Relieving Midstream Constraints in Natural Gas Flaring

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Abstract

Natural gas extracted from the ground must be flared rather than sold in markets when processing capacity is insufficient. Flaring releases carbon dioxide, methane, and other pollutants harmful to the environment and human health. I theoretically derive a subsidy that depends on the economic relationship between capacity and flaring, which I quantify using an instrumental variable model and new data from North Dakota. I find that processing bottlenecks significantly increase flaring and that a subsidy of $135 per thousand cubic feet of capacity would have reduced annual flaring by roughly 200 million cubic feet statewide, offsetting $1.5 million in damages.

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1 Introduction

Every year, oil and gas producers in the U.S. burn off billions of cubic feet of natural gas. This is a longstanding practice known as flaring, and it poses three significant problems for the environment and human health. First, flaring emits carbon dioxide, a primary greenhouse gas that drives climate change, without generating useful energy for heating or electricity. Second, defective flares release large quantities of methane, which holds a greater heat trapping potential than carbon dioxide despite its shorter half life in the atmosphere. Lastly, flaring releases toxic pollutants into the air, endangering the health of nearby communities, most of whom are low-income and non-white (Cushing et al., 2021).

Many states have implemented policies that aim to reduce natural gas flaring. However, the emissions from flaring continue to soar over the years. In the U.S., carbon dioxide emissions from flaring increased from 40.9 million tons in 2010 to 84.52 million tons in 2019, more than doubling in quantity in less than a decade (Global Carbon Budget, 2025). Given that natural gas is a priced commodity, much of the observed flaring is not economically justified and is instead largely driven by infrastructure constraints and bottlenecks throughout the natural gas supply chain. Unlike oil, the extracted natural gas cannot be transported via trucking or rail. Instead, it must be delivered by pipelines to gas processing facilities to produce clean, "dry"[1] gas for sale. In this paper, I show that midstream bottlenecks play an important role in natural gas flaring and examine how these constraints can be relieved to curb the associated emissions.

I quantify the role of insufficient processing capacity in natural gas flaring and use the empirical estimates to derive a capacity subsidy that offsets the flaring damages. In doing so, I gather new data from North Dakota to connect oil and gas wells to their respective gas processing plants in the state. Over the last decade, North Dakota has experienced a sharp increase in total production of oil due to recent breakthroughs in hydraulic fracturing. While the producers drill for oil, the existing infrastructure for gas processing has struggled to keep up with the production of associated gas from the oil wells. As a result, producers in North Dakota have contributed to a significant share of total gas flared in the U.S. in the recent years (EIA, 2020). I empirically demonstrate that flaring decreases as processing capacity increases and theoretically derive a subsidy which depends on the estimated economic relationship between capacity and gas flared.

In an optimal setting, a regulator would tax flaring emissions. However, policies targeting midstream capacity constraints merit consideration for two reasons. First, flaring efficiency

[1] Dry natural gas is free from impurities and heavier hydrocarbons such as natural gas liquids.

varies with environmental conditions such as wind and precipitation (Leahey et al., 2001). Recent studies using aerial surveys have reported that most flares in the Permian Basin are unlit, releasing five times more methane than previously estimated (Plant et al., 2022). As a result, producers may evade emissions taxes by leveraging hard-to-detect unlit flares. Second, although well operators may be let off the emissions taxes by state regulators due to lax enforcement (Lade and Rudik, 2020), gas plants would want to claim the processing capacity subsidy which directly incentivizes producers to capture and market the gas.

I formally show that gas processing plants require an upfront capacity subsidy to ensure that emissions from flaring remain at the socially optimal levels. The profit-maximizing decisions of gas plants at the equilibrium do not account for damages they cause by forcing wells to flare when capacity is insufficient. In contrast, the social planner determines the total processing capacity to maximize social welfare accounting for all costs, including total damages from flaring. Therefore, gas plants underinvest in processing capacity compared to the social optimum. To correct this, I propose a capacity subsidy that reconciles the market incentives with the social planner's equilibrium conditions.

The subsidy depends on the relationship between the quantity of natural gas flared and the capacity available to the wells. However, estimating the causal effect of capacity on flaring is complicated by shocks that can affect both variables of interest in any given month. For example, pipeline extensions from plants to new wells take up a higher share of the available capacity. This contributes to increased flaring by other wells connected to the same plant. Wells may also engage in repeated fracking to increase the reservoir pressure that drives up production, which then affects processing capacity at the plant, as well as how much gas gets flared from increased congestion in the gathering network. To address the endogeneity problem posed by the unobservables, I construct an instrument for processing capacity using new data that connects oil and gas wells to gas processing plants in North Dakota between 2012 and 2019.

I instrument for each well's share of processing capacity at the plant using total natural gas production from other wells connected to the same plant that are located away from the well of interest. Changes in gas production at a given well are largely driven by reservoir pressure, while changes in the number of wells drilled are driven by oil profitability. Production from connected wells therefore generates fluctuations in available processing capacity at the plant, which in turn affects flaring. However, production from nearby wells is endogenous to flaring at the well of interest: they may share segments of the gathering network or be exposed to common local shocks, allowing their production to affect flaring through channels other than capacity at the processing plant. By restricting the instrument to wells located away from the gathering network of the well of interest, their production affects flaring only through fluctuations in the plant's available processing capacity.

I find that on average, an additional 1 thousand cubic feet (mcf) of processing capacity at a plant decreases flaring by 89 cubic feet (cf) among all the wells connected to the plant. This relationship isn't exactly one-to-one because constraints beyond processing capacity, such as congestion, may also drive flaring. However, my results show that constrained processing capacity plays an important role in natural gas flaring, and that relieving the midstream bottlenecks can reduce the emissions from flaring.

Combining my theoretical analysis with the estimated economic relationship between capacity and flaring, I show that on average, gas plants require an ex-ante subsidy of $135 per thousand cubic feet of processing capacity to ensure that flaring emissions remain at the socially optimal levels. This accounts for approximately 13.5% of the per unit capacity construction costs.[2] Back of the envelope calculations suggest that the proposed subsidy would reduce monthly flaring by 18.5 million cubic feet, offsetting roughly $1.5 million in flaring damages per year.

The environmental, health, and economic consequences of the U.S. shale revolution have been extensively studied in recent literature. Existing work contends that the fracking boom led to positive wage and consumption benefits from increased oil and gas production (Feyrer et al., 2017; Bartik et al., 2019; Jacobsen, 2019), as well as negative impacts on housing prices in locations that rely on groundwater contaminated by fracking operations (Gopalakrishnan and Klaiber, 2014; Muehlenbachs et al., 2015). In addition, natural gas production accompanied by the fracking boom has driven producers to burn off the natural gas that cannot be captured due to cost and capacity constraints.

The negative externalities associated with natural gas flaring are well-documented. Communities that live near flare sites experience higher respiratory hospitalization rates as total emissions from flaring increase (Blundell and Kokoza, 2022), and symptoms for pediatric asthma tend to worsen with increased drilling and natural gas production nearby (Willis et al., 2020). In addition to health impacts, flaring emissions translate to millions of dollars in lost natural gas revenue (Rabe et al., 2020), as well as climate damages from greenhouse gas emissions (Agerton et al., 2023). To reduce flaring emissions, it is crucial to understand why producers burn off a valuable commodity, which begins with investigating the production constraints throughout the natural gas supply chain.

To date, the most comprehensive review of mechanisms that drive flaring comes from Agerton et al. (2023), which summarizes the economics surrounding producers' decision to drill and flare. How much gas gets flared versus captured is often influenced by the prof-

[2] Capacity costs, lifted from the gas plant siting permits submitted to the regulators, are roughly $1000 per thousand cubic feet (mcf).

itability of natural gas given oil production from the same well sites: on average, oil prices are much higher than gas, and the additional investment required to capture and sell the gas may be too costly (Gilbert and Roberts, 2020; Agerton et al., 2023). Mandates that restrict the share of production flared can reduce flaring by encouraging wells to connect to gathering pipelines faster (Lade and Rudik, 2020), but the majority of flaring in shale reservoirs still stems from connected wells facing constraints along the supply chain (Agerton et al., 2023). To my knowledge, the present paper is the first to formally examine the economic relationship between processing capacity constraints and natural gas flaring, and also the first to propose a policy solution for flaring through relieving the midstream capacity constraints in natural gas production.

In the next section, I discuss the background on natural gas production and outline the existing flaring regulations in North Dakota. In Section 3, I formally derive the optimal subsidy on processing capacity using a theoretical model that will motivate my empirical estimation. In Section 4, I provide summary statistics on the data used in my analysis. In Section 5, I describe the empirical model, threats to identification, and instrument. In Section 6 I present the results along with policy implications of my estimates. Section 7 concludes and provides directions for future research.

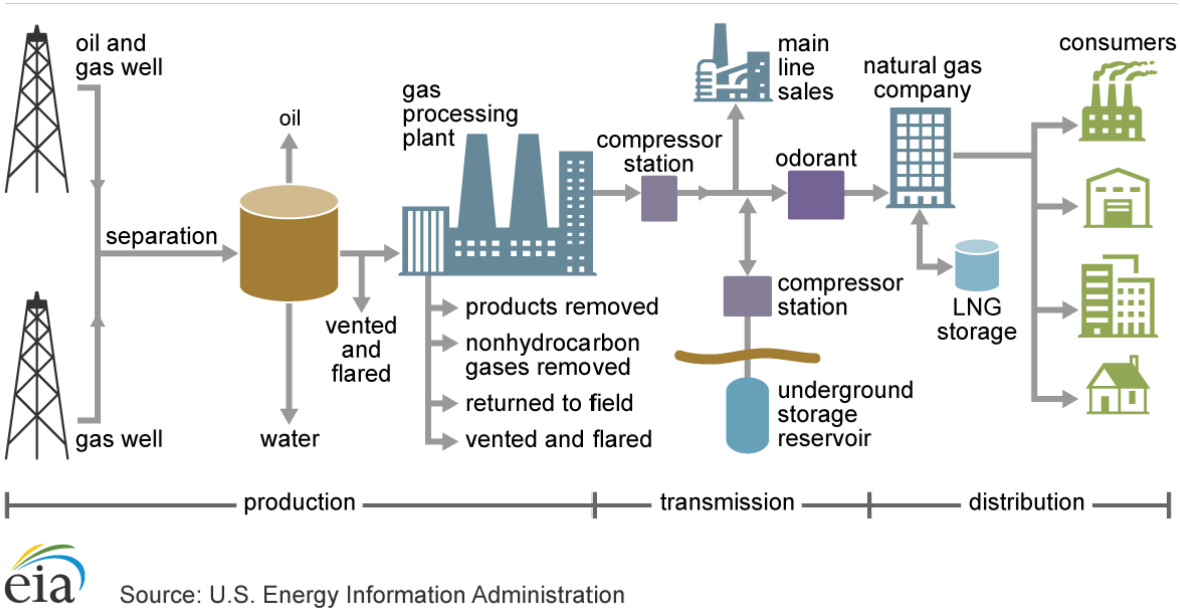
2 Institutional Background

2.1 Natural Gas Extraction and Processing

The oil and gas industry can be divided into upstream, midstream, and downstream segments. The upstream sector of the industry drills and operates the wells, where production is primarily determined by the reservoir pressure. The extracted hydrocarbons are then processed and transported by the midstream segment of the industry to the downstream retail markets. Figure 1 demonstrates the process of production and delivery of natural gas. Unlike oil, natural gas extracted from the wells cannot be transported via trucking or rail. Wellhead gas must be delivered to nearby processing plants to remove heavier hydrocarbons and produce dry, market-grade natural gas fit to be transported through distribution pipelines.

