# Can Vertically Integrated Firms Evade Pricing Regulation? Evidence from Energy Utilities

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**Abstract**

Cost-of-service regulation commonly allows utilities to pass on increases in input costs onto captive consumers. When utilities are vertically integrated with input suppliers, this form of regulation may distort cost-minimizing behavior as utilities can increase profits of affiliated suppliers by over-procuring inputs from them and then passing on costs to consumers. This paper empirically tests whether regulation distorts US utilities' input procurement decisions for a long-lived fossil fuel asset: natural gas pipeline capacity. Using a hand-built dataset of pipeline expansion contracts, I apply a triple-differences approach to test whether, relative to unregulated buyers, utilities procure more capacity at higher prices when contracting with an affiliated versus an unaffiliated pipeline company. Results show that utilities procure too much capacity from affiliates, causing pipeline companies to overbuild new pipelines by 28-33 percentage points on average. In contrast, utilities do not pay differentially higher markups to affiliated pipeline companies. Extrapolating estimates of overbuilding to all interstate natural gas pipeline projects built between 2010 and 2021, my estimates suggest that utilities have shifted $2.4 billion in excessive pipeline costs onto consumers. Decreasing information asymmetry between regulators and firms during the permitting process may curb unnecessary expansion of fossil fuel infrastructure.

**Keywords:** natural monopoly, cost-of-service regulation, stranded costs, vertical mergers, energy utilities, natural gas pipelines

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# 1 Introduction

There is an active debate around the degree to which regulatory evasion should be a concern for antitrust enforcement (J. B. Baker et al. 2018; Khan 2019; Sappington and Weisman 2021). Regulatory evasion arises when a firm subject to cost-based pricing regulation increases profits by manipulating input prices through a vertically integrated affiliates–i.e., firm with common corporate ownership (Brennan 1990; Posner 1978; Riordan and Salop 1994). For example, utilities facing cost-based pricing regulation can pass on fuel cost increases on to captive customers. If the utility is affiliated with an upstream input supplier, it can inflate input prices, earning profits in its input division while passing the cost onto customers. Regulators, however, reviewing utility costs constrain the firm's ability to set high prices; successful evasion requires sufficient obfuscation or plausible justification for cost increases. While vertical integration theoretically creates incentives for such evasion, whether firms act on those incentives an unstudied empirical question.

This paper investigates whether vertical integration enables regulated firms to inflate input costs by studying the contracting decisions of U.S. energy utilities for a key input: natural gas pipeline transportation.[1] Natural gas and electric utilities contract with pipeline companies to transport gas from supply basins to service territories. In this setting, utilities can strategically raise input costs, and thereby increase profits in their pipeline division, through two mechanisms. First, is through *price*: the utility can sign capacity contracts with an affiliated pipeline company at above-market rates. Second, is through *quantity*: if contract prices exceed marginal costs, then buying excessive capacity also boosts affiliate profits. That is, utilities can inflate costs not only by paying more per unit, but also buy buying more units at a mark-up.

This paper makes two main contributions. First, I provide causal evidence on whether vertical affiliation leads to cost inflation in regulated industries, testing for both price and quantity inflation distortions in pipeline capacity contracts. I exploit rich cross-sectional variation in the vertical structure and regulatory status of pipeline-buyer pairs to isolate regulatory evasion incentives from other distortions induced by cost-of-service regulation and vertical integration alone. Second, I estimate the extent of pipeline overbuilding driven by quantity inflation and explore the role of vertical merger policy in creating conditions for climate stranded assets.

To conduct this analysis, I construct a panel on vertical relationships, capacity contracts and usage of all interstate natural gas pipelines in the United States, covering 65% of pipeline mileage (PHMSA 2023).[2] Because existing datasets exclude confidential pricing, I assemble a novel dataset of capacity contracts,

[1] Vertical integration can distort input decisions in other industries where firms' pricing decisions face regulatory scrutiny such as healthcare (Bovbjerg and Berenson 2015) and telecommunications (Economides 1998; Reiffen et al. 2000).

[2] The mileage measure underestimates the importance of the interstate pipeline network, as many intrastate pipeline networks depend on interstate systems for supply. Two-thirds of states rely almost completely on interstate pipelines for access to natural gas supplies.

focusing on a key subset known as "precedent agreements," which reserve capacity on new pipeline expansions. These contracts are central to expansion decisions and regulatory approval processes (Keefe 2022), and due to disclosure requirements, many are publicly available in full. I identify precedent agreements in 128 pipeline expansion filings and manually extract pricing information from digitized contracts. The final dataset includes 403 contracts from 2010 and 2021, representing $143 billion in new pipeline investment.

I begin by testing whether utilities that are vertically integrated with pipeline companies contract for excess capacity. Using changes in daily usage at expansion locations, I construct a measure of a contract quantity inflation. If evasion incentives are actionable, I expect post-expansion under-utilization when affiliated utilities are the contracting buyers. A difference-in-differences design leverages pre-determined variation in the regulatory status and vertical relationships of buyers, comparing utilization before and after expansions while controlling for buyer type. The industry geography supports identification: pipelines are geographically proximate to population centers where *regulated* utilities are located, as well as to pre-historic shale deposits where many *unregulated* buyers such as natural gas producers are located. Further, mergers in the pre-sample period generate substantial variation in vertical structure, as pipelines are affiliated with a fraction of their buyers. As a result, I observe contracting behavior between pipelines and all two-by-two combinations of regulated and affiliated buyers, although only buyers that are both regulated *and* affiliated with the pipeline company are incentivized to inflate inputs.

Next, I estimate price distortions by comparing contract prices and markups across buyer types using a similar differences-in-differences strategy. Since the Federal Energy Regulatory Commission (FERC) publishes benchmark cost-based prices for each expansion, I can measure contract markups relative to this regulatory benchmark. This allows me to isolate price effects attributable to vertical integration and regulatory evasion separately from other cost drivers.

I find that affiliated, regulated utilities (hereafter known as "utility affiliates") show large and statistically significant decreases in post-expansion capacity utilization, consistent with evidence of contract quantity inflation. Post-expansion usage falls by 51-70% on average at pipeline locations contracted by such buyers relative to other buyer types. These estimates imply that contract quantities are inflated by 28-34 percentage points due to evasion incentives. Event study figures show that under-utilization begins only after pipeline expansion occurs and persists for at least four years. In contrast, expansions led by affiliated, but unregulated buyers increase utilization by 60-160%, consistent with efficiency gains from vertical integration. In most specifications, the productivity benefits of integration also documented in previous literature are more than offset by the distortion induced by regulatory evasion incentives (Atalay, Hortaçsu, and Syverson 2014; L. W. Davis and Wolfram 2012; Demirer and Karaduman 2022).

To rule out alternative explanations, I test whether utility affiliates disproportionately use capacity on days when returns to utilization are highest. I find no evidence of this. Under-utilization persists on cold days with high heating heating demand, during periods of high price spreads (a proxy for congestion),[3] and when compared to nearby locations on other pipelines matched by pre-expansion usage.

In contrast to the quantity mechanism, I find no evidence of price inflation by utility affiliates. Despite wide dispersion in observed markups ranging from -100 to 300%, variation is not well-explained by incentives for regulatory evasion. The differences in evidence for pricing and quantity inflation align with a model of contracting under information asymmetry where well-informed regulators can suppress cost inflation (Cicala 2015; Vickers 1995), but not quantity. Pipeline construction costs are transparent to regulators at the time of contracting, but the regulator cannot verify the necessity of capacity (which depends on long-run utility demand and drilling productivity) until after the fact. Due to informational timing, my results suggest quantity is a more accessible channel for evasion.

Finally, I estimate that the costs of overbuilding due to quantity inflation are large and the exposure of residential energy consumers to these costs is significant. A back-of-the envelope calculation reveals regulatory evasion induced overbuilding represented a \$2.4 billion transfer from consumers to pipeline companies between 2010-2020, equivalent to roughly 5% of all spending on interstate pipelines during the period. Exposure is widespread: I calculate that 53% of all residential natural gas customers and 16% of electricity customers are served by utilities affiliated with a pipeline company.

From a policy perspective, this work contributes to several debates in energy regulation and antitrust. First, I provide new empirical evidence that the net efficiency effects of vertical integration in regulated markets can be negative, due to distortions in input procurement. Second, I show that precedent agreements between affiliated firms can overstate demand for new pipeline projects, raising questions about the standard of review for these agreements during project certification (Keefe 2022; Klass 2022).[4]

Finally, I argue that vertical market structure has implications for climate policy. Natural gas is a fossil fuel estimated to be responsible for 11% of total anthropogenic methane emissions and 34% of US carbon emissions from the energy sector (EIA 2022; IEA 2023). Natural gas infrastructure is both costly to reallocate and exposed to risk in value decline due to climate policy targeted at the clean energy transition. My findings show that vertical relationships can misallocate capital towards emission-intensive technologies, creating conditions for "stranded assets" (Kemfert et al. 2022; Van der Ploeg and Rezai 2020) and displace these stranded costs onto ratepayers.

[3] Local spot prices above one standard deviation of the mean monthly Henry Hub price are predictors of congestion in the pipeline network (Covert and Kellogg 2017; McRae 2018).

[4] This concern is not theoretical. In 2018, the FERC approved the \$287 million Spire STL Pipeline project based on a long-term contract between Spire STL Pipeline and an affiliated utility, Spire Missouri, despite stagnant gas demand in the region. The Spire STL Pipeline is one of several new pipeline projects whose certificate of approval has faced legal challenges on the grounds that such projects fail to meet the "public convenience and necessity" (Stockman and Trout 2017).

This study contributes to several literatures. The first is economic analysis of how cost-of-service regulation distorts utility decisions. Prior work in this area emphasizes that fixed rates of return can incentivize over-investment in capital through the so-called "Averch-Johnson" effect (Fowlie 2010; Jha 2020; Knittel et al. 2019; Lim and Yurukoglu 2018), and that pass-through of variable costs to captive ratepayers reduces operational efficiency of utility-owned power plants (Chan et al. 2017; Cicala 2015; L. W. Davis and Wolfram 2012; Fabrizio et al. 2007). This study highlights a related, but distinct concern: pass-through can distort decisions not just by the utility itself, but by its *affiliates* through shared corporate ownership. In addition to pipeline companies, recent research has identified affiliations between utilities and coal mines, retail electric providers, and wholesale electric generators (Kovvali and Macey 2022), including those that were previously divested by the utility during restructuring (MacKay and Mercadal 2024). This paper investigates whether rate regulation distorts the behavior of these non-price regulated affiliates.[5]

This paper also contributes to the literature on how pricing regulation affects the conduct of a firm operating in both price-regulated and unregulated markets. Previous theoretical work has shown that regulation may enable vertically integrated firms to increase prices in the regulated market where it is a monopolist, either directly by shifting costs from the unregulated to regulated portion of the firm (Braeutigam and Panzar 1989; Brennan 1990), or indirectly through non-price discrimination against rivals (Beard et al. 2001; Economides 1998; Mandy 2000; Sibley and Weisman 1998).[6] I leverage uniquely rich contract data to test predictions from this theoretical literature, showing that even when regulators constrain price increases, vertical integration can still harm consumers by enabling the firm to sell itself an inflated *quantity*. This result contributes to mixed empirical studies of vertical mergers in unregulated markets (L. Baker et al. 2014; Boehm and Sonntag 2023; Crawford et al. 2018; Dafny et al. 2019; Houde 2012), and emphasizes the importance of assessing vertical mergers on non-price outcomes.

The rest of the paper is organized as follows: Section 2 explains institutional details of the natural gas pipeline market that I study. Section 3 proposes a model of how vertical integration affects contracting in regulated industries under asymmetric information. Section 4 describes the data. Section 5 documents incentives for regulatory evasion. Section 6 describes the empirical strategy and results for inflation of contract quantities. Section 7 shows results for price inflation. Section 8 discusses policy relevance and concludes.

[5] Although interstate natural gas pipelines are formally subject to rate regulation by FERC, the Commission's *Alternative Rate Policy Statement* permits pipelines and buyers to negotiate rates that depart from the cost-based rates in the pipeline's tariff. Both industry sources and the contract data confirm that negotiated rates are common for precedent agreements (see Section 2.1). For this reason, I treat the market for pipeline services market as effectively non-rate regulated, although posted tariff rates may still influence price formation.

[6] Forms of non-price discrimination that raise the cost of rivals in the unregulated market include degrading the quality of the good the regulated monopolist sells, delaying access to the good, or imposing burdensome purchasing requirements on rivals.

## 2 Institutional Details on Interstate Natural Gas Pipelines

Natural gas is a major feature of the energy landscape in the United States; as of 2020, gas is the source of 32% of all energy consumed nationally and 47% of homes are heated using natural gas (EIA 2024). Long distances between the urban centers of gas demand and often rural regions focused on gas supply has led to the need for a midstream segment, namely natural gas pipelines, to transport the gas and connect consumers with producers. Natural gas consumption is largely driven by demand for electricity and heating, and as a result different weather patterns and power plant profiles make demand for gas highly heterogeneous across the United States. Meanwhile, gas production is geographically concentrated in regions with larges gas reserves known as gas basins. Figure 1 shows the location of gas basins in purple and adjacent gas trading hubs in red, each black line is a natural gas pipeline. Pipelines are pivotal to the gas industry, since unlike in the case of oil which can be transported by rail, ship or pipeline, pipelines are the only economically feasible way of transporting gas domestically in the United States.

The gas pipeline transportation industry generates $28.3 billion dollar in annual revenue and consists of roughly 3 million miles of pipe (Cook 2021). Pipeline companies sell transportation services to firms known as "buyers", which include traditional users of natural gas such as gas utilities, gas fired power plants, and large industrial facilities, in addition to natural gas producers and natural gas marketing companies.

