Costs of Inefficient Regulation: Evidence from the Bakken

Gabriel E. Lade and Ivan Rudik*

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Abstract

Efficient pollution regulation equalizes marginal abatement costs across sources. We study a new flaring regulation in North Dakota and document its efficiency. The regulation reduced flaring 4 to 17 percentage points, accounting for most of the observed flaring reductions at new wells in the state since 2015. We construct firm-specific marginal abatement cost curves and find that the flaring reductions could have been achieved at 46% lower cost by taxing flared gas instead of imposing firm-specific requirements. Taxing flared gas at the public lands royalty rate would achieve 90% of the year-on-year flaring reductions at 60% lower cost.

JEL Codes: L71, Q3, Q4

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*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 Catie Hausman, Dave Keiser, Brian Prest, John Rupp, Carly Urban, Ashley Vissing, Sonia Yeh, and seminar participants at ASSA 2018, Cornell University, East Carolina University, the 2018 Heartland Workshop, Indiana University, Montana State University, Resources for the Future, University of Minnesota, and the NBER EEE Summer Institute and 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 regulated sources. Environmental regulations that achieve this condition include pollution taxes and cap-and-trade programs. Current environmental policies frequently deviate from this central economic principle and quantifying the gains from moving to more efficient regulation may not be possible. 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 would reduce total compliance costs by $1.6 billion (6%).

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 oil production, infrastructure to capture and process 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 requires well operators in North Dakota to capture a minimum percentage of gas produced by all their wells, with an ultimate objective of capturing 91% of produced gas in the state 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 same flaring standard every month. If abatement costs change over time due to expanding pipeline infrastructure or firms drilling new wells, firms may inefficiently allocate 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), so the costs of abatement misallocation may be large.

We first characterize the impact of the NDIC regulation using two research designs. The first compares wells completed before and after 2015, controlling for observable differences in economic and infrastructure conditions. The second is a difference-in-differences research design where our control group is the set of wells on Montana's side of the Bakken, which were not subject to the North Dakota flaring order. We find that the regulation decreased flaring rates by 4 to 17 percentage points over the first year of production at new wells, accounting for 33% to 140% of the observed year-on-year flaring reductions in the state. We find that firms primarily complied with the regulation by accelerating how quickly they connected to gas capture infrastructure.

Next, we construct firm-specific MAC curves. The exercise is motivated by our empirical finding that firms' primary compliance mechanism is connecting wells to pipeline infrastructure. We use detailed pipeline location data to measure the distance between wells and the nearest pipeline. We then use engineering cost estimates to construct on-site and pipeline infrastructure costs for each well, and aggregate the costs to construct firm and industry MAC curves. Our model's predictions of firm behavior in response to the regulation closely match actual firm behavior observed in the data. We use the estimated cost curves to simulate several 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 substantial heterogeneity in abatement costs both across firms and over time. Using our preferred estimates, reallocating abatement to low cost wells could achieve the same gas capture at 46% lower cost over the first eighteen months of the regulation. Most of the efficiency gains come from equating marginal abatement costs across firms. We find that the state could achieve the same flaring reductions by taxing flared gases at \$1.35/mcf. To put the value in perspective, the average public lands royalty rate on gas revenues over this period was around \$0.45/mcf, and the efficient tax amounts to taxing carbon emissions from flared gas at \$26/tCO_2, well under current social cost of carbon estimates.

Regulators have several incentives to limit flaring. First, flaring is associated with 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 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. Lost value due to flaring in the Permian basin was recently valued at over \$1 million per day (Elliott, 2018).

In response to these concerns, federal and state agencies have passed or considered several regulations to reduce the practice. The Bureau of Land Management and the EPA considered rules to regulate flaring and methane emissions from oil wells (U.S. Environmental Protection Agency, 2012; Bureau of Land Management, 2016), and the Fish and Wildlife Service considered regulating hydraulically fractured wells drilled on and near protected habitats. However, many of these proposals have since been weakened. In 2018 the Department of the Interior moved to repeal existing regulations on venting and flaring natural gas on federal lands (Friedman, 2018), and the EPA proposed weakening regulations on methane leak inspections and repairs (Davenport, 2018).

Our work contributes to a growing literature studying the impacts of the shale 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 in this setting (Covert, 2015; Lange and Redlinger, 2018). To date, little work has studied the effects of environmental regulations on oil and gas firms.

We contribute more generally to a large 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 empirical measurement of the associated efficiency gains has been limited (Carlson et al., 2000; Kerr and Newell, 2003; Fowlie et al., 2012).

We proceed 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 decision-making to clarify the margins by which firms may respond to the regulation. Section 4 describes the data and provides summary statistics. We describe our empirical strategy and present results for the effects of the regulation on firms' flaring and production decisions in Section 5. Motivated by our empirical findings, in Section 6 we estimate firm-specific marginal abatement cost curves and construct counterfactual flaring scenarios. Section 7 concludes. The appendix contains methodological details on the counterfactual scenarios, additional summary statistics, and robustness and sensitivity 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 drastically improved the economic viability of oil extraction 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 transformed the oil and gas industry. In 2015, oil production from fracked wells accounted for nearly half of US production (Energy Information Administration, 2015), and oil production in North Dakota increased tenfold between 2005 and 2015, from 90,000 barrels per day (bpd) to over 1.2 million bpd (North Dakota Industrial Commission, 2016). Firms have also dramatically reduced extraction costs such that break-even oil prices in North Dakota have recently been 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, 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 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 the associated gas has been flared, a loss to landowners and the state government since 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] Before its passage, the only flaring regulation was a requirement that operators pay taxes and royalties on flared gas after the first year of production, though exemptions were frequently granted (Energy Information Administration, 2016b; Rabe et al., 2018). Order 24665 created ambitious gas capture goals. The regulation requires that every firm operating in the Bakken capture 77% of their produced gas 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 they must comply with the regulation every month.[4] 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.[5] The regulation allows firms to bank excess gas captured for up to three months but does it not allow for borrowing, and the NDIC indicated that few firms have taken advantage of these provisions. Firms that violate the regulation can be ordered to curtail production at out-of-compliance wells 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 capture target.

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

$$(\%\ \text{Capture})_i = \frac{\sum_j \left(\mathrm{g}^s_{i,j} + \mathrm{g}^u_{i,j} + \mathrm{g}^p_{i,j}\right)}{\sum_j \mathrm{g}_{i,j}}, \tag{1}$$

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 $\mathrm{g}_{i,j}$ is the total gas produced by well

[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]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).

[5]In theory, firms could effectively trade flaring rights by buying and selling wells. We do not observe the date of well sales in our data and so cannot determine if trades occur when a firm is not capturing a sufficient fraction of gas. There is evidence of larger-scale purchases when firms exit the market (e.g. Scheyder, 2015).

[6]Average production at new wells in North Dakota in 2015–2016 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]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.

j.[8] Firms' primary compliance mechanism is to connect wells to gas pipeline infrastructure. This involves installing smaller pipelines, called gathering lines, that connect 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 in 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. A well is not subject to the regulation for the well's first 90 production days, and as a result, firms have flexibility with regards to their flaring rates at new wells until the fourth month of production.

2.3 Oil Production in the Bakken

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 oil-rich shale; 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 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 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 main factors (i) the amount of hydrocarbons in the underlying shale; and (ii) the length of the well and intensity with which firms frack the well. Firms can affect the former by drilling in more productive areas, but firms are not perfectly informed and do not always drill into the most productive

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

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 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 segments, 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.

We focus on the second stage and 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 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. There is little evidence of oil production losses from installing gas capture infrastructure. After completion, oil and gas production follows a relatively stable decline curve. A common characterization is the 'ARPS' model (Fetkovich, 1980). The model specifies well j's oil and gas production at a given time of production t as

$$\begin{aligned} \mathrm{o}_{jt} &= \mathrm{O}_{j0} t^{\beta_{\mathrm{o}}} \exp(\epsilon_{jt}) \\ \mathrm{g}_{jt} &= \mathrm{G}_{j0} t^{\beta_{\mathrm{g}}} \exp(e_{jt}) \end{aligned} \tag{2}$$

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

[9] Anderson et al. (2018) 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.

observing a well's initial production and decline rates at similar wells.[10]

Consider the firm's second stage 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 (2) 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

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

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

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

$$P^g + \lambda \geq \frac{C_j(1)}{g_j}, \qquad j = 1, ..., J. \tag{3}$$

The firm connects well j if the marginal benefit of capturing 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 over its lifetime.

The first-order condition yields key insights that allow us to evaluate the efficiency of the regulation. Economic theory tells us that cost-effective policy equalizes shadow prices across all firms and, in a dynamic setting, equalizes a firm's shadow price across 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 production. 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 allocates 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

[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 (ICF International, 2018).

equal in all compliance periods. We take advantage of these insights in Section 6.1 when we construct firm marginal abatement costs curves and evaluate the cost-effectiveness of the flaring regulation.

4 Data Description and Summary Graphs

Our data consist of monthly, well-level production, flaring, and sales data for wells in North Dakota and Montana. The NDIC reports data for over 9,300 horizontal wells owned and operated by 54 firms between 2007 and 2016 in North Dakota. Montana data are reported by the Montana Board of Oil and Gas Conservation for over 570 wells. For most of our analysis, we focus on the roughly 6,800 North Dakota and 310 Montana wells completed between January 2012 and June 2016. We process the data in a few ways. First, we focus on horizontal oil 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 first production since they have likely been re-fractured and are not comparable to other wells.[12]

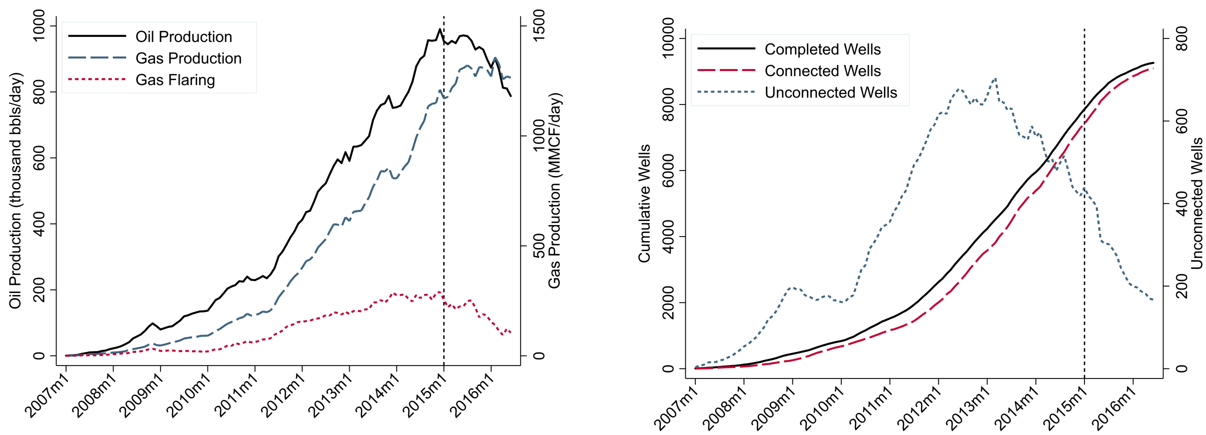
We observe several well-level characteristics including the year and month of spudding and completion; wells' latitude and longitude; the vertical and horizontal length of all wells; and the current and original owners of all wells.[13] We merge this with relevant data from several sources. First, we obtained GIS data for all natural gas and oil pipelines in North Dakota 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 use weather data from the nearest weather monitoring station provided by the North Dakota Agricultural Weather Network, which also operates stations in Montana, and we use snowfall data from the NOAA National Operational Hydrologic Remote Sensing Center. Third, we collect data from the North Dakota Pipeline Authority to calculate the monthly capacity factor at the nearest natural gas processing plant for every well. Last, we control for historical oil and gas price data using futures prices for Henry Hub (HH) natural gas and Clearbrook oil prices from

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

[13] Only the most recent and initial operator are observed. We do not observe sales date and cannot determine when wells were purchased.

[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 North Dakota.



(a) Oil Production, Gas Production, and Flaring

(b) Completed and Connected Wells

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

Bloomberg.[15,16] We do not have pipeline or natural gas plant data for Montana.

