

# Long-Term Contracts and Secondary Markets: Theory and Evidence from Natural Gas Pipelines\*

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This Version: *August 30, 2024*

## Abstract

We examine the role of long-term contracts and secondary markets in influencing the resilience of supply chains. Specifically, we assess the efficiency of the US natural gas pipeline network in allocating capacity in response to unexpected demand and supply shocks, which are increasingly common with the advent of climate change. Long-term contracts can create an imbalance between supply and demand because they reserve capacity for contract holders prior to shocks. Utilizing daily transaction data from 2005 to 2023, we find that a secondary market, where contract holders can lease capacity to other shippers, reacts to significant regional demand fluctuations and alleviates the imbalance between supply and demand. We also find evidence that the formation of long-term relationships between buyers and sellers reduces search costs in the secondary market. However, the presence of a largely unregulated secondary market within a heavily regulated primary market raises concerns about market dominance. We find evidence that both buyers and sellers can influence prices based on their market share, which could reduce the secondary market's efficiency gains. This secondary market is a rare, real-world example of a market for legal entitlements, and our study is the first to examine it empirically. We aim to provide some evidence that generalizes to other similar heavily regulated markets with large sunk investment costs, and to provide guidance for the organization of pipeline networks beyond the US.

**Keywords:** Capacity Release, Secondary Market, Pipeline, Supply-Chain, Transportation

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\*We are grateful to Victor Aguirregabiria, Eduardo Souza-Rodrigues, Yao Luo, and seminar participants at the University of Toronto and Western University for helpful discussions and comments. We also thank Eden Zheng, Anna Li, and William Qi for excellent research assistance. All errors are our own.

# 1 Introduction

In North America, pipelines are the dominant method for transporting natural gas. They are extremely costly to build, averaging \$5 million/km with 10 to 20 years for the pipeline to break even on its investment. To share the risk associated with large sunk investment costs, pipelines must sign long-term contracts (typically ten years or more) with customers prior to the pipeline’s construction, which entitles the customer to reserved capacity. Long-term contracts in the primary market can create situations of artificial constraint in which physical capacity is available, but contracting frictions impede the flow of natural gas. For these reasons, there is a secondary market unique to the U.S. where shippers can lease capacity to other shippers for any length of time. The secondary market is much less regulated than the primary market, with the aim of fostering a competitive environment between shippers.

In this project, we evaluate the efficiency of the U.S. natural gas pipeline network at intertemporally allocating pipeline capacity in response to demand and supply shocks through its secondary market. We study trade-offs associated with the secondary market and provide guidance for deregulation efforts in similar industries. We study shocks to large weather fluctuations that affect the supply and demand for energy, increasingly common with the advent of climate change (Wang, Biasutti, Byrne, Castro, Chang, Cook, Fu, MGrimm, Jaha, Hendon et al., 2021; Bathiany et al., 2018). Through the lense of the secondary market for capacity release, we contribute to a growing literature studying the resilience of energy systems and markets in response to such atmospheric conditions (Gonçalves, Costoya, Nieto and Liberato, 2024; Jasiūnas, Lund and Mikkola, 2021; Waseem and Manshadi, 2020).

Using novel daily transaction data for selected U.S. natural gas pipelines between 2005 and 2023, we find that the secondary market responds to large regional fluctuations in demand for natural gas. We narrow down our study to the extreme cold wave of February 2021. This cold wave significantly increased natural gas demand, particularly demand for residential heating and electricity generation in the Deep South. Notably, natural gas prices at hubs in Texas and southeastern California rose substantially during this period. In contrast, prices at hubs outside the cold wave’s radius, such as in Northwestern California, did not rise.

We leverage this spatial variation in natural gas prices to identify control and treated pipelines. We choose Gas Transmission Northwest (GTN) as a control, which carries natural gas from Western Canada to Northwestern California. We chose the El Paso pipeline as a treatment, which carries natural gas to major hubs in Texas and Southeastern California. In a difference-in-difference event study framework similar to Miller (2023) and Freyaldenhoven, Hansen, Pérez and Shapiro (2024), we find that the cold wave caused a 50% increase in

capacity released from buyers (replacers) to sellers (releasers) in the secondary market. We also find that the secondary market facilitates a reduction in search costs between replacers and releasers but fosters an anti-competitive environment where both sides of the market influence prices.