While there are many kinds of firms that contract with pipelines, there are two important, non-exclusive, types of buyers relevant for a study of how vertical integration with regulated firms can affect investment: utility and affiliate buyers. An affiliate buyer refers to buyer who is vertically integrated with the pipeline, either because the pipeline company and the buyer are owned by the same parent company, or because the pipeline company and the buyer have joint ownership of the pipeline asset. It is necessary for a buyer to be affiliated with a pipeline in order for it to be jointly profitable for the pipeline to increase transportation prices for the buyer; otherwise higher prices are simply losses for the buyer. Utility buyers refer to natural gas and electricity utilities, who are large consumers of natural gas and typically make up a significant fraction of transportation contracts on a pipeline. Utility buyers are the only kinds of buyers that are subject to cost-of-service regulation, which allows them to pass-through higher transportation prices in the form of increased electricity or gas prices for consumers. buyers need to be both utilities and affiliates for incentives for regulatory evasion to arise.

Figure 2 provides an example of how the relevant types of buyers are defined for Millennium Pipeline, a 263-mile interstate pipeline that transports gas between New York and Pennsylvania. In this example, Millennium provides gas transportation to two groups of buyers: affiliates, such as Boston Gas and non-affiliates, such as Bkv Operating and Narragansett Electric. Affiliates and non-affiliates can be further divided by regulatory status. Amongst its non-affiliate buyers Millennium has both regulated and unregulated buyers, as Narragansett Electric is an electric utility with service territory in New York and Bkv Operating is a large natural gas producer with wells in the Marcellus Shale. Millennium only has one affiliate buyer Boston Gas, who is a natural gas utility in Massachusetts that, at the time of construction held a 26.25% stake in Millennium Pipeline. Under the regulatory evasion hypothesis, Boston Gas faces incentives to increase transportation prices paid to Millennium since they earn profit from their joint stake in the pipeline and can pass higher costs onto Boston Gas consumers. These incentives do not exist for Narrangasett Electric or Bkv Operating.

Natural gas pipelines are regulated natural monopolies and therefore face a unique contracting environment. Constructing pipelines is costly and capital-intensive; a study of 2016 construction projects found that on average firms spent $5.34 million per mile of pipe (Petak et al. 2017). Due to the high fixed costs of construction and low costs of maintenance, firms build pipelines to cover distinct geographic routes, a decision that has left many pipelines with local monopolies over the transport of gas. As traditional natural monopolies, prices and entry of interstate natural gas pipelines are regulated by Federal Energy Regulatory Committee (FERC); this project studies interstate pipelines which account for 63% of pipeline-miles in the US. The details of entry and pricing regulation are important to understanding how regulatory evasion occurs and I explain both here.

## 2.1 Pricing natural gas transportation contracts

A pipeline company sells transportation on their network, which is composed of a series of origin and destination points at which gas can be injected onto the pipeline and delivered off the pipeline, respectively. Sales happen in the form of long-term transportation contracts between pipelines and buyers where a pipeline agrees to transport gas between the buyer's elected origin and destination points in return for payment. It is important to note that pipelines are exclusively gas transporters under FERC Order No. 636, and buyers must arrange to buy (or sell) natural gas separately from their transportation contract with the pipeline. For every origin and destination pair, a transportation contract defines the quantity and price of transportation services. The quantity is defined as the maximum daily quantity (MDQ) of gas that a pipeline must be able to transport for the buyer between the origin and destination points for the duration of the contract period.

The pricing structure of transportation contracts is defined under FERC Order No. 636, which mandates the two-part tariff structure. Under this structure, natural gas pipelines charge buyers both a monthly fixed price and a usage price. The usage price is a fee that is charged for every unit of gas that the pipeline actually transports on behalf of the buyer, while the fixed price is a monthly fee paid on each unit of capacity under contract. The fixed price component is essentially a "take-or-pay" provision in which the buyer must pay for a specified quantity of transportation each month even if they do not provide any gas to ship (MacLeod and Malcomson 1993; Masten and Crocker 1985). The fixed price is the reason why increasing the quantity under contract (but not necessarily the quantity used by the buyer) raises the total cost of pipeline transportation and acts as a mechanism by which pipelines and utilities can evade pricing regulation.

Fixed and usage prices are set either through cost-of-service ratemaking or through bilateral negotiation between pipelines and buyers. FERC regulates prices by setting minimum and maximum prices caps through a ratemaking process known as "cost-of-service." Under this ratemaking paradigm, FERC approves maximum prices such that the pipeline is able to recover its investments and costs of operation, while earning a "reasonable" rate of return, usually 14%. In practice, many contract prices are set through bilateral negotiations; over 48% of pipeline capacity under contract in 2019 is contracted through negotiated rates.[7] The outcomes of negotiations can lead prices to be below or in excess of the maximum price set through cost-of-service regulation, and buyers are always able to elect to contract under regulated prices. Understanding the difference between cost-of-service and negotiated prices is important for this study, as the mechanism by which pipelines and utilities are able to inflate per-unit fixed prices will differ based on the price setting process.

## 2.2 Investment in natural gas pipelines

This paper is primarily concerned with how regulatory evasion distorts investment in new natural gas pipeline capacity, where capacity investment allows a pipeline to expand services in transportation market.[8] The process of capacity investment unfolds in two stages.

First, pipelines notify buyers of and allocate potential new capacity through an open season, an open bidding process where prospective buyers can bid on the capacity that will be made available through the capacity expansion. Successful bidders undergo negotiations with the pipeline to sign ex-ante contracts for the proposed capacity known as "precedent agreements." Precedent agreements follow the pricing structure described above, but are typically more complete than contracts signed for existing capacity as investment

[7] In 1996, FERC granted interstate pipelines the option of charging negotiated prices instead of cost-based rates. Responding to demands from pipelines and customers for "greater flexibility" in the ratemaking process, FERC agreed that pipelines and their customers could negotiate rates and terms of service that differed from the tariff on file, so long as customers always retained the option to contract service under the cost-of-service based tariff. The policy statement emphasized the importance of the filed tariff as a recourse rate to "prevent pipelines from exercising market power."

[8] Although the pipeline network connects gas markets across the entire US, it is useful to think of pipeline corridors between major production and consumption regions as distinct markets for transportation. To see this distinction clearly, consider the case of Ruby Pipeline, a pipeline that connects gas produced in the Rockies with West Coast gas consumers, and Maritimes & Northeast Pipeline, a pipeline that connects gas produced in Atlantic Canada to consumers in the Northeast. Although Ruby and Maritimes & Northeast are technically connected thorough the interstate pipeline network, Ruby and Maritimes & Northeast are not in the same transportation market because they do not compete over the same set of buyers, as they serve gas producers and consumers in geographically distinct regions.

in new capacity creates additional risks for pipelines and buyers.[9] Because buyers and pipelines agree to contracted quantities and prices in the precedent agreement, the precedent agreement stage is the primary period in which regulatory evasion incentives can distort investment.

The next stage involves the permitting and construction of the expansion. Expansions of natural gas capacity are regulated by FERC and pipelines must submit detailed applications to FERC to seek approval. One main dimension on which FERC evaluates pipeline applications is on the basis of "public necessity." While the notion of public necessity is theoretically broad, FERC's longstanding practice in implementing this authority under its 1999 Policy Statement on Certification of New Natural Gas Facilities is to assess whether there is a market need for the proposed pipeline project before addressing other considerations such as adverse impacts on existing pipeline company customers, other pipelines in the market and their customers, and impacted landowners and communities (Klass 2022). In determining market need, FERC historically has relied heavily on precedent agreements between pipelines and buyers, with the understanding that if pipelines would not be able to sign long-term contracts for proposed capacity if it was not in the public interest. After FERC approves the expansion application, the pipeline constructs and opens additional capacity.

# 3 Conceptual Framework

This section presents a model of contracting between a seller of pipeline capacity and a single buyer that faces a cost-of-service regulation. The goal is to provide a simple framework for how vertical integration affects contract prices and quantities in the presence of cost-of-service regulation and the importance of information asymmetry in mediating this effect. If vertical integration biases the firm towards choosing prices or quantities in excess of those chosen by the regulated utility, then I argue that vertical integration creates incentives for the firm to evade regulation. This model yields testable predictions regarding the impact of market structure and regulation on contract prices and quantities that I then take to the data.

## 3.1 Model set-up

A utility is vertically integrated with a pipeline that builds and operates transportation capacity. The vertically integrated firm sells two goods, energy and pipeline capacity, where only the energy portion of its business is regulated.[10] In the utility portion of its business, the utility combines capital $K$, gas $g$

[9] These risks typically center around the timing of construction and the creditworthiness of the buyer.

[10] In reality, interstate pipeline transportation is regulated by FERC. I abstract from this detail for two reasons. First, although pipelines are required to offer regulated rates to buyers as a recourse against market power, many buyers and pipelines choose to set prices through bilateral negotiation, particularly in the case of precedent agreements when firms are contracting for capacity that has not yet been built. Second, allowing the pipeline to earn a rate of return on investment in transportation

and pipeline capacity $Q$ to produce a homogeneous good according to a quasi-concave production function $G(g, K, Q)$. Depending on whether it is a natural gas or electric utility, the good will either be natural gas for home heating or electricity generation from natural gas power plants.[11] Let $p$ be the price the utility receives from the regulator for selling a unit of the good to consumers, and given this price, the utility faces inverse demand $p = p(G(g, K, Q))$. I assume consumers have perfectly inelastic demand for energy. The utility maximizes the following profit:

$$\max_{g,K,Q} \pi^u = pG(g, K, Q) - F(g) - \tau Q - rK \tag{1}$$

In order to produce the good, the utility faces several costs. First, the utility purchases natural gas $g$ from producers at cost $F(g)$, where fuel costs are increasing in the amount of gas $g$.[12] Next, the utility rents pipeline capacity from its pipeline division at cost $\tau Q$ to transport the gas from producers to the utility service territory, where $Q$ is the amount of capacity and $\tau$ is the per-unit rental price.[13] Lastly, the utility pays the rental rate of capital $r$ on its stock of capital $K$.

The vertically integrated firm maximizes the sum of utility and pipeline profits. Pipeline profit $\pi^l$ is the difference between contract revenues and construction costs

$$\max_{Q} \pi^p = \tau(Q)Q - C(Q) \tag{2}$$

where $C(Q)$ is a concave cost function and the pipeline faces inverse demand for capacity $\tau(Q)$. Because the utility division of the vertically integrated firm faces cost-of-service price regulation, the firm maximizes joint profits subject to a constraint on utility revenues. Under this form of pricing regulation the regulator allows the firm to recover "prudent" operational expenditures and earn a rate of return $s$ which is larger than the market rate $r$ on capital investments. Let the regulator approve–or deem "prudent"–expenditures on pipeline capacity with probability $\theta(\tau, Q)$, a function that is decreasing in both price and quantity of capacity, $\frac{\partial\theta(\tau,Q)}{\partial\tau} < 0$, $\frac{\partial\theta(\tau,Q)}{\partial Q} < 0$. Assume for simplicity that the probability of approval is known to firm and the

capacity only increases the wedge shown in the first order conditions.

[11] This definition of the good excludes electric utilities that do not own generating units and only handle long-distance transmission and local distribution of electricity. The model focuses on traditionally vertically integrated electric utilities and does not speak to the incentives faced by utilities in restructured markets. See Borenstein and Bushnell (2015) for greater detail on the difference between restructured and vertically integrated utilities.

[12] Additional pipeline capacity may also lower gas prices by relieving pipeline congestion and increasing market integration (Covert and Kellogg 2017; McRae 2018). A related literature has also found that relieving transmission constraints lowers costs in electricity markets, including L. Davis and Hausman (2016), Gonzales et al. (2023), Ryan (2021), and Wolak (2015). The model can be extended to capture the benefit of relieving pipeline constraints by making $F(\cdot)$ a function of capacity $Q$.

[13] For ease of notation, I do not impose the constraint that amount of gas $g$ sold to consumers is limited by the amount of transportation capacity $Q$. However, incentives for regulatory evasion still distorts the vertically integrated firm's decision even when gas sales are restricted by pipeline capacity. When the utility is only allowed to sell as much gas as it can transport, $g \leq Q$, then the right-hand side of the first order equation of Equation (4) with respect to $Q$ will include an additional term $f_Q(1 - \lambda)(R_g(g, K) - F_g(g, Q))$.

regulator approves all fuel costs with certainty. The regulatory constraint is that the utility's revenues are no greater than its expected recovered costs:

$$pG(g, K, Q) \leq F(g) + \theta(\tau, Q)\tau Q + sK. \tag{3}$$

Note that this constraint does include any revenues or costs incurred by the pipeline division because the vertically integrated firm can only recover costs from the regulated portion of its business.[14]

Combining Equations (1)-(3), we can write the vertically integrated firm's problem as:

$$\max_{g,K,\tau,Q} \mathcal{L} = pG(g, K, Q) - F(g) - rK - C(Q) + \lambda(F(g) + \theta(\tau, Q)\tau Q + sK - pG(g, K, Q)) \tag{4}$$

where $\lambda$ is the Lagrange multiplier on the regulatory constraint. Define $\mu \equiv \theta_Q Q + \theta(\tau, Q)$, so that $\mu$ captures the impact of regulatory discretion on marginal contract revenues.[15] The first order conditions to this maximization problem are:[16]

$$\begin{aligned}
&[g]: pG_g = F_g \\
&[K]: pG_K = r - \frac{\lambda}{1-\lambda}(s - r) \\
&[Q]: pG_Q = C_Q - \frac{\lambda}{1-\lambda}(\mu\tau - C_Q) \\
&[\tau]: \tau = \frac{\theta(\tau, Q)}{-\theta_\tau}
\end{aligned}$$

where $C_Q$ is the marginal cost of capacity construction, $F_g$ is the marginal fuel cost and $\theta_\tau = \frac{\partial\theta(\tau,Q)}{\partial\tau}$ is change in the probability of approval for a marginal increase in $\tau$. Because gas is perfectly recovered in the regulatory constraint, the firm's choice of gas input is identical to that of an unregulated firm. I discuss the implications of the remaining three first order conditions below.

## 3.2 Incentives for regulatory evasion

The first order condition for price shows that for a given quantity of capacity, the vertically integrated firm will choose $\tau$ to maximize the expected capacity costs it can recover from the regulator. The magnitude

[14] Regulatory evasion can also arise if the firm is able to shift costs between the regulated and unregulated sectors. Braeutigam and Panzar (1989) and Brennan (1990) discusses cases where the regulated and unregulated products have a common cost and the regulator must decide what fraction can be recovered.

