Yes	No
Township FE	Yes	Yes	Yes	No
Weather Controls	Yes	Yes	Yes	No

Notes: The coefficients of interest are Post-2015 (M1-M12), which equals 1 if the well was completed after 2015. Dif and NN Match denote our differences and nearest neighbor matching estimators. Standard errors are clustered at the well level, and standard errors in the NN match specifications are robust to arbitrary heteroskedasticity. *, **, and *** denote significance at the 10%, 5%, and 1% level.

Other features of our setting complicate this static efficiency measure. First, we observe empirically that firms ultimately connect most of their wells to gas capture infrastructure. Second, abatement costs evolve – new wells begin producing oil and gas every month, and the potential gas captured at a given well decreases every month that it is not connected. Last, firms must comply with the regulation in every month. Given this, we limit our analysis in a few important ways. First, we restrict our attention to the efficiency of the policy in its first eighteen months. Second, we assume the ex-post observed flaring reductions over this period are the desired levels envisioned by the NDIC. This allows us to calculate total abatement over the first year-and-a-half of the program, construct counterfactual compliance paths for firms that achieve the same aggregate abatement, and compare abatement costs across scenarios.

We first must construct firm and industry MAC curves. For a given month, we construct firm MAC curves by calculating the right-hand side of equation (2) for every well owned by a firm that is not already connected to gas capture infrastructure in that month. The calculation consists of two components: (i) the well connection costs; and (ii) the well's expected gas production. We calculate the latter using the ARPS model from Table 4. We specify well i's gas production g_{it} in any month t as:

$$log(\mathrm{g}_{it}) = \beta_1 \log(t) + \theta_i + \varepsilon_{it} \tag{9}$$

where θ_i is a well fixed effect. The estimated decline rate is $\hat{\beta}_1 = -0.342$. For new wells, we assume firms know G_{i0}, the initial gas production from well i. Given G_{i0} we can compute the expected lifetime gas production g_i for any well i. We use a twenty year lifetime to calculate the total amount of gas that a well will produce.

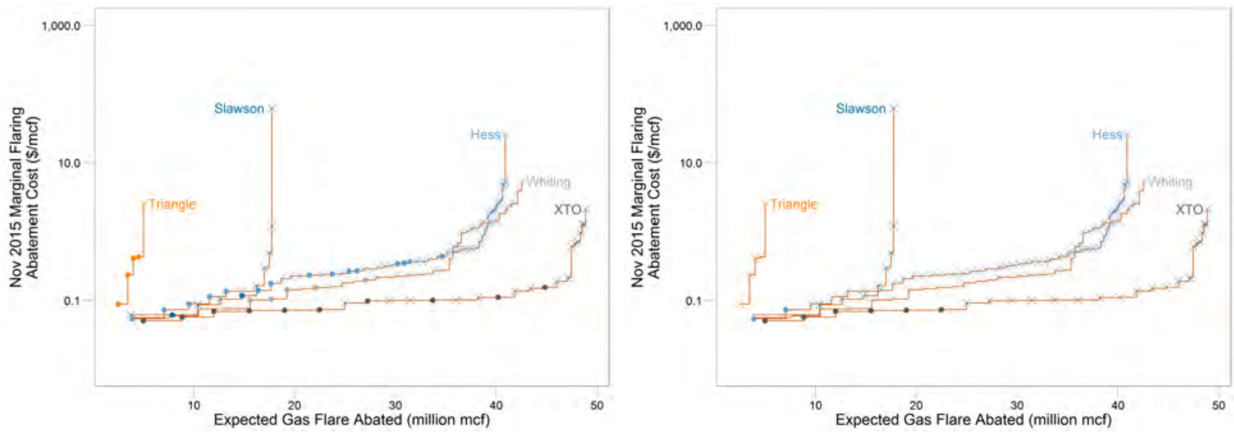
Given g_i we compute the right-hand side of equation (2), the per unit connection cost for connecting the well, as:

$$\frac{\text{(On-site Fixed Costs)} + \text{(Pipeline Costs)} \times d_i}{g_i}. \tag{10}$$

The first term in the numerator is the fixed cost of on-site equipment.[28] The second term is the cost of constructing a gathering line to well i, which is a function of the length of the line, d_i. We obtain on-site costs and per-mile estimates of gas gathering line costs from the Interstate Natural Gas Association of America (INGAA). INGAA reports the average costs for equipment at \$210,000 per well. Data from Rextag indicate that the average gathering line diameter is 4 inches, and INGAA reports that the cost per mile of 4-inch gathering

[28]This includes dehydrators, compressors, and other technologies that remove hazardous pollutants like hydrogen sulfide.

Figure 5: Firm marginal flaring abatement cost curves.



(a) Observed Connection Decisions

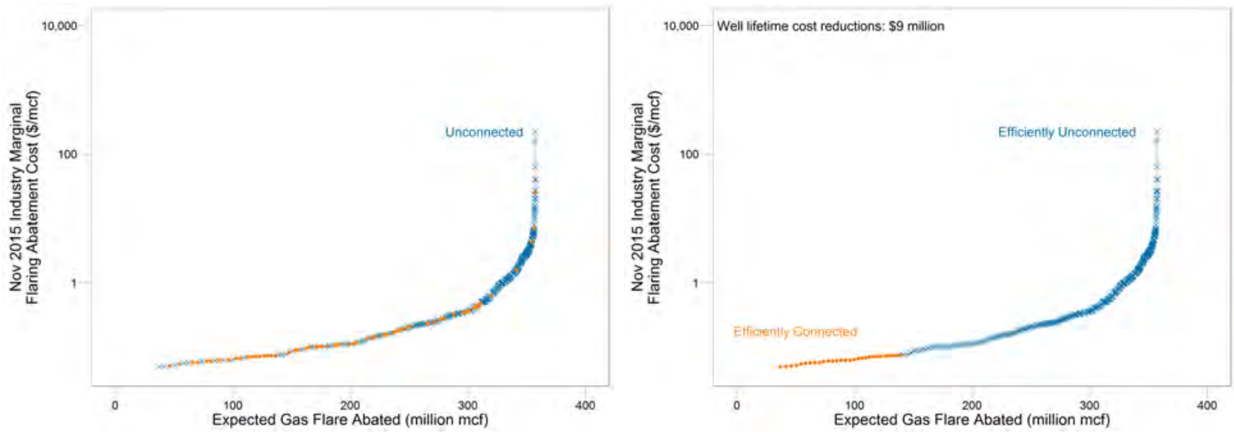
(b) Efficient Connection Decisions

Notes: The left figure graphs MAC curves for five firms in November 2015 and their well connection decisions in that month. The right figure graphs the connection decisions under the efficient industry outcome. Orange circles indicate wells that are connected and orange X's indicate wells that are left unconnected.

line is $155,000. To compute the length of the gathering line, we calculate the minimum distance from a well to another gathering line or a natural gas pipeline using the data from Rextag. Because we only observe a snapshot of the pipeline network, we do not capture how gathering line distance may be changing over time. Since we consider our counterfactual over an eighteen month horizon, a one time snapshot of the pipeline network is likely a close approximation. Firms' MAC curves still change from month to month – new wells come online, wells are connected to gas capture infrastructure and excluded from future MAC curves, and wells that are not connected in the previous month have higher per unit connection costs as the well is depleted of gas.