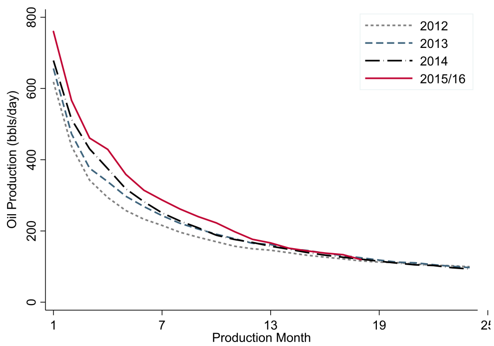
Figures 1a and 1b graph monthly oil and gas production, gas flaring, the number of completed and connected wells, and the number of unconnected wells from January 2007 to June 2016 for all wells in North Dakota. Oil and gas production grew exponentially until mid-2014 when oil prices began to fall. After 2015, oil production dropped precipitously, while gas production remained relatively stable, even increasing slightly. This is due to two factors. First, wells drilled in the state since 2015 have generally had greater gas-to-oil ratios. Second, wells' monthly gas production tends to decrease slower than oil production.

Operators flared a substantial amount of their produced gas over this period. Flaring rates regularly exceeded 30% through 2014. Both the amount and rate of flaring decreased since 2015 when the flaring regulation began. Figure 1b highlights the primary mechanism by which firms reduced flaring – the number of unconnected wells in the state declined rapidly. The decline began as early as 2013, and the number of unconnected wells in the state shows

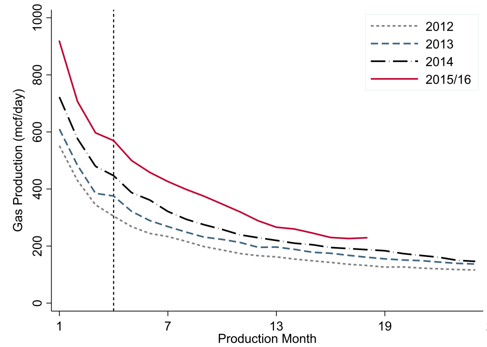
[15]Results are similar if we use West Texas Intermediate (WTI) crude oil prices or Guernsey crude oil prices. We are unaware of any posted prices for natural gas or NGL co-products in North Dakota or Montana. Recent work by Avalos et al. (2016) suggests that natural gas prices are integrated even in distant markets across the US.

[16]Clearbrook prices are spot. Results are not sensitive to using the average of all concurrently traded WTI contract prices for up to twelve months ahead, the six month ahead futures price, or the 12 month ahead futures price. In our main specification, Henry Hub prices are the average of all concurrently traded contract prices for up to twelve months ahead.

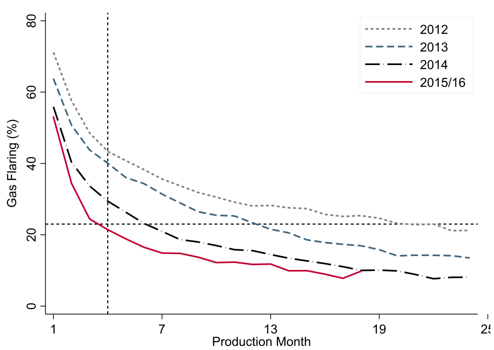
Figure 2: Well production, flaring and connection rates by production month in North Dakota.



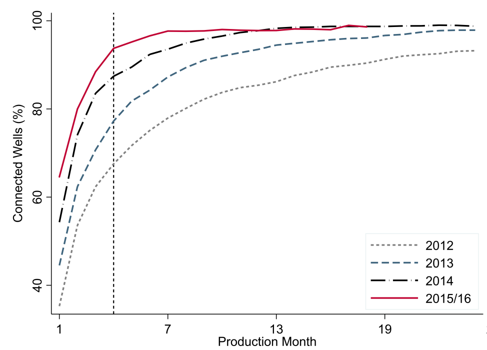
(a) Average Oil Production



(b) Average Gas Production



(c) Average Flaring Rate



(d) Average Connection Rate

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

steeper drops after January 2015.

Figure 2 graphs average oil production, gas production, flaring rates, and the fraction of wells connected to gas capture infrastructure in well 'production time,' the months since the first observed production from a well using data from North Dakota. The figures document substantial productivity gains 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. Average flaring rates decline slowly over wells' productive lifetimes. In 2012 and 2013, firms flared around 40% of produced gas 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 show nearly identical flaring rates in the first two production months. However, beginning in their third month, wells completed in 2015–2016 flare less on average relative to 2014 wells until around their 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]

Similar graphs for Montana wells are available in Figures A.1 and A.2 in the appendix. A few key differences are apparent. First, Montana is much less productive both in the number of oil wells drilled and average productivity of those wells. As in North Dakota, oil production declined dramatically with the fall in oil prices starting in 2014 while gas production remained relatively stable due to a higher gas-to-oil ratio at new wells. Unlike North Dakota, few wells were unconnected through 2011, after which flaring increased substantially in the state. The number of unconnected wells in Montana remained steady since 2015, and average flaring and connection rates in production time remain well above those in North Dakota. This is consistent with firms in Montana, where wells were not subject to the same stringent flaring regulations, choosing to invest less in gas capture infrastructure when facing lower oil and gas prices in 2015 through mid-2016.

5 Effects of the NDIC Flaring Order

We now describe our empirical strategy to estimate the impact of the NDIC regulation on flaring 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. We do not consider other margins of behavior 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 potential oil production, which makes up the vast majority of revenue from a well, rather than gas production or the presence of nearby gas capture infrastructure. Last, we present our results.

[17]Table A.1 in Appendix A presents other relevant summary statistics for both North Dakota and Montana, comparing wells completed in 2012–2014 to those completed after 2015.

5.1 Empirical Strategy: Flaring

Our primary empirical strategy uses difference and difference-in-differences estimation. We limit our analysis to the impact of the regulation on wells completed after January 2015 and focus on wells' first year of production for a few reasons. First, a large amount of a well's lifetime gas production occurs in the first year.[18] Second, a main goal of Order 24665 is to incentivize firms to connect wells to gas capture infrastructure early in their production lifetimes. The NDIC gas capture calculation, equation (1), disproportionately decreases if a new, high-production well is not connected by its fourth production month.[19] Third, the NDIC may require firms to pay taxes and royalties on flared gas after their first year of production, and we do not want to conflate the impacts of the 2015 flaring regulation with other requirements.

In our differences estimation we limit our sample to North Dakota wells. For this approach, we define untreated wells as those that were completed in 2014 and treated wells as those completed after 2015. 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 calendar year 2015 observations for wells in our control group. We include several 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. We estimate the following regression

$$Y_{ift\tau yT} = \rho\mathbf{1}[\text{Completed 2015}] + g(t;\theta) + \mathbf{X}'_{if\tau y}\beta + \pi_T + \omega_f + \gamma_\tau + \varepsilon_{ift\tau yT}. \tag{4}$$

$Y_{ift\tau}$ is the flaring rate at well i owned by firm f in month of production t, calendar month τ, year y and township T.[20] $\mathbf{X}_{if\tau y}$ includes the log of the well's gas production; the log of changes in HH and Clearbrook prices; the log distance to the nearest gas pipeline; the capacity factor at the closest natural gas processing plant; and local weather conditions.[21] The function $g(t;\theta)$ is a flexible function in production time that controls for common prac-

[18]Based on our estimated ARPS decline rate of -0.342 from wells in our sample, gas production declines by an average of 57% after the first year of production.

[19]An alternative empirical strategy would be to designate North Dakota wells as 'treated' only after their fourth production month. We do not pursue this strategy because installing gas capture infrastructure can involve months of planning and construction. This requires firms to consider a gas capture plan long in advance of the fourth production month.

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

[21]We cannot reject the null hypothesis that log Clearbrook 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 prices are increasing or decreasing in any given month. Weather controls include total precipitation and temperature.

tices across wells in each production month. In our main specification, we specify $g(t;\theta)$ as production time fixed effects. We also include township fixed effects in $\mathbf{X}_{if\tau y}$ to control for fixed characteristics of wells' locations such as the underlying geology, firm fixed effects to control for fixed owner characteristics, and month fixed effects to control for seasonality in production, drilling, and prices.[22]

Our difference-in-differences strategy addresses a key empirical challenge in our setting – oil prices collapsed between 2014 and 2015.[23] To address this, we add data on wells drilled in the Montana portion of the Bakken formation from January 2014 to June 2016. We use the same sample restriction where we drop calendar year 2015 observations for wells completed in 2014. Montana wells are our control group and North Dakota wells are treated by the regulation if they were completed between January 2015 and June 2016.[24] We estimate the following regression[25]

$$\begin{aligned} Y_{ift\tau ys} =& \rho \mathbf{1}[\text{Completed 2015, s = ND}] + \mathbf{X}'_{if\tau ys}\beta \\ & + \eta_s + \alpha_y + \gamma_\tau + \omega_f + \zeta_t + \varepsilon_{ift\tau s} \end{aligned} \tag{5}$$

where s indexes the state the well is in. $\mathbf{X}_{if\tau s}$ controls for the log of the well's gas production; the log of changes in HH and Clearbrook prices and local weather conditions. We also include state effects, year effects, month effects, firm effects, and production time effects.

The identifying assumption for the differences design is that, absent the NDIC regulation and conditional on our full set of controls and fixed effects, 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. Our differences-in-differences design relies on the less restrictive assumption that wells completed in 2015 in North Dakota would have followed parallel trends to wells completed in 2015 in Montana. This second strategy is especially important given the dramatic change in the economic environment from 2014 to 2015 – oil prices crashed over this period which may have substantially changed firms' operations. Section C examines the robustness of our model and identifying assumptions. It contains a host of results showing that our model estimates have parallel pre-trends, and our model is robust to alternative samples and placebo tests.

We also explore heterogeneity in the regulation's effect by estimating the following flexible

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

[23] Oil prices were relatively stable from 2011 through July 2014, with WTI averaging \$95/bbl. Prices began to decline rapidly in the fall of 2014. Average prices from January 2015 through June 2016, the period when the flaring policy came into place, were \$45/bbl. This substantially decreased both the economic viability of oil wells throughout the U.S., and the available capital for gas capture infrastructure investments.

[24] Lange and Redlinger (2018) and Brown et al. (2018) also compare North Dakota to Montana to estimate the impacts of well bonding requirements and state severance taxes.

[25] Section C contains a suite of sensitivity and robustness checks. We test alternative control groups, placebo treatments, and pre-trends for the difference-in-differences design.

difference-in-differences model that allows for treatment effects to vary by production month

$$
\begin{aligned}
Y_{ift\tau ys} = & \sum_{r=2}^{12} \rho_r \mathbf{1}[\text{Treated, t=r}] + \mathbf{X}'_{if\tau ys}\beta \\
& + \eta_s + \alpha_y + \gamma_\tau + \omega_f + \zeta_t + \delta_i + \varepsilon_{ift\tau s}.
\end{aligned} \tag{6}
$$

Equation (6) allows for separate coefficients ρ_r for the second through twelfth production months. Given the interaction of treatment with production month, we can include well fixed effects to more finely control for well-specific unobservables. Each coefficient ρ_r estimates the impact of the regulation on average flaring rates relative to the impact of the regulation on flaring rates in the first production month.