[15] A special case is when $\mu = 1$, and the regulator approves any quantity with certainty $\theta(\tau, Q) = 1$ and $\theta_Q = 0$.

[16] To see that $\lambda < 1$, observe that we can re-write the first order condition of Equation (4) as $pG_K(1-\lambda) = r - \lambda s$. $\lambda = 1$ implies $s = r$, which violates our assumption that the regulator allows the firm receives a rate of return greater than the rental rate of capital. We also know $\lambda > 0$ for the constraint to bind.

of $\tau$ then depends on the information structure of the regulatory environment.[17] In an edge case where the regulator is perfectly informed regarding the cost of capacity, then she can reject any contract with $\tau > C_Q$ such that $\theta(\tau, Q) = 0$ for all values $\tau \neq C_Q$ and the value of $\tau$ that maximizes expected capacity costs is equal to marginal cost. However, in the case of information asymmetry when the regulator cannot perfectly observe industry costs and must be willing to approve a distribution of capacity prices $[\underline{\tau}, \bar{\tau}]$ such that $\theta(\tau, Q) > 0$ for $\tau \in [\underline{\tau}, \bar{\tau}]$. In this case, the profit maximizing price may no longer be equal to marginal cost if the range of prices the regulator is willing to approve is sufficiently large.

To see this, re-arrange the optimal pricing condition to show that the probability of approval evolves such that $\theta_\tau = \frac{-\theta(\tau,Q)}{\tau}$. This implies that as $\bar{\tau} - \underline{\tau}$ grows larger there will eventually be a range of $\tau$ for which the probability of approval is equal to one, and the largest value of $\tau$ in this range will be the profit-maximizing price for the vertically integrated firm. Intuitively, when the regulator is sufficiently uninformed as to approve a range of prices with certainty, the firm will be able to evade regulation by charging itself an excessively high price. From this model alone, it is unclear that this price will be higher or lower than monopoly price of pipeline capacity paid by the standalone utility.

The model shows that the vertically integrated firm will not choose the cost minimizing amount of pipeline capacity. To isolate the impact of vertical integration from information asymmetry on a utility's choices, temporarily assume that the regulator approves all contracts with certainty so that $\mu = 1$. Observe that the input proportion of capacity relative to gas is distorted:

$$\frac{G_Q}{G_g} = \frac{C_Q}{F_g}\left(1 - \frac{\tau - C_Q}{C_Q}\frac{\lambda}{(1-\lambda)}\right) < \frac{C_Q}{F_g} \tag{5}$$

While the cost-minimizing firm would set the marginal rate of technical substitution between pipeline capacity and gas equal to the ratio of input prices, the vertically-integrated firm does not; as long as $\tau > C_Q$, the firm will use too much capacity relative to gas. When the pipeline company is able to charge prices above marginal cost, the regulatory constraint drives a wedge between the firm's actual cost of pipeline capacity and its effective net cost of capacity after taking account of the fact that the pipeline portion of the business earns $\tau - C_Q$ on the margin. The distortion in the choice of pipeline capacity is reminiscent of the "Averch-Johnson" effect, where the regulator's choice of a higher rate of return $s$ induces the firm to over-invest in capital relative to a variable input (Averch and Johnson 1962; Baumol and Klevorick 1970). However, the difference between the Averch-Johnson effect and the distortion documented here is that the former applies to all utilities subject to cost-of-service regulation, while the latter only arises when the utility is vertically integrated.[18]

[17] I discuss the factors that shape the regulator's information set in the following section.

[18] The Averch-Johnson effect can be seen from both the vertically-integrated and standalone utilities' first order conditions.

This distortion is only present for regulated firms that are vertically integrated with their input supplier. Compare the marginal rate of technical substitution for the vertically integrated firm in Equation (6) to that of standalone utility:

$$\frac{G_Q}{G_g} = \frac{\tau}{F_g} \tag{6}$$

Unlike in Equation (6), the standalone utility equates the marginal rate of technical substitution to the ratio of input prices because the regulatory constraint does not allow the firm to recover a per-unit price of capacity in excess of what it paid.[19] The profits generated by overbuilding capacity are transfers from consumers to the pipeline. If the pipeline is no longer within the firm boundaries of the utility, the standalone utility has no incentive to increase pipeline profits.

In addition to the requirement that the capacity price include a markup, the conditions for regulatory evasion through quantity also depend on the regulator's information on the utility's demand for capacity. As in the case of prices, assume that the regulator is imperfectly informed regarding the utility's demand for pipeline capacity and approves a range of contract quantities $[\underline{Q}, \bar{Q}]$ with positive probability $\theta(\tau, Q)$. Re-introduce $\mu$, the impact of regulatory approval on marginal contract revenues with respect to quantity, into the the marginal rate of technical substitution for the vertically integrated firm,

$$\frac{G_Q}{G_g} = \frac{C_Q}{F_g}\left(1 - \frac{\mu\tau - C_Q}{C_Q}\frac{\lambda}{(1-\lambda)}\right). \tag{7}$$

We see that the wedge in input prices is maximized when $\bar{Q} - \underline{Q}$ is large enough such that $\mu = 1$. The case of $\mu = 1$ is the extreme case of information asymmetry between the regulator and the firm regarding demand for capacity: conditional on $\tau$, there exists a region of $Q$ where regulator will approve a capacity contract with certainty ($\theta(\tau, Q) = 1$ and $\theta_Q = 0$). As the range of quantities with positive probability of approval narrows and $\mu$ shrinks to zero, a marginal increase in $Q$ removes the firm's ability to recover any expected contract costs. The takeaway is that the more likely the regulator is to approve a large range of quantities, the more the firm is incentivized to distort input usage towards pipeline capacity.

The model yields two results regarding the vertically-integrated utility's incentives for regulatory evasion. First, the firm will exaggerate the price of capacity when the degree of information asymmetry between the firm and the regulator regarding input prices is large, and second when the price of capacity is above marginal cost and the regulator is uninformed about capacity demand, the firm will choose to overbuild

However, this model has abstracted from other distortions that might affect the input procurement of utilities including career concerns (Borenstein, Busse, et al. 2012) and regulatory capture (Cicala 2015; Dal Bó and Rossi 2007).

[19] For the standalone firm, the price of capacity is the market price $\tau$, and for the vertically-integrated utility that purchases capacity from its pipeline division, the effective input price is the marginal cost of construction. This result is consistent with a large literature on how vertical integration can eliminate double marginalization (Berto Villas-Boas 2007; Gil 2015; Ito and Lee 2007; Luco and Marshall 2020).

pipeline capacity. The following section details the data and empirical strategy I will use to test whether these predictions hold.

## 4 Data

I compile and link data on natural gas pipeline contracts, expansions and usage to test whether utilities are able to evade pricing regulation through vertical integration. My treatment variable is defined by the sixteen vertically integrated utilities that face incentives for cost inflation. The outcome variables include contract prices for 574 precedent agreements and daily capacity utilization at 599 pipeline nodes that are expanded as a result of those precedent agreements. Price is a contract level outcome, while pipeline utilization is measured at the expansion level.

### 4.1 Data on the treatment: buyer types

Buyers face incentives for regulatory evasion due to a unique combination of two characteristics: exposure to cost-of-service regulation and affiliation with the pipeline seller. To define the incentives faced by contracting pairs, I assign the buyer in each contract a type depending on the combination of their regulatory status and pipeline affiliation. Figure 3 summarizes the four buyer types: regulated affiliates, regulated non-affiliates, unregulated affiliates and unregulated non-affiliates. The buyer type predicted to inflate input costs , utility-affiliates, is shaded in the top-left quarter. I explain how I determine each component of the types below.

**Affiliation** Information on the vertical relationship between the buyer and seller of a contract is listed in the "Index of Customers" section of FERC Form 549B. This form provides data on the universe of natural gas pipeline capacity contracts from 2010-2021 for the 147 interstate natural gas pipeline companies required submit quarterly reports of their transportation and storage contracts. For each contract, the pipeline must report the buyer of a contract and whether the buyer is an "affiliate," meaning that the buyer and pipeline company are either co-owned by the same parent company or jointly own the pipeline asset.[20] I define whether a buyer is an affiliate at the start of a contract using this binary variable, providing me with the full set of vertical relationships in the natural gas pipeline market each quarter. The Index of Customers reports detailed information about 37,208 contracts signed between 8,672 buyer-pipeline pairs. Of all contracts in the Index of Customers, buyers and their pipeline affiliates sign 4.8% of contracts and hold rights to 23% of all capacity between 2010-2021.

[20] The formal definition of an affiliate in the Code of Federal Regulations clarifies that ownership in either case must exceed 10%: "another person that controls, is controlled by or is under common control with, the specified entity... "Control" as used in this definition means the direct or indirect authority, whether acting alone or in conjunction with others, to direct or cause to direct the management policies of an entity. A voting interest of 10 percent or more creates a rebuttable presumption of control."

**Regulatory status** Because regulated buyers in my setting are all electric and natural gas utilities, I determine whether buyers are regulated by establishing if they are US utilities that face cost-of-service regulation. I define buyers as being regulated if they file as an investor-owned utility in the census of US electric utilities (form EIA-861) or as a local distribution company in the census of natural gas companies (form EIA-176). Utilities sign 24% of contracts in the Index of Customers and hold rights to 71% of pipeline capacity during the sample period. I also obtain annual data on the number of natural gas and electricity customers served by each utility from the EIA. The data capture pipeline contracts for utilities that serve the majority of residential energy customers; on an average year, utilities in this data provide electricity to 55% of all US households and serve 99% of all residences that use gas for home heating.

## 4.2 Constructing a data set of precedent agreements

To study the role of affiliate contracting in the context of new natural gas pipeline investment, I focus on a subset of contracts known as "precedent agreements" that secure buyers capacity on pipeline expansions. Each precedent agreement is a contract between a buyer and seller for capacity on a single expansion; for example, Connecticut Natural Gas is a non-affiliate utility that signed contract #331570 with Tennessee Gas Pipeline Company to reserve 35,000 Dth of daily capacity on the pipeline, including some capacity created by the pipeline's Connecticut Expansion Project.

However, the Index of Customers does not indicate whether a contract is a precedent agreement. The Index of Customers will provide all the information in the example above, except that contract #331570 includes capacity on the Connecticut Expansion Project. To identify precedent agreements and link them to expansion-related outcomes, I leverage the fact that Tennessee Gas Pipeline Company must reveal information about their precedent agreements for the Connecticut Expansion Project during the permitting process for interstate pipelines companies. The intuition behind the matching process is that if we know enough details about the precedent agreements for a given expansion, we should be able to match them with a contract listed in the Index of Customers. I explain the three steps in the process below.

### 4.2.1 Step 1: Collecting information on an expansion

I collect data on the universe of natural gas pipeline expansions from the Energy Information Administration's Natural Gas Pipeline Tracker. The Pipeline Tracker is a database of pipeline expansions and reports details for 252 completed interstate pipeline expansions from 2010-2020, including cost, date of completion, thru-states, and the amount of additional capacity created by the project. For the purposes of this analysis, each expansion is identified by its docket number, which is a code assigned to the expansion when it was filed for approval with FERC.

In the first step, I locate a copy of the expansion's certificate application using its docket number. Companies looking to construct pipeline facilities under the jurisdiction of the FERC undergo a permitting process to obtain certification from the agency. Depending on the scope of the expansion, pipeline companies either submit a full application under Section 7(c) of the Natural Gas Act to obtain a certificate of public convenience and necessity, or a more abridged filing known as request for prior notice to obtain a blanket certificate.[21] These filings list detailed information about the proposed expansions, including a description of the project and an explanation of market demand for the new capacity. To allow for public comment, FERC requires certificate applications be made accessible on their online records database, eLibrary, and indexes all filings related to a particular expansion under that expansion's docket number.

I am able to locate applications for 204 expansions. For each, I read the application and locate the section on market demand which explains the steps taken by the pipeline company to secure buyers for the expansion capacity. This section includes information on the open season bidding process help by the pipeline to allocate capacity, as well as the precedent agreements that result from the open season process.

#### 4.2.2 Step 2: Matching application descriptions with contracts

I cross-reference descriptions of precedent agreements the market demand section with contract details in the Index of Customers to see if any of the contracts fit the description provided in the application. Under a capacity contract, the buyer has the right to on- and off-load gas at some origin and destination points on the pipeline up to a maximum daily quantity and the pipeline agrees to transport gas between these points. In addition to the contracting parties, the Index of Customers reports other contract characteristics that appear in the application descriptions, including the start date, maximum daily quantity, duration, origin and destination points for each contract.

I am able to identify precedent agreements for 176 of the 204 expansion applications that I read for a total of 574 precedent agreements.[22] The most common precedent agreement descriptors that can be found in the Index of Customers data include the names of buyers, the start date and duration of a contract, and the maximum daily quantity. If a contract in the Index of Customers fits the descriptors in the application, I record the contract number alongside the expansion's docket number, creating a cross walk between contracts

[21] Blanket certificates allows for two types of projects; automatic approval projects can be constructed without any notice to FERC except after the project is placed into service in an annual report that each pipeline files, while slightly larger and more complex projects, referred to as "prior notice" projects, require the pipeline to notify FERC of the intent to construct them. If no one protests the project within sixty days after FERC issues a notice of the application, or if any such protest is resolved within 90 days after the notice is issued, then the project can proceed without further approval by FERC.

[22] Of 28 unmatched applications, 10 state they do not have any precedent agreements. There are 18 expansions where the certificate application includes precedent agreements, but I am not able to locate a match in the Index of Customers.

in the Index of Customers and expansions in the Pipeline Tracker.[23]

#### 4.2.3 Step 3: Verifying a match

To assure the quality of my matches, I verify whether contract numbers identified above correspond to the expansion by analyzing language from the actual capacity contract. Under the Natural Gas Act, pipelines are required to submit public filings known as the FERC gas tariff that describe their services, rates and terms of service agreements. For any contract that does not conform to the standard terms of service agreements, the pipeline must make a full copy of the contract available in their gas tariff. This regulatory requirement allows me to observe most precedent agreement contracts in their entirety, as these kinds of contracts frequently feature non-conforming provisions.[24] For every contract number associated with an expansion identified above, I locate the copy of the contract by querying FERC's filings database with terms related to the expansion, contract number, or tariff filing type and then manually review the contract for language relating to the expansion. I am able to locate a copy of the contract and verify its connection to an expansion for 86% of the precedent agreements identified through certificate applications.