After calculating equation (10) for every unconnected well in month t, we construct firm MAC curves by ordering all wells owned by a firm by their costs. Figure 5a graphs an example of five firms' MAC curves for one month in our sample, November 2015. Hess, Whiting, and XTO own many wells that have low connection costs and high gas production, while Triangle and Slawson own fewer wells, the wells they own are typically less gas productive, and the wells have higher connection costs. Circles indicate the wells that the firms connected in that month and X's indicate wells that were left unconnected. Consistent with our theoretical model, firms mostly connect their lowest cost wells and leave high-cost wells unconnected. It is also clear from the Figure that the most productive wells, those with the largest horizontal gaps, also tend to be low-cost wells. This is consistent with firms clustering drilling activity

Figure 6: Industry marginal flaring abatement cost curves.



(a) Observed Industry MAC Curve

(b) Efficient Industry MAC Curve

Notes: The left figure graphs the industry MAC curve in November 2015. The right figure graphs the connection decisions under the efficient industry outcome. Orange circles indicate wells that are connected and orange X's indicate wells that are left unconnected.

in productive oil and gas regions with nearby gas capture infrastructure. The unproductive wells' high connection cost wells may be exploratory wells, and are typically far from existing gas capture infrastructure.

Figure 5 highlights clear differences in MACs across the five firms. Figure 6a aggregates all MAC curves. As before, connected wells are denoted by orange dots, and unconnected wells are denoted by blue X's. Industry-wide, many cheap wells were left unconnected while several costly wells were connected to gas capture infrastructure. These findings motivate our following dynamic counterfactuals.

6.2 Counterfactual Policy Simulations

We now use our estimated firm and industry MAC curves to compare three counterfactual compliance scenarios and compare them to firms' observed connection decisions and abatement costs over the first eighteen months of the regulation. Here we describe our three scenarios and discuss our findings. Section B in the appendix contains details on how we compute the counterfactuals.

Our first counterfactual, *inter-firm trading*, considers the gains from allowing inter-firm trading within a month but requires the counterfactual total industry abatement to equal the observed total industry abatement every month. The exercise isolates potential gains from inter-firm trade. The outcome would be achieved by instituting a cap-and-trade program with a time-varying cap and no banking or borrowing, or a time-varying flaring tax.

Table 5: Least-cost counterfactual simulation results.

	Relative Cost Savings	Absolute Cost Savings (Million $)
Scenario 1: Inter-Firm Trading	16%	$77
Scenario 2: Within-Firm Banking and Borrowing	10%	$49
Scenario 3: Inter-Firm Trading with Banking and Borrowing	20%	$96

Figures 5b and 6b illustrate this exercise graphically for one month – November 2015. In the counterfactual, Triangle does not connect any of its wells, while all other firms connect just a few wells to achieve the same flaring reduction. Figure 6b illustrates this in the aggregate.

Our second counterfactual, *within-firm banking and borrowing* allows greater flexibility in the timing that firms connect wells, but re-institutes a ban on inter-firm trading and requires each firms total counterfactual abatement to equal its observed total abatement. This outcome can be achieved under a firm-specific cap-and-trade program with fully flexible banking and borrowing, or a firm-specific tax on flaring.

Our final counterfactual, *inter-firm trading with banking and borrowing* combines the previous two and allows for both inter-firm and inter-temporal flexibility. This is equivalent to an industry cap-and-trade program with unlimited banking and borrowing, or an industry flaring tax.

Table 5 presents the absolute and relative cost savings from the three counterfactual simulations. For reference, we estimate that from January 2015 through June 2016, the oil and gas industry in North Dakota captured 3.3 billion mcf of gas at the cost of $478 million. The first column shows that allowing inter-firm trading reduces compliance costs by 16%, saving $77 million. The second column shows that allowing firms to bank and borrow reduces costs by 10%, or $49 million. For this second counterfactual, the firm-specific taxes that achieve the same counterfactual flaring reductions for every firm, varies between $0.15/mcf and $9.47/mcf. This illustrates the large differences in compliance costs. For reference, this amounts to a carbon tax between $9/tCO_2$ and $179/tCO_2$.[29]

The final column of Table 5 presents gains from moving to the most flexible regulation – an industry tax on flared gas or an industry cap-and-trade program with full banking and borrowing. This would reduce compliance costs by 20%, or $96 million, over the eighteen month window. The calculated tax that would achieve this reduction is $0.42/mcf. For

[29] We use the average carbon intensity of natural gas. Propane and butane have carbon intensities about 15% higher.

reference, this amounts to a carbon tax of about \$8/tCO_2, well below current estimates of the social cost of carbon. Alternatively, royalty rates for public land are 16.66% of gross revenue. Using the average Henry Hub gas price over this period (\$2.72/mcf), this amounts to a \$0.45/mcf tax. Thus, conditional on our cost estimates being accurate, this suggests that the NDIC could achieve the same flaring reduction at considerably lower cost by requiring oil and gas firms to pay public lands royalty rates on their flared gas.

We make several important simplifying assumptions for the counterfactual scenarios. For example, we use a twenty year lifetime horizon for all wells, assume all wells build pipelines that are the same diameter, assume the gathering line distance is the shortest distance to an existing line, assume that right-of-way costs are minimal, use a uniform cost for wells' on-site infrastructure costs, and assume away any forward-looking behavior by firms. We test the sensitivity of some of these choices in the appendix. In general, while the level of cost savings differs when we vary, for example, well diameter, the relative cost savings remain roughly of the same magnitude.