5.2 Empirical Strategy: Mechanisms

We use a similar empirical strategy to study how firms comply with the regulation. We first test whether firms take longer to complete wells after spudding (drilling). Longer completion times are consistent with firms installing more on-site infrastructure, including gas capture infrastructure. Second, we test whether firms connect to gas capture infrastructure earlier in a well's lifetime. Because output is highest in the first production months, earlier gas connections disproportionately increase the fraction of gas captured and sold. 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 first estimate a non-parametric Kaplan-Meier (KM) survivor function for spud-to-completion and first production-to-connection time. Let $\bar{t}_j$ denote the spud month, i_j denote the number of wells not completed before month $\bar{t}_j$, and c_j be the number of wells that are completed in month $\bar{t}_j$. For the first production-to-completion time, $\bar{t}_j$ is the production month, i_j is the number of unconnected wells before $\bar{t}_j$, and c_j is the number of wells that are connected in $\bar{t}_j$. 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 spudded (completed) in 2014 and those spudded (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 the same difference and difference-in-differences models outlined in equations (4) and (5). Here, the outcome variable is an indicator function that equals zero if the well has not yet been completed or connected, and equals one in the month the well is completed or connected.[26] Wells are dropped for all months after the month in which they are completed or connected. For our spud-to-completion regressions, we control for weather, depth (combined vertical and horizontal length), oil prices, and initial oil production. Deeper wells take longer to frack and complete, firms may accelerate or slow down completion based on oil prices, and we use initial oil production as a proxy for fracking inputs and intensity which may affect time to completion. For our production-to-connection regressions, we control for initial gas production, oil and gas prices, distance to pipeline, and gas plant capacity factor. Our coefficient of interest is on the indicator function for whether the well was spudded in North Dakota after 2015 for the spud-to-completion regressions, and on the indicator function for whether the well was completed in North Dakota after 2015 for the first production-to-connection regressions. For the first production-to-connection regressions we also estimate a flexible difference-in-differences model allowing the treatment effects to vary by production month.

Oil and gas production: Last, we test whether the regulation affects wells' oil and gas production. We estimate regression equations (4) and (5), where we replace $Y_{ift\tau s}$ 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. We use production time fixed effects, though results are similar using other common production time controls such as an ARPS specification and a cubic spline in production time.[27] Controls include oil or gas prices, initial oil or gas production, local weather conditions, and other similar fixed effects as described in the flaring regressions. As in the flaring regressions, we present results for all wells in our sample and for wells that were connected to gas capture infrastructure by their second production month because wells that remain unconnected later in their productive lifetime have a greater incentive to curtail production to comply with the regulation.

5.3 Results: Flaring Treatment Effects

Table 1 presents the estimated impacts of the NDIC regulation. In this and all subsequent tables, the coefficient of interest is 'Flaring Regulation.' Columns (1) and (2) show our differences estimates, and columns (3) to (4) show our difference-in-differences estimates.

[26] Previous versions of the paper estimated hazard models of the regulation's impact on spud-to-completion and first production-to-connection times. Results are similar when using these alternative modeling strategies.

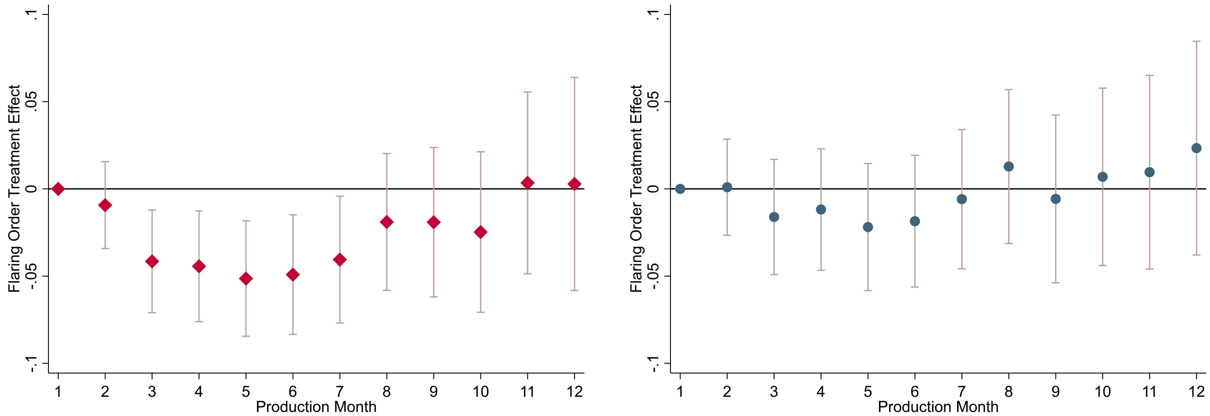
[27] The difference-in-difference regressions include production time by state fixed effects to allow for different average lifetime production for wells in Montana and wells in North Dakota.

Table 1: Average effect on flaring rates.

	(1)	(2)	(3)	(4)
	Dif	Dif	D-in-D	D-in-D
Panel A: All Wells				
Flaring Regulation	-0.112***	-0.045***	-0.266***	-0.167**
	(0.008)	(0.011)	(0.101)	(0.081)
Log Gas Production (mcf/day)		0.034***		0.032***
		(0.002)		(0.002)
Log Dist. to Gathering Line (miles)		0.027***		
		(0.003)		
Δ Log HH Price ($/MMBtu)		-0.450***		-0.250***
		(0.064)		(0.068)
Δ Log Clearbrook Price ($/bbl)		-0.194***		-0.149***
		(0.031)		(0.031)
Closest Gas Plant Capacity Factor (%)		0.006		
		(0.023)		
Observations	26,610	26,610	27,129	27,129
Wells	3,358	3,358	3,421	3,421
Panel B: Wells Connected by Second Production Month				
Flaring Regulation	-0.034***	0.001	-0.188*	-0.096
	(0.008)	(0.010)	(0.101)	(0.075)
Log Gas Production (mcf/day)		0.012***		0.017***
		(0.003)		(0.003)
Log Dist. to Gathering Line (miles)		0.012***		
		(0.004)		
Δ Log HH Price ($/MMBtu)		-0.236***		0.007
		(0.065)		(0.073)
Δ Log Clearbrook Price ($/bbl)		-0.166***		-0.110***
		(0.033)		(0.034)
Closest Gas Plant Capacity Factor (%)		-0.005		
		(0.020)		
Observations	15,527	15,527	16,385	16,385
Wells	1,980	1,980	2,083	2,083
Firm FE	No	Yes	No	Yes
Township FE	No	Yes	No	No
State FE	No	No	Yes	Yes
Production Month FE	No	Yes	No	Yes
Month-of-Year FE	No	Yes	No	Yes
Year FE	No	No	Yes	Yes
Weather Controls	No	Yes	No	Yes

Notes: The dependent variable is the well-level flaring rate. The coefficient of interest is Flaring Regulation, which equals one if a well was completed in North Dakota after 2015. Dif and D-in-D denote differences and difference-in-differences estimators, respectively, where the former contains data from North Dakota wells only. Standard errors are clustered at the well. *, **, and *** denote significance at the 10%, 5%, and 1% level.

Figure 3: Treatment effects by production month.



(a) All Wells

(b) Connected Wells

Notes: Figure 3 graphs the point estimates and 95% confidence intervals from a flexible difference-in-differences model with the same controls as in Column (4) of Table 1 but with well fixed effects. All treatment effects are relative to the regulation's effect on flaring rates in the first production month. Standard errors are clustered at the well.

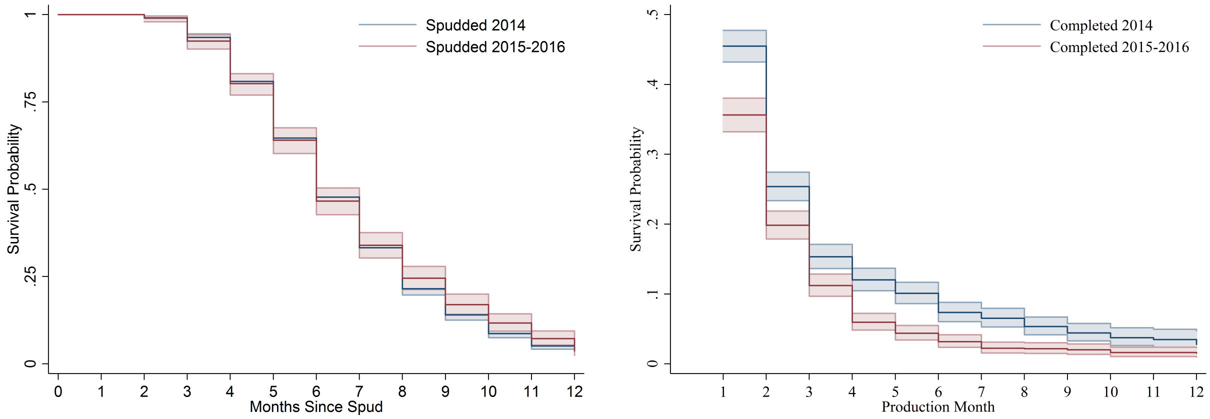
Panel A includes all wells, and Panel B includes only wells that were connected by their second production month. The latter is meant to test whether the regulation impacts routine flaring after a well is connected to gas gathering infrastructure.

After controlling for observable differences between wells completed in 2014 versus those completed after 2015, we find that wells flared 4.5% to 16.7% less on average over the first production year. The large difference in the estimated treatment effect between the differences and difference-in-differences estimates suggesting that time-varying unobservables are important in this setting, and likely confound the differences results. Panel B presents results for connected wells. After controlling for observables and including our suite of fixed effects, we do not find a systematic reduction in flaring at these wells. The result suggests that the regulation has little to no impact on routine flaring. The point estimates for other covariates have intuitive signs for both samples. Firms flare more at wells that are more gas productive, that are further from pipeline infrastructure, and when natural gas prices decrease.

Figure 3 presents the flexible difference-in-differences results where we replace firm fixed effects with well fixed effects.[28] The regression includes the same controls as in column (4) of Table 1, and we present estimates for all wells in the left panel and wells that were connected in their first two production months in the right panel. All estimates are relative

[28]Interacting treatment with production month allows us to introduce well fixed effects in place of state fixed effects.

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.

to the omitted first production month. When we consider all wells, flaring reductions are largest relative to the first production month between the third and seventh production months, where we estimate an additional 4% to 5% reduction. The timing coincides with the regulation having a larger impact on flaring rates around the production months when the wells are included in firms' gas capture targets. We find no discernible differential impact of the regulation at connected wells across production months. The finding suggests that, conditional on connecting to gas capture infrastructure, firms do not strategically curtail around the fourth production month.[29]

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 similar for wells spudded after 2015 and those spudded in 2014. 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

[29] Appendix C.2 explores heterogeneous treatment effects across firms. We show that, on average, firms with the largest estimated treatment effects: (i) have wells that are further from pipeline infrastructure; (ii) have wells that produce less gas; and (iii) own fewer wells.

Table 2: Average effect on completion probability.

	(1) Dif	(2) Dif	(3) D-in-D	(4) D-in-D
Flaring Regulation	-0.000	0.001	-0.110***	0.049***
	(0.003)	(0.007)	(0.008)	(0.010)
Δ Log Clearbrook Price ($/bbl)		-0.103**		-0.066
		(0.042)		(0.042)
Log Well Depth (feet)		-0.070*		-0.072**
		(0.036)		(0.036)
Log Initial Oil Production (bbl/day)		-0.003		-0.003
		(0.003)		(0.003)
Observations	17,822	17,338	17,822	17,338
Wells	2,614	2,583	2,614	2,583
Firm FE	No	Yes	No	Yes
Township FE	No	Yes	No	No
State FE	No	No	Yes	Yes
Spud Month FE	No	Yes	No	Yes
Month-of-Year FE	No	Yes	No	Yes
Year FE	No	No	Yes	Yes
Weather Controls	No	Yes	No	Yes

Notes: The dependent variable is an indicator variable that equals zero if a well remains uncompleted in a spud month and one when the well is completed. The well is dropped for all subsequent months after the completion month. The coefficient of interest is Flaring Regulation, which equals one if a well was spudded in North Dakota after 2015. Dif and D-in-D denote differences and difference-in-differences estimators, where the former contains data from North Dakota wells only. Standard errors are clustered at the well. *, **, and *** denote significance at the 10%, 5%, and 1% level.

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.

Table 2 presents our estimates of the effect of the flaring regulation on the probability of completing a well after spudding. The first two columns show results for the differences design and the second two columns for the difference-in-differences design. The average impact of the regulation on completion probability varies depending on the specification. We see no discernible difference in completion probabilities in the differences model, consistent with evidence in Figure 4a. We find a slight increase in the completion probability in the differences-in-differences model with controls. In our preferred specification, we estimate that the regulation induced a 5% increase in completion probability.

Table 3 presents our estimates of the regulation on the probability of connecting to gas capture infrastructure after first production. Here, the evidence is more clear. Wells com-

Table 3: Average effect on probability of connecting to gas capture infrastructure.