In total, precedent agreements were identified for 176 expansions through the matching process between the expansion data in the NGPT and the contract data in the IOC. This corresponds to a 70% match rate. Figure 6 summarizes the results. The dashed line shows the total number of completed expansion projects each quarter between 2010 and 2020, while the solid line counts the number of expansions that are matched with a precedent agreement. The near overlap of the two lines suggests that the matching process was able to identify precedent agreements for nearly all expansions, except for those completed in 2010 and 2011.

### 4.3 Data on the outcomes: price and capacity utilization

I collect data to test the hypothesis that utility affiliate buyers inflate contract prices and quantities. Collecting data on actual contract prices and benchmark prices allows us to measure markups for each contract and test the price inflation theory. To test for quantity inflation, I study whether capacity usage is lower in locations that are expanded by utility affiliates.

[23] This is not an exact matching process. Pipeline companies can claim open season outcomes are privileged information and may limit the amount of buyer information listed in the public portions of the certificate application. In addition, contract details, such as the maximum daily quantity, may change from the time the precedent agreement is signed and the contract is executed several years later. Restrictions on or changes in contract details can lead to a limited number of situations in which multiple or zero contracts in the Index of Customers data can be considered a good match with the descriptors in the certificate application. These data limitations motivate the need for additional checks to minimize researcher discretion.

[24] For example, most-favored nations clauses, stronger credit requirements and negotiated rate structures.

#### 4.3.1 Prices

I manually collect the negotiated price for a contract from contract copies posted located in Step 3 of the matching process; to my knowledge, this is the first instance that negotiated prices in the natural gas pipeline industry have been compiled. Here the contract price refers to the "reservation" price, which is a fixed, per-unit monthly fee to reserve capacity, and the average contract price is $12.22/Dth/month. Contracts are complex and include prices for other services including prices for capacity usage, fuel, overrun and power.[25] Because the cost of a contract is overwhelmingly made-up by the fixed component of the price, I restrict attention to the fixed fee.

A critical component of my empirical strategy is that I am able to measure markups for each contract because I also observe a cost-based benchmark price for service published by the pipeline company. Approved by FERC, these benchmark prices are based on a cost-of-service calculation and include maximum and minimum rates. They are the counterfactual rate a buyer would have paid absent negotiation and deviation from the benchmark price reflect contract specific markups (or markdowns) by the pipeline. I collect data on maximum benchmark prices for each interstate pipeline and every kind of transportation service from 2013-2021 using the S&P Capital IQ Pro platform. To match benchmark price data from S&P to contract data in the Index of Customers, I manually clean the rate schedule and zone names in the Index of Customers to match the names used by S&P Capital IQ Pro. Absent this cleaning, I am only able to match 7% of contracts. After cleaning, I am able to detect the benchmark prices for 91% of contracts in the Index of Customers.

#### 4.3.2 Capacity utilization

Pipelines offer a series of locations, which I refer to as "nodes" where gas can be delivered onto and off the pipeline, and I collect data on the utilization of capacity at each node. I download daily scheduled and maximum capacity data from S&P Capital IQ Pro for the intraday 3 and 2 cycle for 2009-2021 for each node on the interstate pipeline system. Each node has a physical limit to the amount of gas which can flow from that point based on the diameter of the pipe and pressure of gas contained inside. I refer to this as the node's "maximum capacity." In order to ensure that the use of the pipeline does not exceed its physical constraints, firms must schedule the amount of gas they will send through their contracted points so that pipeline operators can arrange for timely and safe gas transport. The daily utilization rate is calculated by dividing the scheduled capacity by node's listed maximum capacity. The average total capacity is 270,000 dth per day.

[25] I also limit the sample to natural gas contracts with a single negotiated price, as it is difficult to compare negotiated prices across buyers when negotiated prices that vary by origin-destination pairs or by contract period.

The main empirical test of quantity inflation is whether pipeline capacity built by utility affiliate contracts is underutilized after an expansion. For this test, we need to identify nodes on the pipeline that are undergo expanded due to specific project. In order to detect nodes that undergo expansion, I link data on capacity utilization with precedent agreements. To do so, I identify pipeline "nodes" where the maximum capacity changes in a 3-month window around the date the expansion openings. Figure 4 shows an example of this process for Eastern Gas Transmission and Storage's expansion project, New Market Project. The black line represents the location of Eastern Gas Transmission and every gray point is a node where the pipeline either receives gas from buyers or delivers gas to buyers. Capacity at any of the gray nodes could have been expanded as a part of the New Market Project, but only the blue nodes experienced large shifts in maximum capacity around the 11/09/2017 opening date.[26] I conclude that the blue nodes were expanded as a part of the New Market Project and merge I repeat this process to detect nodes for every expansion.

Table 1 summarizes the data structure after both matching processes. In total the data contain information regarding 176 expansion projects. Every expansion project is linked to a set of precedent agreements and, in cases where pipeline locations with capacity changes were detected, a set of expanded nodes. There are 369 contracts in total and 222 pipeline nodes that were detected as undergoing expansion. The control group, in this case projects or buyers that are neither affiliates nor utilities, composes the majority of contracts and expansions, followed by standalone utilities and then roughly tied between non-utility affiliates and utility affiliates.

# 5 Incentives for regulatory evasion

Incentives for regulatory evasion rest on the existence of vertical relationships between pipelines and buyers. How prevalent are these relationships? I measure vertical relationships between buyers and pipelines by counting the number of pipeline-buyer pairs listed in the IOC data as affiliates, where an affiliate refers to buyer that is owned by the same parent company as the pipeline has joint ownership of the pipeline asset. Figure 7 plots the number of affiliates per utility. I find that vertical relationships are common for pipelines: 102 pipelines, roughly 69%, have a contract with an affiliate and 30% of pipelines are vertically integrated with at least one electric or natural gas utility. As a point of comparison for market structure, consider that 49% of investor-owned electric utilities are vertically integrated with a power plant (MacKay and Mercadal 2019).

In the average capacity expansion, a pipeline company signs precedent agreements with 2.8 buyers. 69 out

[26] Specifically, I look for nodes that satisfy five criteria: the change in maximum capacity changes by more than 5%, the duration of the change lasts at least one month, the timing of the change is within three months of the expansion opening date, and the node is less than 3 miles from at least one of the nodes in the expansions's precedent agreement.

of 147 interstate pipeline companies in the contract data have built on at least one pipeline expansion during the 2010-2020 sample period. In comparison, a small number of buyers make investments in new pipeline capacity; only 261 of 3,979 buyers invested in transportation capacity by signing a precedent agreement during the same period, just under 6.6%.

Table 2 shows that this concentrated number of buyers has a disproportionate role in natural gas transportation contracting. On average, buyers with precedent agreements are larger and more well-connected in the transportation network; they contract with 3.6 times as many pipelines compared to the remaining 93% of buyers and are buyers for 50% of all contracted capacity. Buyers with precedent agreements are also much more likely to be vertically integrated as 31% of these buyers are affiliated with a pipeline company compared to 5% of buyers without investments in new capacity. The skewness in the number of links between buyers and pipelines echoes findings from the "superstar" firm literature which document significant heterogeneity in the number of relationships between large buyers and sellers, mostly in settings with high-frequency sales [27] I find that large buyers are also disproportionately vertically integrated with sellers and over-represented in long-term contracts in the form of capacity investment.

Utilities and natural gas production are important drivers of demand for pipeline capacity. Table 2 shows that among buyers with and without precedent agreements about 30% are electric and/or natural gas utilities and that 40% of buyers have at least one contract that allows them to receive gas directly from a natural gas well, gathering system or processing facility. The importance of utilities and gas producers is reflected in the locations of pipeline expansions, 56% of which are located in the Northeast and South Central regions of the US. Figure 1 shows the locations of expanded points on the natural gas pipeline network. Natural gas producers are active in the cluster of points around Pennsylvania and West Virginia located within the Marcellus and Utica shale plays, as well as the set of points in east Texas and Louisiana that are close to the Barnett and Haynesville shale plays and natural gas export terminals. Other clusters of points occur in areas with strong natural gas demand for home heating and electricity, including around New England and Florida.

What kinds of points on the pipeline network get expanded? 32% of expansions exclusively increase capacity at locations that service buyers at buyer-specific sites, such as utility delivery points or natural gas wellheads. For example, a site-specific expansion can increase the amount of gas a utility is able to deliver from the interstate network onto its local distribution system in a city. 29% of expansions exclusively increased capacity at more central network locations; these expansions either allowed a higher throughput in the main artery of the pipeline or increased the amount of gas that can flow between two interstate pipelines. In the former case, expansions are specialized to specific needs of the pipeline and buyer and exhibit a high

[27]See Bernard and Moxnes (2018) for a review on the literature of heterogeneity in firm networks.

degree of "asset-specificity" (Williamson 1981) since the value of additional capacity is significantly greater for the buyer in the contract than it is for other firms. 39% of expansions occur at a combination of site specific and non-site specific locations. The prevalence of long-term contracting between pipelines and buyers over non-specific assets is distinctive from prior work on bilateral contracting in energy settings which has emphasized the role of site-specificity in shaping the contracting environment (Joskow 1987; Preonas 2023; Scott 2021).

# 6 Effect of regulatory evasion incentives on overbuilding

I consider the impact of incentives for regulatory evasion on the quantity of pipeline capacity under contract. Theory predicts that buyers who are both vertically integrated with the pipeline and face cost-of-service pricing regulation will contract an excessively high quantity of capacity, leading to "overbuilding." In this section, I propose a measure of overbuilding–pipeline utilization–and use data on pipeline usage rates to test whether pipeline usage is lower in locations that have been expanded through contracts with vertically-integrated, regulated firms.

## 6.1 Identification strategy

I compare changes in capacity utilization across pipeline expansions that do and do not have precedent agreements with utility affiliates, controlling for a rich set of expansion and firm characteristics. The main estimating equation is:

$$\begin{aligned} y_{ipt} = &\beta(\text{Post}_t \times \text{Utility}_p \times \text{Affiliate}_p) + \gamma\text{Post}_t + \phi_1(\text{Post}_t \times \text{Affiliate}_p) + \phi_2(\text{Post}_t \times \text{Utility}_p) \\ &+ X'_{ti} + \delta_{ti} + \kappa_p + \epsilon_{ipt}. \end{aligned} \tag{8}$$

In this equation $y$ is the inverse hyperbolic sine of utilization at point $i$ on pipeline expansion $p$ on date $t$. I use the inverse hyperbolic sine transformation to address the fact that the distribution of utilization is skewed and contains zeroes. An expansion is treated (Utility $= 1$ and Affiliate $= 1$) when it has at least one precedent agreement with a utility affiliate, the type of buyer which faces incentives for regulatory evasion. I allow mean utilization rates to change after a point expanded by including a post-expansion dummy (Post $= 1$). The main coefficient of interest is $\beta$ which captures the mean effect of a utility affiliate precedent agreement on the percent change in post-expansion utilization rates. A finding of $\beta < 0$ indicates that expansions that face incentives for overbuilding are under-utilized relative to expansions undertaken by solely utilities and solely affiliates.

Equation 8 includes an important set of controls. The vector $X'_{ti}$ includes mean monthly temperature and heating degree days around the node to control for node specific weather shocks. Expansion fixed effects $\kappa_p$ allow average utilization to vary at the expansion level to address time-invariant patterns in capacity usage. Time-invariant patterns can include the proximity of expansion points to busy"mainline" pipeline arteries or whether the primary users of the expansion points regularly transport gas; expansions that enlarge interconnections with other pipelines are more frequently used than those that serve peaker power plants. Day-by-region fixed effects $\delta_{ti}$ allow for utilization to differ in each region in each day, and they control for forces such as local weather events near a node, opening of natural gas power plants, state environmental regulations and changes in local drilling productivity.

The identifying assumption of Equation 8 is that the *change* in utilization across treated and un-treated expansions is not correlated with unobservables after conditioning on the controls described above. This assumption may be violated if factors other than regulatory evasion distort utility affiliates' level of investment or if utility affiliates are more productive firms. To address concerns that utility affiliates may make and use investments differently than other kinds of firms, I allow the mean change in utilization to differ by two important firm types: utility and affiliate. An expansion is considered an affiliate expansion ($\text{Affiliate}_p = 1$) if the expansion is supported by a precedent agreement with at least one affiliate buyer and considered a utility expansion ($\text{Utility}_p = 1$) if it has at least one precedent agreement with a utility. Affiliate and utility indicators are not co-linear with treatment because I observe expansions supported by affiliates who are *not* utilities and expansions supported by utilities who are *not* affiliates.

The time-buyer type interaction terms help to rule out several competing theories with the regulatory evasion hypothesis. First, the $\text{Post}_t \times \text{Utility}_p$ interaction term allows for the average impact of expansion on utilization rates to vary for utility supported capacity expansions. Previous work finds that cost-of-service regulation distorts utilities' decisions on the level and (Cicala 2015; Fowlie 2010; Knittel et al. 2019) and timing (Jha 2020; Lim and Yurukoglu 2018) of capital investments, and that utilities face reliability standards that can lead to over-procurement (Borenstein, Busse, et al. 2012). Like the regulatory evasion hypothesis, both these theories suggest that the change in capacity usage for utility expansions should be relatively lower than other kinds of firms. Failing to control for changes in capacity usage common to all utilities may lead us to overstate the impact of incentives for regulatory evasion specific to utility affiliates.

Second, the $\text{Post}_t \times \text{Affiliate}_p$ interaction term addresses an opposite set of concerns: that affiliates may see higher than average changes in utilization after expansion. Firms that choose to vertically integrate are more productive (Alfaro et al. 2019; Hortaçsu and Syverson 2007), and vertical integration can lead to greater transfers of intangible and tangible inputs (Atalay, Hortaçsu, Li, et al. 2019; Atalay, Hortaçsu, and Syverson 2014; Demirer and Karaduman 2022). If vertically integrated firms make more productive investments, failing to control for the $\text{Post}_t \times \text{Affiliate}_p$ would understate the impact of regulatory evasion. Controlling for both sets of interaction terms allows us to identify the impact of regulatory evasion incentives separately from the impact of other factors that affect the decisions of utilities and affiliates.