This secondary market is one of the only real examples of a Coasian market in which participants trade legal entitlement to natural gas pipeline capacity. Our paper is the first to empirically study such a secondary market. We aim to provide some evidence that generalize to other similar heavily regulated markets with large sunk investment costs, and to provide guidance for the organization of pipeline networks outside of the U.S.

To understand the aforementioned trade-offs better, we show that the vast majority of shippers that release capacity are end-consumers (power plants, local distribution companies that serve specific urban areas, and industrial plants) who have long-term contracts with pipelines and must pay the large reservation fees even if they do not utilize their capacity. The vast majority of replacers are marketers. Marketers are intermediaries that engage in arbitrage opportunities, buying gas in cheap hubs and selling gas in expensive hubs to consumers.

In this context, we provide empirical evidence for long-term relationships between market participants in the capacity release market and propose a potential hypotheses for why such relationships exist. We show that over 95% of contracts signed are private arrangements made between shippers. Many of these arrangements recur between shippers that meet multiple times over the sample period, which we call long-term relationships. This is similar to the U.S. trucking industry, where 80% of the shipping contracts are signed through existing relationships between shippers (analogous to the replacement shippers) and carriers (analogous to releasing shippers), and only 20% of the contracts are signed via a spot market (Harris and Nguyen, 2023).

Considering the unique aspects of this market, search costs are the key factor influencing the formation of long-term relationships. This is attributed to the frequent requirement to secure capacity at various delivery and receipt locations, along with other customary contractual obligations such as the option for a releaser to be able to recall its capacity at any time, making each contract a highly differentiated product. Thus, when releasers do not need their capacity, they search for replacers to avoid paying reservation fees, whereas replacers search for releasers when facing an arbitrage opportunity. Using event studies, we find that contracts are much more likely to be signed between long-term partners during the cold wave. This suggests that the opportunity cost of searching is higher in periods of high demand, and that long-term relationships reduce search costs.

Moreover, the secondary market facilitates the formation of long-term relationships.

While contracts are mostly private arrangements, the Federal Energy Regulatory Commission (FERC) mandates that pipelines publicly post transaction details from the secondary market on public data-sharing platforms. We argue that this regulatory constraint is what facilitates the formation of long-term relationships.

However, the quasi-lack of regulation on the price charged for pipeline capacity in the secondary market fosters an anti-competitive environment.<sup>1</sup> To show this, we leverage variation in market concentration across different pipelines and regions, where some pipeline zones have dominant releasers, some have dominant replacers, and some have both. We find that a 1% increase in releaser market share is associated with a 0.1% increase in prices for capacity. In contrast, a 1% increase in replacer market share is associated with a 0.04% decrease in capacity prices. The welfare implications of these price-setting behaviors are uncertain, and we plan to study them using a search model with two-sided market power in future research.

## Related Literature

This paper contributes to three broad strands of literature on (i) supply-chain and energy market resilience, (ii) the effectiveness of secondary markets, and (iii) the pipeline industry.

[Chen \(2023\)](#) shows that mergers among those networks result in significant cost reductions and a notable rise in markups. Nonetheless, there is still a cost pass-through to customers, leading to a reduction in shipment prices. Based on the findings of [Chen \(2023\)](#), we investigate the effects of decreased shipping costs resulting from the consolidation of transport networks on downstream firms. However, transport companies and their downstream customers typically establish long-term relationships, and our knowledge of these long-term relationships is limited. To shed light on these issues, we examine how these relationships are formed and how demand and supply shocks affect the formation of such relationships. One challenge in examining these relationships is that typically, the specifics of such contracts are not observed. However, the U.S. natural gas pipeline industry is an exception, as all contract details are observable. This includes information on the ownership of transmission capacity in the primary market and details of transactions related to capacity release in the secondary market. By examining the formation of long-term relationships in the natural gas pipeline industry, we offer insights that could be applied to other similar transport markets with substantial sunk investment costs.