	(1) Dif	(2) Dif	(3) D-in-D	(4) D-in-D
Flaring Regulation	0.080***	0.077***	0.221**	0.181**
	(0.018)	(0.017)	(0.112)	(0.078)
Log Gas Production (mcf/day)		0.071***		0.072***
		(0.003)		(0.003)
Log Dist. to Gathering Line (miles)		-0.035***		
		(0.005)		
Δ Log HH Price ($/MMBtu)		0.596***		0.365**
		(0.139)		(0.156)
Δ Log Clearbrook Price ($/bbl)		0.205***		0.164**
		(0.076)		(0.077)
Closest Gas Plant Capacity Factor (%)		0.013		
		(0.037)		
Observations	6,523	6,523	6,694	6,694
Wells	3,358	3,358	3,421	3,421
Firm FE	No	Yes	No	Yes
Township FE	No	Yes	No	No
State FE	No	No	Yes	Yes
Production Month FE	No	Yes	No	Yes
Month-of-Year FE	No	Yes	No	Yes
Year FE	No	No	Yes	Yes
Weather Controls	No	Yes	No	Yes

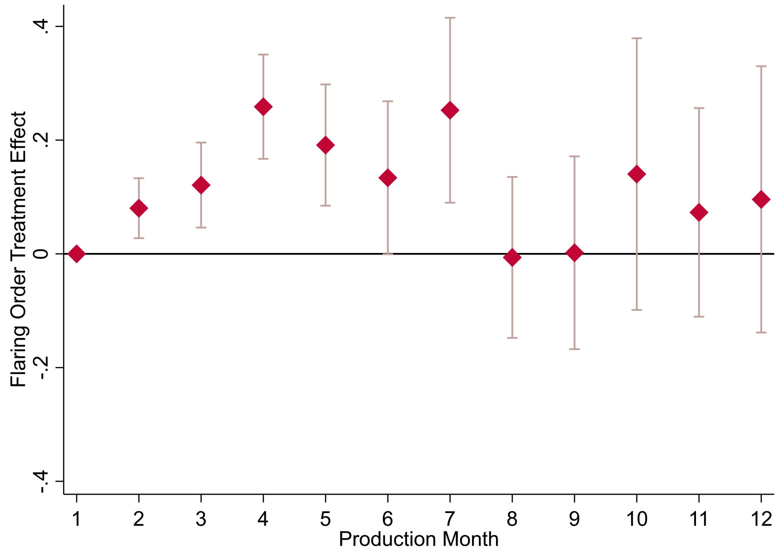
Notes: The dependent variable is an indicator variable that equals zero if a well is unconnected and equals one in the month the well connects. The well is dropped for all subsequent production months after the connection month. The coefficient of interest is Flaring Regulation, which equals one if a well was completed in North Dakota after 2015. Dif and D-in-D denote differences and difference-in-differences estimators, respectively, where the former contains data from North Dakota wells only. Standard errors are clustered at the well. *, **, and *** denote significance at the 10%, 5%, and 1% level.

pleted after 2015 have an increased probability of connecting to gas capture infrastructure in all specifications. After completion, we estimate the regulation results in a well having an 18% increased probability of being completed in a given month during its first production year.

Figure 5 plots the estimates for connection probabilities across production months. As in Figure 3, the interaction of treatment with production month allows us to replace firm fixed effects with well fixed effects, while still including the same controls as in column (4) of Table 1. All estimates are relative to the omitted first production month. The estimates indicate that the regulation accelerated connection to gas capture infrastructure most between the second and seventh production months. The finding aligns with both the KM statistics in Figure 4b and the flexible difference-in-difference estimates for the impacts of the regulation on average flaring in Figure 3a.

Table 4 presents our results for the effects of the regulation on firms' oil and gas produc-

Figure 5: Average effect on probability of connecting to gas capture infrastructure by production month.



Notes: Figure 5 graphs the point estimates and 95% confidence intervals from a flexible difference-in-differences model with the same controls as Table 3, but with well fixed effects in place of firm fixed effects. All treatment effects are relative to the regulation's effect on connection time in the first production month. Standard errors are clustered at the well.

tion. We show results for the same two samples as in the flaring regressions, all wells and wells that were connected by their second production month, because wells that are already connected to gas capture infrastructure may have less of an incentive to curtail production. We include production-month fixed effects in all specifications, so the regressions compare average deviations from expected oil production at wells in the Bakken after they are subject to the regulation.

In Panel A, we find some evidence that firms curtailed oil production, though the point estimates are noisy and the size of the treatment effect varies across the differences and differences-in-differences models. Estimated oil curtailments are largest and statistically significant when we include all wells in the sample. We find less evidence that firms curtail wells that are already connected to gas capture infrastructure. In contrast, we see no consistent evidence of gas curtailment in Panel B. Given that we do not find robust evidence of firms curtailing gas production, our primary outcome of interest, we focus in our next section on the mechanism for which we find the most robust evidence – gathering line connections.

Table 4: Average effect on oil and gas production.

(4.A) Oil Production

	(1) Dif	(2) Dif	(3) D-in-D	(4) D-in-D
Flaring Regulation	-0.050**	0.032	-0.362***	-0.149
	(0.026)	(0.027)	(0.125)	(0.098)
Δ Log Clearbrook Price ($/bbl)	0.175*	-0.041	0.075	-0.083
	(0.100)	(0.095)	(0.096)	(0.090)
Log Initial Oil Production (bbl/day)	0.289***	0.346***	0.293***	0.403***
	(0.017)	(0.024)	(0.017)	(0.030)
Sample	All	Connected	All	Connected
Observations	26,610	15,527	27,127	16,383
Wells	3,358	1,980	3,421	2,083
Firm FE	Yes	Yes	Yes	Yes
Township FE	Yes	Yes	Yes	Yes
State FE	No	No	Yes	Yes
Production Month FE	Yes	Yes	Yes	Yes
Month-of-Year FE	Yes	Yes	Yes	Yes
Year FE	No	No	Yes	Yes
Weather Controls	Yes	Yes	Yes	Yes

(4.B) Gas Production

	(1) Dif	(2) Dif	(3) D-in-D	(4) D-in-D
Flaring Regulation	-0.019	0.062*	-0.236	0.082
	(0.031)	(0.033)	(0.180)	(0.134)
Δ Log HH Price ($/MMBtu)	0.861***	0.288	0.339	0.145
	(0.231)	(0.256)	(0.233)	(0.235)
Log Initial Gas Production (mcf/day)	0.261***	0.372***	0.263***	0.414***
	(0.016)	(0.025)	(0.016)	(0.029)
Sample	All	Connected	All	Connected
Observations	26,140	15,527	26,591	16,317
Wells	3,292	1,980	3,349	2,077
Firm FE	Yes	Yes	Yes	Yes
Township FE	Yes	Yes	Yes	Yes
State FE	No	No	Yes	Yes
Production Month FE	Yes	Yes	Yes	Yes
Month-of-Year FE	Yes	Yes	Yes	Yes
Year FE	No	No	Yes	Yes
Weather Controls	Yes	Yes	Yes	Yes

Notes: The dependent variable is oil or gas production. The coefficient of interest is Flaring Regulation, which equals one if a well was completed in North Dakota after 2015. Dif and D-in-D denote differences and difference-in-differences estimators, respectively, where the former contains data from North Dakota wells only. Standard errors are clustered at the well. *, **, and *** denote significance at the 10%, 5%, and 1% level.

6 Heterogeneous Costs and Gains from Trade

In this section, we take advantage of insights from our theoretical model and empirical results to construct monthly MAC curves for all firms in North Dakota over the first year and a half of the regulation. We use the estimated functions to study the efficiency of the NDIC regulation and quantify potential gains from using more flexible flaring standards. We explore three counterfactual policies. The first allows for inter-firm trading but continues to enforce the same flaring standard every month. The second allows inter-temporal trading but leaves in place the firm-specific standard. The third combines the two. We also explore the impacts of two alternative policies: taxing flared gas at the social cost of carbon and making firms pay royalties on flared gas at the public lands rate.

6.1 Firm Abatement Costs

Section 3 showed that a firm connects a well if the cost of doing so is below some threshold. 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. 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.

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 construct firm and industry MAC curves. For a given month, we construct firm MAC curves by calculating the right-hand side of equation (3) for every well that is not already connected to gas capture infrastructure in that month. The calculation consists of two components (i) the well's connection costs; and (ii) the well's expected gas production. We calculate the latter by estimating an ARPS model for wells completed between 2014 and 2016 in North Dakota. We specify well i's gas production g_{it} in any month t as

$$log(\mathrm{g}_{it}) = \beta_1 \log(t) + \theta_i + \varepsilon_{it}, \tag{8}$$

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 remaining lifetime gas production g_{it} for any well i in production month t. We use a twenty year lifetime to calculate the total amount of gas that a well will produce.

Given g_{it} we compute the right-hand side of equation (3), the per unit connection cost for connecting the well, as

$$\frac{(\text{On-site Fixed Costs}) + (\text{Inch-Mile Line Costs}) \times d_i \times w_{it}}{g_{it}}. \tag{9}$$

The first term in the numerator is the fixed cost of on-site equipment such as dehydrators, compressors, and other equipment that removes hazardous pollutants. The second term is the cost of constructing a gathering line to well i in production month t. This term is a function of the length of the line, d_i, and the diameter of the line, w_{it}, which we allow to vary in production time t.

We construct these costs using data from ICF International in a report prepared for the Interstate Natural Gas Association of America (INGAA) (ICF International, 2018). ICF reports both average on-site equipment costs and per-mile gathering line costs for wells in the United States. Average equipment costs are reported to be \$202,000 per well, while average gathering line costs vary by the assumed diameter of the line. ICF reports average per inch-mile costs in 2015 for 4, 6, and 8 inch gathering lines as \$36,244, \$30,313, and \$31,631 respectively.[30]

We calculate d_i as the minimum distance from a well to another gathering line or a natural gas pipeline using the data from Rextag.[31] We use data from Rextag on existing gathering line diameters to estimate an ordered probit model of pipeline's diameter, w_{it}, as a function of each well's initial gas production and connection month.[32] Firms' MAC curves change from month-to-month due to several factors. First, new wells come online and are added to future MAC curve if left unconnected. Second, existing wells are connected to gas capture infrastructure and are removed from future MAC curves. Third, expected lifetime gas sales g_{it} decreases as a well ages. Finally, the installed gathering line diameter decreases in the age of the well.[33]

After calculating equation (9) for every unconnected well in month t, we construct firm

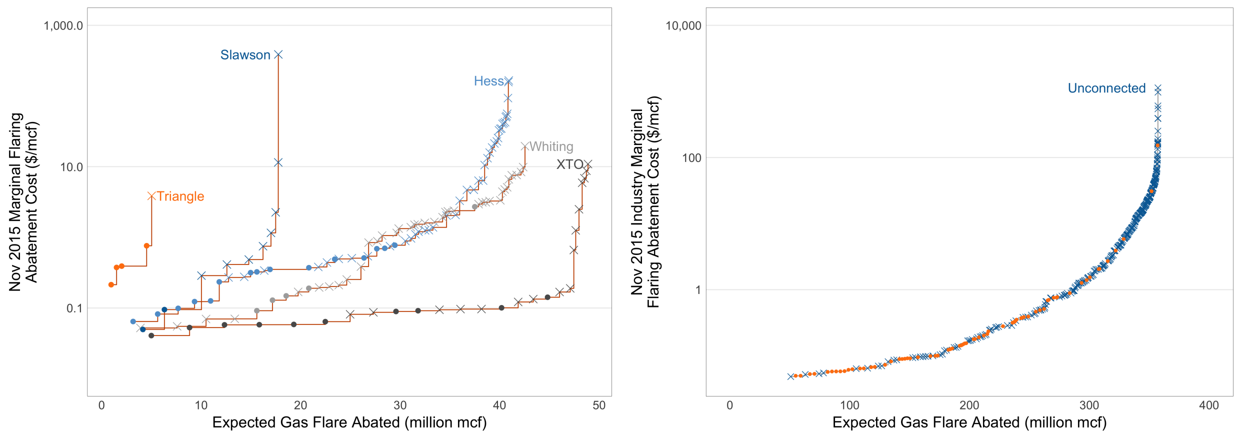
[30]In per mile terms, these costs are \$137,868 for 4 inch line, \$172,962 for 6 inch line, and \$240,640 for 8 inch line.