Most of the wells in North Dakota are drilled for tight oil in the Bakken shale formation using fracking technologies. Therefore, natural gas is often an associated product of these oil wells. Hence, the decision to drill these wells is exogenous to natural gas production. Upon

Figure 1: Natural Gas Production and Delivery



Notes: This figure shows the process of natural gas production, from wellhead to distribution across different consumers. This figure is obtained from the U.S. Energy Information Association.

completion of the wells, producers are unlikely to wait for the gas gathering infrastructure to be built in order to begin production, and hence flaring can occur when wells are unconnected to the gathering network. In this paper, I only consider flaring from wells that are connected to gas processing plants and therefore must be connected to gathering pipelines, to better understand the role of processing capacity constraints in flaring.

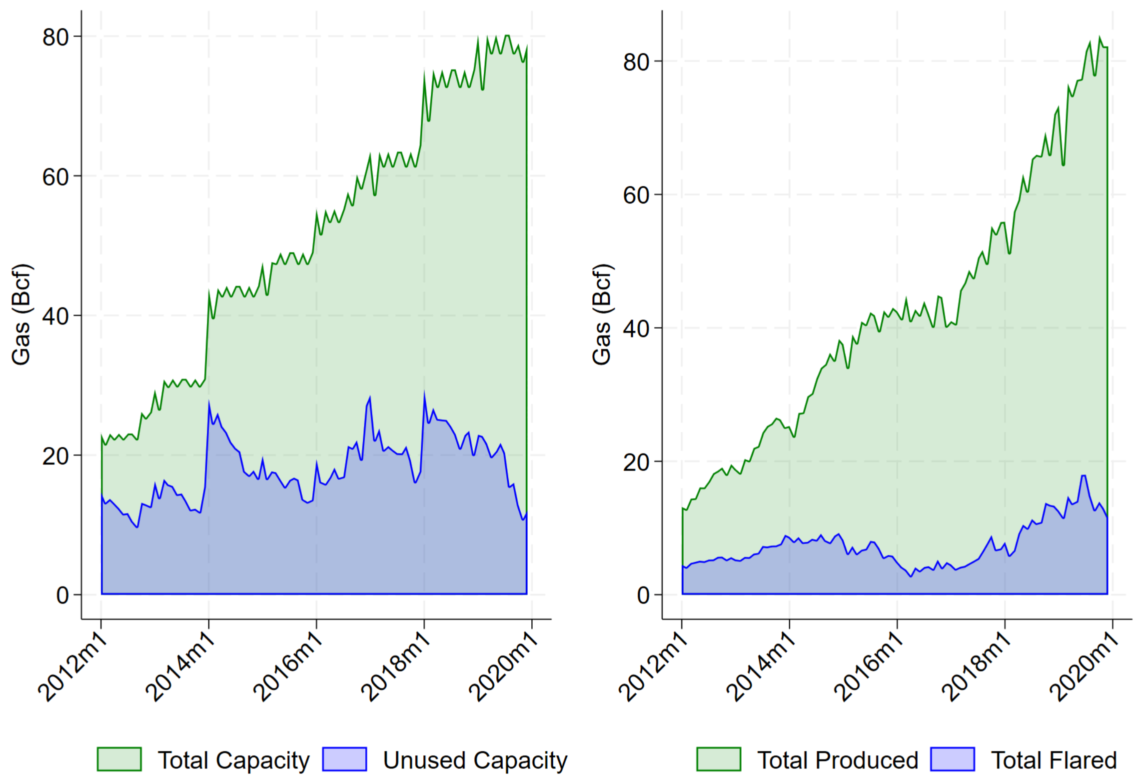
Oil and natural gas are separated at the extraction site and processed at different facilities. Oil is typically transported via liquids pipelines or trucks to refineries, and natural gas is delivered to gas processing plants via gas gathering pipelines. Producers generally do not construct the gathering network themselves. Instead they purchase gathering services from midstream firms that directly invest in pipeline construction. Some of these midstream firms also own gas processing facilities, but not all processing plants provide gathering services. Producers generally enter into long-term contracts with gas processing plants.

The primary term of the contracts can be anywhere from 7 to 15 years and can be renewed on a year by year basis afterwards. These contracts typically require producers to dedicate the entire stream of production from an area to the processing plant, meaning that a well cannot deliver their production to other plants during the contract term. Acreage dedication agreements are often accompanied by the minimum delivery requirement: producers are required to pay for an agreed upon minimum volume to be delivered to the plant, regardless of whether this volume is actually delivered.

More often than not, wells and plants will agree on a banking mechanism. Well operators will bank the obligated minimum volume fees if the plant is at capacity for when the minimum volume cannot be delivered due to unexpected changes in production (Howe, 2016). The plant, on the other hand, does not need to guarantee processing capacity unless the contract specifies otherwise. When the processing capacity is fully utilized, producers will flare the gas that cannot be processed. Upon facing capacity constraints, natural gas transmitted through gathering pipelines will flow back to producers who then burn off the gas at the well site.

Despite the growth of unconventional tight oil developments in North Dakota, the

Figure 2: Gas Processing Capacity in North Dakota



Notes: This figure shows monthly gas processing capacity and utilization in North Dakota between 2012 and 2019. The left panel plots total processing capacity and unused capacity, and the right panel plots total gas produced and total gas flared. All quantities are measured in billion cubic feet (Bcf). Data are aggregated at the state–month level.

existing infrastructure to gather and process the gas co-produced has been insufficient. Consequently, flaring levels have been increasing over the years, at least until 2019 before the pandemic. Figure 2 shows that over time, flaring has increased and capacity has barely kept up with production. It also highlights that flaring occurs even in years with capacity availability, indicating the spatially differentiated nature of constraints where spare capacity might exist across the network but cannot accommodate producers far away.

2.2 Regulatory Setting in North Dakota

North Dakota bans venting of natural gas and requires that gas be burned through a flare with the estimated volume flared reported to the North Dakota Industrial Commission (NDIC). Prior to 2014, the only existing flaring regulation was that the operators pay royalties on flared gas after the first year of production. In 2014, North Dakota passed its first flaring regulation which requires all oil and gas well operators in the state to capture a minimum share of all gas produced. The gas capture target specified in the regulation is intended to increase over time to encourage producers to flare less. However, gas capture goals have remained constant at 91% of total production since 2018 given insufficient infrastructure along the natural gas supply chain.

North Dakota's gas capture rules are inefficient for three reasons. First, the rules imply that operators are allowed to increase the quantity of gas flared as long as the total production increases, which can be achieved by repeated re-fracturing of the wells. Second, the gas capture rule applies uniformly across all operators regardless of their abatement costs. Existing research shows that this results in misallocation of flaring abatement driven by heterogeneity in compliance costs across firms (Lade and Rudik, 2020). Lastly, operators facing gathering and processing constraints are exempt from the gas capture requirement (NDIC, 2014). Considering the inefficiency of current flaring regulations, it becomes crucial to examine policies that target the production bottlenecks by encouraging investment in infrastructure necessary to capture the gas.

3 Theoretical Model

I present a theoretical model that formalizes the decisions of (1) the social planner seeking to maximize welfare, and (2) gas processing plants maximizing profit. Using the first order conditions at the market equilibrium and the social optimum, I derive the ex-ante capacity subsidy that would offset the damages from flaring.

Suppose that there are $j = 1, 2, 3, ..., J$ gas processing plants and $i = 1, 2, 3, ..., N$ natural gas producing wells connected to each plant in any given month t. Let $q^P_{i,j,t}$ be the monthly natural gas produced by each well i connected to plant j. Total gas produced by all wells connected to the plant is the sum of production across all wells, $Q^P_{j,t} = \sum_i q^P_{i,j,t}$. I assume that $Q^P_{j,t}$ is continuously distributed over $[0, \overline{Q}_{j,t}]$ in each month and is $i.i.d$ across all j and t.

In month $t = t_1$, gas plants set new processing capacity K_j that will last indefinitely given monthly discount rate $\delta > 0$. This decision can represent either the construction of a new plant, or new capacity at the existing plant. In t_1, plants incur a fixed cost of capacity construction $C(K_j)$ where $C(\cdot)$ is positive, strictly increasing, and strictly convex, as well as a constant marginal cost $c_t \geq 0$ to process the gas delivered to them each month.

Let $Q_{j,t}$ be the quantity of gas processed by plant j in month t. Plants earn monthly profits $\pi(Q_{j,t}) = (p_t - c_t)Q_{j,t}$ where p_t is the exogenous market price of natural gas. Damages from gas left unprocessed or flared are $D_j(Q_{j,t}) = \gamma_j(Q^P_{j,t} - Q_{j,t})$, where $\gamma_j > 0 \quad \forall j \in \{1, 2, 3, ..., J\}$ is the per unit social cost of flaring. Although climate damages do not vary by j, external health costs from particulate pollution likely vary by plant depending on density and characteristics of the population nearby. Natural gas processed by all gas plants in each month, $Q_t = \sum_j Q_{j,t}$, is delivered to households via transmission pipelines.

The representative household gains utility $u(Q_t)$ from consumption of the processed natural gas in each month. Suppose that the household's marginal utility of natural gas consumption is greater than the marginal processing cost over the relevant domain, i.e. $u'_{Q_{j,t}}(Q_t) > c_t \; \forall Q_t \leq \sum_j \overline{Q}_{j,t}$. This implies that all of the natural gas processed by the plants is eventually consumed in the market.

In each month, the total quantity of gas processed by each plant must be less than the total monthly production of all connected wells, i.e. $Q_{j,t} \leq Q^P_{j,t}$. Moreover, total gas processed cannot exceed the total available capacity at the plant, i.e. $Q_{j,t} \leq K_j$.

3.1 The Social Planner's Problem

I first derive the optimal quantity of monthly gas processed conditional on available capacity. I then derive the conditions for setting the optimal capacity.

For a given vector of plant capacity $\{K_1, K_2, K_3, ..., K_J\}$ in each month, the social planner seeks to maximize the utility of consuming the natural gas processed by all plants, net of processing costs and damages from flaring:

$$\begin{aligned} \max_{\{Q_{j,t}\}_{j=1}^{J}} \quad & \Big\{ u(Q_t) - c_t Q_t - D_j(Q_t) \Big\} \\ \text{s.t.} \quad & Q_{j,t} \leq K_j, \\ & Q_{j,t} \leq Q_{j,t}^P \quad \forall j \in \{1, 2, 3, ..., J\}. \end{aligned} \tag{1}$$

The solution to the optimization problem is symmetric across all periods. Therefore the following Lagrangian solves equation (1) in each t:

$$\mathcal{L} = \max_{\{Q_{j,t}\}_{j=1}^{J}} \quad \Big\{ u(Q_t) - c_t Q_t - D_j(Q_t) - \Big[\sum_{j=1}^{J} \lambda_{j,t}^1 (Q_{j,t} - K_j) \Big] - \Big[\sum_{j=1}^{J} \lambda_{j,t}^2 (Q_{j,t} - Q_{j,t}^P) \Big] \Big\}.$$

Per the first order conditions, the marginal utility net of associated monthly costs is equal to the shadow value of relaxing the constraints for each $Q_{j,t}$:

$$u'(Q_t) - c_t + \gamma = \lambda_{j,t}^1 + \lambda_{j,t}^2.$$

Following the assumption that $u'(Q_t) > c_t \; \forall Q_t \leq \sum_j \overline{Q}_{j,t}$, it must be that $u'(Q_t) - c_t > 0$. Given that $\lambda_{j,t}^j, \lambda_{j,t}^j \geq 0$, and $\gamma > 0$, the equilibrium conditions are satisfied.