Our study of the secondary market in the natural gas pipeline industry also contributes to a literature investigating the effect of capacity constraints, bottleneck, and congestion

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<sup>1</sup>There are some constraints on capacity prices in the secondary markets based on how long capacity is expected to be released. See [Section 2](#) for details.

on market efficiency measures such as price integration across hubs (Avalos, Fitzgerald and Rucker, 2016; Oliver, Mason and Finnoff, 2014; Brown and Yücel, 2008; Marmer, Shapiro and MacAvoy, 2007). This literature studies physical constraints and how regulation interacts with these physical constraints in preventing spatial price integration. By contrast, we study the role of artificial capacity constraints created by long-term contractual agreements that reserve capacity, which has not been studied before. Our findings on the effectiveness of the secondary market suggests that these constraints are important and should be considered along with physical constraints when studying market efficiency.

Lastly, our findings on the exercise of market power in the secondary markets relate to the literature on intermediation in search markets and monopsony power (Berger, Herkenhoff, Kostøl and Mongey, 2023; Salz, 2022; Spulber, 1996; Gehrig, 1993). Our results are consistent with some of these results in contexts where intermediaries (marketers) have market power.

## 2 Industry Background

Natural gas transmission pipelines provide for the bulk of natural gas transportation within North America, often transporting commodities hundreds or thousands of kilometers from production locations to three main demand markets: electricity generation, local distribution companies (LDCs) primarily used for space heating, and industrial consumption. In comparison to other modes of domestic freight, pipelines transport the most tonnes-kilometers. Natural gas transportation in anything other than pipelines is complicated and often unprofitable.

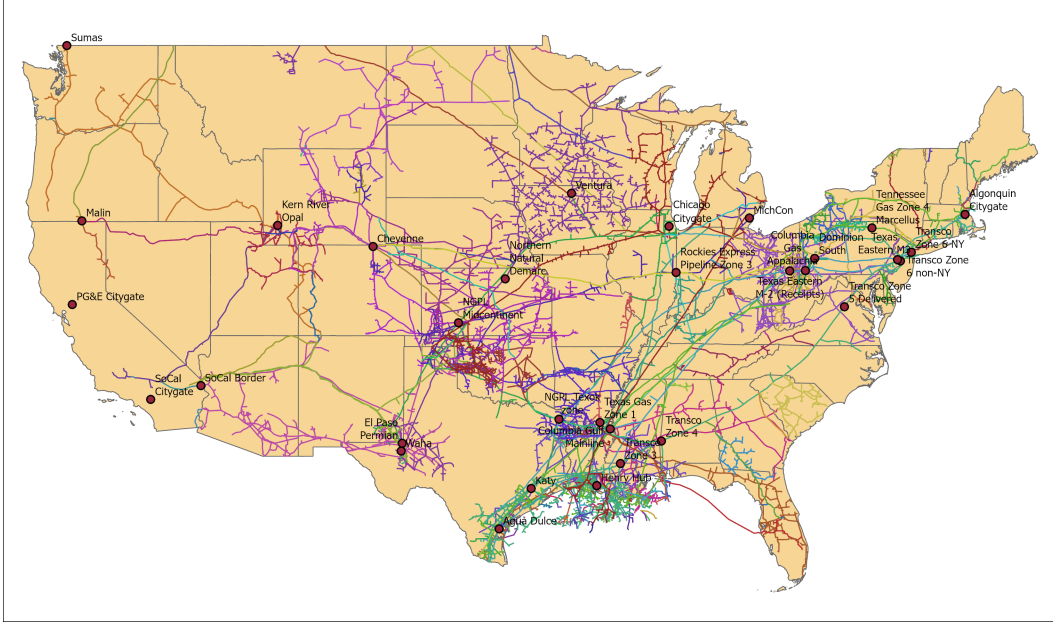
Within the U.S., there are more than 120 major natural gas transmission pipelines whose tolls/rates are directly regulated by the Federal Energy Regulatory Commission (FERC). Most of these pipelines facilitate the transmission of natural gas from production areas, concentrated in regions such as Texas, Pennsylvania, and Canada, to demand areas such as major metropolitan areas, major export interconnections, and natural gas storage facilities. The major interstate transmission pipelines are shown in the map below in Figure 1.

Transmission pipelines are extremely costly to build, averaging \$5 million/km with 10 to 20 years for the pipeline to break even on its investment. To share the risk associated with large sunk investment costs, the pipelines are required to sign long-term contracts (typically ten years or more) with customers prior to the pipeline construction, which entitles the customer to reserved capacity.