[31]Because we only observe a snapshot of the pipeline network, we do not capture how gathering line distance may change 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.

[32]We describe our pipeline cost construction in greater detail in Appendix B.

[33]Connection month is the strongest predictor of gathering line diameter in our ordered probit model. Predicted gathering line diameters are 8" for the first nine months, decrease to 6" if the well is connected 10 to 12 months after initial production, and decrease to 4" after that.

Figure 6: Marginal flaring abatement cost curves.



(a) Observed Connection Decisions

(b) Observed Industry MAC Curve

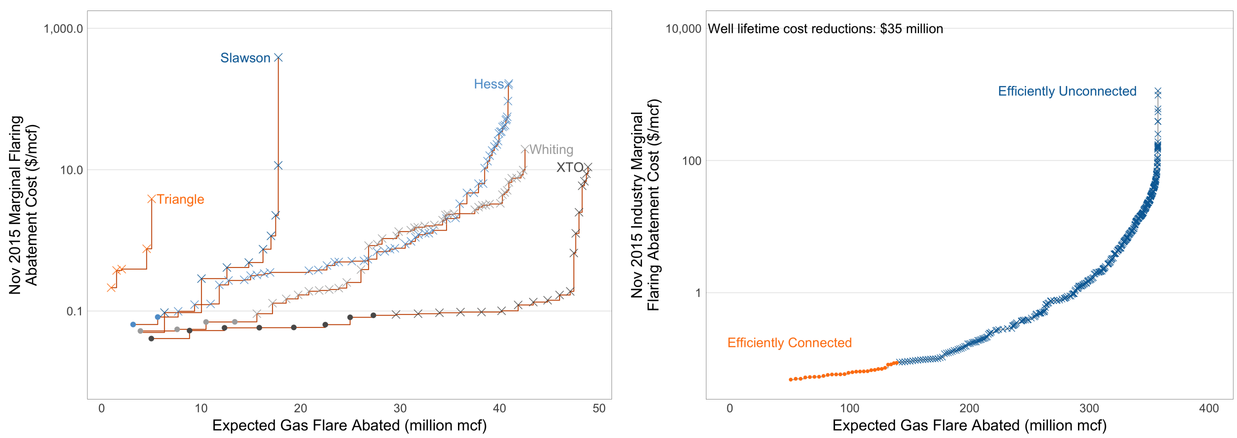
Notes: The left figure graphs MAC curves for five firms in November 2015 and their well connection decisions in that month. The left figure graphs the industry MAC curve in November 2015. Circles indicate wells that are connected and X's indicate wells that are left unconnected.

MAC curves by ordering all wells owned by a firm by their costs. Figure 6a graphs an example of five firms' MAC curves in November 2015, where the x-axis shows the expected captured gas. Circles indicate wells that were connected in November 2015, and X's indicate wells that were left unconnected going into December 2015. Consistent with our theoretical model, firms mostly connect their lowest cost wells and leave high-cost wells unconnected.[34]

Figure 6a highlights clear heterogeneity in MAC curves across the five firms. Hess, Whiting, and XTO own many wells with low connection costs and high gas production. Triangle and Slawson own fewer wells that are less productive and have higher connection costs per unit of gas captured. Figure 6b aggregates the MAC curves across firms. As before, connected wells are denoted by circles, and unconnected wells are denoted by X's. Industry-wide, many cheap wells were left unconnected while several costly wells were connected to gas capture infrastructure.

[34]Errors in our model's predictions typically occur for wells with low connection cost on the flatter part of the firm MAC curves. For example in Figure 6a, XTO seventh and eighth cheapest wells according to our model were left unconnected, while they connected their ninth and tenth cheapest wells. Since errors tends occur on flatter, low-cost portions of the MAC curve, connection cost differences between observed firm behavior and model predictions are small, and thus errors in estimating compliance costs will be small. We test the size of our model prediction errors in Section 6.2.

Figure 7: Marginal flaring abatement cost curves under efficient policy.



(a) Efficient Connection Decisions

(b) Efficient Industry MAC Curve

Notes: The left figure graphs counterfactual connection decisions of five firms in November 2015 under an efficient policy. The right figure graphs the efficient connection decisions at the industry level. Circles indicate wells that are connected and X's indicate wells that are left unconnected.

6.2 Counterfactual Policy Simulations

We use our estimated MAC curves to compare counterfactual compliance scenarios and assess the validity of our model.[35] We first consider three alternative flaring intensity standards that introduce greater flexibility in firms' compliance choices. We then consider the impacts of two flaring tax schemes. Last, we explore the accuracy of our model by comparing actual firm connection decisions against what our model predicts.

We first weaken the restrictions that firms face under the current NDIC regulation. In all cases, we simulate alternative compliance scenarios that achieve (approximately) the same level of observed abatement over the first year and a half of the program.[36] The first counterfactual, inter-firm trading, considers the gains from allowing trading between firms within a month but requires the counterfactual total industry abatement to equal the observed total industry abatement in each month. The exercise isolates potential gains from inter-firm trade and could be achieved by instituting a cap-and-trade program with a time-varying cap with no banking or borrowing. Figures 7a and 7b illustrate this exercise graphically for 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 7b illustrates this in the aggregate.

[35] Appendix B contains more details on how we compute the MAC curves and counterfactuals, as well as additional simulation results.

[36] Error in matching total gas capture for these three scenarios is less than 2 Bcf out of over 3,300 Bcf captured.

The second counterfactual, within-firm banking and borrowing, allows flexibility in the timing that firms connect wells, but re-institutes a ban on inter-firm trading. We require that each firms' total counterfactual abatement equal its observed abatement over the eighteen-month window. This outcome could be achieved using a firm-specific cap-and-trade program with fully flexible banking and borrowing. The third counterfactual, inter-firm trading with banking and borrowing, combines the two previous scenarios 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.

The final two counterfactual policies explore two particularly relevant price-based alternatives to the NDIC regulations. First, we consider the impact of taxing flaring at existing public lands royalty rates. This policy would extend well-owners' tax obligation to all natural gas produced by a well, regardless of whether they sell or flare it. Second, we consider the impact of taxing the carbon content of flared gas. In both cases, we assume the tax is levied on wells beginning in their first production month.

Finally, we check the error in our model's predicted firm behavior against actual firm behavior. In all months, firms consistently connect our predicted, lowest cost wells, suggesting that our model is accurate. However, our model does contain some errors where firms leave a few low-cost wells unconnected. These may occur for several reasons such as mismeasured pipeline distance or size, mismeasured future gas productivity, or forward-looking behavior and anticipation of future gas pipeline roll-out. We therefore compute the relative difference between the cost of the observed firm behavior, and the cost when firms optimize their connection decisions every month exactly according to our model.[37] This allows us to compare the importance and magnitude of modeling errors relative to the identified cost inefficiencies from the policy.

Table 5 presents the absolute and relative cost savings from the alternative compliance scenarios. We report excess gas capture for the two tax scenarios, and report average capture costs for all scenarios. For reference, we estimate that over this period the oil and gas industry in North Dakota captured 3,307 Bcf of gas at a total (average) cost of $1.82 billion ($0.55/mcf) during a period when the average wholesale natural gas price was $2.72/mcf.

All three alternative compliance scenarios show substantial gains from more flexible regulation. Allowing inter-firm trading (Scenario 1) reduces compliance costs by 45% or $816 million. Allowing firms to bank and borrow (Scenario 2) reduces costs by 26% or $480 million. Combining the two results in slightly higher cost savings than Scenario 1, 46% or $832 million over the first year and a half of the regulation. The cost savings amount to

[37] Given the discrete nature of abatement when honing down to the firm-month level, we are unable to match gas capture quantities exactly.

Table 5: Counterfactual simulation results.

	Relative Savings (%)	Absolute Savings (Million $)	Excess Gas Captured (Bcf)	Average Cost of Capture ($/mcf)
Compliance Scenario 1: Inter-Firm Trading	45%	$816	–	$0.30
Compliance Scenario 2: Within-Firm Banking and Borrowing	26%	$480	–	$0.40
Compliance Scenario 3: Trading & Banking and Borrowing	46%	$832	–	$0.30
Tax Scenario 1: Tax at Existing Royalty Rate ($0.45/mcf)	–	–	-361	$0.21
Tax Scenario 2: First-Best Carbon Tax ($40/tCO$_2$)	–	–	60	$0.34
Observed Behavior:	–	–	–	$0.55
Model Error Test:	–	–	83	$0.58

around 13% of industry revenues from oil and gas production at wells in our sample between January 2015 and June 2016.[38] The size of these cost savings highlights the importance of inter-firm arbitrage opportunities. Once firms are allowed to trade among themselves, there are minimal inter-temporal cost saving opportunities.

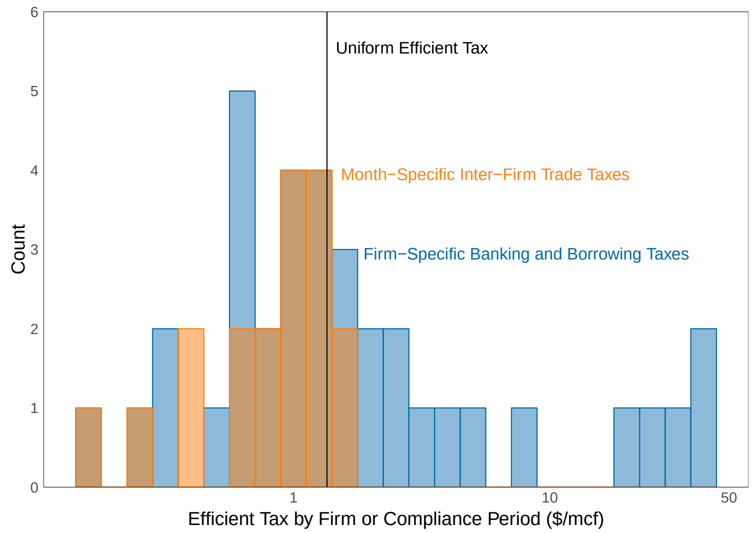
An alternative way to recast the compliance scenarios is as tax schemes. Scenario 1 could equivalently be implemented as a time-varying flaring tax that is uniform across firms. Scenario 2 could be achieved by instituting a firm-specific flaring tax. Full inter-firm and inter-temporal flexibility is equivalent to an industry-wide flaring tax. Figure 8 graphs the histogram of these implicit taxes under each scenario, illustrating the heterogeneity in marginal compliance costs when the various restrictions are imposed.[39] The Scenario 1 month-specific taxes are plotted in orange, and range from $0.15/mcf in January 2015 to a high of $1.66/mcf in May 2016. The Scenario 2 firm-specific taxes are plotted in blue and vary more widely, ranging from $0.14/mcf to $42.53/mcf. For reference, a $42.53/mcf tax on natural gas is equivalent to $803/tCO$_2$ carbon tax.[40] The efficient, uniform flaring tax from Scenario 3 is plotted in the black line and equals $1.35/mcf for each firm and month. To put the value in perspective, this is three times larger than the average public lands royalty rate on gas revenues over this period ($0.45/mcf). Alternatively, this amounts to a

[38]Revenues are calculated using Clearbrook and Henry Hub prices. Oil revenues are about an order of magnitude larger than gas revenues during this time frame. The cost savings are about 12% of oil revenues when using WTI prices.

[39]Note that the x-axis is plotted on a $\log_{10}$ scale.

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

Figure 8: Tax distributions for the first three counterfactuals.



Notes: The orange histogram shows the Scenario 1 taxes, the blue histogram shows the Scenario 2 taxes, the black line is the Scenario 3 tax. The x axis is on a $\log_{10}$ scale.

carbon tax of about $26/tCO$_2$, below current estimates of the social cost of carbon. The Figure further highlights the large differences in marginal compliance costs across firms that were already apparent in Figure 6a. These large differences remain even after allowing for unlimited within-firm banking and borrowing of flaring.

Both tax scenarios show that nearly the same flaring reductions could be achieved at a substantially lower cost if flared gas was taxed. Tax Scenario 1, when firms pay royalties on both flared at the public lands rate for sold gas ($0.45/mcf), results in around 90% of the observed flaring reductions from the NDIC policy at 60% lower cost. Alternatively, if firms were required to pay a carbon tax on flared gas equal to $40/tCO$_2$ (≈ $2.12/mcf), they would capture 2% more gas at 38% lower average cost.