From the inequality constraints in equation (1), the following complementary slackness conditions arise for each $Q_{j,t}$:

$$\lambda_{j,t}^1 (Q_{j,t} - K_j) = 0 \text{ and } \lambda_{j,t}^2 (Q_{j,t} - Q_{j,t}^P) = 0.$$

The capacity and production constraints cannot both hold with equality unless total capacity just happens to be equal to the total production delivered each month, i.e. $K_j = Q_{j,t}^P$. As a result, the optimal quantity of gas processed in each month for each plant is

$$Q_{j,t}^* = \min\{K_j, Q_{j,t}^P\}.$$

This implies that all of the natural gas produced by the wells must be processed as long as there is sufficient capacity at the plant. The total optimal quantity of natural gas processed across all plants is $Q_t^* = \sum_{j=1}^{J} Q_{j,t}^*$.

Now consider the planner solving for the optimal processing plant capacity as follows:

$$\max_{\{K_j\}_{j=1}^{J}} \quad \Big\{ \sum_{t=t_1}^{\infty} \frac{1}{(1+\delta)^t} \, \mathbb{E}[u(Q_t^*) - c_t Q_t^* - D_j(Q_t^*)] - C(K_j) \Big\}. \tag{2}$$

Per the first order necessary conditions for each K_j, we have that

$$\sum_{t=t_1}^{\infty} \frac{1}{(1+\delta)^t} \frac{\partial\, \mathbb{E}[u(Q_t^*)]}{\partial K_j} = \sum_{t=t_1}^{\infty} \frac{1}{(1+\delta)^t} \Big\{ \frac{\partial\, \mathbb{E}[D_j(Q_t^*)]}{\partial K_j} + c_t \frac{\partial\, \mathbb{E}[Q_{j,t}^*]}{\partial K_j} \Big\} + \frac{\partial C(K_j)}{\partial K_j} \qquad \forall j \in \{1, 2, 3, ..., J\}. \tag{3}$$

At social optimum, the present value of marginal utility from additional capacity must be equal to the marginal costs of capacity setting and processing, plus the present value of marginal damages from natural gas left unprocessed or flared.

The expected marginal damages in equation (3) for each j can be decomposed as:

$$\mathbb{E}\Big[\frac{\partial D_j(Q_t^*)}{\partial K_j}\Big] = \underbrace{\mathbb{E}\Big[\frac{\partial D_j(Q_t^*)}{\partial Q_t^*}\Big]}_{\text{social cost of flaring, } \gamma_j} \; \mathbb{E}\Big[\frac{\partial Q_t^*}{\partial K_j}\Big],$$

where $\mathbb{E}\Big[\frac{\partial Q_t^*}{\partial K_j}\Big] \neq 0$ if and only if the capacity constraint can bind in some state of the world. When total production exceeds total processing capacity at each plant, unprocessed gas is burned off at the extraction site and the marginal damages from flaring are non-zero. The expected marginal damages then depend on changes in total gas flared with respect to changes in total processing capacity at each plant.

3.2 Market Equilibrium

Now, consider the market for natural gas. The price of processed gas p_t is exogenous and determined nationally. In each month t, the representative household maximizes their utility from consuming the natural gas processed by gas plants as follows:

$$\max_{\{Q_{j,t}\}_{j=1}^{J}} \quad \Big\{ u\Big(\sum_j Q_{j,t}\Big) - p_t \sum_j Q_{j,t} \Big\}. \tag{4}$$

At market equilibrium, the marginal utility of consuming the processed gas is equal to the market price of natural gas $\forall j \in \{1, 2, 3, ..., J\}$:

$$\frac{\partial u(\sum_j Q_{j,t})}{\partial Q_{j,t}} = p_t. \tag{5}$$

For given capacity in each month t, gas plants choose the optimal quantity of natural gas to process, accounting for the market price and processing costs:

$$\begin{aligned} \max_{Q_{j,t}} \quad & \Big\{(p_t - c_t)Q_{j,t}\Big\} \\ \text{s.t.} \quad & Q_{j,t} \leq K_j, \\ & Q_{j,t} \leq Q^P_{j,t}. \end{aligned} \tag{6}$$

The solution satisfies the following Lagrangian in each period:

$$\mathcal{L} = \max_{Q_{j,t}} \quad \Big\{p_t Q_{j,t} - c_t Q_{j,t} - \eta^1_{j,t}(Q_{j,t} - K_j) - \eta^2_{j,t}(Q_{j,t} - Q^P_{j,t})\Big\}.$$

Per the first order conditions, we have that at equilibrium, $p_t - c_t = \eta_{j,1} + \eta_{j,2} \quad \forall j \in \{1, ..., J\}$. From the household's consumption problem in equation (6), the marginal utility of consuming the processed gas is equal to the price of natural gas. Hence, plants' marginal profit of processing each unit of gas is strictly positive, or $p_t - c_t > 0$, following the assumption that the marginal utility is greater than the marginal cost of processing. Given that $\eta_{j,1}, \eta_{j,2} \geq 0$ $\forall j$, the equilibrium conditions are satisfied.

Note that both of the inequality constraints in equation (6) cannot hold except in knife-edge cases where the plant's capacity happens to be exactly equal to the total production of all connected wells. At equilibrium, each plant must then process all of the gas produced so long as the capacity does not exceed total production:

$$Q^*_{j,t} = \min\{K_j, Q^P_{j,t}\}.$$

Comparing to equation (1) from the social planner's problem, we achieve efficiency conditional on capacity K_j for each plant.

Now consider the processing capacity chosen in the market. Given the optimal quantity of gas processed each month, plants set their capacity to be operational in $t = t_1$ by solving

$$\max_{K_j} \quad \Big\{\sum_{t=t_1}^{\infty} \frac{1}{(1+\delta)^t} \mathbb{E}[\underbrace{\pi(Q^*_{j,t})}_{(p_t - c_t)Q^*_{j,t}}] - C(K_j)\Big\}, \tag{7}$$

where each plant maximizes the present value of expected monthly profits net of processing and capacity construction costs. The first order necessary conditions imply that at equilibrium, the present value of marginal profits must be equal to the marginal cost of capacity construction,

$$\sum_{t=t_1}^{\infty} \frac{1}{(1+\delta)^t} \underbrace{\frac{\partial\,\mathbb{E}[u(Q_t^*)]}{\partial K_j}}_{p_t \frac{\partial\,\mathbb{E}[Q_{j,t}^*]}{\partial K_j}} = \sum_{t=t_1}^{\infty} \frac{1}{(1+\delta)^t} \Big\{ c_t \frac{\partial\,\mathbb{E}[Q_{j,t}^*]}{\partial K_j} \Big\} + \frac{\partial C(K_j)}{\partial K_j}. \tag{8}$$

Compared to the social optimum in equation (3), gas plants underinvest in processing capacity due to the external damages from flaring that are unaccounted for.

Consider a corrective capacity subsidy that reconciles market incentives with the social planner's equilibrium conditions. Comparing equations (3) and (8), the capacity at market equilibrium would be efficient if each plant j were offered the following per unit capacity subsidy:

$$s_j = \sum_{t=t_1}^{\infty} \frac{1}{(1+\delta)^t} \frac{\partial\,\mathbb{E}[D_j(Q_t^*)]}{\partial K_j}. \tag{9}$$

Here, I recover a first-best capacity subsidy that varies by each plant given that damages from flaring may be heterogeneous across plants.

3.3 Optimal Single Subsidy

The subsidy s_j derived in the previous section requires the regulator to offer a different subsidy to each plant, depending on plant characteristics. For instance, health-related damages from flaring may likely vary by plant, depending on the density of the population nearby. However, the regulator may realistically only be able to offer a single subsidy for all plants, which I here formally examine.

The regulator now chooses a single subsidy s across all plants $j = 1, 2, 3, ..., J$ that maximizes the utility of consuming all processed gas, net of associated costs including damages from total gas flared:

$$\max_s \quad \Big\{ \sum_{t=t_1}^{\infty} \frac{1}{(1+\delta)^t} \Big\{ \mathbb{E}\Big[u(\sum_j Q_{j,t}^*) - c_t \sum_j Q_{j,t}^* - D(\sum_j Q_{j,t}^*) \Big] \Big\} - \sum_j C(K_j) \Big\}. \tag{10}$$

The following proposition characterizes the optimal single subsidy offered to all gas processing plants.

Proposition 1. *The optimal subsidy the regulator offers to all plants is*

$$s^* = \sum_{t=t_1}^{\infty} \frac{1}{(1+\delta)^t} \Big(\sum_j \gamma_j w_j \, \mathbb{E}\Big[\frac{\partial Q^F_{j,t}}{\partial K_j} \Big] \Big), \tag{11}$$

where

$$w_j = \frac{\frac{\partial K_j}{\partial s}}{\sum_j \frac{\partial K_j}{\partial s}},$$

such that $w_j \in [0,1]$, *and* $\sum_j w_j = 1$.

Proof. See Appendix A. □

The regulator's optimal subsidy is the weighted average of the marginal flaring damages with respect to capacity across all plants, where the weights are determined by how each plant's processing capacity responds to the subsidy. If the effect of subsidy on processing capacity is homogeneous across plants, the weight then becomes $\frac{1}{J}$, and the subsidy is the present value of discounted average damages from insufficient capacity across all plants. However, under heterogeneity, the subsidy in (11) depends on the weighted average over marginal damages from flaring. As a result, the size of the subsidy will vary depending on the responsiveness of plant capacity to the subsidy, and how it covaries with marginal damages.

In my empirical application, I assume that the effect of subsidy on processing capacity is homogeneous across all plants, so that $w_j = \frac{1}{J}$. Consequently, the uniform subsidy depends on marginal damages averaged across plants. Combining the tract-level marginal cost estimates of local pollutants from Air Pollution Emission Experiments and Policy Analysis (APEEP) model with marginal damage estimates for carbon dioxide and methane, I calculate plant-level social costs of flaring, γ_j. I then estimate the average changes in flaring with additional processing capacity across all gas plants $\mathbb{E}\Big[\frac{\partial Q^F_{j,t}}{\partial K_j}\Big]$ using an instrumental variable model, and calculate the optimal single subsidy that offsets flaring damages driven by insufficient processing capacity.

4 Data

4.1 Oil and Gas Production

I obtain the data on well-level monthly oil and gas produced, sold, and flared for 2012-2019 from North Dakota Industrial Commission (NDIC). I also use well-level characteristics data obtained from Enverus (previously Drillinginfo). There are 13,578 active wells in the sample, all of which co-produce natural gas along with oil. Among them, 92% are horizontally drilled, which is a common technology used in hydraulic fracturing. This aligns with the industry outlook in the Bakken that most wells are drilled primarily to extract tight oil in the shale formation, and that natural gas is an associated product. Moreover, the disparity in the revenue from oil and gas sales in the sample indicates that producers are motivated by the profitability of oil. On average, gas sales contribute to only 8% of the total monthly revenue for the wells.