7 Conclusions and Discussion

We use rich, well-level data on oil firms' operations in North Dakota to study the effects and efficiency of a new regulation aimed at reducing gas flaring in the state. Our results suggest that the regulation has been effective. Well operators have reduced flaring rates 4 to 7 percentage points, and we attribute between one-third and one-half of the observed year-on-year reduction in flaring at new wells to the regulation. The primary mechanism that firms comply is by connecting wells to gas capture infrastructure more quickly than they did historically.

While the regulation was effective at reducing flaring in the state, we also show that there are substantive costs from misallocation of abatement caused by heterogeneous compliance costs and the regulation being enforced uniformly across firms. Using a simple counterfactual exercise based on estimated MAC curves, we show that reallocating abatement from high- to low-cost firms would reduce aggregate compliance costs considerably. Moreover, using our preferred estimates, a relatively modest flaring tax could achieve the same aggregate reduction in flaring at lower cost. The finding highlights a key feature of oil and gas production in North Dakota that discourages flaring – firms pay royalty and taxes only on sold gas in the first year of production. Using our preferred infrastructure cost estimates, the state could have achieved the same reduction in state-wide flaring by simply charging firms royalties on flared gases at the current public lands rate.

Our results are subject to important caveats. We rely on reduced-form methods to estimate the average treatment effects of the regulation. The methods do not allow for strategic decision-making by firms or take full advantage of the feature that connecting to gas capture infrastructure requires large upfront costs and forward-looking behavior. Also, our results are conditional on the existing state of gas capture infrastructure in North Dakota. Thus, our results pertain only to the effects of the regulation on oil operators' gathering line installation decisions and do not allow for strategic investments in other gas capture and processing infrastructure. Discussions with regulators in North Dakota confirm that among the more salient changes since the passage of the regulation is more regular coordination between oil operators and gas processing plants. Future work may consider the interactions between these two groups, as well as examine the effects of the NDIC regulation on the development and placement of gas pipelines and processing plants.

In addition, recent work studying the Texas oil and gas industry shows that a failure to internalize environmental risks due to bankruptcy protections shifts industry structure towards smaller firms (Boomhower, 2016). Small firms may also take advantage of the benefits of limited liability in the North Dakota shale fields. The introduction of new, stringent flaring standards may, therefore, act to increase capital costs for drilling new wells. If these new, larger upfront costs affect firms' entry decisions, the new standard may have the effect of pricing smaller, capital constrained firms out of the market. Future research may explore these issues along with a number of other effects of this and similar regulations.

References

Abadie, A. and G. Imbens (2011). Bias-corrected matching estimators for average treatment effects. *Journal of Business and Economic Statistics 29*(1), 1–11.

Anderson, S., R. Kellogg, and S. Salant (2016). Hotelling Under Pressure. Working Paper.

Avalos, R., T. Fitzgerald, and R. Rucker (2016). Measuring the effects of natural gas pipeline constraints on regional pricing and market integration. *Energy Economics 60*, 217–231.

Bailey, A. (2015). NDPA Director Analysis Reveals Bakken Breakeven Pricing. *The Bakken Magazine.* September 16, 2015.

Bartik, A., J. Currie, M. Greenstone, and C. Knittel (2017). The Local Economic and Welfare Consequences of Hydraulic Fracturing. Working Paper.

Baumol, W. J. and W. E. Oates (1988). *The Theory of Environmental Policy.* Cambridge University Press.

Boomhower, J. (2016). Drilling Like There's No Tomorrow: Bankruptcy, Insurance, and Environmental Risk. Working Paper.

Brandt, A. R., T. Yeskoo, M. S. McNally, K. Vafi, S. Yeh, H. Cai, and M. Q. Wang (2016). Energy intensity and greenhouse gas emissions from tight oil production in the bakken formation. *Energy & Fuels 30*(11), 9613–9621.

Bureau of Land Management (2016). Proposed Rule: Waste Prevention, Production Subject to Royalties, and Resource Conservation. *Federal Register 81*(25), 6616–6686.

Carlson, C., D. Burtraw, M. Cropper, and K. L. Palmer (2000). Sulfur Dioxide Control by Electric Utilities: What Are the Gains from Trade? *Journal of Political Economy 108*(6), 1292–1326.

Covert, T. (2015). Experiential and Social Learning in Firms: The Case of Hydraulic Fracturing in the Bakken Shale. Working Paper.

Energy Information Administration (2015). Hydraulic Fracturing Accounts for about Half of Current U.S. Crude Oil Production. Today in Energy, March 15, 2016.

Energy Information Administration (2016a). International Energy Statistics.

Energy Information Administration (2016b). Natural gas flaring in North Dakota has declined sharply since 2014. Today in Energy, June 13, 2013.

Fetkovich, M. (1980). Decline Curve Analysis using Type Curves. *Journal of Petroleum Technology 32*(6), 1065–1077.

Feyrer, J., E. Mansur, and B. Sacerdote (2017). Geographic Dispersion of Economic Shocks: Evidence from the Fracking Revolution. *American Economic Review 107*(4), 1313–1334.

Fowlie, M., C. R. Knittel, and C. Wolfram (2012). Sacred Cars? Cost-Effective Regulation of Stationary and Nonstationary Pollution Sources. *American Economic Journal: Economic Policy 4*(1), 98–126.

Gaswirth, S., K. Marra, T. Cook, R. Charpentier, D. Gautier, D. Higley, T. Klett, M. Lewan, P. Lillis, C. Schenk, M. Tennyson, and K. Whidden (2013). Assessment of undiscovered oil resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota, and South Dakota. U.S. Geological Survey Fact Sheet 2013–3013.

Gopalakrishnan, S. and H. Klaiber (2014). Is the Shale Energy Boom a Bust for Nearby Residents? Evidence from Housing Values in Pennsylvania . *American Journal of Agricultural Economics 96*(1), 43–66.

Hausman, C. and R. Kellogg (2015). Welfare and Distributional Implications of Shale Gas. *Brookings Papers on Economic Activity Spring*, 71–125.

Hill, E. (2015). Impacts of Shale Gas Development on Ambient Air Pollution and Infant Health in Texas. Working Paper.

Kellogg, R. (2011). Learning by Drilling: Interfirm Learning and Relationship Persistence in the Texas Oilpatch. *The Quarterly Journal of Economics 126*(4), 1961–2004.