The fourth row of Table 5 shows the error between the observed firm behavior and firm behavior as predicted by our model regarding average cost of capture. If firms behaved precisely according to our model, they would capture 89 Bcf (3%) more gas in aggregate, at $0.03/mcf (5%) higher average cost. The difference in average capture costs is much smaller than the cost reductions under all counterfactual scenarios.[41] The close match between

[41]In this counterfactual scenario the weighted-average error in the number of wells connected by a firm, with weights given by the number of wells connected plus one since some firms connect zero wells, is 8%. The error in the unweighted average of the total number of wells connected industry-wide is also 8%. For about half of firms, we perfectly predict the number of wells connected. For three firms we have errors of 25% or larger. However, these firms only connected, at most, three wells during this time frame, so the absolute error is small. The average error in the timing of connected a well is approximately one month whether we weight wells by their lifetime gas production or leave them unweighted.

our model predictions and observed firm behavior alleviates many concerns regarding the simplifying assumptions underlying our model including forward-looking firm behavior or uncertainty in future gas production at a well. Our results suggest that these issues are not of first-order importance for decision-making and welfare.

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 17 percentage points, and we attribute between one-half and all of the observed year-on-year reduction in flaring at new wells to the regulation.

While the regulation was effective at reducing flaring in the state, we find substantive costs from abatement misallocation caused by heterogeneous compliance costs and the regulation being enforced uniformly across firms. Using a counterfactual exercise based on estimated MAC curves, we show that reallocating abatement from high to low-cost firms would reduce aggregate compliance costs considerably. Taxing flared gas could achieve the same aggregate flaring reduction at a substantially lower cost.

Our results are subject to several important caveats. We rely on reduced-form methods to estimate the average treatment effects of the regulation and do not account for certain margins of behavior that could also be affected by the regulation such as drilling location. We also treat natural gas infrastructure as exogenous to firms' oil operations. Strategic location decisions or interaction with natural gas processing plants and pipeline companies may bias our results.

Several simplifying assumptions were necessary to construct our MAC curves in Section 6. For example, we assume that firms receive the same gas price once they connect to gas capture infrastructure; assume that right-of-way costs are minimal; use a uniform cost for wells' on-site infrastructure and per-mile gathering line costs; assume away any forward-looking behavior by firms; and assume that the natural gas processing sector in North Dakota is competitive. We explore the sensitivity of some of these choices in Appendix B. While the level of cost savings differs when we vary, for example, gathering line costs, the relative cost savings are around the same magnitude. Due to data limitations, we are unable to account for all of these concerns. In general, we argue that most of our assumptions result in us underestimating the extent of cost heterogeneity across firms and fully addressing these limitations would only increase the value of flexibility in meeting the NDIC flaring requirements.

Future research may explore any number of these and other issues. For example, recent work studying the Texas and North Dakota oil and gas industries shows that bankruptcy protections shifts industry structure towards smaller firms (Boomhower, 2016; Lange and Redlinger, 2018). Small firms may also take advantage of the benefits of limited liability in North Dakota. If larger upfront capital costs due to the flaring regulation affect entry decisions, the new standard may have the effect of pricing capital constrained firms out of the market. Future research could also allow for strategic decision-making by firms, take advantage of the feature that connecting to gas capture infrastructure requires significant upfront costs and forward-looking behavior, or explore for strategic investments in gas capture and processing infrastructure.

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Online Appendix for

Costs of Inefficient Regulation: Evidence from the Bakken

Gabriel E. Lade and Ivan Rudik

January 10, 2019

A Additional Summary Statistics

Tables A.1 and A.2 present summary statistics, disaggregated by the pre- and post-regulation, for North Dakota and Montana wells. Production and total well depth increased over time in both states. In North Dakota, gas flaring rates in the first year of production fell from 34% in 2012–2014 to 22% in 2015–2016. Flaring rates are lower, but still non-zero at connected wells. Flaring at connected wells changed little between the two periods, consistent with routine flaring rates being unaffected by the regulation. The decrease in flaring rates in North Dakota coincides with shorter gas connection times, which decreased from 3.5 months on average to 1.7 months. In contrast, flaring rates increased in Montana between the two periods. This is true whether we consider all wells or connected wells. As discussed previously, oil and natural gas prices collapsed beginning in 2014 from $89/bbl and $3.80/mcf in 2012–2014, respectively, to $43/bbl and $2.55/mcf in 2015–2016. This left many firms with less operable capital. Increased flaring in Montana is consistent with firms investing less in gap capture infrastructure when faced with lower oil and gas revenues.

Figures A.1 and A.2 present the same summary statistics for Montana wells as in Figures 1 and 2. Aggregate oil production, gas production, and flaring from wells completed in Montana (Figure A.1a) show several similarities, and a few notable differences, compared to wells in North Dakota. Beyond the lower level of production and drilling activity in the state, production from wells completed since 2007 increased more rapidly in the early years of the fracking revolution and flattened out from 2009 to 2011 before increasing again. Flaring as a percentage of gas production in earlier years was much lower in Montana than in North Dakota, but began to increase in 2012 and decline again after 2015. The reason for this can be seen in Figure A.1b – most wells were connected to gas capture infrastructure in Montana before 2011, after which the number of unconnected wells increased before flattening out at a relatively constant rate in mid-2014.

North Dakota and Montana wells look similar in their production time characteristics. Average oil and gas production follow the expected exponential decline curves. Figures A.2a and A.2b show that for 2014–2015, wells in Montana saw large increases in average productivity. Montana wells differ from North Dakota wells in their flaring rates in a few important ways. Before 2015, flaring rates decreased steadily (though slowly) over their production time as connections increased. However, connection rates never exceed 90% in Montana. Since 2015, flaring in early production months increased as connection in the first six months of production declined compared to wells completed in 2014.

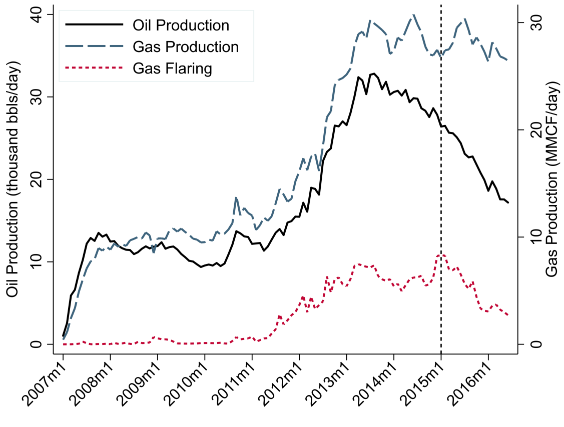
Table A.1: Summary statistics (North Dakota):
Well characteristics and prices by completion year.

		Mean	Median	Std. Dev.	N	N(Wells)
2012-2014	Oil Production in 1st Year (bbl/day)	297.89	222.77	280.28	63,034	5,253
	Gas Production in 1st Year (mcf/day)	328.90	219.33	391.87	63,034	5,253
	Well Depth (feet)	20,081.55	20,496.00	1,615.49	5,248	5,248
	Flaring in 1st Year: All Wells (%)	0.34	0.11	0.40	63,034	5,253
	Flaring in 1st Year: Connected Wells (%)	0.21	0.05	0.30	50,731	5,253
	Time to Gas Connection (months)	3.51	2.00	4.93	5,139	5,253
	Distance from Pipeline (miles)	–	–	–	–	–
	Clearbrook Oil Price ($/bbl)	89.21	90.99	10.72	–	–
	Henry Hub Price ($/MMBtu)	3.89	3.94	0.49	–	–
2015-2016	Oil Production in 1st Year (bbl/day)	377.80	297.10	318.36	15,543	1,551
	Gas Production in 1st Year (mcf/day)	514.97	372.70	506.57	15543	1,551
	Well Depth (feet)	20,351.90	20,690.00	1,630.16	1,533	1,533
	Flaring in 1st Year: All Wells (%)	0.22	0.06	0.31	15,543	1,551
	Flaring in 1st Year: Connected Wells (%)	0.17	0.05	0.25	14,160	1,551
	Time to Gas Connection (months)	1.73	1.00	1.39	1,521	1,521
	Distance from Pipeline (miles)	0.38	0.12	0.89	1,551	1,551
	Clearbrook Oil Price ($/bbl)	43.24	42.81	7.81	–	–
	Henry Hub Price ($/MMBtu)	2.72	2.85	0.28	–	–

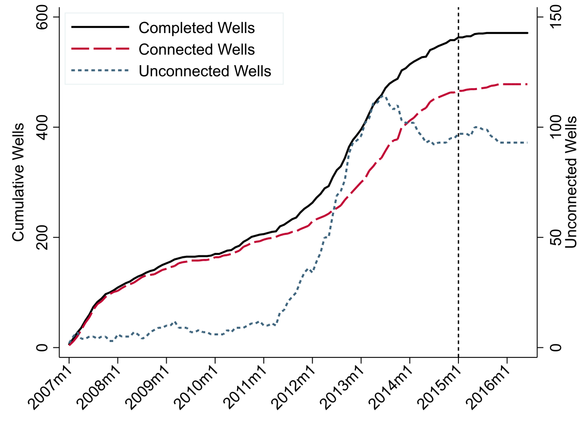
Table A.2: Summary statistics (Montana):
Well characteristics and prices by completion year.

		Mean	Median	Std Deviation	N	N(Wells)
2012-2014	Oil Production in 1st Year (bbl/day)	158.15	139.90	126.79	3,533	297
	Gas Production in 1st Year (mcf/day)	113.74	95.57	108.33	3,533	297
	Well Depth (feet)	16,974.46	18,643.00	3,583.21	3,533	297
	Flaring in 1st Year: All Wells (%)	0.34	0.02	0.44	3,533	297
	Flaring in 1st Year: Connected Wells (%)	0.10	0.01	0.23	2,039	297
	Time to Gas Connection (months)	4.17	2.00	5.27	221	221
2015-2016	Oil Production (bbl/day)	222.14	185.94	144.62	155	13
	Gas Production (mcf/day)	171.95	145.84	122.58	155	13
	Well Depth (feet)	18,214.67	19,716.00	3,451.38	155	13
	Flaring in 1st Year: All Wells (%)	0.44	0.39	0.42	155	13
	Flaring in 1st Year: Connected Wells (%)	0.25	0.04	0.32	110	13
	Time to Gas Connection (months)	2.91	1.00	3.02	11	11

Figure A.1: Oil and gas production, gas flaring, and well completions in Montana.



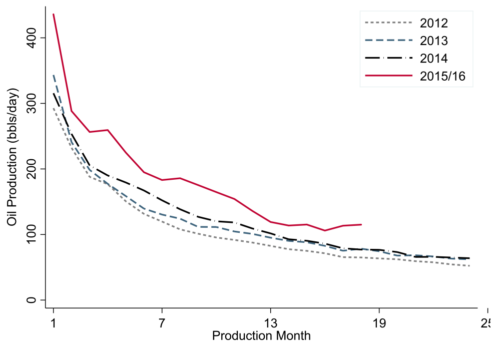
(a) Aggregate Oil & Gas Production and Flaring



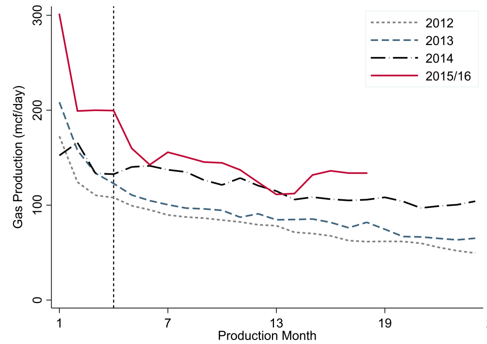
(b) Completed and Connected Wells

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

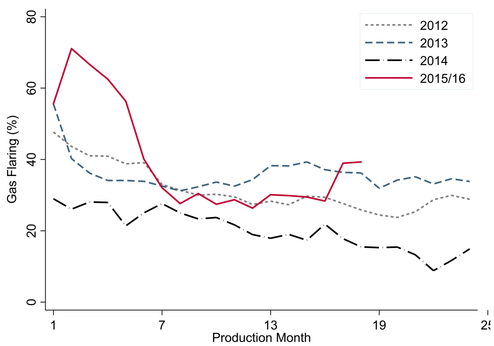
Figure A.2: Well production, flaring and connection rates by production month.