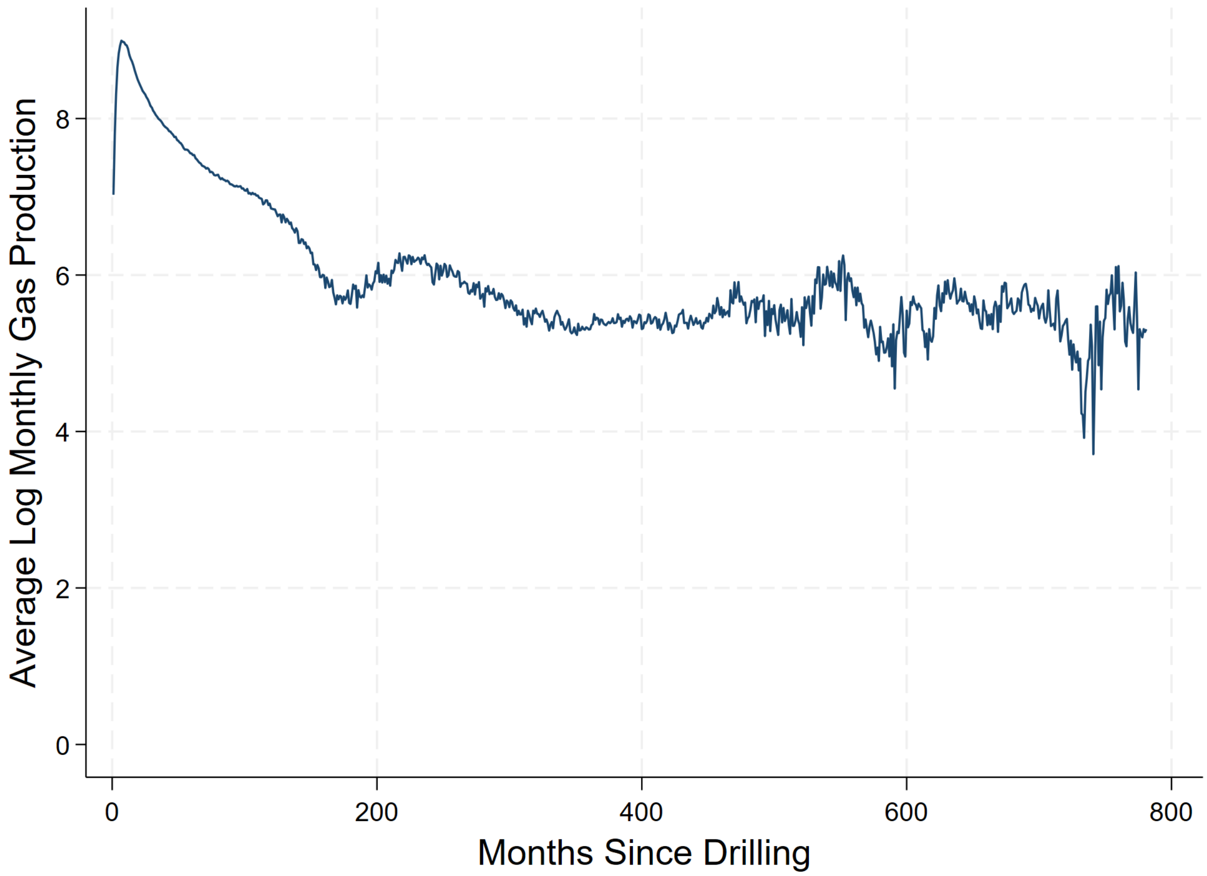
Although some of the oldest wells in the sample were drilled in the 1950s, the median age of wells is around 30 months or 2.5 years. Generally, reservoir pressure declines with age and production diminishes over time. Figure 3 plots the relationship between gas production and well tenure. Production peaks shortly after completion and declines rapidly in early years before transitioning into a period of gradual decline. Similarly, monthly gas flared tends to decrease with tenure as seen in Figure 4, which is likely to be driven by the diminishing production.

4.2 Gas Processing Plants

I download the plant location data from North Dakota Industrial Commission's geographic information systems server, and I fill in for missing locations via Environmental Protection Agency's record of gas processing plants across the country. I then obtain the data on plant capacity from North Dakota Pipeline Authority, which is measured as millions of cubic feet per day for each year from 2012 to 2019. I obtain plant expansion permits submitted to the North Dakota Public Service Commission to determine the exact month of the expansion in the years capacity changes and adjust for monthly capacity accordingly.

Figure 5 shows the total capacity along with plant entries and exits over the sample period. The total gas processing capacity has been increasing over the years: in 2019, it stood at approximately 3 billion cubic feet per day. The number of gas processing plants is

Figure 3: Monthly Gas Production and Well Tenure



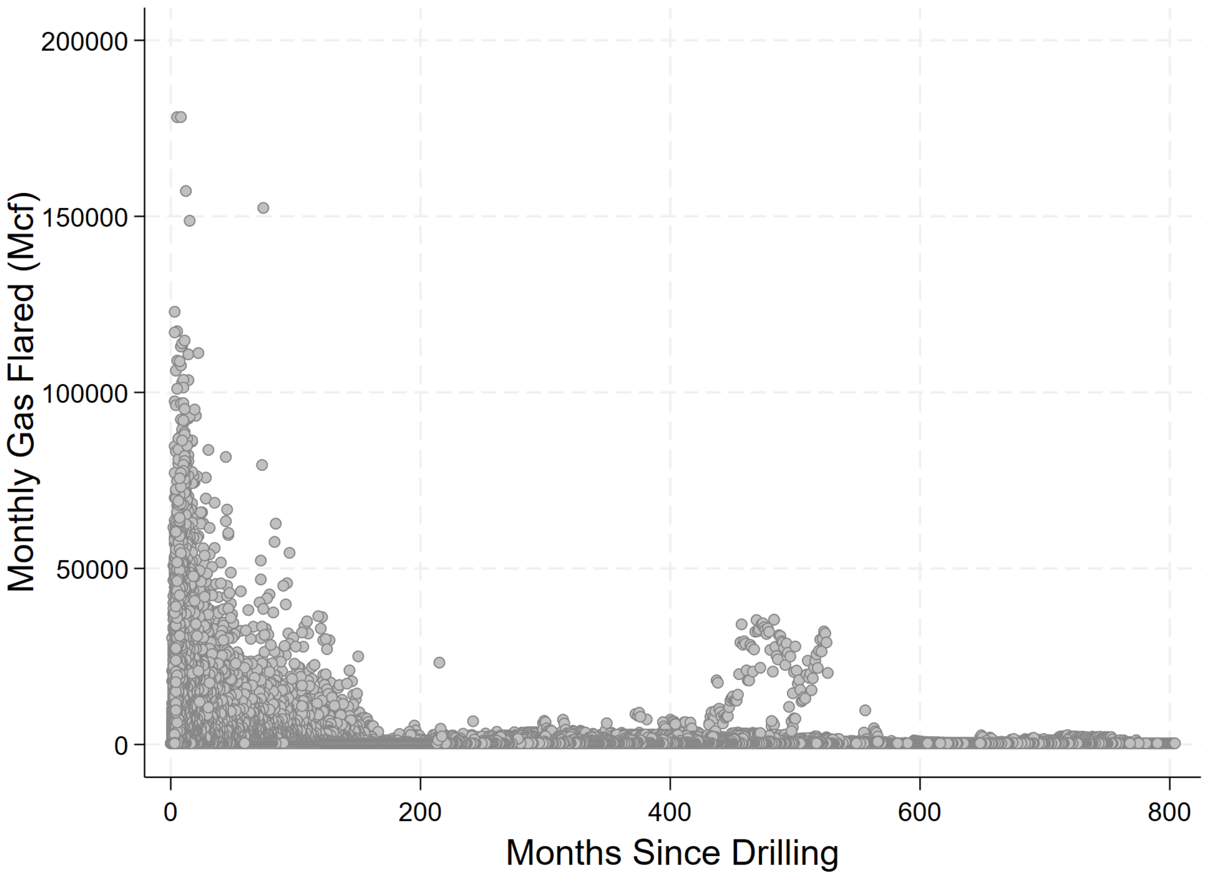
Notes: This figure plots the log of average monthly gas production against well tenure measured as months since drilling. Average monthly gas production is measured in thousand cubic feet, and well tenure is measured in months. There are 13, 578 wells in the sample over the sample period 2012-2019.

also increasing over time starting at 17 in 2012 and growing to 27 by 2019. Over the sample period, two gas plants shut down in 2014 and 2017. Consequently, total processing capacity appears to remain stagnant during the exit years. Flaring increased immediately following those same years, even though production didn't experience a significant spike, as seen in Figure 2– this suggests that reduction in processing capacity may potentially drive flaring.

4.3 Connecting Wells and Plants

To connect gas processing plants and wells, I use monthly gas plant receipts obtained from representatives at the North Dakota Industrial Commission (NDIC) Oil and Gas Division. These receipts are submitted by gas plants recording the total gas processed and sold by all

Figure 4: Monthly Gas Flared and Well Tenure



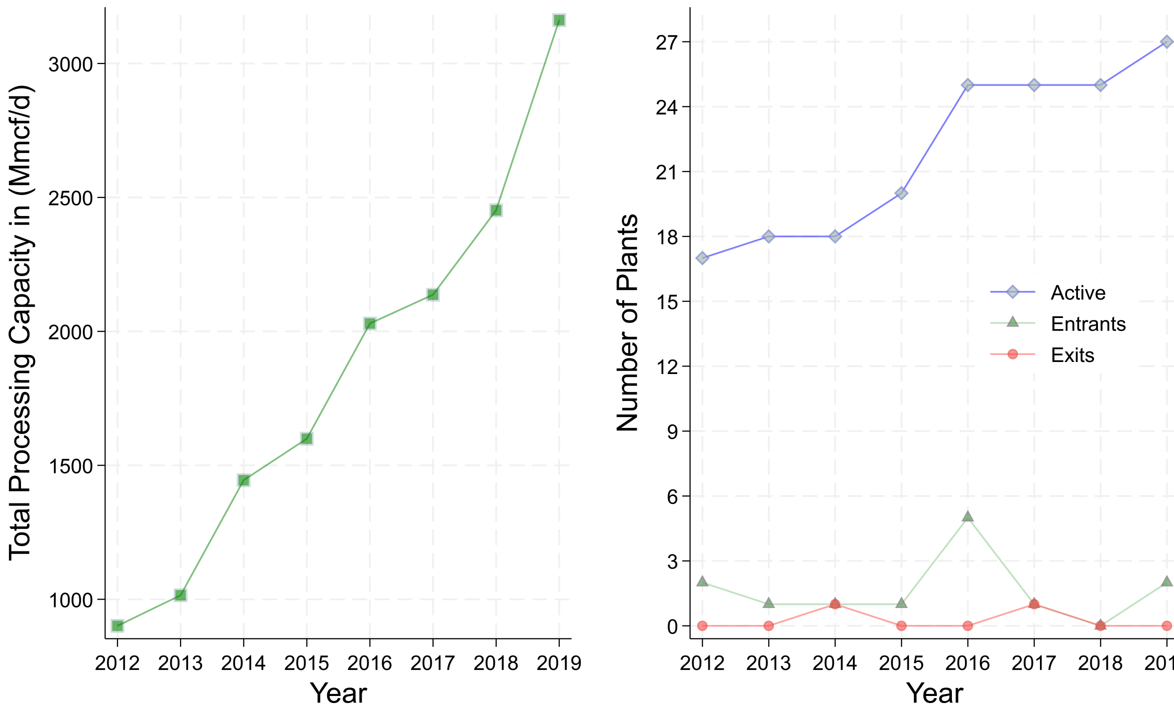
Notes: This figure plots monthly gas flared by wells against well tenure measured as months since drilling. Monthly gas flared is measured in thousand cubic feet, and well tenure is measured in months. There are 13, 578 wells in the sample over the sample period 2012-2019.

connected wells in each month. Figure 6 shows an example of the receipts. Of 27 plants in North Dakota, I was able to obtain these data for 26 plants. I extract the information from the monthly scanned receipts using optical character recognition (OCR), and then use regular expressions (regex) to standardize the OCR output and parse key fields (e.g., well identifiers, reporting month, and volumes) into a structured, plant-month dataset.