Kerr, S. and R. Newell (2003). Policy-Induced Technology Adoption: Evidence from the U.S. Lead Phasedown. *The Journal of Industrial Economics 51*(3), 317–343.

Montgomery, W. D. (1972). Markets in Licenses and Efficient Pollution Control Programs. *Journal of Economic Theory 5*(3), 395–418.

Muehlenbachs, L., E. Spiller, and C. Timmins (2015). The Housing Market Impacts of Shale Gas Development. *American Economic Review 105*(12), 3633–3659.

Newell, R., B. Prest, and A. Vissing (2016). Trophy Hunting vs. Manufacturing Energy: The Price-Responsiveness of Shale Gas. RFF Discussion Paper 16-32.

North Dakota Industrial Commission (2015). Order 24665. Technical report.

North Dakota Industrial Commission (2016). North Dakota Monthly Oil Production Statistics.

Olmstead, S., L. Muehlenbachs, J.-S. Shih, Z. Chu, and A. Krupnick (2013). Shale Gas Development Impacts on Surface Water Quality in Pennsylvania. *Proceedings of the National Academy of Sciences 110*(13), 4962–4967.

Salmon, R. and A. Logan (2013). Flaring Up: North Dakota Natural Gas Flaring More than Doubles in Two Years. Ceres Research Report. July 2013.

Storrow, B. (2015). Could North Dakota be a Model for How to Reduce Flaring? *The Casper Star Tribune.* March 10, 2015.

Swanson, A. (2014). America's Oil Boom is Visible from Space. *The Washington Post.* October 20, 2014.

Vissing, A. (2016). One-to-Many Matching with Complementary Preferences: An Empirical Study of Natural Gas Lease Quality and Market Power. Working Paper.

World Bank (2015). Zero Routine Flaring by 2030.

Zirogiannis, N., J. Alcorn, J. Rupp, S. Carley, and J. D. Graham (2016). State Regulation of Unconventional Gas Development in the U.S.: An Empirical Evaluation. *Energy Research & Social Science 11*, 142–154.

Appendix

Section A contains our summary statistics table, Section B describes our counterfactual algorithms, Section C contains sensitivity analysis and robustness checks.

A Summary Statistics

Table A.1 presents summary statistics, disaggregated by the pre and post-regulation periods. Production, fracking input use, and total well depth increased between the two periods. Gas flaring rates in the first year of production fell from 34% in 2012–2014 to 22% in 2015–2016. Flaring rates are lower at connected wells, but are non-zero and similar across wells completed before and after the regulation.[30] The decrease coincides with shorter gas connection times. Oil and gas prices vary substantially over the sample. Average WTI and HH prices were \$94/bbl and \$3.80/mcf in 2012-2014, respectively. Both have fallen considerably since the summer of 2014, averaging just \$46/bbl and \$2.55/mcf in 2015–2016.

[30]Flaring at connected wells is typically the result of issues with or excess pressure in pipelines, or to natural gas plants operating at or near capacity.

Table A.1: Summary Statistics

		Mean	Median	Std. Dev.
2012-2014	Oil Production in 1st Year (bbls/day)	297.89	222.77	280.28
	Gas Production in 1st Year (mcf/day)	328.90	219.33	391.87
	Water Products Injected (1000 gals)	3,093.36	2,479.55	2,320.94
	Non-Water Products Injected (1000 gals)	3.44	0.00	22.79
	Well Depth (ft)	20,081.55	20,496.00	1,615.49
	Flaring in 1st Year: All Wells (%)	0.34	0.11	0.40
	Flaring in 1st Year: Connected Wells (%)	0.21	0.05	0.30
	Time to Gas Connection (Months)	3.51	2.00	4.93
	Distance from Pipeline (miles)	N/A	N/A	N/A
	WTI Price ($/bbl)	93.15	95.60	9.13
	Henry Hub Price ($/mcf)	3.89	3.94	0.49
2015-2016	Oil Production in 1st Year (bbls/day)	377.80	297.10	318.36
	Gas Production in 1st Year (mcf/day)	514.97	372.70	506.57
	Water Products Injected (gals)	4,516.25	3,539.84	4,609.35
	Non-Water Products Injected (gals)	866.73	0.00	11057.80
	Well Depth (ft)	20,351.90	20,690.00	1,630.16
	Flaring in 1st Year: All Wells (%)	0.22	0.06	0.31
	Flaring in 1st Year: Connected Wells (%)	0.17	0.05	0.25
	Time to Gas Connection (Months)	1.73	1.00	1.39
	Distance from Pipeline (miles)	0.38	0.12	0.89
	WTI Price ($/bbl)	48.76	48.41	7.35
	Henry Hub Price ($/mcf)	2.72	2.85	0.28

B Counterfactual Algorithm Details

Here we describe the algorithm for computing our three different counterfactual scenarios: inter-firm trading, within-firm banking and borrowing, and inter-firm trading with banking and borrowing.

Inter-firm trading Our first counterfactual scenario considers the gains from allowing inter-firm trading within a month/compliance period, but requires the same counterfactual flaring abatement within every compliance period as the observed flaring abatement. This exercise isolates potential gains from inter-firm trade.

We compute the counterfactual compliance scenario for every month starting from January 2015 to June 2016 as follows:

1. For every month, compute the observed total abatement (captured gas).
2. Starting in January 2016, order all wells by their MAC. Compute the least-cost connection decisions to achieve the same flaring reduction observed in that month.
3. Carry forward all wells that were not connected in the counterfactual, recompute their expected lifetime gas production, and add any new wells that begin producing in that month to the counterfactual industry MAC curve. Compute the least-cost connection decisions to achieve the same, monthly observed abatement.
4. Repeat step 3 through June 2016.

Within-firm banking and borrowing Our second counterfactual allows greater flexibility in the timing that firms connect wells, but re-institutes a ban on inter-firm trading. For this, we take advantage of the fact that, given a sufficiently long time horizon, a firm-specific cap-and-trade program with fully flexible banking and borrowing is equivalent to a firm-specific tax on flaring.

For each firm, we compute the following:

1. Compute the total volume of gas captured by firm j from January 2015 to June 2016.
2. Search for some constant t_j^* such that when all unconnected wells owned by firm j with MACs below t_j^* are connected in the first month that their MAC is below t_j^*, the total amount of gas captured over the full horizon equals the observed amount of gas captured by firm j.

This counterfactual induces individual firms to capture the same amount of gas as in reality but allows flexibility in the timing of gas capture.