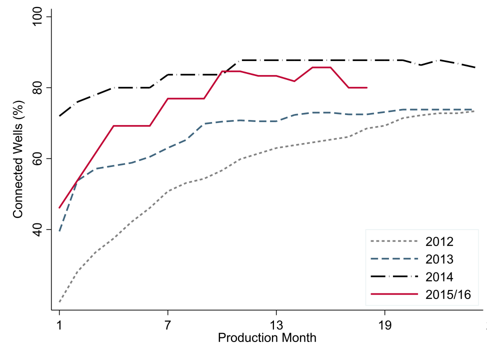
(a) Average Oil Production



(b) Average Gas Production



(c) Average Flaring Rate



(d) Average Connection Rate

Notes: The figures graph average oil and gas production, flaring rates, and connection rates in production time at Montana wells completed in 2012, 2013, 2014, and 2015/16.

B Simulation Details

B.1 Connection Costs

We use data on pipeline locations and characteristics from Rextag to estimate connection costs. Here, we discuss in greater detail how we construct each component of a well's connection costs. Average connection costs for well i are given by equation (9)

$$\frac{C_{it}}{g_{it}} = \frac{\text{(On-site Fixed Costs)} + \text{(Inch-Mile Line Costs)} \times d_i \times w_{it}}{g_{it}},$$

where C_{it} is the total connection cost, d_i is the gathering line distance, w_{it} is the gathering line diameter, and g_{it} is well i's remaining lifetime gas production. We assume that connecting a well to a gathering line captures all gas and there is no subsequent routine flaring.

We estimate the on-site and gathering line costs as follows

$$C_{it} = F + \xi(w_{it}) \times d_i \times w_{it}$$

where F is the estimated on-site fixed costs and is fixed across all wells, $\xi(w_{it})$ is the per inch-mile gathering line cost which is a function of the gathering line diameter, d_i is the estimated gathering line distance, and w_{it} is the predicted gathering line diameter.

On-site fixed costs: ICF International uses data on oil and gas leasing equipment and operating costs from the Energy Information Administration to estimate the average on-site equipment costs to process gas. The equipment includes dehydrators, compressors, and equipment to remove hazardous pollutants on-site. Table B.1 reports ICF's estimates. Our main estimates rely on costs reported in a 2018 report, though we also report results using estimates from an earlier 2016 report.

Table B.1: Engineering estimates of on-site fixed costs and per inch-mile gathering line costs.

Report Year	2016	2018
Lease Equipment ($/well)	$250,000	$202,000
4" Gathering Line ($/inch-mile)	$34,467	$36,244
6" Gathering Line ($/inch-mile)	$28,827	$30,313
8" Gathering Line ($/inch-mile)	$30,080	$31,631

Note: Per-mile costs for 4", 6", and 8" diameter gathering lines are $137,868, $172,962, and $240,640, respectively. Sources: ICF International (2016, 2018)

Table B.2: Distribution of gathering line diameters in the Rextag data.

Diameter (inches)	Frequency	Percent	Cumulative
4	9	4.79	4.76
6	39	20.74	25.40
8	140	74.47	100

Gathering line diameter costs: Gathering line costs per inch-mile $\xi(w_{it})$ are a function of the diameter w_{it}. We use data reported by ICF International to assign gathering line costs. Table B.1 reports estimated per inch-mile gathering line costs from ICF International (2016, 2018) for diameters we assign to wells in our data. Costs from both reports are for gathering line laid in 2015.

We use data on gathering line diameters from Rextag to predict each well's gathering line diameter as a function of the well's initial gas production and the production month that it is connected. The data from Rextag are limited – only 188 of the roughly 3,300 wells in our sample have non-missing diameter data. Table B.2 reports the frequency of each pipeline diameter in our data.[42] Around 75% of wells are connected to 8" gathering lines, just over 20% are connected to 6" lines, and the remaining 5% are connected to 4" lines.[43]

Figure B.1 graphs the correlation between pipeline diameter and wells' initial gas production and the production month in which the well was connected to gas capture infrastructure. Most 4" lines are connected to lower production wells, while the highest producing wells are almost always connected to 8" gathering lines. Most wells connected in their first production month are connected to 8" gathering lines, while wells connected after their fourth production month are more likely to be connected to 6" gathering lines.

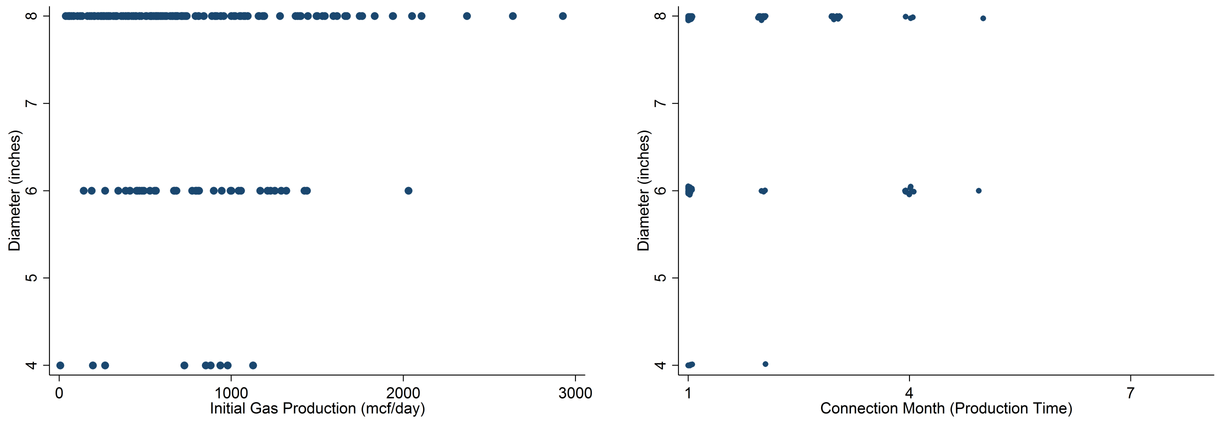
We use an ordered probit model to predict wells' gathering line diameters as a function of initial gas production and the production month that the well is connected to gas capture infrastructure. Specifically, we specify the probability of observing well i being connected to a gathering line with diameter $j = \{4, 6, 8\}$ as:

$$\begin{aligned}
\Pr(y_i = 4) &= \Phi(\kappa_0 - \mathbf{x}_i\beta) \\
\Pr(y_i = 6) &= \Phi(\kappa_1 - \mathbf{x}_i\beta) - \Phi(\kappa_0 - \mathbf{x}_i\beta) \\
\Pr(y_i = 8) &= 1 - \Phi(\kappa_1 - \mathbf{x}_i\beta),
\end{aligned}$$

[42]We exclude three observations that had 3" diameters, three that had 10" diameters, and two that had 12" diameters since they are non-standard sizes. We also exclude a single well that was connected a year after initial production.

[43]ICF International (2018) reports that average gathering line diameters in North America from 2013 to 2017 was 6.4". Our average diameter is slightly higher, 7.3".

Figure B.1: Gathering line diameter, gas production, and connection month.



(a) Diameter and Initial Gas Production

(b) Diameter and Connection Month

Notes: Figure B.1a graphs the correlation between each well's initial gas production and it's pipeline diameter. Figure B.1b graphs the correlation between each well's connection month to gas capture infrastructure, specified in production time, and the gathering line diameter.

where $\mathbf{x}_i$ are the well characteristics. We estimate our parameters of interest (κ_i and β) using maximum likelihood estimation with robust standard errors.

Table B.3 reports our results. Column (1) estimates the model as a function of wells' initial gas production, column (2) as a function of connection month, and column (3) as a function of both. As expected, wells with high initial gas production have a higher probability of being connected to a larger gathering line, while wells that are connected later in their productive lifetimes have a lower probability of being connected to a larger gathering line. Similar comparative statics hold when we include both covariates in the regression.

We use the estimates from column (3) to predict the probability of each well being connected to 4", 6", and 8" gathering lines as a function of the wells' initial production and production month. We assign the diameter with the highest predicted probability as the wells' gathering line diameter in the simulations. In column (3), the connection timing has a larger impact on the diameter than initial gas production. This is evident in our predicted gathering line sizes. All wells connected before their ninth production month are assigned an 8 inch gathering line, those connected in months 10 to 12 are assigned a 6 inch gathering line, and those connected after the first year are assigned a 4 inch gathering line.

Table B.3: Gathering line diameter regressions.

	(1)	(2)	(3)
Initial Gas Production (mcf/day)	0.000036	–	0.000005
	(0.0002)	–	(0.0002)
Connection Month	–	-0.124	-0.123
	–	(0.080)	(0.080)
κ_0	-1.638***	-1.859***	-1.854***
	(0.214)	(0.239)	(0.287)
κ_1	-0.630***	-0.849***	-0.844***
	(0.165)	(0.168)	(0.216)
Observations	188	188	188

Notes: The table presents estimated coefficients from an ordered probit model. The dependent variable is gathering line diameter (4, 6, or 8 inches). Connection month is specified in production time. Standard errors in all regression equations are robust to arbitrary heteroskedasticity. *, **, and *** denote significance at the 10%, 5%, and 1% level.

Distance to pipeline network (d_i): We use geospatial data from Rextag on the location of all natural gas pipelines in North Dakota to estimate the distance between every unconnected well and the nearest pipeline. We assume the shortest distance equals d_i, the distance that the gathering line must be built. Wells completed since 2015 are, on average, 0.4 miles from the nearest pipeline. However, distribution of distance is highly skewed. The median well is only 0.12 miles from the pipeline network, the 95th percentile is 1.6 miles from a pipeline, and the 99th percentile is over 6 miles from a pipeline.

B.2 Counterfactual Algorithms

Here we describe our counterfactual algorithms for the three alternative compliance scenarios that require us to search for the optimal connection decisions.

Inter-firm trading Our first counterfactual scenario considers the gains from allowing inter-firm trading within a month/compliance period, but requires the counterfactual flaring abatement within every compliance period to equal 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 by connection of wells this month).

2. Starting in January 2016, order all unconnected wells by their MAC. Compute the least-cost connection decisions to achieve the same flaring reduction observed in that month.

3. Carry forward to the next month 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. t_m^* is equal to the highest MAC of the set of wells connected in month m.

4. Repeat step 3 through June 2016.

The vector of t_m^*s are our month-specific flaring taxes in Figure 8.

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. The vector of t_j^*s are our firm-specific flaring taxes in Figure 8.

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.

Reconcile model and observed behavior Our final counterfactual scenario considers the cost differences between observed firm connection decisions and connection decisions predicted by our model.

For each firm-month combination, starting from January 2015 and going forward in time to June 2016, we compute the following:

1. For every firm-month combination, compute the observed total abatement (captured gas by connection of wells this month).

2. Starting in January 2016, order all unconnected wells for a given firm by their MAC. Compute the least-cost connection decisions to achieve at least the same flaring reduction observed in that firm-month. If no wells were observed to be connected in that firm-month do not counterfactually connect any wells.

3. Carry forward to the next month 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 firm MAC curve. Compute the least-cost connection decisions to achieve the same, monthly observed abatement. If no wells were observed to be connected in that firm-month do not counterfactually connect any wells.

4. Repeat step 3 through June 2016.

B.3 Additional Simulation Results

Table B.4: Sensitivity analysis of counterfactual cost and production parameters.

	4 Inch Pipe	6 Inch Pipe	8 Inch Pipe
Half Fixed Cost	39%, 44%, \$0.72/mcf	44%, 49%, \$1.26/mcf	47%, 53%, \$2.21/mcf
Base Fixed Cost (\$202,000)	32%, 36%, \$0.87/mcf	39%, 44%, \$1.37/mcf	44%, 49%, \$2.35/mcf
Double Fixed Cost	25%, 28%, \$1.15/mcf	32%, 36%, \$1.69/mcf	38%, 43%, \$2.55/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 has pipe diameter being a function of production time, and the base fixed cost.