All plants in the sample, except for five owned by a single operator, report gas deliveries from wells separately for each plant. For these five plants, gas deliveries are reported in aggregate across the group, as wells route gas along the path of least resistance to the nearest plant within the operator's network.[3] For wells associated with this operator, I compute the great-circle distance between each well and each plant in the group and assign each well to

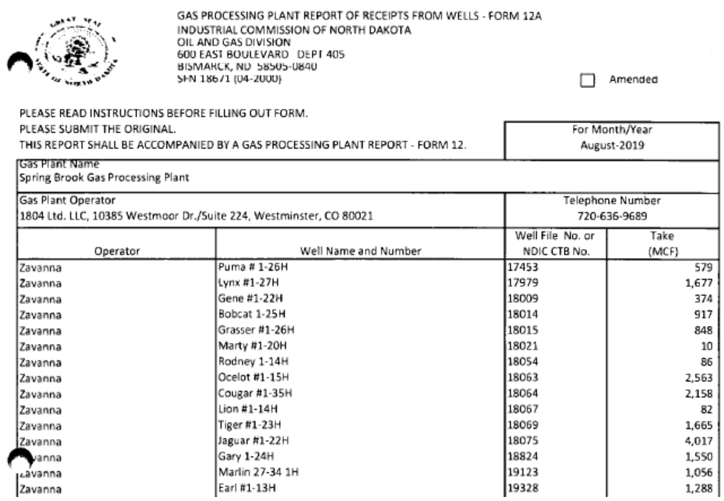
[3]Confirmed through phone interviews with Melissa Herz at the North Dakota Industrial Commission in April 2023 and October 2025.

Figure 5: Variation in Gas Processing Capacity Over the Years



Notes: This figure plots the variation in processing capacity over the sample period. There are 26 plants in the sample over the period 2012-2019.

Figure 6: An Example of Scanned Monthly Gas Plant Receipts



GAS PROCESSING PLANT REPORT OF RECEIPTS FROM WELLS - FORM 12A
INDUSTRIAL COMMISSION OF NORTH DAKOTA
OIL AND GAS DIVISION
600 EAST BOULEVARD DEPT 405
BISMARCK, ND 58505-0840
SFN 18671 (04-2000)

☐ Amended

PLEASE READ INSTRUCTIONS BEFORE FILLING OUT FORM.
PLEASE SUBMIT THE ORIGINAL.
THIS REPORT SHALL BE ACCOMPANIED BY A GAS PROCESSING PLANT REPORT - FORM 12.

For Month/Year: August-2019

Gas Plant Name: Spring Brook Gas Processing Plant

Gas Plant Operator: 1804 Ltd. LLC, 10385 Westmoor Dr./Suite 224, Westminster, CO 80021

Telephone Number: 720-636-9689

Operator	Well Name and Number	Well File No. or NDIC CTB No.	Take (MCF)
Zavanna	Puma # 1-26H	17453	579
Zavanna	Lynx #1-27H	17979	1,677
Zavanna	Gene #1-22H	18009	374
Zavanna	Bobcat 1-25H	18014	917
Zavanna	Grasser #1-26H	18015	848
Zavanna	Marty #1-20H	18021	10
Zavanna	Rodney 1-14H	18054	86
Zavanna	Ocelot #1-15H	18063	2,563
Zavanna	Cougar #1-35H	18064	2,158
Zavanna	Lion #1-14H	18067	82
Zavanna	Tiger #1-23H	18069	1,665
Zavanna	Jaguar #1-22H	18075	4,017
Zavanna	Gary 1-24H	18824	1,550
Zavanna	Marlin 27-34 1H	19123	1,056
Zavanna	Earl #1-13H	19328	1,288

Notes: This is an example of scanned gas plant receipts obtained from North Dakota Industrial Commission. This receipt, in particular, shows Spring Brook gas plant's August 2019 records.

the closest plant, which I designate as its delivery plant. Results presented in Section 6 are robust to excluding these wells from the sample.

Almost all the wells in the sample are connected to a single plant throughout their lifetime. A total of 10 wells reconnected to a different plant when two plants shut down in 2014 and 2017, and no other wells in the sample switched plants during the sample period. This aligns with personal accounts by plant managers in North Dakota[4] that it is customary for wells to maintain a relationship with one processing plant over their lifetime since the construction of gathering pipelines requires lengthy permitting procedures and high costs.

I examine the heterogeneity in flaring across wells in Table 4.1, where I regress the share

Table 4.1: Well Characteristics and Heterogeneity in Flaring

	(1) % of Months Flared	(2) p-value	(3) Mean
Distance to Plant (km)	0.0195	0.748	30.13
Avg. Gas Production (mcf)	-0.0007	0.026	3156.72
Avg. Monthly Oil Sales (bbl)	0.0076	0.000	1929.86
Avg. Tenure	-0.0039	0.588	62.52
Publicly Traded	-0.9895	0.882	0.70
No. of Wells within 100 meters	-2.0662	0.007	2.43
Owned by Large Operators	4.5131	0.473	0.70
No. of Wells	13,572	-	-
No. of Plants	26	-	-
Plant FE	YES	-	-
Std. Errors Clustered by	Plant	-	-

Notes: This table reports estimates from regressing the share of months that a well flares at least some of their production on monthly average gas production, monthly average oil sales, average tenure, whether owner companies are publicly traded, whether the wells are owned by large companies, distance to gas plants, and number of wells within 100 meters. Observations are at the well-plant level and the sample period is 2012-2019. There are 13, 578 wells in the sample, where ownership information is missing for 6 of them. There are 26 plants in the sample. Standard errors are clustered by plants.

of months that a well flares at least some of their production on its distance to the processing plant, average monthly gas production, average monthly oil sales, average tenure, number of wells within a 100-meter radius, whether the well is owned by operators above $2 billion market capitalization, and whether the well is owned by publicly traded operators. I include plant fixed effects to analyze the variation in flaring among the wells that share processing capacity. Standard errors are clustered at the plant level given that the fluctuations in flaring are likely to be correlated among the wells connected to the same plant.

The results show that the average number of nearby wells is negatively correlated with

[4] According to the manager of Red Wing Creek gas plant in McKenzie County, ND via phone interview in 2023 March.

the share of months a well flares: higher-density production areas are more likely to be served by existing gas processing capacity. Distance also seems to matter, as well as the size and type of the operating firm. In my estimating equation, I control for time-varying characteristics of the wells that drive flaring and include well fixed effects to account for the time-invariant well attributes.

5 Empirical Model

Each month, oil and gas wells transport their natural gas production to processing plants to extract clean, dry gas ready for sale. If plants are at capacity, the remaining gas that cannot be processed is flared off at the extraction site, harming the environment and those who live nearby. To offset these damages from flaring driven by insufficient processing capacity, I propose a subsidy outlined in Section 3 that depends on changes in flaring from additional processing capacity. Using an instrumental variable model, I estimate this relationship in the following equation:

$$q^F_{i,j,t} = \alpha_0 + \alpha_1 K^R_{i,j,t} + X_{i,j,t}\Theta + \gamma_i + \zeta_m + \eta_y + \varepsilon_{i,j,t}. \tag{12}$$

Here, $q^F_{i,j,t}$ is the total gas flared by well i connected to plant j in month t, calculated as the difference between total gas produced ($q^P_{i,j,t}$) and total gas processed ($q_{i,j,t}$). $K^R_{i,j,t}$ is the residual capacity at plant j to process gas from well i in month t, calculated as:

$$K^R_{i,j,t} = K_{j,t} - \sum_{k \neq i} q_{k,j,t},$$

where $K_{j,t}$ is the total capacity at plant j in month t, $\sum_{k \neq i} q_{k,j,t}$ is the total gas processed by plant j for all other connected wells in month t. This measure can be understood as the space available at plant j to process well i's monthly natural gas production, given the total production of all other connected wells[5].

I control for time-varying well attributes that affect total gas production and flaring, such as monthly oil and water production, well tenure and well tenure squared. I also control for natural gas processed and sold by neighboring wells. To account for time-invariant

[5] While residual capacity is non-negative in a physical sense, measurement error and short-run operational flexibility imply that this measure can be negative in the data. Negative values indicate months in which plants are effectively capacity constrained. In the analysis, I treat residual capacity as zero in these cases and interpret such observations as binding capacity months.

well characteristics that may affect flaring, I include well fixed effects. I also include year and month-of-year fixed effects to control for potential shocks that may have occurred during the sample period. Standard errors are clustered by groups of wells within a 100-meter radius, since flaring is likely to be correlated among wells in the same well-pad that share the equipment for production and transport, and the average well-pad size is about 5.6 acres in North Dakota (Fernando and Stika, 2021).

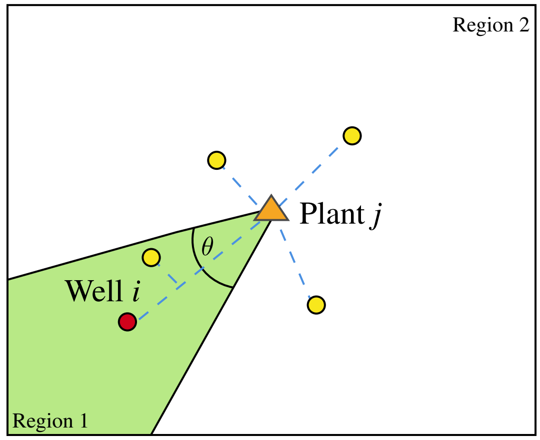
The coefficient of interest $\hat{\alpha_1}$ captures the marginal effect of residual capacity on the amount of gas flared by each well. This is identified by the idiosyncratic shocks to residual capacity, relative to the average flaring for that well in a given month. There are three main threats to the identification of $\hat{\alpha_1}$. First is the presence of unobserved shocks that can affect how much gas is captured and flared, which are likely to be correlated with the independent variable of interest, $K^R_{i,j,t}$. For example, pipeline extensions from the plant to new wells increase the total gas delivered to processing plants. This takes up the residual capacity available for each well connected to the plant. These new drilling activities also affect the geological components that drive production and flaring of nearby wells.

Second, congestion in the gathering lines can drive up flaring. The pressure in the gathering pipelines is primarily determined by (1) total production of wells in the network, and (2) compressor stations along the pipelines that maintain the pressure at a desired rate. Stochastic changes in the compressor station operations can drive congestion among the wells that share the gathering network, affecting how much gas gets delivered to the plant, and how much gas gets flared by wells in the network. In addition, unconventional wells often require re-fracturing over their lifetime to increase production as the wells age, and this can increase congestion in the gathering pipelines. As more gas is delivered by re-fracked wells to processing plants, it reduces the share of capacity available to nearby wells connected to the same plant.

Third, the variation in residual capacity for each well is driven by (1) the amount of gas captured by the well, and (2) total gas processed from all other wells connected to the plant. As such, when plants are at capacity, each well's reduction in flaring, $q^F_{i,j,t}$, increases the residual capacity, $K^R_{i,j,t}$, by occupying a higher share of the available capacity at the plant. Consequently, when the capacity constraint binds, residual capacity depends on the quantity of gas flared, resulting in a simultaneity bias.