Inter-firm trading with banking and borrowing Last, we allow for both inter-firm and inter-temporal flexibility. As in the previous scenario, we take advantage of the equivalence between a flaring tax t^{**} and an industry cap-and-trade program with unlimited banking and borrowing.

For the entire industry, we compute the following:

1. Compute the total volume of gas captured by all firms from January 2015 to June 2016.

2. Search for some constant t^{**} such that when all unconnected wells with MACs below t^{**} are connected in the first month their MAC is below t^{**}, the total amount of gas captured over the full horizon is equal to the observed amount of gas captured by the industry.

The value t^{**} can be interpreted as the permit price in the tradable permit system with banking and borrowing or as an industry-wide flaring tax.

C Sensitivity Analyses and Robustness Checks

Table C.1 tests the sensitivity of our flaring results from Table 1 to specifying alternative control wells. We explore three alternative control well specifications: (i) wells completed between January and August 2014; (ii) wells completed from 2013–2014; and (iii) wells completed in 2013. The first and third, in particular, address concerns that wells drilled just before the policy may have altered their flaring rates in anticipation of the flaring regulation. Where the results differ from our main specification, the effects are generally larger. Figure C.1 presents corresponding flexible difference-in-difference results using alternative control wells.

Table C.2 provides further validation of our empirical design, performing placebo regressions. We define the placebo treatment group in the top panel as those completed in 2014 and the control group as those completed in 2013. We again limit our focus to the first twelve months of production at a well and drop 2014 data for wells completed in 2013. The bottom panel presents similar placebo tests defining the treatment group as wells completed in 2013 and the control group as wells completed in 2012. We find significant reduction sin flaring in the placebo treatments when we use the differences and nearest neighbor estimators. This suggests that we may omit some relevant well characteristics in comparing flaring rates in production time from year-to-year. We find no impact of the regulation in the difference-in-difference estimators – passing the placebo test. This is further validated in the flexible difference-in-difference placebo regressions, presented in Figure C.2. The 2014 placebo does not result in any statistically significant estimates, and the 2013 placebo treatment results in a few positive estimates. This suggests we are unlikely simply picking up on flaring rates decreasing over calendar time differentially throughout a well's lifecycle.

Table C.3 explores the sensitivity of our spud-to-completion time duration models. As in the flaring regressions above, we test the sensitivity of our estimates to redefining the control group in three ways. All estimates are similar to those in Table 2, or generally larger.

Table C.4 explores the sensitivity of our connection time duration models to using alternative control groups. As with the flaring regressions, where differences arise, we find larger treatment effects. Table C.5 contains estimates from regressions exploring the timing of firms' gas capture connection decisions to test whether the regulation leads to firms connecting to gas capture infrastructure in specific months. For this, we estimate linear probability models testing whether firms completed after 2015 were more likely to connect in the first production month, the first four production months, and the fourth production month conditional on entering the fourth production month unconnected. The regressions more directly test whether the regulation impacts the timing of firms' connection decisions.

Conditional on our controls, wells are 10%–12% more likely to connect in the first month of production or the first four months of production, respectively. Conditional on not having connected before month 4, wells completed in 2015 are over 50% more likely to connect a well in the fourth production month when the well is included in the firm flaring rate. This is consistent with the results in the KM estimates from Figure 4b.

Table C.6 and Table C.7 present similar sensitivity test results using alternative control groups for the impacts of the policy on wells' oil and gas production. The corresponding results in the main text are in Table 4. Oil production results are largely similar. However, as the comparison group includes older wells, those completed in 2013, we find larger impacts. Similar issues arise with gas production. This is likely due to older wells being less appropriate controls for 2015 wells – technological advances in oil and gas drilling have advanced rapidly over this period.

Table C.1: Average effect of the regulation on flaring rates using alternative control wells.

	(1) Dif	(2) Dif	(3) NN Match	(4) D-in-D	(5) D-in-D	(6) NN Match
Panel A: Alternative Control Wells - Completed 2014, January to August						
Post-2015 (M1-M12)	-0.093***	-0.041***	-0.102***			
	(0.009)	(0.011)	(0.012)			
Post-2015 (M4-M12)				-0.234***	-0.018	-0.066***
				(0.007)	(0.012)	(0.011)
Observations	25,033	25,000	2,527	25,011	25,011	2,527
Wells	2,728	2,725	2,527	2,706	2,706	2,527
Panel B: Alternative Control Wells - Completed 2013-2014						
Post-2015 (M1-M12)	-0.129***	-0.116***	-0.130***			
	(0.007)	(0.009)	(0.008)			
Post-2015 (M4-M12)				-0.234***	-0.015*	-0.121***
				(0.007)	(0.009)	(0.007)
Observations	47,177	47,132	4,934	46,990	46,990	4,389
Wells	5,072	5,068	4,934	4,885	4,885	4,389
Panel C: Alternative Control Wells - Completed 2013						
Post-2015 (M1-M12)	-0.139***	-0.146***	-0.209***			
	(0.008)	(0.010)	(0.010)			
Post-2015 (M4-M12)				-0.234***	-0.009	-0.138***
				(0.007)	(0.010)	(0.007)
Observations	36,097	36,061	2,575	36,075	36,075	2,660
Wells	3,259	3,256	2,575	3,237	3,237	2,660
Well FE	No	No	No	Yes	Yes	No
Firm FE	No	Yes	No	No	No	No
Township FE	No	Yes	No	No	No	No
Production Month FE	No	Yes	No	No	Yes	No
Weather Controls	No	Yes	No	No	Yes	No

Notes: The dependent variable is the well-level flaring rate. The coefficients of interest are Post-2015 (M1-M12), which equals 1 if the well was completed after 2015, and Post-2015 (M4-M12), which equals one if the well was completed after 2015 and it is after the well's fourth production month. Dif, D-in-D, and NN Match denote our differences, difference-in-differences, and nearest neighbor matching estimators. Regression standard errors are clustered at the well level, and NN match standard errors are robust to arbitrary heteroskedasticity. *, **, and *** denote significance at the 10%, 5%, and 1% level. Panel C NN match was based on the two nearest neighbors instead of five because of limited numbers of exactly matched wells on the number of production months observed.

Table C.2: Average effect of placebo regulations on flaring rates.