Table B.4 displays sensitivity check results for our counterfactual. We check the sensitivity of our results on two margins. First we vary the fixed cost component to be double or half the base value. Second, we vary the gathering pipeline diameter used to be 4, 6, or 8 inches for all wells instead of having the diameter be a function of production time. The first value in each cell is the relative cost reduction from the inter-firm trading scenario, the second value is the relative cost reduction from the inter-firm trading with banking and borrowing scenario, and the third value is the cost-effective flaring tax for inter-firm trading with banking and borrowing. Relative cost savings can range from one-quarter to one-half of our estimates of the cost of the observed connection decisions, and the cost-effective flaring taxes range from half to double our estimate in the main text.

C Sensitivity Analyses and Robustness Checks

C.1 Flaring Treatment Effects

Pre-trends in flaring rates. We first test the parallel trends assumption for our difference-in-differences specifications. Figure C.1 plots treatment effects for wells completed in North Dakota by each calendar month of our sample relative to December 2014. The first month (1) corresponds to January 2014, and the last month (30) corresponds to June 2016. The dashed vertical line denotes when the flaring order went into effect in North Dakota. The eight months preceding the implementation of the regulation have nearly identical treatment effects, supporting the parallel trends assumption. In the months after the regulation was implemented, month-specific treatment effects are noisy but consistently negative.

Alternative control wells. Second, we test the sensitivity of our Table 1 flaring results to specifying alternative control wells. We explore two alternative control well specifications: (i) wells completed in 2013; and (ii) wells completed in 2012. These alternative control wells are meant to address concerns that wells drilled in North Dakota in the months leading up to the policy going into effect may have altered their flaring decisions in anticipation of the upcoming regulation. Table C.1 reports the results. Estimates are largely similar to our main results, and where the results do differ, the estimated impact of the flaring regulation is typically larger.

Placebo tests. We also perform a number of placebo regression tests to further support our research design. We define the first placebo treatment group as wells completed in 2014, where the control group are wells completed in 2013, shifting back the treatment and control definitions by a year. For all placebo tests the treatment period lasts 1 year. For the second placebo, we shift the control and treatment designations back by three months so treated wells are those completed between October 2013 and October 2014, and controls are those completed between September 2012 and September 2013. For our third placebo we shift the control and treatment designations again back by three months so treated wells are those completed between July 2013 and July 2014, and controls are those completed between June 2012 and June 2013. Because the regulatory environment did not change over this timeframe we should not expect to find a placebo treatment effect.

Table C.2 reports the results. We find significant flaring reductions associated with the placebo treatment effects in the differences estimators. This suggests that we may omit some relevant well characteristics in comparing flaring rates in production time from year-to-year. However, we find no impact of the regulation for our preferred difference-in-difference estimators in column 4 – supporting our research design.

Figure C.1: Difference-in-differences treatment effects by calendar month.

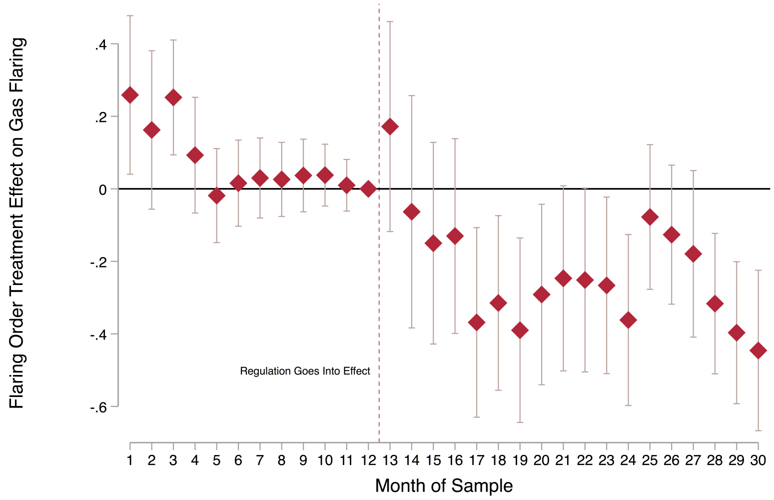


Table C.1: Average effect of the regulation on flaring rates using alternative control wells.

	(1) Dif	(2) Dif	(3) D-in-D	(4) D-in-D
Panel A: Alternative Control Wells - Completed 2013				
Flaring Regulation	-0.139***	-0.145***	-0.204**	-0.157**
	(0.008)	(0.010)	(0.096)	(0.078)
Observations	37504	36097	37333	37333
Wells	3378	3259	3364	3364
Panel B: Alternative Control Wells - Completed 2012				
Flaring Regulation	-0.185***	-0.219***	-0.236**	-0.182**
	(0.009)	(0.010)	(0.095)	(0.075)
Observations	36368	34720	35982	35865
Wells	3282	3154	3250	3250
Firm FE	No	Yes	No	Yes
Township FE	No	Yes	No	No
State FE	No	No	Yes	Yes
Production Month FE	No	Yes	No	Yes
Month-of-Year FE	No	Yes	No	Yes
Year FE	No	No	Yes	Yes
Weather Controls	No	Yes	No	Yes

Notes: The dependent variable is the well-level flaring rate. The coefficient of interest is Flaring Regulation, which which equals 1 if a well was completed in North Dakota after 2015. Dif and D-in-D denote differences and difference-in-differences estimators, respectively, where the former contains data from North Dakota wells only. Standard errors are clustered at the well. *, **, and *** denote significance at the 10%, 5%, and 1% level.

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

	(1)	(2)	(3)	(4)
Panel A: January 2014 Placebo Treatment				
January 2014 Placebo Treatment	-0.151***	-0.103***	0.036	-0.018
	(0.010)	(0.010)	(0.067)	(0.056)
Observations	33600	33600	23509	23509
Wells	3616	3616	3721	3721
Panel B: September 2013 Placebo Treatment				
October 2013 Placebo Treatment	-0.061***	-0.076***	0.130***	-0.007
	(0.012)	(0.012)	(0.025)	(0.045)
Observations	21774	21774	22943	22943
Wells	3504	3504	3692	3692
Panel C: June 2013 Placebo Treatment				
July 2013 Placebo Treatment	-0.077***	-0.080***	0.037**	-0.017
	(0.013)	(0.012)	(0.016)	(0.042)
Observations	22552	22552	23849	23849
Wells	3424	3424	3644	3644
Model	Dif	Dif	D-in-D	D-in-D
Firm FE	No	Yes	No	Yes
Township FE	No	Yes	No	No
State FE	No	No	Yes	Yes
Production Month FE	No	Yes	No	Yes
Month-of-Year FE	No	Yes	No	Yes
Year FE	No	No	Yes	Yes
Weather Controls	No	Yes	No	Yes

Notes: The dependent variable is the well-level flaring rate. The placebo treatment variable equals 1 if a well was completed in North Dakota in the 12 months after the labeled date. Dif and D-in-D denote differences and difference-in-differences estimators, respectively, where the former contains data from North Dakota wells only. Standard errors are clustered at the well. *, **, and *** denote significance at the 10%, 5%, and 1% level.

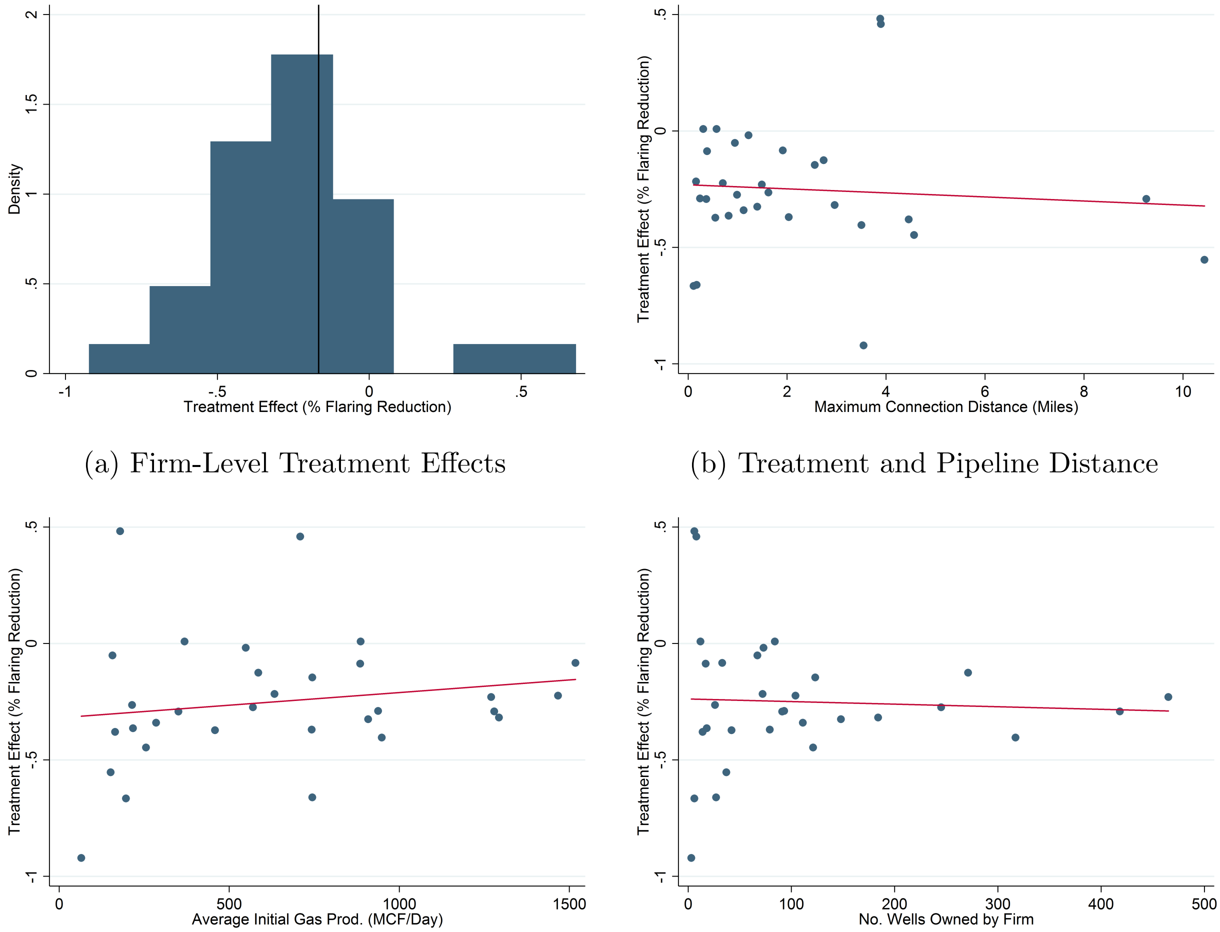
C.2 Flaring Treatment Effects Across Firms

Our estimated marginal abatement cost firms show substantial heterogeneity in firms' abatement costs. Naturally, we would therefore expect firms to be differentially impacted by the regulation. To explore this, we re-estimate equation (5) for each firm in the North Dakota sample.

Figure C.2a graphs the distribution of treatment effects for 31 firms in our North Dakota sample.[44] The average treatment effect from Table 1 is shown by the black line. The regulation caused most firms to reduce flaring between 20% and 50%, though we estimate that some firms increased flaring in spite of the regulation while others reduced flaring substantially more than others. Figures C.2b to C.2d show that firms with a smaller maximum distance between any well and a pipeline connection have smaller estimated treatment effects; firms with lower average initial gas production across their wells have larger treatment effects; and the firms with the smallest number of wells (generally) have the largest treatment effects.

[44]We are unable to estimate firm-specific treatment effects for 12 firms due to size issues.

Figure C.2: Treatment effect heterogeneity across firms.



(a) Firm-Level Treatment Effects

(b) Treatment and Pipeline Distance

(c) Treatment and Gas Production

(d) Treatment and Number of Wells

Notes: Figure C.2a presents a histogram of the 31 estimated firm-specific treatment effects. Figure C.2b graphs the correlation between firm treatment effects and the maximum distance from well owned by each firm and the nearest pipeline connection. Figure C.2c graphs the correlation between firm treatment effects and the average initial gas production at every firm's wells from 2015-2016, and Figure C.2d graphs the correlation with the number of wells owned by firms. All correlations include best fit lines.