To address both the endogeneity and simultaneity concerns, I construct an instrument for residual capacity, $K^R_{i,j,t}$. This instrument is calculated as the total natural gas produced by all other wells connected to the same plant, but located far enough from i to not interfere with its gathering line. Figure 7 depicts the construction of the instrument for well i connected to plant j. Centering plant j, I draw a θ-degree angular sector towards well

Figure 7: Construction of the Instrument for Residual Capacity at Gas Processing Plants



i, to denote a region, labeled "Region 1" in the figure, in which unobserved variables are correlated. Then I aggregate the production of all other wells outside this area in "Region 2" to ensure that these localized unobservables are excluded in the variation of the instrument.

Pipeline extensions from plant j to wells outside this region allow for more gas to be delivered to the plant, directly affecting available capacity for well i. As gas production from wells in "Region 2" increases, the residual capacity for well i decreases, as seen in Section 6. Hence, the instrument is relevant. The instrument is also exogenous to residual capacity, since production from wells in "Region 2" is unlikely to contribute to congestion along well i's gas delivery path to plant j. Due to their location, operations of wells in "Region 2" are also unlikely to affect the geological factors that drive well i's flaring. As a result, the instrument affects well i's flaring only through the available processing capacity at plant j.

The exogeneity of the instrument is reinforced by two key facts about natural gas production in the Bakken. First, producers primarily drill for oil where natural gas is an associated byproduct. As a result, drilling decisions are driven mainly by expectations about oil profitability rather than by considerations related to natural gas processing capacity or flaring outcomes. This limits the producers' ability to strategically adjust drilling activity in response to congestion at plant j or flaring incentives that affect well i.

Second, conditional on drilling, production levels are largely determined by underground reservoir pressure that governs rate at which hydrocarbons can be extracted, which is largely outside the producer's control. Consequently, fluctuations in gas production from wells in "Region 2" primarily reflect underlying reservoir dynamics rather than operational responses to processing constraints or flaring behavior elsewhere in the area. Therefore the variation in production from wells in "Region 2" is plausibly unrelated to the localized unobservables that influence flaring at well i. Instead, their production affects well i's flaring only indirectly, by competing for processing capacity at plant j and altering the residual capacity available to well i.

In my primary analysis I set θ to be 70 degrees. As θ increases the area of "Region 1" increases, and fewer wells are included in the calculation of the instrument. This reduces the power of the instrument but makes it more likely that the exclusion restriction is fully satisfied. I demonstrate robustness to varying the θ degree perimeter of the exclusion boundary.

6 Results

Table 6.1 reports the results for both the OLS and IV specifications of equation (12). The OLS estimate in column (1) is biased because unobserved shocks affect both the quantity of gas flared and the residual processing capacity at the plant. An example for such a shock is variation in pipeline pressure along the gas delivery path from wells to processing plants. For a given well i connected to plant j, the pressure in its gathering line during month t, $p_{i,j,t}$, may decline due to stochastic equipment failures or other disruptions. Lower pressure reduces the volume of gas that well i can deliver to the plant, which increases the amount of gas flared at the well. At the same time, reduced inflow from this well decreases the plant's residual processing capacity for that well, since capacity can be utilized by other wells that are not affected by the localized shock.

As a result, pressure shocks are correlated with both flaring and residual capacity. In particular, $Cov(p_{i,j,t}, q^F_{i,j,t}) < 0$ because lower pressure increases flaring, and $Cov(p_{i,j,t}, K^R_{i,j,t}) < 0$. Because the expected causal relationship between residual capacity and flaring is negative, this biases the OLS coefficient upwards.

The OLS estimate may also suffer from simultaneity bias. When plants operate at or near capacity, residual capacity and flaring are jointly determined: limited processing capacity increases flaring, while increased flaring reduces the amount of gas delivered to the plant. In contrast, the IV estimation results in column (2) demonstrate that the instrumental variable model corrects the bias.

In the first stage of the IV estimation, an increase of 1 thousand cubic feet (mcf) in gas production from wells located on the opposite side of the plant reduces the residual capacity available to the well of interest by approximately 0.16 mcf. The coefficient is statistically significant at the 1% level, and the corresponding F-statistic exceeds the conventional threshold of 10, indicating that the instrument is sufficiently strong.

Table 6.1: Estimation Results

	(1) Gas Flared (mcf)	(2) Gas Flared (mcf)	(3) Residual Capacity (mcf)
Model	**OLS**	**IV Second Stage**	**IV First Stage**
Residual Capacity (mcf)	0.0000277***	-0.000147***	-
	(0.00000648)	(0.0000347)	
Gas Prod. on the Opposite Side (mcf)	-	-	-0.162***
			(0.00318)
Gas Sold in Vicinity (mcf)	-0.0349***	-0.0351***	0.715
	(0.00172)	(0.00174)	(0.577)
Oil Prod. (bbl)	0.462***	0.462***	0.0853
	(0.0153)	(0.0153)	(1.737)
Water Prod. (bbl)	0.0304***	0.0302***	-3.649***
	(0.00826)	(0.00824)	(1.322)
Well Tenure (months)	-4.046***	-4.068***	-261.3
	(0.728)	(0.734)	(987.8)
Well Tenure Sq.	0.00119**	0.00317***	6.380***
	(0.000569)	(0.000678)	(1.358)
Gas Price ($/mcf)	53.29***	82.83***	133158.5***
	(9.167)	(11.49)	(2186.2)
Oil Price ($/bbl)	1.478***	2.926***	7985.5***
	(0.524)	(0.563)	(203.9)
Observations	1,301,952	1,301,952	1,301,952
F-Stat	-	-	2605.15
Year FE	YES	YES	YES
Well FE	YES	YES	YES
Month-Of-Year FE	YES	YES	YES
Std. Clustered By	100-meters	100-meters	100-meters

Notes: This table reports estimates from regressing the amount of gas flared by wells on residual capacity in the IV specification (see equation (12)), and the OLS specification without instrumenting the regressor. Observations are at the well-plant-month level and the sample period is 2012-2019. There are 13, 578 wells and 26 plants in the sample. Standard errors are clustered by groups of wells within a 100-meter radius. *** $p < 0.01$, ** $p < 0.05$, * $p < 0.1$.

The second-stage IV results, reported in Table 6.1 column (3), show that an additional 1 thousand cubic feet (mcf) of residual processing capacity reduces flaring by approximately 0.146 cubic feet (cf) per well per month. The coefficient is statistically significant at the 1% level.

The regressions also control for time-varying well characteristics that may affect flaring. The results indicate that flaring decreases as total gas sales by nearby wells increase: an additional 1 mcf of gas sold in the vicinity reduces flaring by approximately 0.035 mcf. This pattern is consistent with localized production and market conditions affecting both gas production and flaring. Oil production is positively associated with flaring; an additional barrel of oil produced increases flaring by about 0.462 mcf, suggesting that operators may prioritize oil extraction even when the associated gas cannot be fully processed. Similarly, higher water production is associated with increased flaring, which may be driven by wells at later stages of their life cycle facing increased constraints to handle associated gas production.

Well tenure is negatively correlated with flaring, indicating that flaring declines as wells age, although the positive coefficient on the squared tenure term suggests a non-linear relationship over the well's lifespan. Finally, oil and gas prices are also correlated with the quantity of gas flared. Higher oil prices increase flaring, consistent with increased oil production incentives when oil revenues rise. The positive coefficient on gas prices likely reflects increased production activity when prices rise. In the presence of short-run processing and transportation constraints, higher production volumes can generate additional associated gas that cannot be fully processed, resulting in increased flaring.

6.1 Robustness of the Instrument

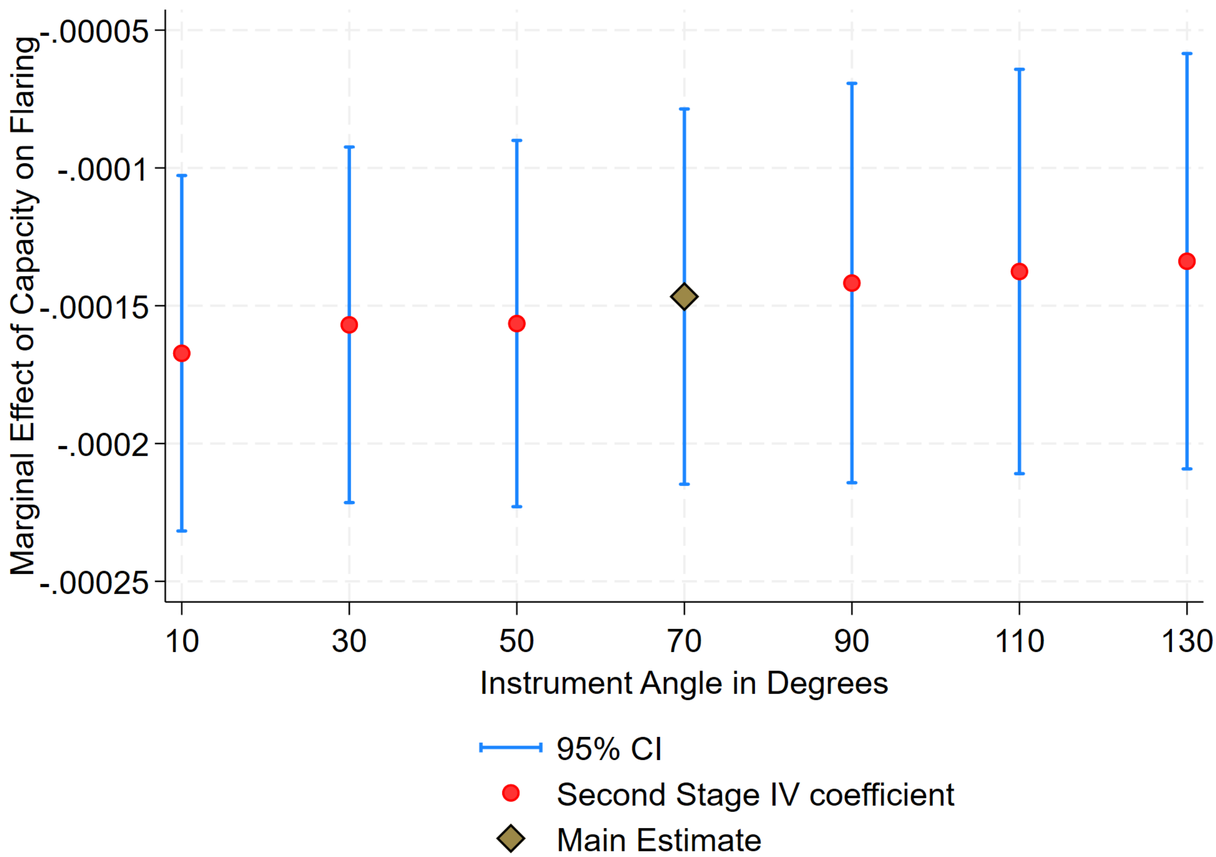
I vary the 70 degree angle perimeter around the well to define the exclusion area described in Figure 7. This changes the number of wells included in the calculation of the instrumental variable, which is total gas produced by wells located on the opposite side of the plant, outside this area. As I increase the size of the exclusion area, fewer wells are included in the calculation of the instrument, which reduces its power, as shown in Figure 8. Despite increases in standard errors and the decrease in magnitude of the coefficient $\hat{\alpha}_1$, my results are robust to this variation– the relationship between flaring and residual capacity is consistently negative, and the estimates are significant.