Long-term contracts in the natural gas transmission pipeline industry primarily focus on shipment capacity,<sup>2</sup> as shipment pricing is often heavily regulated. Pipeline rates are often set

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<sup>2</sup>A firm transportation contract grants capacity to a service requester at one or more points along a



**Figure 1:** Natural Gas Pipelines in the U.S.

to enable pipelines to recover all prudently incurred expenses associated with service delivery while also earning a reasonable profit. Regulators usually establish this by determining the revenue requirement for pipelines — the yearly revenue needed to maintain service and secure a fair return.<sup>3</sup> In Appendix A, we provide further details on rate regulation within the pipeline industry.

While long-term contracts in the primary market help reduce investment risks, they can introduce substantial frictions in capacity allocation amidst fluctuations in the natural gas supply and demand, thereby obstructing gas delivery to customers in need. The secondary market has emerged to address these frictions. In this market, service requesters who hold long-term contracts in the primary market can trade their contractual rights. This process,

pipeline. Capacity is either specific as to both location (point) and quantity or is general as to location and specific as to quantity. A firm transportation contract gives a service requester the right to cause a TSP to receive a specific quantity of gas from that service requester at a point and/or deliver a specific quantity of gas to that service requester at a point over a specific time period.

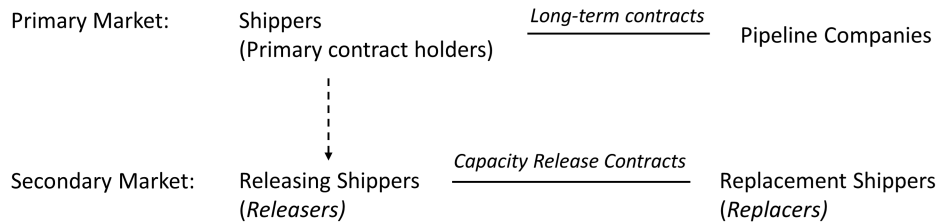
<sup>3</sup>A typical revenue requirement will be comprised of the following:

$$\text{Operations\&Maintenance Costs} + \text{Taxes} + \text{Depreciation} + \text{Return} = \text{Revenue Requirement}$$

Looking more specifically at the “fair” return for a pipeline in the cost of service regulation terminology, the return is typically determined through a rate base. A rate base is defined as a pipeline’s gross plant in service less its accumulated depreciation. You then earn a return based on an assumed capital structure the regulator sets. Those portions of debt and equity then earn a return based on your cost of debt and cost of equity, both of which are determined by the regulator. The cost of debt is typically based on a pipeline’s outstanding debt. In contrast, the cost of capital is determined through regulatory proceedings utilizing various financial models to determine an appropriate cost of equity for the pipeline based on similarly risky assets (mainly other pipeline systems).

known as “Capacity Release,” allows for the sale of all or part of a contract holder’s rights for varying durations, ranging from less than a month up to the entire contract length.

Figure 2 illustrates the interactions between the primary and secondary markets. Within the capacity release market, those holding primary contracts are known as *releasers*, and their counterparts are referred to as *replacers*.



**Figure 2:** Relationships of the primary and the secondary market

For primary contract holders, the value of transportation tends to rise when there are substantial price differentials between natural gas trading hubs. Consequently, we expect to observe increased capacity releases from these customers when such differentials widen. Additionally, it is important to note that many natural gas end-users either do not possess transportation capacity on interstate pipeline systems or are not connected to natural gas distribution utilities. These customers are often industrial facilities, agricultural operations, smaller power generation facilities, and natural gas retailers. Thus, many of these natural gas end users rely on natural gas marketers to meet their gas needs, both in terms of supply and transportation.

These end users lack transportation capacity on pipelines mainly due to concerns about creditworthiness and balance sheet obligations. The credit obligations necessary for a company to hold pipeline transportation services are often steep, and most companies cannot meet them. For example, a typical credit evaluation criterion for firm service on a natural gas pipeline is to provide security guarantees for three months of firm service at the maximum tariff rate for the entire volume of your contract. This requires companies to have large amounts of cash on hand (in the form of an advance deposit), a strong standing letter of credit from a financial institution, an acceptable security interest in collateral, or a guarantee from a more credit-worthy parent company. As for the balance sheet obligations, given the take-or-pay nature of natural gas transportation firm service contracts, financial institutions view these transportation contracts as debt obligations. If a company were to take out large amounts of transportation capacity, this would result in a large liability on their balance sheet, which may impact their credit metrics, impacting their ability to secure their own financing and financial obligations.