	(1)	(2)	(3)	(4)	(5)	(6)
Panel A: 2014 Placebo Wells						
Post-2014 (M1-M12)	-0.151***	-0.102***	-0.137***			
	(0.010)	(0.010)	(0.027)			
Post-2014 (M4-M12)				-0.228***	0.009	-0.134***
				(0.007)	(0.011)	(0.029)
Observations	33,600	33,600	1,936	33,477	33,477	1,936
Wells	3,616	3,616	1,936	3,493	3,493	1,936
Panel B: 2013 Placebo Wells						
Post-2013 (M1-M12)	-0.117***	-0.066***	-0.082***			
	(0.012)	(0.011)	(0.033)			
Post-2013 (M4-M12)				-0.226***	0.028**	-0.054
				(0.007)	(0.012)	(0.036)
Observations	31,246	31,203	1,779	31,111	31,111	1,779
Wells	3,377	3,373	1,779	3,242	3,242	1,779
Model	Dif	Dif	NN Match	D-in-D	D-in-D	NN Match
Well FE	No	No	No	Yes	Yes	No
Firm FE	No	Yes	No	No	No	No
Township FE	No	Yes	No	No	No	No
Production Month FE	No	Yes	No	No	Yes	No
Calendar Month FE	No	Yes	No	No	Yes	No
Weather Controls	No	Yes	No	No	Yes	No

Notes: The dependent variable is the well-level flaring rate. The coefficients of interest are Post-2015 (M1-M12), which equals 1 if the well was completed after 2015, and Post-2015 (M4-M12), which equals one if the well was completed after 2015 and it is after the well's fourth production month. Dif, D-in-D, and NN Match denote our differences, difference-in-differences, and nearest neighbor matching estimators. Regression standard errors are clustered at the well level, and NN match standard errors are robust to arbitrary heteroskedasticity. *, **, and *** denote significance at the 10%, 5%, and 1% level.

Table C.3: Effect of the regulation on spud-to-completion duration using alternative control wells.

	(1) AFT	(2) AFT	(3) AFT	(4) ATE	(5) ATE
Panel A: Alternative Control Wells - Completed 2014, January to August					
Post-2015	0.209***	0.203***	0.183***	1.351***	1.225***
	(0.017)	(0.017)	(0.018)	(0.101)	(0.107)
Log Distance to Pipeline		-0.020***	-0.023***		
		(0.007)	(0.007)		
Non-water Inputs		-0.001	-0.003		
		(0.005)	(0.005)		
Water Inputs		0.027**	0.028**		
		(0.012)	(0.013)		
Log Total Depth of Well		0.148	0.222**		
		(0.093)	(0.095)		
Δ Log HH Price		0.777***	1.125***		
		(0.115)	(0.142)		
Δ Log WTI Price		-0.585***	-0.520***		
		(0.091)	(0.105)		
Observations	18,758	18,009	17,719	2,593	2,590
Panel B: Alternative Control Wells - Completed 2013-2014					
Post-2015	0.242***	0.233***	0.281***	1.489***	1.420***
	(0.013)	(0.014)	(0.014)	(0.089)	(0.088)
Log Distance to Pipeline		-0.022***	-0.020***		
		(0.005)	(0.005)		
Non-water Inputs		-0.002	-0.004		
		(0.003)	(0.003)		
Water Inputs		0.028***	0.031***		
		(0.010)	(0.011)		
Log Total Depth of Well		0.211***	0.270***		
		(0.080)	(0.071)		
Δ Log HH Price		0.207**	-0.237**		
		(0.086)	(0.104)		
Δ Log WTI Price		0.060	0.111		
		(0.070)	(0.084)		
Observations	32,372	27,245	26,955	4,153	4,149
Panel C: Alternative Control Wells - Completed 2013					
Post-2015	0.294***	0.289***	0.384***	2.074***	1.974***
	(0.015)	(0.018)	(0.020)	(0.103)	(0.116)
Log Distance to Pipeline		-0.038***	-0.036***		
		(0.007)	(0.006)		
Non-water Inputs		0.002	-0.003		
		(0.006)	(0.006)		
Water Inputs		0.053***	0.051***		
		(0.013)	(0.012)		
Log Total Depth of Well		0.041	0.105		
		(0.073)	(0.072)		
Δ Log HH Price		-0.528***	-1.079***		
		(0.101)	(0.129)		
Δ Log WTI Price		-0.316***	-0.308***		
		(0.082)	(0.101)		
Observations	21,030	16,411	16,121	2,438	2,435
Density	Weibull	Weibull	Weibull	Weibull	Weibull
Weather Control	No	No	Yes	No	Yes

Notes: The dependent variable is the spud-to-completion duration. Columns (1)-(3) present estimates from the parametric survival functions which are specified in accelerated failure time (AFT). Columns (4) and (5) present estimated average treatment effects of the regulation measured in months. Standard errors are clustered at the well level. *, **, *** denotes significance at the 10%, 5%, and 1% level.

Table C.4: Effect of the regulation on first production-to-connection duration using alternative control wells.

	(1) AFT	(2) AFT	(3) AFT	(4) ATE	(5) ATE
Panel A: Alternative Control Wells - Completed 2014, January to August					
Post-2015	-0.226***	-0.137***	-0.195***	-0.445***	-0.747***
	(0.043)	(0.035)	(0.037)	(0.079)	(0.103)
Log Distance to Pipeline		0.125***	0.125***		
		(0.012)	(0.012)		
Gas Production		-0.254***	-0.256***		
		(0.012)	(0.012)		
Δ Log HH Price		-0.932***	-0.112		
		(0.191)	(0.225)		
Observations	5,601	5,601	5,601	2,530	2,530
Panel B: Alternative Control Wells - Completed 2013-2014					
Post-2015	-0.408***	-0.299***	-0.296***	-0.701***	-0.859***
	(0.035)	(0.029)	(0.030)	(0.061)	(0.066)
Log Distance to Pipeline		0.138***	0.138***		
		(0.010)	(0.010)		
Gas Production		-0.287***	-0.287***		
		(0.010)	(0.010)		
Δ Log HH Price		0.617***	0.448***		
		(0.145)	(0.173)		
Observations	12,100	12,100	12,100	4,664	4,664
Panel C: Alternative Control Wells - Completed 2013					
post15	-0.612***	-0.466***	-0.498***	-0.887***	-1.144***
	(0.040)	(0.035)	(0.039)	(0.073)	(0.083)
Log Distance to Pipeline		0.148***	0.145***		
		(0.012)	(0.012)		
Gas Production		-0.289***	-0.288***		
		(0.013)	(0.013)		
Δ Log HH Price		0.185	0.131		
		(0.181)	(0.213)		
Observations	8,530	8,530	8,530	2,933	2,933
Density	Weibull	Weibull	Weibull	Weibull	Weibull
Weather Control	No	No	Yes	No	Yes

Notes: The dependent variable is first production-to-connection duration. Columns (1)-(3) present estimates from the parametric survival functions which are specified in accelerated failure time (AFT). Columns (4) and (5) present estimated average treatment effects of the regulation measured in months. Standard errors are clustered at the well level. *, **, *** denotes significance at the 10%, 5%, and 1% level.