6.2 Capacity Subsidy

The subsidy derived in Section 3 depends on the expectations over the marginal effect of processing capacity on flaring, which can be decomposed as follows using the estimated $\hat{\alpha}_1$ for each of the wells i connected to plant j:

$$\mathbb{E}\Big[\frac{\partial q^F_{i,j,t}}{\partial K_{j,t}}\Big] = \underbrace{\mathbb{E}\Big[\frac{\partial q^F_{i,j,t}}{\partial K^R_{i,j,t}}\Big]}_{\hat{\alpha}_1} \cdot \mathbb{E}\Big[\frac{\partial K^R_{i,j,t}}{\partial K_{j,t}}\Big] + Cov\left(\frac{\partial q^F_{i,j,t}}{\partial K^R_{i,j,t}}, \frac{\partial K^R_{i,j,t}}{\partial K_{j,t}}\right). \tag{13}$$

Figure 8: Robustness of the Instrumental Variable



Notes: This figure reports the second stage results from the IV specification in equation 12 for varying the perimeter of instrument construction described in Section 5. Observations are at the well-plant-month level and the sample period is 2012-2019. Standard errors are clustered by groups of wells within a 100-meter radius.

Suppose that the treatment effect of increasing processing capacity on flaring is homogeneous across all wells connected to each plant in the sample. This implies that there is no correlation between changes in residual capacity from plant expansions and how much each well flares from fluctuations in the residual capacity:

$$\mathbb{E}\Big[\frac{\partial q^F_{i,j,t}}{\partial K_{j,t}}\Big] = \hat{\alpha}_1 \cdot \mathbb{E}\Big[\frac{\partial K^R_{i,j,t}}{\partial K_{j,t}}\Big]\,. \tag{14}$$

If treatment effects are heterogeneous and correlated with how plant expansions affect residual capacity across wells, the covariance term in (13) will be non-zero, and the decomposition may under- or overstate the aggregate effect of capacity expansions on flaring.

Having estimated $\hat{\alpha}_1$, the calculation of marginal flaring with respect to capacity in equation (14) now depends on $\mathbb{E}\Big[\frac{\partial K^R_{i,j,t}}{\partial K_{j,t}}\Big]$, which can be derived from the definition of residual capacity for each well. Recall that residual capacity is defined as the difference between total monthly capacity and total gas processed for all other wells connected to the plant:

$$\begin{aligned} K^R_{i,j,t} &= \overbrace{K_{j,t}}^{\text{capacity}} - \overbrace{(Q_{j,t} - q_{i,j,t})}^{\text{gas processed from all wells except } i} \\ &= K_{j,t} - \underbrace{Q^P_{-i,j,t}}_{\text{gas produced by all wells except } i} + \underbrace{Q^F_{-i,j,t}}_{\text{gas flared by all wells except } i}. \end{aligned}$$

Given the homogeneous treatment assumption above, $\frac{\partial q^F_{i,j,t}}{\partial K_{j,t}}$ is symmetric across all wells. In addition, the decision to drill is exogenous to natural gas production as discussed in Section 2 and $Q^P_{-i,j,t}$ is independent of processing capacity. Therefore,

$$\begin{aligned} \frac{\partial K^R_{i,j,t}}{\partial K_{j,t}} &= 1 + \frac{\partial Q^F_{-i,j,t}}{\partial K_{j,t}} \\ &= 1 + (N-1)\frac{\partial q^F_{i,j,t}}{\partial K_{j,t}}, \end{aligned}$$

where N is the total number of wells connected to the plant.

Hence, changes in the quantity of gas flared for each well with respect to total capacity can be expressed in terms of the estimated $\hat{\alpha}_1$ as follows using (14):

$$\mathbb{E}\Big[\frac{\partial q^F_{i,j,t}}{\partial K_{j,t}}\Big] = \hat{\alpha}_1 \cdot \big(1 + (N-1)\,\mathbb{E}\Big[\frac{\partial q^F_{i,j,t}}{\partial K_{j,t}}\Big]\big),$$

and therefore,

$$\mathbb{E}\Big[\frac{\partial q^F_{i,j,t}}{\partial K_{j,t}}\Big] = \frac{\hat{\alpha}_1}{1-\hat{\alpha}_1(N-1)}.$$

Note that well i's residual capacity is partly determined by the share of capacity used by all other wells connected to the same plant. Consequently, accounting for the reduction in flaring by other wells takes up the available capacity for well i. This adjustment brings the estimate closer to 0 when flaring decreases with additional residual capacity (i.e. $\hat{\alpha}_1 < 0$).

The average flaring reduction from changes in capacity per plant per month can then be aggregated as

$$\mathbb{E}\Big[\frac{\partial Q^F_{j,t}}{\partial K_{j,t}}\Big] = \Big\{\frac{\hat{\alpha}_1}{1-\hat{\alpha}_1(N-1)}\Big\}N \approx 0.089 \text{ mcf},$$

where $N = 564$ is the average number of wells connected to all processing plants in my sample. This indicates that an additional 1 thousand cubic feet (mcf) of processing capacity reduces flaring by 89 cubic feet (cf) (or 0.089 mcf with a 95% confidence interval of [0.125, 0.042]) per plant per month. The relationship isn't 1-to-1 given that flaring can be driven by constraints beyond processing capacity. However, my results show that processing capacity plays an important role in natural gas flaring, and relieving these constraints can reduce flaring that stems from insufficient processing capacity.

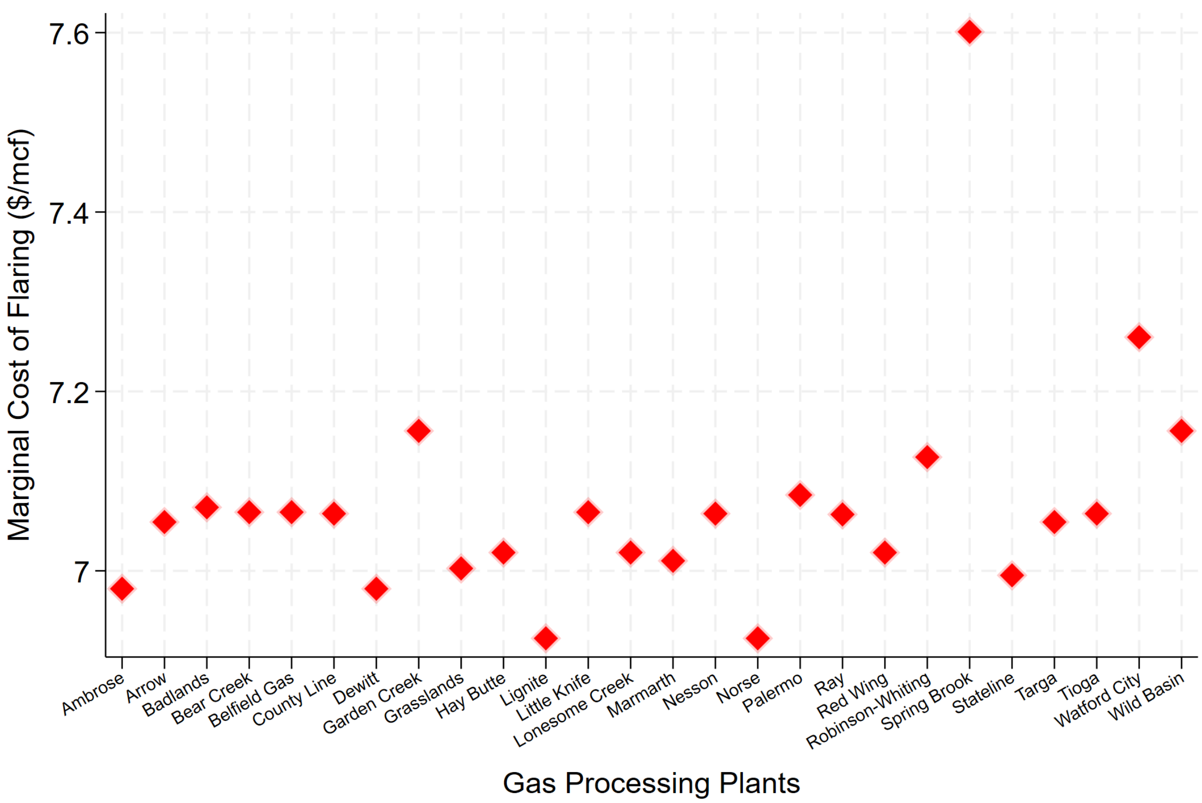
6.3 Heterogeneous vs. Uniform Subsidy

The first-best capacity subsidy derived in Section 3 varies across plants because damages from flaring are location-specific. To calculate plant-level marginal flaring costs[6], I begin by estimating tract-level marginal damages for PM2.5 and volatile organic compounds (VOCs) using the Air Pollution Emission Experiments and Policy Analysis (APEEP) (Dennin et al., 2199). I then combine these marginal damages with flaring emissions factors for PM2.5 from McEwen and Johnson (2012) and for VOCs from the U.S. Environmental Protection Agency to obtain plant-specific local flaring costs. Finally, I incorporate marginal climate damages of \$6.31 per thousand cubic feet of natural gas flared, assuming 93% flare efficiency in the Bakken, calculated by Agerton et al. (2023). Figure 9 plots the marginal cost estimates for each gas processing plant in the sample. The variation in marginal flaring costs drives the heterogeneity in the subsidy calculations below.

Combining the heterogeneous marginal costs, γ_j, with the estimated average reduction

[6] Note that these costs do not include the forgone value of the natural gas flared since it is not considered an externality at the market equilibrium.

Figure 9: Marginal Cost of Flaring



Notes: This figure reports marginal cost of flaring for each plant in the sample in U.S. dollars per thousand cubic feet (mcf) of natural flared, calculated using the local damage outputs for particulate matter (PM2.5) and volatile organic compounds (VOCs) from the APEEP model and global climate costs for CO_2 and CH_4 at 93% flare efficiency.

in flaring from additional processing capacity, I calculate both the first-best capacity subsidy derived in Section 3.2, which varies by plant, and the optimal uniform subsidy derived in Section 3.3.[7] Figure 10 plots the first-best subsidy for each plant against the optimal uniform subsidy derived in Section 3.3. Assuming an annual social discount rate of 5% (equivalent to a monthly discount rate of 0.41%), the optimal uniform capacity subsidy that offsets the damages from flaring is approximately \$135.39 per thousand cubic feet. Because local damages vary only modestly across plants, the welfare loss from implementing a uniform subsidy rather than plant-specific subsidies would be relatively small. In settings where marginal damages vary more substantially across locations, the gains from differentiating subsidies would be larger. Figure 11 plots the optimal uniform subsidy under alternative social discount rates.