Given these restrictive requirements, many of these end users rely on marketers to arrange for the supply and transportation of their gas needs. This comes at an increased cost to the end user, as marketers often require a service fee or markup for arranging the supply and transportation of natural gas.

Since these end users rely on marketers to provide them service when unexpected shocks in demand happen, either to end-use residential, commercial, and industrial demand (increased demand for natural gas retailers) or unexpected shocks in their various industries that do not impact demand for gas utilities/retailers (for example an increase in demand for steel production) they often turn to marketers to supply them with additional natural gas. While the primary market for natural gas transportation is mainly held by utilities to meet their regulatory obligations, they do not require the full use of their transportation capacity for most periods of the year. They would prefer to release that capacity to a marketer who will ultimately provide the transportation services to another end user.

### 3 Data

We utilize four datasets in our analysis—first, the index of customers data. An index of customers provides each specific contract on a pipeline system, including which shipper holds that contract, the start and end dates of the contract, the type and path of the service, the amount of pipeline capacity the shipper can utilize, and the contract rate. In the United States, pipelines regulated by the Federal Energy Regulatory Commission (FERC) are required to publish an index of customers from which we obtain our data. Second, the capacity release data from each pipeline system, which includes details such as the transaction date, type of contract, duration of the contract, rate, and options associated with the contract (such as recall or reput information).<sup>4</sup> Third, the daily spot prices of natural gas at all US-based hubs, which Capital IQ Pro compiles. We obtained the first three datasets from 2004 to 2023.<sup>5</sup> Last, we use geographic data from the U.S. Energy Information Administration (EIA) to gather information about the entire U.S. interstate natural gas pipeline system and the locations of major natural gas gateways and hubs.

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<sup>4</sup>With the advent of the capacity release market, the FERC required pipelines to openly post the deals that their service requesters were seeking to transact (FERC Order No. 636, et al.).

<sup>5</sup>While all of this data is technically public information, most pipelines periodically delete information from past transactions, such as contracts signed in the capacity release market. We purchase the entire history of the capacity release market and spot prices at hubs between 2004 and 2023 from the Capital IQ Pro database to access historical data.



### 3.1 Descriptives for the primary market

We first provide summary statistics for the long-term contracts in the primary market for selected pipelines. Across our sample, the average duration of a contract is approximately nine years.

**Table 1:** Contract Duration (in Months)

Pipeline	p5	p25	p50	p75	Mean	Max
El Paso Natural	9	57	115	180	122	475
Natural Gas Pipe	12	36	60	120	84	432
Texas Eastern	13	48	105	184	118	612
Transwestern	4	12	36	101	65	361
All Sample	12	36	72	154	100	612

Next, we provide insight into the competitive landscape of the industry. Table 2 shows the overview of market concentration in U.S. Interstate Pipelines.

**Table 2:** U.S. Market Share: Top 5 Interstate Pipelines by Capacity (2022)

Pipeline	Market Share
Transcontinental Gas P L Co	.1
Texas Eastern Trans Corp	.08
Tennessee Gas Pipeline Co	.08
ANR Pipeline Co	.05
Rockies Express Pipeline	.04
Mean	.006
N	170

Table 3 shows the major contract holders in the primary market. The data indicate that the top 5 companies own 75% of interstate pipeline capacity. The market power observed in the primary market will significantly impact who can participate in the capacity release market (the secondary market) and will affect shippers' decisions to release capacity during demand or supply shocks.