Table C.5: Effect of the regulation on gas connection probability using a linear probability model.

	(1)	(2)	(3)
Connection Month	Month 1	Months 1 to 4	Month 4
Post-2015	0.098***	0.122***	0.560***
	(0.020)	(0.014)	(0.073)
Log Initial Gas Production	0.050***	0.008*	0.038*
	(0.007)	(0.004)	(0.021)
Log Dist. to Gathering Line	-0.031***	-0.012***	-0.017
	(0.007)	(0.004)	(0.020)
Log Dif. HH Price (Connection Month)	0.244	-0.404***	-3.446***
	(0.181)	(0.106)	(0.766)
Log Dif. WTI Price (Connection Month)	0.120	-0.267***	-1.654**
	(0.171)	(0.092)	(0.752)
Observations	3,243	3,243	400
Firm FE	Yes	Yes	Yes
Township FE	Yes	Yes	Yes
Calendar Month FE	Yes	Yes	Yes
Weather Controls	Yes	Yes	Yes

Notes: The dependent variable is an indicator variable for whether a well connected to gas capture infrastructure in the month(s) specified in the header. Standard errors are robust to arbitrary heteroskedasticity. *, **, and *** denote significance at the 10%, 5%, and 1% level.

Table C.6: Average effect of the regulation on oil production using alternative control wells.

	(1) Dif	(2) Dif	(3) Dif	(4) NN Match
Panel A: Alt. Control Wells - Completed 2014, January to August				
Post-2015 (M1-M12)	-0.009	0.002	0.003	0.059*
	(0.023)	(0.023)	(0.023)	(0.034)
Log Initial Oil Production	0.278***	0.279***	0.279***	
	(0.018)	(0.018)	(0.018)	
Δ Log WTI Price	-0.079	0.050	0.038	
	(0.097)	(0.100)	(0.100)	
Observations	25,033	25,033	25,033	2,572
Wells	2,728	2,728	2,728	2,572
Panel B: Alt. Control Wells - Completed 2013-2014				
Post-2015 (M1-M12)	0.034*	0.034*	0.036**	0.003
	(0.018)	(0.018)	(0.018)	(0.023)
Log Initial Oil Production	0.251***	0.251***	0.251***	
	(0.012)	(0.012)	(0.012)	
Δ Log WTI Price	-0.147*		-0.110	
	(0.079)		(0.079)	
Observations	47177	47177	47177	5072
Wells	5072	5072	5072	5072
Panel C: Alt. Control Wells - Completed 2013				
Post-2015 (M1-M12)	0.073***	0.074***	0.074***	0.038
	(0.020)	(0.020)	(0.020)	(0.026)
Log Initial Oil Production	0.243***	0.243***	0.243***	
	(0.014)	(0.014)	(0.014)	
Δ Log WTI Price	0.065	0.094	0.084	
	(0.097)	(0.097)	(0.097)	
Observations	36,097	36,097	36,097	2,665
Wells	3,259	3,259	3,259	2,665
Prod Time Controls	ARPS	Cubic Spline	Prod FEs	N/A
Firm FE	Yes	Yes	Yes	No
Township FE	Yes	Yes	Yes	No
Weather Controls	Yes	Yes	Yes	No

Notes: Standard errors in all regression equations are clustered at the well level, and standard errors in the NN match specifications are robust to arbitrary heteroskedasticity. *, **, and *** denote significance at the 10%, 5%, and 1% level.

Table C.7: Average effect of the regulation on gas production using alternative control wells.

	(1)	(2)	(3)	(4)
	Dif	Dif	Dif	NN Match
Panel A: Alt. Control Wells - Completed 2014, January to August				
Post-2015 (M1-M12)	0.055**	0.067**	0.067**	0.072*
	(0.027)	(0.028)	(0.028)	(0.039)
Log Initial Gas Production (mcf/day)	0.250***	0.249***	0.249***	
	(0.017)	(0.017)	(0.017)	
Δ Log HH Price	0.152	0.216	0.207	
	(0.131)	(0.133)	(0.133)	
Observations	24,604	24,604	24,604	2,527
Wells	2,683	2,683	2,683	2,527
Panel B: Alt. Control Wells - Completed 2013-2014				
Post-2015 (M1-M12)	0.141***	0.143***	0.143***	0.087***
	(0.022)	(0.022)	(0.022)	(0.025)
Log Initial Gas Production (mcf/day)	0.235***	0.235***	0.235***	
	(0.012)	(0.012)	(0.012)	
Δ Log HH Price	-0.194**	-0.192**	-0.190**	
	(0.095)	(0.096)	(0.096)	
Observations	45,843	45,843	45,843	4,934
Wells	4,934	4,934	4,934	4,934
Panel C: Alt. Control Wells - Completed 2013				
Post-2015 (M1-M12)	0.197***	0.198***	0.198***	0.114***
	(0.024)	(0.024)	(0.024)	(0.028)
Log Initial Gas Production (mcf/day)	0.231***	0.231***	0.231***	
	(0.014)	(0.014)	(0.014)	
Δ Log HH Price	0.041	0.049	0.055	
	(0.121)	(0.122)	(0.122)	
Observations	34,994	34,994	34,994	2,575
Wells	3,166	3,166	3,166	2,575
Prod Time Controls	ARPS	Cubic Spline	Prod FEs	N/A
Firm FE	Yes	Yes	Yes	No
Township FE	Yes	Yes	Yes	No
Weather Controls	Yes	Yes	Yes	No

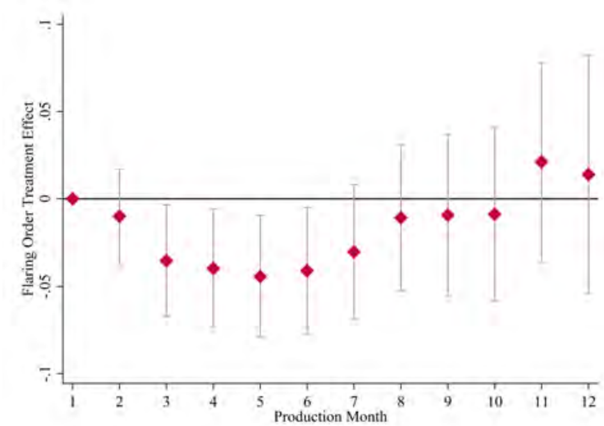
Notes: Standard errors in all regression equations are clustered at the well level, and standard errors in the NN match specifications are robust to arbitrary heteroskedasticity. *, **, and *** denote significance at the 10%, 5%, and 1% level.