The identifying assumption is that regulatory evasion incentives are the only factor that differentially affects treated and non-treated expansions, conditional on the model covariates.

$$\mathbb{E}[(\text{Post}_t \times \text{Treat}_p)\epsilon_{ipt}|\delta_{ti}, \kappa_p, X_{ti}, (\text{Post}_t \times \text{Utility}_p), (\text{Post}_t \times \text{Affiliate}_p)] = 0 \tag{9}$$

I indirectly test for the validity of this assumption by checking whether, conditional on controls, utilization rates for utility affiliates trend similarly to other firms in the years prior to expansion. I run the following regression to generate an event-study figure:

$$\begin{aligned} y_{ipt} = \sum_{t=-20}^{t=20} \beta_t(1[quarter = t] \times \text{Utility}_p \times \text{Affiliate}_p) + \gamma 1[quarter = t] + \phi_1(1[quarter = t] \times \text{Affiliate}_p) \\ + \phi_2(1[quarter = t] \times \text{Utility}_p) + X'_{ti} + \delta_t + \kappa_p + \epsilon_{ipt}. \end{aligned} \tag{10}$$

where $t$ indexes the quarter relative to the date that node $i$ of expansion $p$ is expanded. I plot the $\beta_t$ coefficients which capture the average difference in capacity usage between utility affiliate expansions.

## 6.2 Results

### 6.2.1 Impacts during all days

Table 3 shows that incentives for regulatory evasion cause large and statistically significant decreases in post-expansion utilization rates. Column (1) shows that post-expansion utilization rates at treated nodes are 0.968 log-points, or 62%, lower than utilization rates at expansions with just utility or just affiliate precedent agreements. Given that the average utilization of a non-utility, non-affiliate node in the pre-period is 54.7 percentage points, this effect corresponds to a 33.9 percentage point drop in utilization on average. The event study graph in Figure 8 supports these results. In the quarters before a treated point was expanded, the coefficients estimated from Equation 10 are mostly statistically indistinguishable from zero and do not show a clear trend. In the year after expansion, differential capacity utilization at treated nodes begins to fall and remains steadily negative. The lack of dynamic treatment effects suggests that the lower average utilization is not well explained by differences in the timing of capacity expansion. If utility affiliates signed fewer but larger capacity contracts due to greater economies of scale or dynamics of regulatory review, we would not expect differences in utilization to remain constant, but to shrink over time.

The negative impact of incentives for regulatory evasion on utilization rates is robust to a number of alternative specifications. Column (2) of Table 3 replaces day fixed effects with day-by-region fixed effects to address concerns that $\delta_{ti}$ allow for utilization to differ in each region in each day, and they control for forces such as local weather events near a node, opening of natural gas power plants, state environmental regulations and changes in local drilling productivity. This preferred specification shows that capacity utilization at treated nodes drop by an additional 32% on average relative to nodes that are exposed to just affiliates or just utilities. Weighting by pre-expansion capacity may bias the results if effects are driven by large expansions. Column (3) removes weighting so that percentage changes in capacity usage are weighted equally regardless of the level of unused capacity they result in and shows little change in the magnitude of the impact of evasion incentives. The negative impact of incentives on capacity utilization is also robust to removing the inverse hyperbolic sine transformation. Column (4) re-estimates the baseline specification when the outcome is measured in percentage points in light of concerns that coefficients may not be interpreted as percentage changes when the inverse hyperbolic sine transformation is applied to a variable with a low mean (Bellemare and Wichman 2020).

Lastly, Columns (5) and (6) test for external validity by expanding the sample size. The baseline results are estimated by comparing post-expansion changes in utilization across nodes with different firm characteristics. This requires me to restrict attention to a subset of nodes that have pre-expansion data available, raising the question of whether the findings are driven by sample selection in the data construction process. To check whether the results remain robust to a larger set of nodes that lack pre-expansion data, I run a less stringent specification of Equation (8) that regresses post-expansion utilization on firm characteristics and includes node type instead of node specific fixed effects, so that now the $Utility \times Affiliate$ dummy captures incentives to overbuild. This specification allows me to more than double the number of pipeline capacity expansion I study from 39 to 85 unique expansions. Column (5) shows that even in this larger sample the implied decrease in capacity utilization at nodes expanded by utility affiliates is comparable to those found in the baseline specification, even when including region by day fixed effects in Column (6). Table **??** also shows that the negative finding is robustness to multiple permutations of the data construction process.

### 6.2.2 Impacts during peak times

One concern with the described empirical strategy is that average utilization does not capture overbuilding if the value of additional capacity is concentrated during peak times. Consider the example of a utility that faces constant demand for gas with the exception of one to two days of the year where demand is high due to extreme winter weather conditions. If the marginal benefit of additional capacity during these weather events is greater than the marginal cost of construction, the optimal pipeline capacity will be greater than its off-peak demand and a fraction of pipeline capacity will be unused throughout the year. This will lead to low *average* utilization rates, despite the fact that the total return to additional capacity over the lifetime of the contract is high.

Several aspects of the triple-differences regression in Equation 8 mitigate these concerns. First, to the extent that average utilization underestimates the total return to additional capacity, it is unlikely that the degree of underestimation is greater for utility affiliates relative to other utilities and affiliates. The example above showed how the contracting patterns of a utility facing seasonal demand may lead to long periods of low utilization. However, including $\text{Utility}_t$ and $\text{Post}_t \times \text{Utility}_p$ terms in the regression controls for both pre- and post-expansion patterns in capacity usage by utilities, allowing average utilization for utilities to differ from other kinds of firms such as gas producers.

Table 4 examines whether under-utilization of treated nodes persists during days where the predicted value of additional capacity is large. If low utilization on average masks the fact that utility affiliates are fully using capacity during peak days when congestion rents are high, we would expect that coefficient on $\text{Post} \times \text{Utility} \times \text{Affiliate}$ in Equation (8) would not be significant after restricting the sample to these "peak" days. To determine whether this prediction holds, I re-estimate Equation (8) using data only from days where capacity utilization is predicted to be high due to large differences in natural gas prices. Column (1) of Table 4 restricts the sample to node-days where the spot price of natural gas at the hub nearest to a node is one standard deviation greater than the average monthly spot price at Henry Hub and finds that utilization at treated nodes is 25 percentage points lower on average. Additionally, I test for low utilization at treated nodes during two alternative measures of "peak" days. Column (2) only includes node-days where the local weather is at least 32 heating degree days, and Column (3) limits the sample to node-days where a node has at least one "matched" node from the $k$-nearest neighbors process with a 75% utilization rate. In both cases, I find that capacity usage is 23-25 percentage points lower on average, suggesting that the full capacity of the utility affiliate pipeline expansion is not needed to meet transportation demand even during days where the returns to using additional capacity are large.

# 7 Effects of Evasion Incentives on Price

How do incentives for regulatory evasion affect contract prices? Theory predicts that if the regulator is relatively uninformed about the market value of capacity, vertically integrated utilities will choose to inflate the price of a capacity contract with their affiliated pipeline company to maximize expected cost recovery. To test this prediction regarding markups on capacity contract prices, I leverage variation the in vertical relationships between buyers and pipeline companies and compare contract prices for utility affiliates to those for other kinds of firms.

## 7.1 Empirical strategy

Buyers reserve capacity on a newly built pipeline expansion project at a per-unit price for the duration of the contract (eg. \$5/Dth/month for 15 years). Due to pre-existing market structures, pipelines enter bilateral contracts for capacity expansion with both affiliated and unaffiliated buyers. I exploit cross-sectional variation in vertical relationships to compare differences in price for affiliated utilities to unaffiliated buyers:

$$log(P)_{jp} = \rho(\text{Utility}_j \times \text{Affiliate}_j) + \gamma \mathbf{C}_{jp} + \beta_1 \text{Utility}_j + \beta_2 \text{Affiliate}_j + \beta_X \mathbf{X}_j + \delta_p + \epsilon_{jpt}, \tag{11}$$

The outcome is the price $y_{jpt}$ of a bilateral contract $j$ for expansion $p$ that was completed in year $t$. $\text{Utility}_j \times \text{Affiliate}_j$, an indicator variable for whether the contract buyer is a utility affiliate, is the variable of interest and $\gamma$ captures the average markup faced by vertically integrated utilities relative to affiliates and utilities without incentives for evasion.

While I do not directly observe markups over marginal cost, I observe a cost-based benchmark contract price visible to the regulator. To capture markups over the market rate for capacity, I use price as a outcome variable and control for a function of benchmark price for expansion $p$ of contract $j$ in $C_{jp}$. Publicly issued by the pipeline company, the benchmark price is a cost-of-service based rate for natural gas pipeline service that is available to buyers who choose to not directly negotiate a rate with the pipeline company.[28] Effectively, the benchmark price is counterfactual rate paid by the buyer to the pipeline if either party did not exert influence over pricing.[29] The $\rho$ coefficient therefore captures something close to the ideal measure of price inflation; it is the differential average markup faced by utility affiliates directly due to pricing decisions made by buyers and sellers during negotiation.

A suite of controls helps to address other factors that may influence markups above the benchmark price. I include buyer type indicators, $\text{Utility}_j$ and $\text{Affiliate}_j$ which equal one when the buyer is a utility or affiliate, to net out the separate effects that regulation and vertical integration may have on markups. I also include a matrix of fixed effects in $\delta_{\mathbf{p}}$: pipeline fixed effects, year-of-completion fixed effects and route fixed effects. The vector of contract characteristics $X_{jp}$ controls for contract size, duration and the total capacity

[28]The benchmark price is known as the "recourse rate" because a buyer can always demand to contact at this price as a last resort. Pipeline companies submit these rates for approval to the Federal Energy Regulatory Commission and they are designed to allow the pipeline to recover costs and earn a "reasonable" rate of return. The Commission has argued that the presence of recourse rates is necessary to prevent pipelines from exercising market power. Rates may be specific to buyers who reserve capacity on expansion project or be system wide, depending on if pipelines use "incremental" or "rolled-in" pricing treatment.

[29]It is important to note that the benchmark price includes markup over *cost* to account for the pipeline's return on equity. Markups are substantive: a cost recovery analysis for the 20 largest pipeline companies shows that the return on equity in 2022 was 16%, (**ngsa2022**).

added by the expansion that the contract reserves space on. I parameterize the benchmark price $C_{jp}$ as the benchmark price and its interaction with total expansion capacity to allow the impact of posted prices om markups to differ by market size.[30] $\epsilon_{jpt}$ is an idiosyncratic error term clustered by pipeline and completion year, allowing for arbitrary within-pipeline and within-year serial correlation. I weight each observation by the size of each contract in order to estimate differential markups for the average unit of capacity.

## 7.2 Challenges to identification

The identifying assumption is that incentives for regulatory evasion are the only factor that affect markups for affiliated utilities, after controlling for any price distortions separately induced by cost-of-service regulation or vertical integration and other contract characteristics. Because I control for affiliate status, the conditional independence assumption is not that assignment of vertical integration is as good as random among utilities (or that utility status is as good as random among vertically integrated firms). Instead, the assumption is that conditional on observable contract and expansion characteristics, the difference in the distribution of prices between affiliated and non-affiliated utilities is explained by the impact of vertical integration that is not accounted for by variation in the prices of non-regulated affiliated firms. That the transaction costs of negotiation are lower for vertically integrated firms in general or utilities exert less effort in negotiating in general is not a threat to identification. It is a threat to identification if vertically integrated utilities face stricter regulators on average than non-affiliated utilities because that is not accounted for by the $\text{Affiliate}_j$ dummy.

The incentive for utility affiliates to inflation quantities is effectively a demand shifter; it will lead incentivized buyers to participate in larger capacity expansions than their standalone counterparts. Controlling for benchmark prices separately identifies the impact of price inflation on prices from that of quantity inflation. Both through total expansion costs and quantity, the benchmark price directly captures how (or whether) additional capacity demand translates into rates for each contract, allowing the markup estimation to be unaffected. Including an interaction between the posted price and expansion capacity also mitigates concerns the coefficient on $\text{Utility}_j \times \text{Affiliate}_j$ is picking up heterogeneous effects of expansion size on markups that are systematically more present for contracts affected by quantity inflation.

Origin-destination route fixed effects also control for unobserved geographic confounders. A route is defined by the region the expansion begins in and the region it ends in using regional definitions from the Energy Information Agency in its pipeline tracker.[31] While Figure 5 largely shows geographic overlap

[30]The assumption is that larger expansions occur in larger markets where competition may be tougher. Contracts between buyers and sellers in larger markets may therefore see lower markups, as would be predicted by a Melitz and Ottaviano (2008) style model.

[31]The Natural Gas Pipeline Tracker lists an origin and destination region for each expansion. Each state is assigned to one of six regions: South Central, Mountain, Pacific, Northeast, Southeast, and Midwest.

between utility affiliate expansions and expansions contracted by other kinds of firms, I include route fixed effects to explicitly control for differences along transportation corridors in market structure and permitting delays that affect markup levels over the benchmark price.

## 7.3 Results

### 7.3.1 Impacts on utility affiliates

I find limited evidence that vertically integrated firms face higher markups due to incentives for price evasion. Column (1) of Table 5 shows results from Equation 11, which estimates differential markup levels faced by buyers types of interest, controlling for pipeline and year of expansion fixed effects. The result in Column (1) shows that utility affiliates, the buyer type that faces incentives for price inflation, pays average differential markups of 14.8% on an average contract price of $9.50 for non-regulated, non-vertically integrated buyers. However, this result is not robust to the inclusion of geographic controls. The coefficient on Utility $\times$ Affiliate remains positive but loses significance as we include route fixed effects in Columns (2)-(4), suggesting that geographic confounders account for the differential markup faced by utility affiliates and not incentives for price inflation. Defining the dependent variable as price, as opposed to log price, in Columns (5) and (6), we cannot reject the null hypothesis of zero price inflation even in the specification without route fixed effects. Together, I interpret the regression results as providing little evidence of price inflation by utility affiliates.