### 3.2 Descriptives for the secondary market

Regarding the capacity release market, we first demonstrate its importance. Table 4 shows the amount released in the secondary market compared to the primary market. The percentage of the amount released is calculated at the Pipeline-Shipper-Quarterly level, using the

**Table 3:** Top 10 Contract Holders by Capacity in the Primary Market (2022)

Primary Owner	Market Share
Kinder Morgan	.195
TC Energy	.192
Enbridge	.151
The Williams Companies	.12
Energy Transfer	.1
Tallgrass Energy	.05
Boardwalk Pipeline	.035
Berkshire Hathaway	.032
Boardwalk Pipelines	.024
Dominion Energy	.024
Mean	.013
N	76

**Table 4:** Amount Released in Comparison to IOC Data (Quarterly)

	p25	p50	p75	Mean	Max
Proportion of quantity released	2.3%	6.8%	25.0%	32.4%	4212.7%

Max Daily Transport quantity as a basis. The result shows that in any quarter, on average 30% of capacity is being treaded on the secondary market.

Next, we examine the percentage of shippers participating in the capacity release market at any point during the contract period. Table 5 reveals that 40% of shippers holding long-term contracts participate in the capacity release market. This underscores the significant importance and active usage of the secondary market in this industry. The data therein highlights substantial variations in both the number of capacity releases and the number of participants in the secondary market across different pipeline systems every quarter.

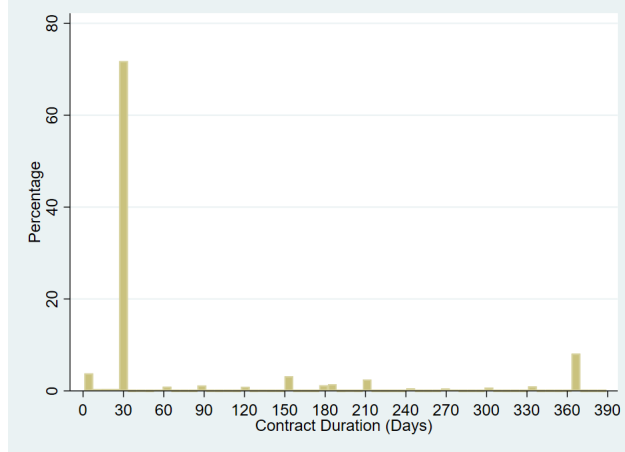
**Table 5:** Number of Shippers that are Within the Secondary Market

Not in the Capacity Release Market	555	60%
In the market	373	40%
Total	928	100%

Table 6 shows the average duration of a contract in the capacity release market. Most contracts last a month, with some lasting half a year or a whole year. It is rare for a contract in the secondary market to last for more than a year. Figure 3 illustrates the distribution of contract durations.

**Table 6:** Contract Durations in the Capacity Release Market (Days)

	Mean	p5	p50	p95	Min	Max
Contract Duration	85.17	27	30	364	1	1000

**Figure 3:** Distribution of Contract Durations

In the capacity release market, there are several options that a contract might include: recallable, reputable, capacity resale allowed, affiliation of the counterparty with the contracting party, and inclusion of previously released capacity. Table 7 shows the percentage of contracts that feature these options.

**Table 7:** Percentage of Contracts with Different Options

Year	Recallable	Reputable	Resale Allowed	Affiliate	Previously Released
2006	72%	58%	72%	0%	13%
2011	93%	65%	92%	1%	12%
2016	97%	78%	97%	0%	6%
2021	98%	78%	96%	0%	18%

We then present data descriptives to illustrate the interactions between releasers and replacers in the secondary market. The selected pipelines are “El Paso Texas Pipeline”, “Texas Eastern Transmission”, “Natural Gas Pipeline Company of America” (*NGPL*), and the Transwestern Pipeline. We observe data between 2006 and 2023. Using the points identifiers for the contracts, we were able to separate capacity release between different categories:

We aggregate these categories into local distribution companies (LDC), storage, and others (where others is mostly comprised of transmission between pipelines). Additionally,

**Table 8:** Distribution of sub-contracts by category—Selected pipelines

	Number of sub-contracts	Percentage
Compressor	984	0.7
Delivery to End User	3,057	2.1
<b>Delivery to an LDC</b>	<b>58,877</b>	<b>40.3</b>
Exchange	59	0.0
Gas Processing Plant	458	0.3
Gathering	278	0.2
<b>Interconnect</b>	<b>53,146</b>	<b>36.4</b>
LNG	36	0.0
Park and Loan	1	0.0
Pool	3,662	2.5
Power Plant	93	0.1
Receipt by LDC	79	0.1
Segment	313	0.2
Stand Alone Meter	3,033	2.1
Storage Injection	264	0.2
<b>Storage Quantity</b>	<b>19,093</b>	<b>13.1</b>
Storage Withdrawal	352	0.2
Unknown	973	0.7
Wellhead	1,265	0.9
Total	146,023	100.0

*Notes:* A sub-contract is defined as an agreement on capacity release at a specific point, as part of larger capacity release contracts.

we separated contracts into two types based on the frequency of contracts between the same shippers on a pipeline: (1) Met  $< 5$  times and (2) Met  $\geq 5$  times.