Table C.8: Sensitivity analysis of counterfactual cost and production parameters.

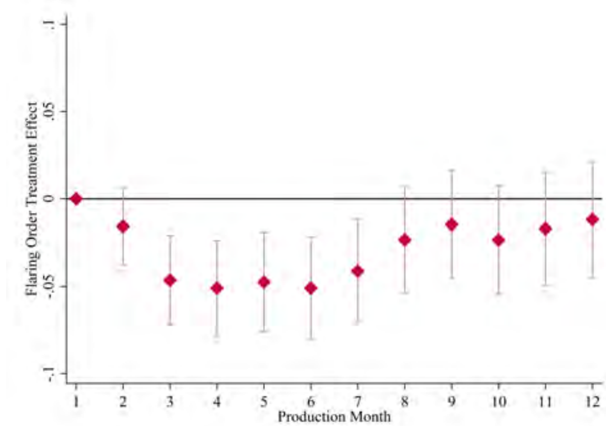
	10 Year Production Horizon		
	2 Inch Pipe	4 Inch Pipe	8 Inch Pipe
Half Fixed Cost	18%, 23%, \$0.33/mcf	22%, 27%, \$0.40/mcf	28%, 34%, \$0.51/mcf
Base Fixed Cost (\$210,000)	14%, 19%, \$0.59/mcf	17%, 22%, \$0.64/mcf	21%, 26%, \$0.74/mcf
Double Fixed Cost	11%, 17%, \$1.11/mcf	13%, 18%, \$1.14/mcf	16%, 21%, \$1.25/mcf
	20 Year Production Horizon		
	2 Inch Pipe	4 Inch Pipe	8 Inch Pipe
Half Fixed Cost	18%, 21%, \$0.22/mcf	22%, 25%, \$0.26/mcf	28%, 32%, \$0.35/mcf
Base Fixed Cost (\$210,000)	14%, 17%, \$0.39/mcf	16%, 20%, \$0.42/mcf	21%, 24%, \$0.50/mcf
Double Fixed Cost	11%, 15%, \$0.72/mcf	12%, 16%, \$0.75/mcf	15%, 19%, \$0.82/mcf

Notes: The first entry in each cell is the cost reduction from the inter-firm trading counterfactual scenario. The second entry in each cell is the cost reduction from the inter-firm trading and banking and borrowing counterfactual scenario. The third entry in each cell is the cost-effective flaring tax associated with the second entry. Divide by 0.053 tCO_2/mcf to convert into an equivalent carbon tax. Our base parameterization is a 20 year production horizon, 4 inch pipe, and the base fixed cost.

Figure C.1: Treatment effects of the regulation on flaring rates by production month using alternative control wells.



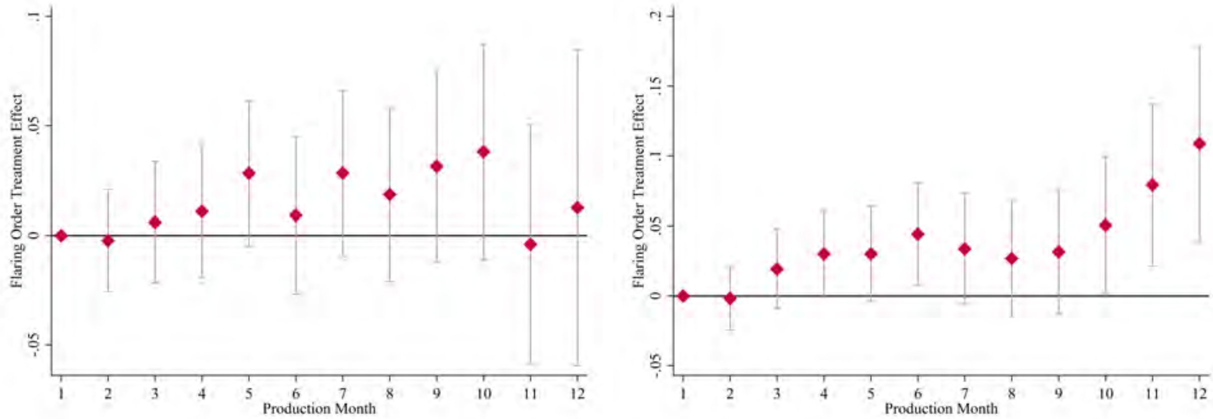
(a) Alternative Control Wells - Completed 2014, January to August



(b) Alternative Control Wells - Completed 2013-2014

Notes: Figure C.1a graphs the point estimates and 95% confidence intervals from estimating equation (6) using wells completed in January 2014 – August 2014 as the control group. Time is specified in production time, with month 1 corresponding to the first production month, and the effects are relative to the regulation's effect in the first production month. Figure C.1b graphs the point estimates and 95% confidence intervals from estimating equation (6) using wells completed in 2013 as the control group. Both regressions include the same controls as in column 2 of Table 1. Standard errors are clustered at the well level.

Figure C.2: Treatment effects of placebo regulations on flaring rates by production month.



(a) 2014 Placebo Wells - All Months

(b) 2013 Placebo Wells - All Months

Notes: Figure C.2a graphs the point estimates and 95% confidence intervals from estimating equation (5) using a placebo regulation that goes into effect in 2014 and a control group defined as wells completed in 2013. Time is specified in production time, with month 1 corresponding to the first production month, and the effects are relative to the regulation's effect in the first production month. Figure C.2b graphs the point estimates and 95% confidence intervals from estimating equation (5) using a placebo regulation that goes into effect in 2013 and a control group defined as wells completed in 2012. Both regressions include the same controls as in column 2 of Table 1. Standard errors are clustered at the well level.