Why might regulated, vertically integrated buyers choose not to inflate prices above the benchmark rate? The conceptual framework shows markups will rise when information asymmetry regarding the price of capacity is large and the regulator is willing to approve a wide range of capacity prices. In this setting, several factors allow regulators to have information regarding the market value of additional capacity. Most notable is the presence of benchmark prices. Pipelines must propose and justify cost-based rates prior to the construction of new capacity and these rates are visible to public utility commissioners. These justifications disclose the projected project cost and capacity, as well as the assumed rate of return and depreciation assumed by the pipeline company, revealing cost information that is typically perfectly known to the firm and imperfectly known to the regulator.[32] The benchmark price is a strong signal of the market value of capacity and therefore narrows the distribution of capacity prices the regulator is willing to accept, reducing

[32] This information is disclosed in the pipeline's application for a Certificate of Public Convenience and Necessity. For example, in Tennessee Gas Pipeline Company's application under docket CP15-148:

"The incremental recourse rate consists of: (i) a monthly reservation rate of $17.3057 per Dth (equivalent to a daily reservation rate of $0.5690 per Dth)...The incremental recourse rate has been calculated based on an incremental cost of service for the Project facilities of approximately $30.1 million, based on the design capacity of the Project facilities of 145,000 Dth per day. The incremental cost of service reflects: (a) the income tax rates, capital structure, and rate of return approved in Tennessee's rate settlement in Docket No. RP95-112-000, et al. and reaffirmed in Tennessee's last rate settlement in Docket No. RP11-1566-000, and (b) a straight-line depreciation rate of 3.33 percent, based on an estimated useful life of the Project facilities of 30 years. The derivation of the incremental recourse rate is set forth in enclosed Exhibit N."

scope for markups. The role of publicly available information on limiting markups recalls Cicala (2015), who finds that divestiture had no effect for gas-fired power plants that purchase fuel on a spot market, but that it decreased prices for coal-fired power plants who purchased fuel through bilateral contracts.

Other features of this market also explain why incentives to inflate prices are limited. Regulators can observe a lengthy contracting history between utilities and pipelines that inform their knowledge of appropriate rates. Prior to signing the contracts studied in this paper, the average utility has signed forty capacity contracts with their affiliate over the course of 18 years. There is a secondary spot market where buyers with long-term contracts can sell temporary use of their capacity. Inflating contract prices reduces the ability for the utility to earn profits through arbitrage on the capacity release market.[33] Lastly, benchmark prices already include markups over cost since pipeline companies can factor in a return on equity into their price calculation, estimated to range from 7-38% in 2022 (**ngsa2022**). This means that vertically-integrated firms can already earn profit through the regulatory constraint without inflating prices above benchmark rates and risking rejection by the regulator.

### 7.3.2 Impacts on non-regulated affiliates

Table 5 reveals a stark pattern among unregulated companies: Columns (1)-(4) shows that affiliates of pipeline companies face differential markups that are 11.5-15.8% lower than those for non-affiliates on an average contract price of roughly \$9. Given that the total cost of the average non-affiliate contract is \$32 million, this estimate implies that affiliates save \$3.8-5.1 million over the lifetime of a contract on average. Adding route fixed effects in Column (2) decreases the magnitude of the coefficient by 14%, but the result remains significant at the 0.01 level. Columns (5) and (6) re-estimate the basic and the preferred specifications in Column (1) and (4), respectively, to report differential mark-ups in levels. I find affiliates pay lower mark-ups by \$1.46-2.20 compared to unaffiliated, unregulated buyers.

These results are robust to a wide range of controls. Column (3) shows that affiliates pay lower differential markdowns after accounting for markups faced by spatially concentrated buyers. While route fixed effects capture the overall level of competition for pipeline transportation within and across regions, they do not account for whether a buyer can actually access pipelines in this region. For example, there may be many pipelines in South Central region which includes Texas and Louisiana, but a power plant in that region may only be geographically proximate to receive gas from one of them. To account for pipelines' ability to exert market power over these captive buyers, I control for a binary measure of captivity: whether a buyer has reserved capacity with any *other* pipelines at the start of the contract.[34] Controlling for captivity

[33] 74% of investor-owned utilities participated as sellers in the secondary capacity market in 2020.

[34] Under this definition, 20% of buyers are captive to a particular pipeline. This is lower than reported in other transportation industries; for example, Preonas (2023) finds that 47% of coal plants are captive to a railroad.

slightly increases the magnitude of the coefficient, suggesting that unregulated captive firms may face higher markups.

The use of benchmark prices allows us to approximate markup explicitly through negotiation channel, but these prices do not always scale with costs due to intricacies of the ratemaking process. In cases where a cost-based rate for expansion capacity on its own would be less than the benchmark price applicable to existing capacity on their system, pipeline companies often adopt the higher existing rate as their benchmark price.[35] Column (4) includes total expansion cost as a control variable to account for the fact that costs may affect negotiations, but be imperfectly captured by the benchmark price. The results remain largely the same: differential markups for affiliates decrease slightly, but remains statistically significant.

Without additional data, it is unclear whether these results demonstrate efficiency gains from vertical mergers. If lower pipeline transportation prices for affiliates lead to lower gas prices, the reduction in input prices paid by an integrated firm is consistent with the elimination of double marginalization (Spengler 1950). It does not appear that the documented discounts offered to unregulated affiliates are efforts to raise costs for the rivals of integrated buyers; of the 11 expansions in the sample where both affiliated and non-affiliated buyers subscribe to capacity, there is only one expansion where all non-affiliated buyers pay higher markups than the affiliated ones. Absent data on the allocation of (scarce) capacity among buyers, we cannot rule out that non-affiliates were foreclosed from acquiring capacity on expansions in the first place (Salinger 1988). While important to studying investment in natural gas pipelines, a full examination of the impacts of vertical integration in this industry are beyond the scope of this paper.

# 8 Policy Implications and Discussion

The passage of federal and state decarbonization policies in the United States has led to public scrutiny on the construction of new fossil fuel assets. As the agency tasked with granting certificates of approval for the construction of new interstate natural gas pipelines, the Federal Energy Regulatory Commission (FERC) has faced concerns that its current certification process does not adequately evaluate whether new pipelines are in the "public need and benefit."[36] One ongoing concern has been the use of precedent agreements to demonstrate whether a pipeline project is in the public need, especially when these agreements are signed

[35] This practice, known as "rolled-in" rate treatment, must be explicitly requested and approved by the pipeline company in their project application to the Federal Energy Commission. The pipeline must demonstrate that rolling in the costs associated with the construction and operation of new facilities into system rates will not result in existing customers subsidizing the expansion.

[36] Section 7 of the Natural Gas Act grants FERC the authority to issue is certificates to applicants who operate and construct pipelines that are "required by the present or future public convenience and necessity." For history on how courts have interpreted economic and environmental factors as determining public convenience under Section 7, see Webb (2020).

with affiliated buyers.[37] The conflict generated by affiliates in determining public need was raised by the Commission itself in a 2018 Notice of Inquiry and 2022 updated Policy Statement, as well as by the US Court of Appeals for the DC Circuit in *Environmental Defense Fund v FERC* who found that "evidence of 'market need' is too easy to manipulate when there is a corporate affiliation between the proponent of a new pipeline and a single [buyer]."[38]

I contribute to this discussion by providing empirical evidence that precedent agreements are able to be manipulated by affiliates. I exploit pre-existing cross-sectional variation in the vertical relationships and regulatory status of buyers, to estimate a differences-in-difference model comparing how post-expansion changes in utilization differ for buyers that face evasion incentives. Using data on 12 years of pipeline capacity usage and a manually constructed panel of precedent agreements for 85 pipeline projects, I find that expansions featuring precedent agreements with regulated affiliate buyers are underutilized by 30-34 percentage points on average and that these effects persist during times of high expected demand. The disproportionately large amount of spare capacity on these expansions strongly suggests that precedent agreements overstated demand for pipeline capacity; precedent agreements are likely to be insufficient measures of market demand when utility affiliates are incentivized to inflate contract quantities and additional scrutiny to expansion projects with utility affiliates is warranted.

Quantity inflation by utility affiliates can lead to significant harm for captive ratepayers through the creation of stranded assets. Utilities recover the costs of pipeline capacity contracts through rates paid by customers of natural gas and electric utilities. If contract costs rise due to quantity inflation, these costs will be passed on to captive ratepayers are left to pay higher rates. A back-of-the-envelope calculation suggests that the transfer between ratepayers to pipeline companies as a result of regulatory evasion is large: applying a conservative estimate that pipeline capacity is 28% overbuilt for expansions with utility affiliates to data on total expansion costs from 2010-2021, I estimate that quantity inflation of precedent agreements has cost ratepayers $2.7 billion during the sample period.[39] My results emphasize the role of market structure in creating the conditions for "stranded assets," particularly for long-lived infrastructure such as natural gas pipelines that typically last 50 years.

[37] Keefe (2022) reviews the arguments surrounding the improper use of precedent agreements in determining market need. Incentives for utility affiliates to inflate contract quantities have also been discussed as risks from "self-dealing" between pipelines and utilities. Stockman and Trout (2017) explores concerns of conducts a qualitative study of four proposed pipeline expansions where self-dealing may be a concern and finds that they are likely to harm ratepayers.

[38] In its 2018 Notice of Inquiry, FERC sought comment on certification process. Of the ten questions proposed by the Commission, three related to the use of precedent agreements in determining project need and one of which explicitly asked "Should the Commission consider distinguishing between precedent agreements with affiliates and non-affiliates in considering the need for a proposed project?" Its updated 2022 Policy Statement acknowledges that in the past, the Commission has "relied almost exclusively on precedent agreements to establish project need" and that "affiliate precedent agreements will generally be insufficient to demonstrate need."

[39] This is an understatement of the costs to ratepayers since I am unable to identify buyer types for 10% of expansions with a listed docket number in the Natural Gas Pipeline Tracker and I am missing cost data for four expansions.

My results also contribute to debates regarding vertical merger policy. I empirically show that incentives for regulatory evasion are widespread in the energy utilities industry and can lead to consumer harms through the quantity inflation channel. I take advantage of regulatory disclosure rules to assemble a novel data set on capacity contracts. Comparing contracts of utility affiliates to other buyers that face incentives for price distortions, I find that utility affiliates do not pay higher prices that their unregulated and unaffiliated counterparts. To rationalize this null result, I develop a theory model of contracting for vertically-integrated utilities in the presence of information asymmetry between regulator and the firm and show that cost inflation may not be possible when regulators are sufficiently informed of industry costs. These findings suggest that vertical mergers between regulated and unregulated firms deserve scrutiny, especially in markets where contract prices are not transparent.

# 9 Tables

Table 1: Summary statistics of data structure

| | Control | Just affiliate | Just utility | Utility affiliate | Total |
|---|---|---|---|---|---|
| *Panel A: Counts by buyer type* | | | | | |
| Buyers | 167 | 19 | 78 | 16 | 280 |
| Contracts | 369 | 42 | 133 | 30 | 574 |
| *Panel B: Counts by project type* | | | | | |
| Expansions | 88 | 20 | 48 | 20 | 176 |
| Pipelines | 35 | 16 | 17 | 12 | 80 |
| Nodes | 222 | 122 | 144 | 111 | 599 |

*Notes:* This table tabulates the structure of the data, by buyer and project type. Panel A contains tabulations by buyer types: non-utility non-affiliate ("control"), non-utility affiliate ("just affiliate"), utility non-affiliate ("just utility") and utility affiliate. The rows tabulate the number of contracts and buyers by type. Panel B tabulates statistics by project type. The control group refers to projects that do not have any affiliate or utility buyers. "Just affiliate" refers to expansions that have at least one affiliate that is not an utility affiliate, and "just utility" refers to expansions with at least one non-affiliate utility. Expansions with at least one utility affiliate are coded as "Utility affiliate." The first row lists the number of natural gas pipeline expansion projects that were matched to precedent agreements and the second is the number of pipelines that have expansions in each project category. The last row lists the number of pipeline nodes (locations on the pipeline network) that were identified as undergoing capacity expansion or construction due to an expansion project.