Now consider a back-of-the-envelope approximation of the implications of the flaring subsidy. I gather data on capacity and construction costs from gas plant siting applications submitted to the North Dakota Public Service Commission and estimate a logarithmic relationship between total capacity and total estimated costs. Assuming a constant elasticity of capacity investment with respect to costs, I find that reducing capacity costs by 1% would lead to an increase of 0.8% in processing capacity.[8]

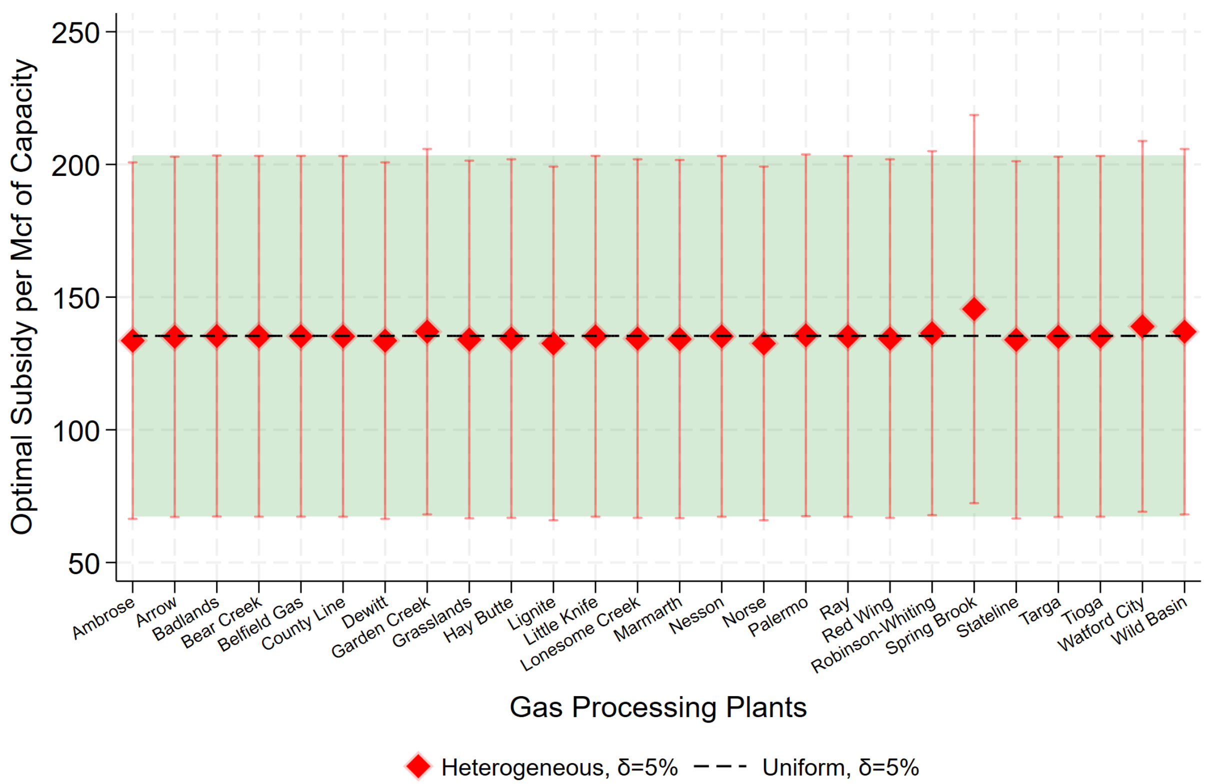
According to processing plant construction and expansion permits submitted to the North Dakota Industrial Commission (NDIC), the cost of capacity construction is roughly \$1000 per thousand cubic feet (mcf). Given that the calculated average capacity subsidy is \$135 per thousand cubic feet, this lowers the per unit capacity costs by approximately 13.5%. The average monthly processing capacity among all plants in the sample period is 1.9 billion cubic feet. This means that the calculated subsidy would increase the average monthly capacity by roughly 205.2 million cubic feet.

The empirical estimates indicate that an increase in 1000 cubic feet of processing capacity reduces flaring by 89 cubic feet per plant per month. This implies that the subsidy would reduce monthly flaring by 18.5 million cubic feet on average. This is roughly \$128, 000 saved in total damages per month, offsetting about \$1.5 million in flaring damages per year.

[7] On average, gas plants become operational within a year of construction, so I set $t_1 = 12$.

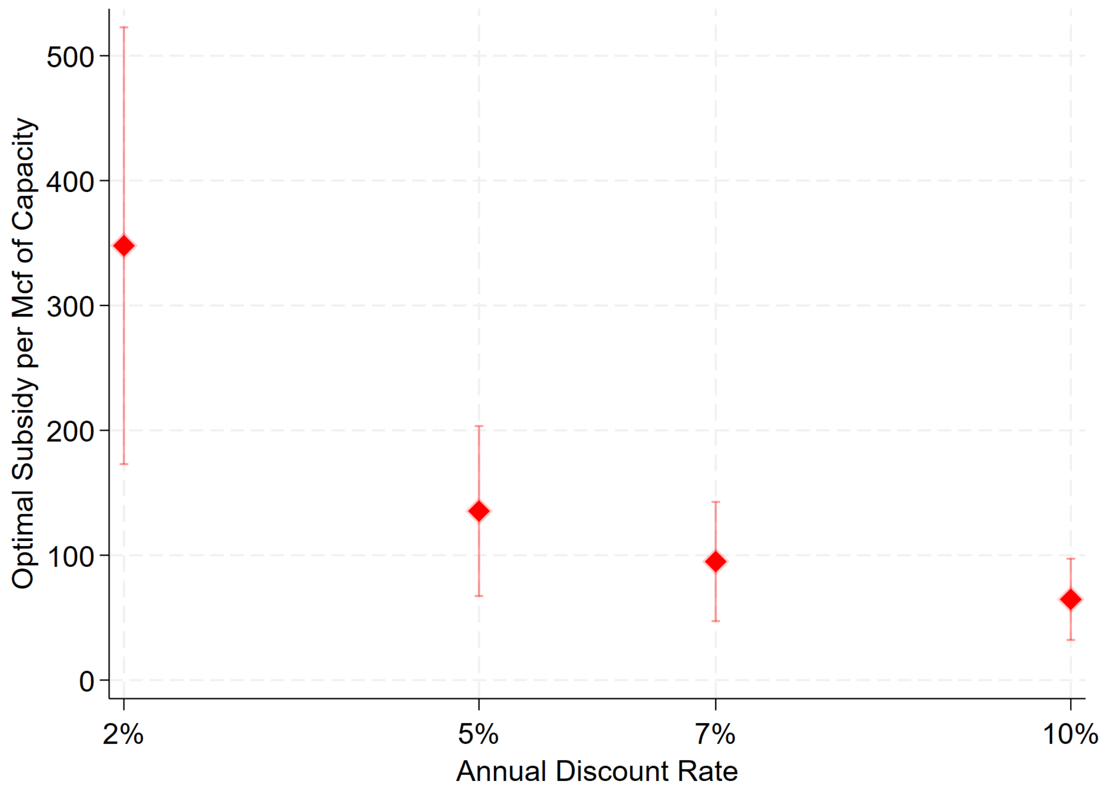
[8] I regress $log(K_j) = \zeta_0 + \zeta_1 log(C_j) + \phi_j$ for 10 plants.

Figure 10: Heterogeneous Vs. Uniform Capacity Subsidy per Thousand Cubic Feet (Mcf)



Notes: This figure plots the heterogeneous subsidy derived in Section 3.2 against the optimal single subsidy derived in Section 3.3 in U.S. dollars per thousand cubic feet of processing capacity, calculated using the IV regression estimates at the annual discount rate of 5%. Standard errors are calculated using the delta method for both, and 95% confidence intervals are displayed.

Figure 11: Uniform Capacity Subsidy per Thousand Cubic Feet (Mcf)



Notes: This figure reports the optimal single subsidy in U.S. dollars per thousand cubic feet of processing capacity, calculated using the IV regression estimates at different annual discount rates. Standard errors are calculated using the delta method, and 95% confidence intervals are displayed.

7 Conclusion

In this paper, I quantify the role of insufficient processing capacity in natural gas flaring using new data from North Dakota where fracking for oil is prominent and midstream constraints are especially relevant. Using an instrumental variable model, I empirically demonstrate that flaring decreases as processing capacity increases and theoretically derive a subsidy which depends on the estimated relationship between processing capacity and the quantity of natural gas flared.

I find that on average, an ex-ante subsidy of $135 per thousand cubic feet (mcf) of processing capacity would ensure that flaring emissions remain at the socially optimal level. The subsidy is derived from the estimated marginal flaring with changes in processing capacity, which indicates that on average, an additional 1 thousand cubic feet (mcf) of processing capacity at a plant decreases flaring by 89 cubic feet (cf) among all the wells connected to the plant.

My results show that constrained processing capacity does in fact drive natural gas flaring, and that damages can be offset by subsidizing the processing capacity necessary to capture the gas. Back of the envelope calculations suggest that investment in additional processing capacity would offset the damages from flaring emissions by roughly $1.5 million per year across the state. Future research should explore empirically testing the heterogeneous responses of plant capacity to the subsidy derived in the theoretical model, relaxing the homogeneity assumption in the application.

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A Proof of Proposition 1

Proof. The first order conditions for the regulator gives us

$$0 = \sum_{t=t_1}^{\infty} \frac{1}{(1+\delta)^t} \Big\{ \sum_j \Big(\frac{\partial K_j}{\partial s} \cdot \Big(\mathbb{E}\Big[\frac{\partial u(\sum_j Q^*_{j,t})}{\partial Q^*_{j,t}} \cdot \frac{\partial Q^*_{j,t}}{\partial K_j} \Big] - c_t \,\mathbb{E}\Big[\frac{\partial Q^*_{j,t}}{\partial K_j} \Big] + \gamma_j \,\mathbb{E}\Big[\frac{\partial Q^*_{j,t}}{\partial K_j} \Big] \Big) \Big) \Big\}$$
$$- \sum_j \Big(\frac{\partial K_j}{\partial s} \cdot \frac{\partial C(K_j)}{\partial K_j} \Big). \tag{15}$$

Adjust the first order conditions for the capacity setting problem of gas processing plants at market equilibrium in equation (8) as each plant being offered a constant subsidy s:

$$\sum_{t=t_1}^{\infty} \frac{1}{(1+\delta)^t} \frac{\partial \,\mathbb{E}[\pi(Q^*_{j,t})]}{\partial K_j} = \frac{\partial C(K_j)}{\partial K_j} + s.$$

Given that $\pi(Q^*_{j,t}) = p_t Q^*_{j,t} - c_t Q^*_{j,t}$ where p_t is the exogenous market price of natural gas, observe that

$$\frac{\partial \,\mathbb{E}[\pi(Q^*_{j,t})]}{\partial K_j} = \mathbb{E}\Big[\underbrace{\frac{\partial u(\sum_j Q^*_{j,t})}{\partial Q^*_{j,t}}}_{p_t} \cdot \frac{\partial Q^*_{j,t}}{\partial K_j} \Big] - c_t \,\mathbb{E}\Big[\frac{\partial Q^*_{j,t}}{\partial K_j} \Big],$$

since $p_t = \frac{\partial u(\sum_j Q^*_{j,t})}{\partial Q^*_{j,t}}$ following equation (5). Therefore, it must be that

$$s = \sum_{t=t_1}^{\infty} \frac{1}{(1+\delta)^t} \Big\{ \mathbb{E}\Big[\frac{\partial u(\sum_j Q^*_{j,t})}{\partial Q^*_{j,t}} \cdot \frac{\partial Q^*_{j,t}}{\partial K_j} \Big] - c_t \,\mathbb{E}\Big[\frac{\partial Q^*_{j,t}}{\partial K_j} \Big] \Big\} - \frac{\partial C(K_j)}{\partial K_j}.$$

Plugging this expression into equation (15) further simplifies the regulator FOC to:

$$0 = \sum_j \Big(\frac{\partial K_j}{\partial s} \cdot \Big(s + \gamma_j \sum_{t=t_1}^{\infty} \frac{1}{(1+\delta)^t} \Big\{ \mathbb{E}\Big[\frac{\partial Q^*_{j,t}}{\partial K_j} \Big] \Big\} \Big) \Big). \tag{16}$$

Since $Q^*_{j,t} = Q^P_{j,t} - Q^F_{j,t}$, and $Q^P_{j,t}$ is exogenous to K, this is equivalent to

$$0 = \sum_j \Big(\frac{\partial K_j}{\partial s} \cdot \Big(s - \gamma_j \sum_{t=t_1}^{\infty} \frac{1}{(1+\delta)^t} \Big\{ \mathbb{E}\Big[\frac{\partial Q^F_{j,t}}{\partial K_j} \Big] \Big\} \Big) \Big). \tag{17}$$

Hence, the optimal subsidy derived in Proposition 1 directly follows from rearranging the above expression to obtain s^*. □