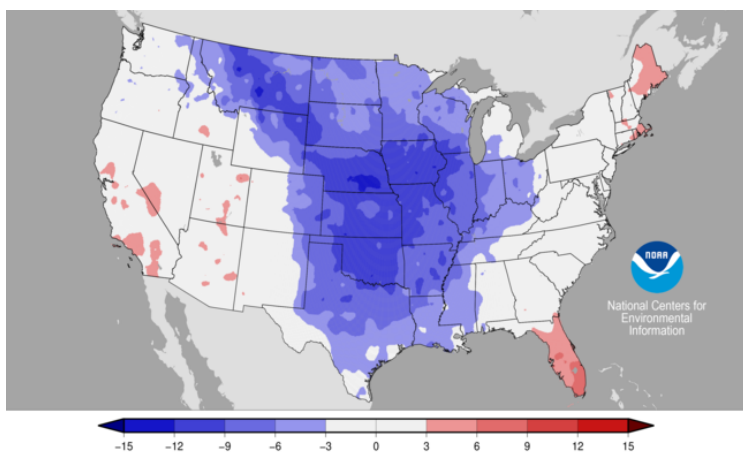
We refer to shippers that met more than five times as engaged in long-term relationships. These categories will help us understand the results of the event studies.

## 4 Empirical Model and Results

### 4.1 Event Study – Investigation of a Cold Wave

#### *February 2021 Cold Wave*

In February 2021, an extraordinary cold wave, driven by a polar vortex’s southward shift following a sudden stratospheric warming, swept across Canada, the United States, and northern Mexico. This rare meteorological event led to severe winter storms, unprecedented snow, and cold temperatures in states forming the deep south, such as Texas, Oklahoma, and Arkansas.



**Figure 4:** Temperature Deviation from Historical Average – February 2021

Notes: Temperatures are expressed as deviation (in Fahrenheit) from average temperatures during the 20<sup>th</sup> century across 5km grid points. Source: National Center for Environmental Information (NCEI).

This cold wave led to an unexpected demand increase for home heating, affecting demand for natural gas as a direct heat source for homes and indirectly through electricity generation. In states such as Texas, natural gas directly heats 35% of homes, and electricity heats the remaining 65%. Meanwhile, natural gas is responsible for over 50% of electricity generation.<sup>6</sup> We expect this cold wave to have led to unprecedented pressure on natural gas pipelines,

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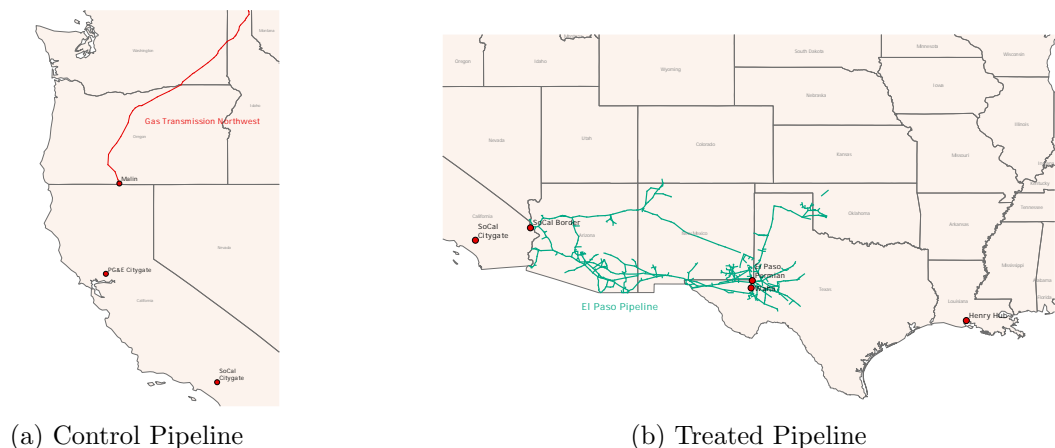
<sup>6</sup>Texas uses natural gas for electricity generation and home heating.