Table 2: Description of buyers

| | Buyers without PAs (N=3,487) | | | Buyers with PAs (N=261) | | |
|---|---|---|---|---|---|---|
| | Mean | SD | Max | Mean | SD | Max |
| *Panel A: Network characteristics* | | | | | | |
| No. of pipelines | 1.97 | 3.73 | 61.00 | 7.02 | 9.55 | 63.00 |
| No. of contracts | 7.87 | 32.25 | 807.00 | 48.31 | 100.88 | 745.00 |
| No. of years in sample | 7.84 | 3.62 | 11.00 | 8.26 | 3.57 | 11.00 |
| Has pipeline affiliate | 0.05 | 0.22 | 1.00 | 0.31 | 0.46 | 1.00 |
| Is utility | 0.30 | 0.46 | 1.00 | 0.33 | 0.47 | 1.00 |
| *Panel B: Contract characteristics* | | | | | | |
| Mean size (thousand MMBtu/day) | 12.77 | 39.52 | 800.00 | 37.68 | 58.13 | 467.39 |
| Mean duration (years) | 8.78 | 10.63 | 96.08 | 8.40 | 6.03 | 31.83 |
| Share negotiated | 0.09 | 0.25 | 1.00 | 0.23 | 0.29 | 1.00 |
| Has contract in production region | 0.38 | 0.48 | 1.00 | 0.69 | 0.46 | 1.00 |

*Notes:* Summary statistics for buyers, ie firms that contract with a pipeline for transportation or storage services. The right columns summarize network, industry and contract characteristics for buyers that have signed at least one precedent agreement (PA) with a pipeline, and the left columns describe buyers that have not signed any precedent agreements. Each observation is at the buyer level. The number of buyers included in each group is listed in parentheses below the group titles. Contract "size" refers to the maximum daily capacity the contract allows the buyer to use. "Share negotiated" is the fraction of a buyer's contracts where the buyer negotiated transportation rates with a pipeline. All data come from FERC's Index of Customers, except for buyer utility status which is obtained by cross-referencing buyer names with utility filings.

| | Utility affiliate | *Difference* Control | Just utility | Just affiliate |
|---|---|---|---|---|
| *Panel A: Contract characteristics* | | | | |
| Capacity (Dth/day) | 49.40 | 74.66*** | 21.24 | 186.12** |
| | (18.36) | (22.58) | (26.00) | (93.57) |
| Capacity, not PA (Dth/day) | 41.95 | -13.15 | -12.91 | 21.00 |
| | (12.57) | (12.99) | (13.2) | (20.95) |
| Duration (years) | 15.22 | -2.06* | -0.16 | -2.09 |
| | (1.16) | (1.23) | (1.28) | (1.47) |
| Benchmark price ($/Dth/month) | 21.61 | -9.87* | -2.95 | -11.21** |
| | (5.27) | (5.31) | (5.44) | (5.55) |
| Nodes (count) | 4.57 | -1.54* | 0.10 | -0.76 |
| | (0.91) | (0.92) | (1.58) | (1.21) |
| Asset specific (1/0) | 0.47 | 0.04 | 0.10 | -0.04 |
| | (0.13) | (0.14) | (0.14) | (0.21) |
| Negotiated (1/0) | 0.65 | 0.15 | 0.11 | 0.11 |
| | (0.11) | (0.11) | (0.12) | (0.15) |
| In production region (1/0) | 0.07 | 0.27*** | -0.04 | 0.24* |
| | (0.07) | (0.07) | (0.07) | (0.15) |
| *Panel B: Buyer characteristics* | | | | |
| Annual pipelines (count) | 1.37 | 3.86*** | 3.04*** | -0.11 |
| | (0.11) | (0.6) | (0.38) | (0.13) |
| Annual contracts (count) | 8.26 | 7.54*** | 9.66*** | -3.87** |
| | (1.71) | (2.78) | (2.37) | (1.82) |
| New contracts per year (count) | 3.69 | 7.05*** | 3.43*** | -0.79 |
| | (0.67) | (1.89) | (0.96) | (0.73) |
| Reserved capacity (Dth/day, millions) | 318.11 | 243.25** | 159.04 | 13.70 |
| | (75.59) | (109.52) | (98.9) | (106.39) |

Table 3: Impact of Regulatory Evasion Incentives on Capacity Utilization

| | Baseline (1) | Day-Region FE (2) | Unweighted (3) | Outcome in pp (4) | Post-period only (5) | (6) |
|---|---|---|---|---|---|---|
| Post × Utility × Affiliate | -0.968** | -0.712*** | -0.923** | -16.2** | | |
| | (0.394) | (0.177) | (0.416) | (7.62) | | |
| Post × Utility | 0.012 | 0.198 | 0.106 | 1.73 | | |
| | (0.248) | (0.207) | (0.321) | (5.88) | | |
| Post × Affiliate | 0.722** | 0.470*** | 0.974** | 13.9** | | |
| | (0.283) | (0.111) | (0.398) | (6.47) | | |
| Utility × Affiliate | | | | | -1.16*** | -1.19*** |
| | | | | | (0.289) | (0.284) |
| Utility | | | | | 0.198 | 0.334 |
| | | | | | (0.222) | (0.221) |
| Affiliate | | | | | 0.773*** | 0.746*** |
| | | | | | (0.254) | (0.255) |
| Avg utilization in omitted group (pp) | 54.7 | 54.7 | 54.8 | 54.7 | 34.5 | 34.5 |
| Implied change in utilization (pp) | -33.9 | -27.9 | -33.0 | | -23.7 | -24.0 |
| Day FE | Yes | | Yes | Yes | Yes | |
| Node FE | Yes | Yes | Yes | Yes | | |
| Day-region FE | | Yes | | | | Yes |
| Node type FE | | | | | Yes | Yes |
| Number of Expansions | 39 | 39 | 39 | 39 | 85 | 85 |
| Observations | 149,106 | 149,106 | 149,106 | 149,106 | 342,159 | 340,943 |
| $R^2$ | 0.681 | 0.864 | 0.620 | 0.696 | 0.175 | 0.238 |

Notes: The table shows the estimates of Equation 8 which estimates the impact of incentives for regulatory evasion in natural gas pipeline expansion contracts on pipeline node utilization. The data are a panel of daily utilization rates for different nodes on the pipeline network that underwent a capacity expansion between 2010-2020. The dependent variable is the utilization rate, which is the percentage of a node's maximum flow capacity that is scheduled for use in a given day, measured in inverse hyperbolic sine for columns (1)-(3) and (5)-(6) and in percentage points for column (4). Nodes expanded by contracts with utility affiliate buyers face incentives for regulatory evasion. Columns (1)-(2) restricts the sample to days in the post-expansion period for each node and columns (3)-(6) includes both pre- and post-expansion days. All columns except for (3) are weighted by each node's pre-expansion maximum capacity. Column (2) includes day by region fixed effects. Column (4) changes the dependent variable to utilization measured in percentage points. The omitted group for Columns (1)-(4) are nodes under expansion contracts with non-affiliate and non-utility buyers in the pre-expansion period, and the omitted group for Columns (5) and (6) refers to the same set of nodes in the post-expansion period. The implied average change in utilization is obtained by multiplying the $exp$(coefficient on Utility × Affiliate) $- 1$ by the average utilization in the omitted group. All columns show two-way clustered standard errors at the day and expansion level in parenthesis and include controls for mean daily temperature and heating degree days at the node level. $^{*}p < 0.10$, $^{**}p < 0.05$, $^{***}p < 0.01$.

# 10 Figures

Table 4: Impacts on Capacity Utilization During High Congestion Days

| | Price spread<br>(1) | Weather<br>(2) | $k$ neighbors<br>(3) |
|---|---|---|---|
| Post × Utility × Affiliate | $-0.854^{**}$ | $-0.846^{**}$ | $-1.32^{**}$ |
| | (0.414) | (0.409) | (0.576) |
| Post × Utility | $-0.466^{*}$ | 0.183 | $0.654^{**}$ |
| | (0.270) | (0.321) | (0.307) |
| Post × Affiliate | $0.710^{**}$ | $0.897^{**}$ | $0.601^{**}$ |
| | (0.280) | (0.349) | (0.269) |
| Avg utilization in omitted group (%) | 61.8 | 40.8 | 63.3 |
| Implied avg change in utilization (pp) | -35.5 | -23.3 | -46.4 |
| Date FE | Yes | Yes | Yes |
| Node FE | Yes | Yes | Yes |
| Number of Expansions | 38 | 39 | 30 |
| Observations | 21,033 | 23,158 | 22,535 |
| $R^2$ | 0.617 | 0.697 | 0.621 |

Notes: This table shows the impact of incentives for regulatory evasion on node utilization during days with expected high congestion. Each regression estimates Equation 8 with a different sample and an observation is a node-day. The dependent variable is daily utilization rate in inverse hyperbolic sine. Column (1) restricts the sample to node-days where the spot price of natural gas at the hub nearest to a node is one standard deviation greater than the average monthly spot price at Henry Hub. Column (2) only includes node-days where the local weather is at least 32 heating degree days. Column (3) limits the sample to node-days where a node has at least one "matched" node from the $k$-nearest neighbors process with a 75% utilization rate.[40] The omitted group refers to nodes under expansion contracts with non-affiliate and non-utility buyers in the pre-expansion period. The implied average change in utilization is obtained by multiplying the $exp$(coefficient on Post × Utility × Affiliate) $-1$ by the average utilization in the omitted group. All columns are weighted by each node's pre-expansion maximum capacity, include controls for mean daily temperature and heating degree days at the node level and show two-way clustered standard errors at the day and expansion level. $^{*}p < 0.10$, $^{**}p < 0.05$, $^{***}p < 0.01$.

Figure 1: US Natural Gas Geography

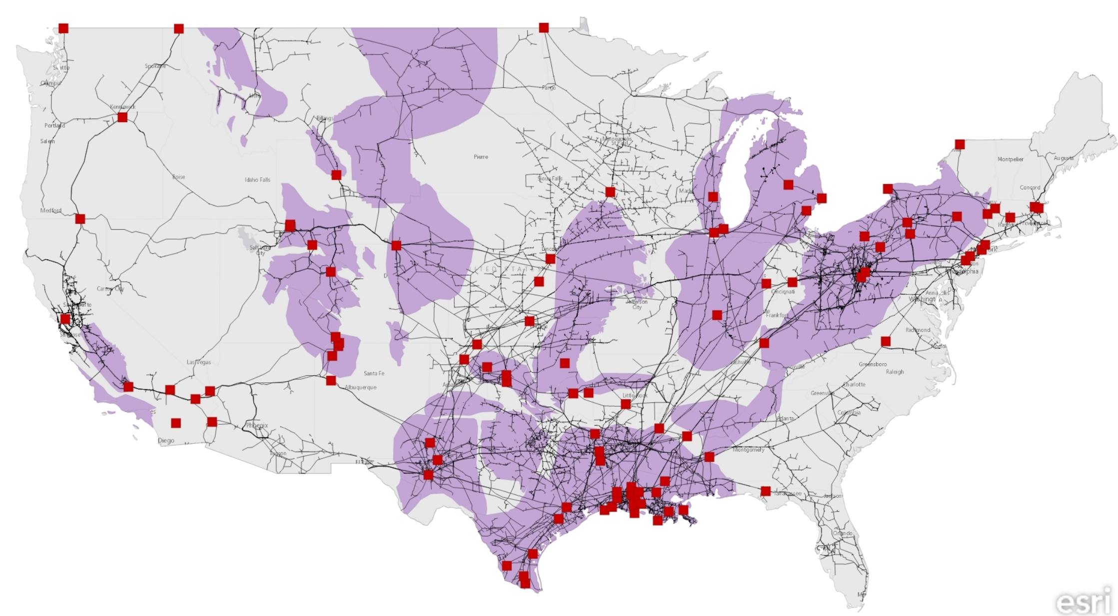
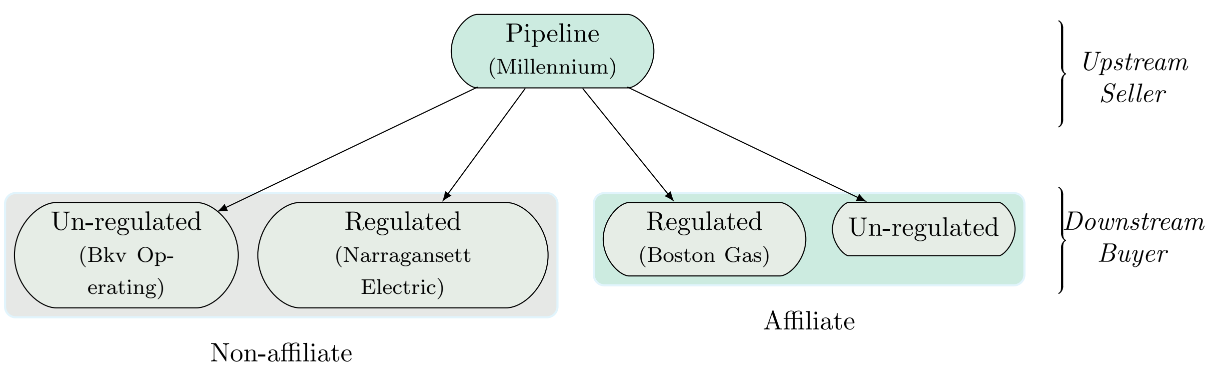


Table 5: Effect of Regulatory Evasion Incentives on Contract Prices

| | log(Price) | | | | Price | |
|---|---|---|---|---|---|---|
| | Base | Route FE | Captivity | Cost | Base | Cost |
| | (1) | (2) | (3) | (4) | (5) | (6) |
| Utility × Affiliate | 0.160** | 0.136 | 0.144 | 0.068 | 2.03 | 1.37 |
| | (0.069) | (0.078) | (0.082) | (0.087) | (1.33) | (1.70) |
| Utility | 0.024 | 0.032 | 0.038 | 0.013 | 0.738 | 0.561 |
| | (0.088) | (0.048) | (0.063) | (0.040) | (1.06) | (0.762) |
| Affiliate | -0.172*** | -0.148*** | -0.155*** | -0.122** | -2.20*** | -1.46* |
| | (0.015) | (0.028) | (0.050) | (0.054) | (0.562) | (0.791) |
| Year of expansion FE | Yes | Yes | Yes | Yes | Yes | Yes |
| Pipeline FE | Yes | Yes | Yes | Yes | Yes | Yes |
| Route FE | | Yes | Yes | Yes | | Yes |
| Observations | 396 | 394 | 394 | 345 | 397 | 346 |
| Number of expansions | 120 | 119 | 119 | 108 | 120 | 108 |
| Avg contract price in omitted group | 9.50 | 9.52 | 9.52 | 9.29 | 9.42 | 9.20 |
| $R^2$ | 0.888 | 0.896 | 0.896 | 0.908 | 0.913 | 0.934 |

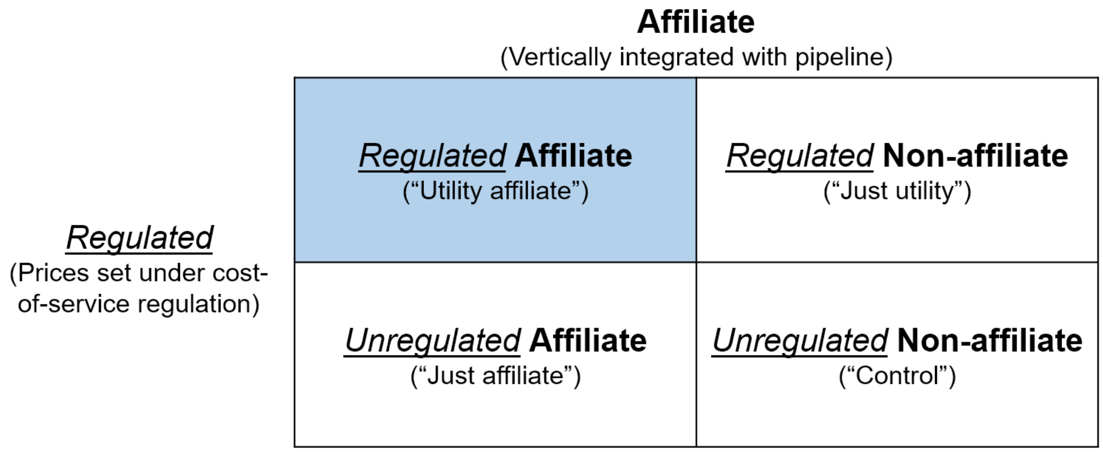
*Notes:* This table shows the joint impacts of cost-of-service regulation and vertical integration on the markup of a pipeline capacity. Each observation is a bilateral contract between a pipeline and a buyer for pipeline capacity on an expansion project and multiple contracts may reserve capacity on the same expansion. The outcome variable in Columns (1)-(4) is $log$(price) and outcome variable in Columns (5-6) is price, where the unit of price is \$/Dth/month. Every specification controls for the benchmark price of the contract, so that the coefficients measure markup above the counterfactual rate paid by buyers absent negotiation. Column (1) estimates the fixed effects model in Equation (11). Column (2) adds route fixed effects, where a route is defined as the origin-destination pair for an expansion (ex. Northeast-South Central). Column (3) includes a dummy variable for whether the buyer has a contracts with any other pipelines at the time the contract is implemented. Column (4) adds a control for total expansion costs. Column (5) re-estimates the base specification with price levels as an outcome, and Column (6) re-estimates the full specification in Column (4) with price as the dependent variable. The omitted group includes contracts signed by non-affiliated, non-utilities. All columns include controls for contract duration, $log$(contract size), total expansion capacity and baseline rate interacted with total expansion capacity. Multi-price contracts are dropped in all specifications. Each observation is weighted by contract size and standard errors are clustered by the year and pipeline. $^{*}p < 0.10$, $^{**}p < 0.05$, $^{***}p < 0.01$.

Figure 2: Market structure of Millennium Pipeline



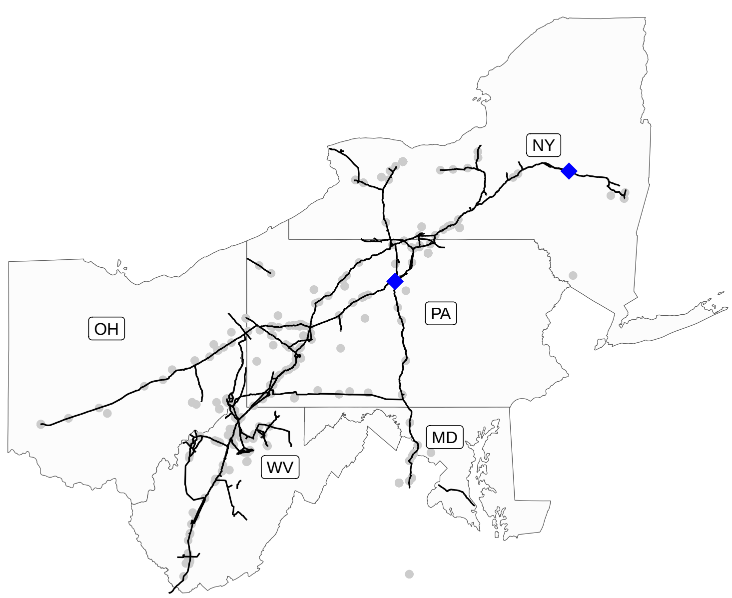

*Notes:* This figure shows the market structure for Millennium Pipeline. At the top is the seller of pipeline capacity, in this case the Millennium. At the bottom are the four types of buyers that purchase capacity from the seller, with example firms listed beneath.

Figure 3: Taxonomy of buyer types



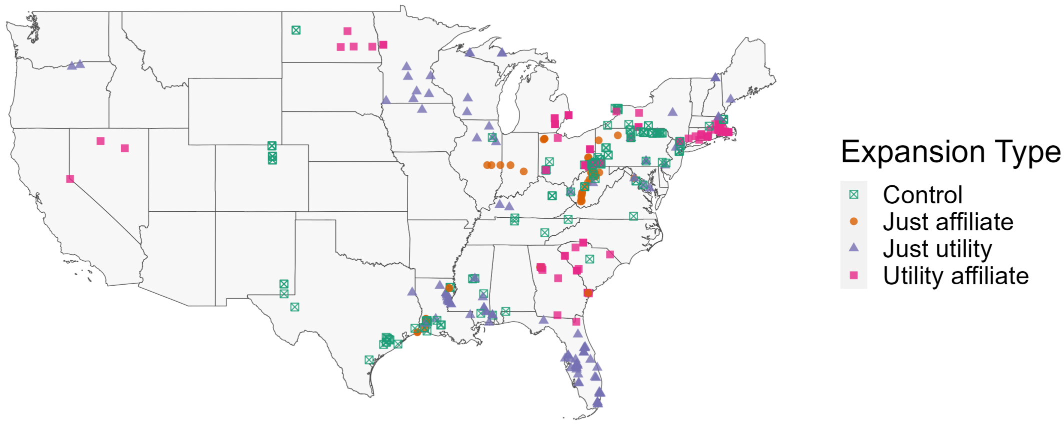

*Notes:* This figure shows the four buyer types with shortened names listed underneath. Buyers are firms that contract for pipeline capacity and for each contract they are classified by a combination of two characteristics: whether they face cost-of-service regulation (regulated) and whether they are vertically integrated with the pipeline (affiliate). The shaded rectangle highlights "utility affiliate" buyers who face evasion incentives due to the fact that they are both regulated and vertically integrated with the pipeline they contract with.

Figure 4: Detected nodes for "New Market Project" expansion



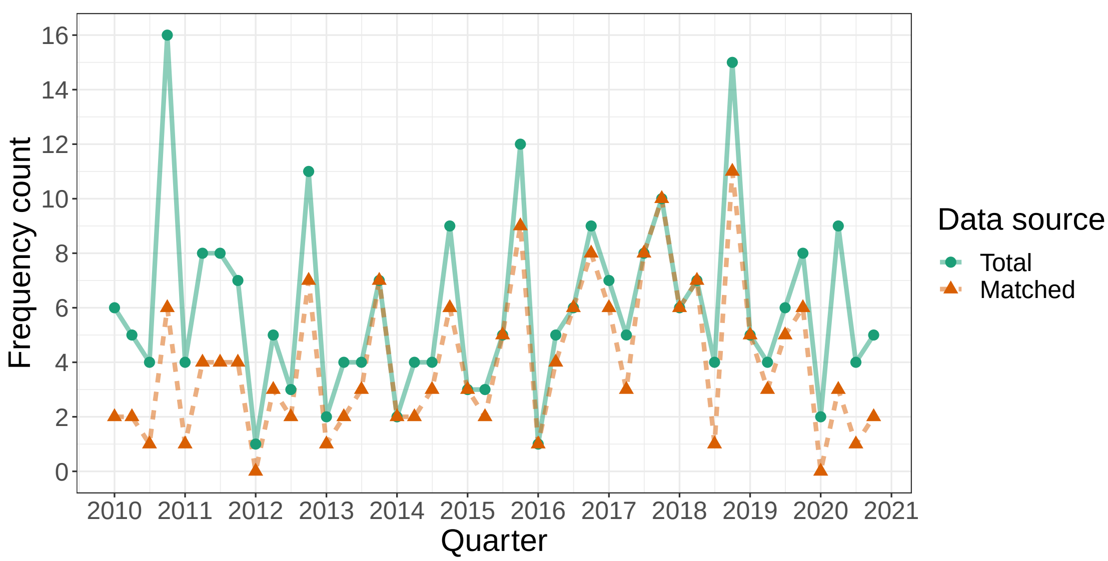

*Notes:* This figure shows the location of expanded nodes for expansion number CP14-497, Eastern Gas Transmission and Storage's "New Market Project." The dark line shows the location of the Eastern Gas Transmission and Storage pipeline and each grey dot is location on the pipeline network where gas is either received or delivered by the pipeline. The diamond blue dots are the nodes that underwent capacity changes due to the New Market Project.

Figure 5: Location of pipeline expansions, by type




*Notes:* This figure shows the location of natural gas pipeline expansions carried out by FERC regulated pipeline companies from 2010-2020. Each point represents a location on the pipeline network that underwent expansion. Note that an expansion can take place in multiple locations, such that each point does not represent a unique expansion. Expansion points are color-coded by type. "Control" refers to an expansion with precedent agreements between a pipeline company and non-utilities and "Utility" refers to an expansion with precedent agreements between a pipeline company and at least one utility. The "Affiliate" expansion has at least one precedent agreement between a vertically integrated pipeline company and non-utility buyer and the "Affiliate-Utility" expansion has at least one precedent agreement between a vertically integrated pipeline and utility.

Figure 6: New interstate pipeline expansions by quarter, 2010-2020




*Notes:* The frequency count is the number of new pipeline expansions, as defined by their docket number in FERC's Natural Gas Pipeline Tracker (NGPT), that are completed in a given quarter. The solid line ("Total") represents all expansions in the NGPT and the dashed line ("Matched") represents expansions in the NGPT that were matched with precedent agreements following the process described in Section 4.2.

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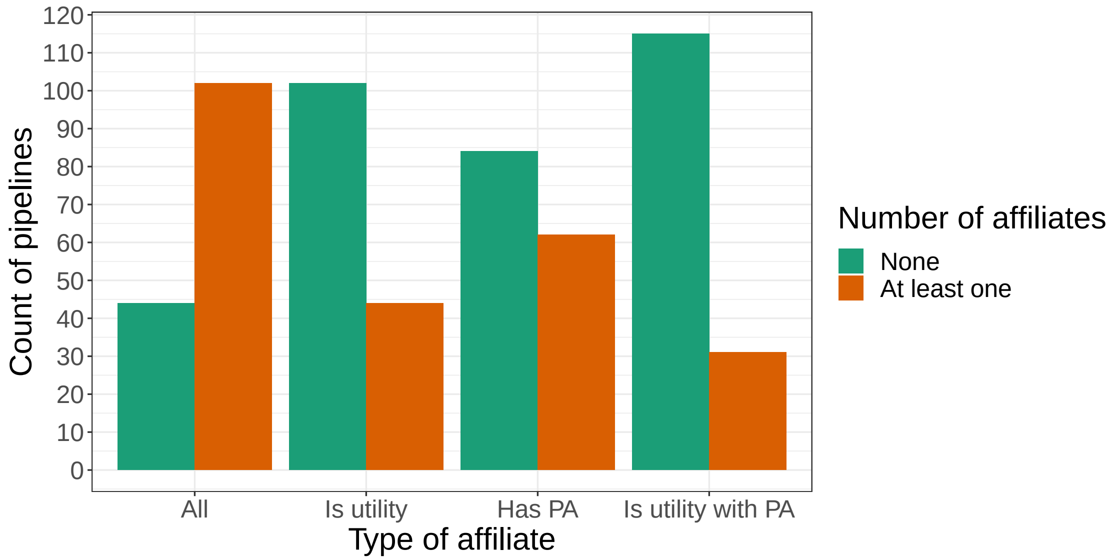
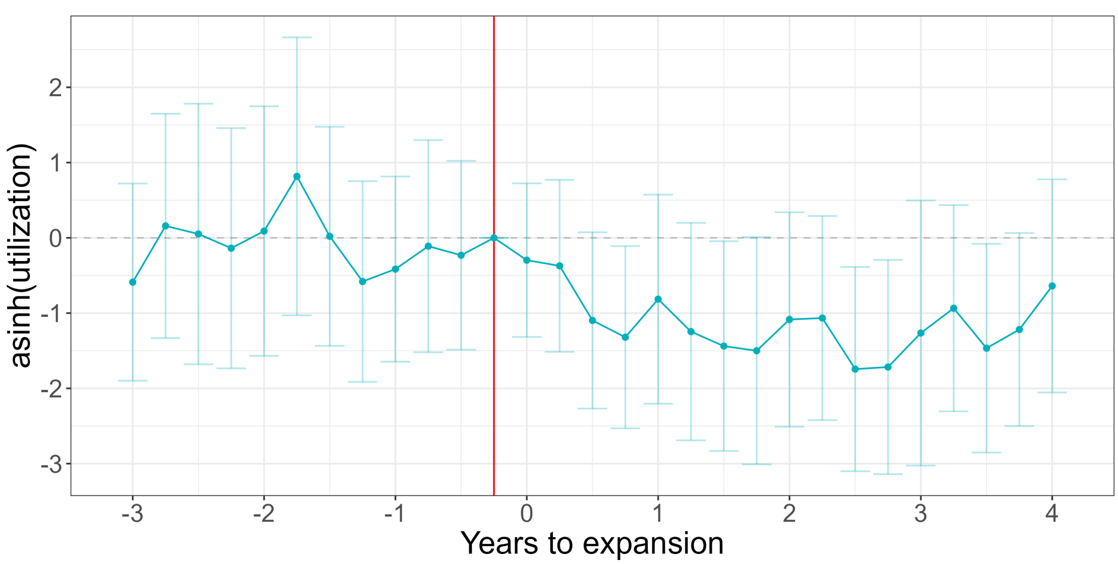
Figure 7: Vertical relationships between pipelines and buyers




*Notes:* This figure shows the distribution of the number of affiliates per pipeline. Affiliates are either buyers that are owned by the same parent corporation as pipeline company, or buyers that own equity in the pipeline asset. Each pair of bars shows the distribution of pipelines with vertical relationships for a different sub-sample of affiliates, except the the "All" group which shows the total number of affiliates. The left and right bars show the number of pipelines with and without the listed sub-samples of affiliates, respectively. Reading the graph for the "All" group, 44 pipelines do not have any affiliates and 102 pipelines have at least one. The "is utility" group refers to utility affiliates, "has PA" refers to affiliates that have signed a precedent agreement and "is utility with PA" refers to utility affiliates that have signed a precedent agreement.

Figure 8: Impacts of incentives for regulatory evasion on capacity utilization over time




This figure is an event-study of the impact of regulatory evasion incentives on capacity utilization. Each point is the estimated coefficient on the interaction between an indicator that equals one if the node is expanded through contracts with at least one utility affiliate and a time dummy; the full regression equation is in Equation 10. The outcome variable is daily node utilization rate, measured in inverse hyperbolic sine. Bars represent 95 percent confidence intervals and the standard errors are clustered by node and day.

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