not only due to the unexpected rise in demand but also as some pipeline segments froze and burst, disrupting some of the supply.<sup>7</sup>

In this section, we investigate the secondary market’s role in allocating natural gas capacity during the cold wave, as well as some of the mechanisms underlying this effect and potential trade-offs associated with the secondary market. We first investigate a simple difference-in-difference event study that allows us to compare outcomes between treated and control pipelines throughout the cold wave. Outcomes such as contracted quantity may have persisted in the weeks following the shock because the end date was not known ex-ante.

### *Defining Control and Treatment Pipelines*

To define control and treatment pipelines, we looked at interstate pipelines with a similar activity ratio in the secondary market relative to the pipeline’s total capacity and location. We chose El Paso Natural Gas Company as a treated pipeline, which transports gas from the San Juan, Permian, and Anadarko basins to selected states, including Texas and Oklahoma. The El Paso pipeline is a good candidate because it covers most hubs that saw massive hikes in natural gas prices relative to prices at Henry Hub during the cold wave. Prices in southwestern Texas and southeastern California rose between 10 and 25 times the national benchmark due to the unprecedented uptake in demand. Panel (b) of Figure 5 shows the map of the treated pipeline with selected hubs.

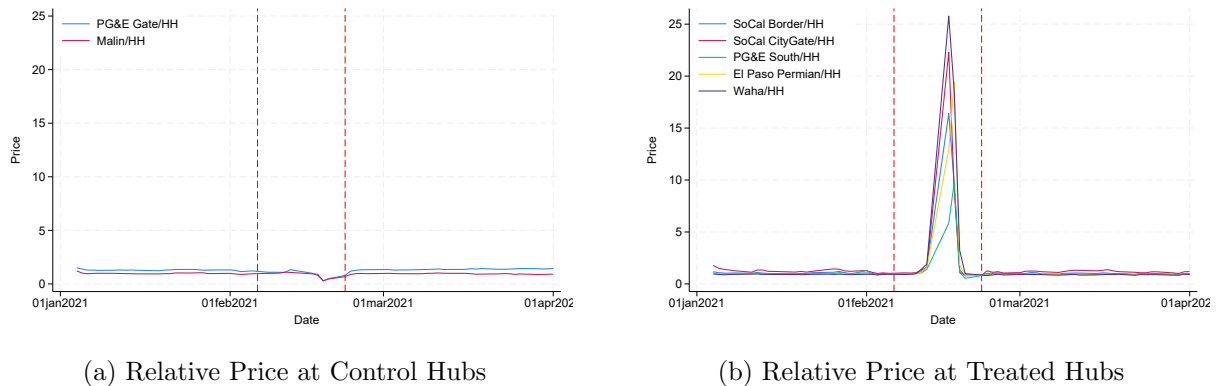


**Figure 5:** Treated and Control Pipeline Maps with Selected Hubs

As a control, we chose the Gas Transmission Northwest pipeline (GTN), which takes gas from Western Canada and takes it to Northern California—in contrast to abnormal weather variation in Texas, Figure 4 indicates that Northern California was not affected by the cold wave because temperature did not deviate from historical averages. Panel (a) of Figure 5 shows the control pipeline map.

<sup>7</sup>February 2021 North American cold wave.

To further validate the categorization of treated and control groups, we calculate the price of natural gas at selected hubs served by treated and control pipelines relative to the Henry Hub benchmark. Figure 6 shows the prices. We can see that during and after the cold wave, the relative prices at control hubs are quite stable. However, for treated hubs, there is a spike in gas prices during the cold wave.



**Figure 6:** Prices relative to Henry Hub

*Notes:* This figure plots the price of natural gas at selected hubs served by treated pipelines relative to the Henry Hub benchmark. The dotted red lines correspond to the official beginning of the cold wave (February 6<sup>th</sup>, 2021) and the end of the cold wave (February 22<sup>nd</sup>, 2021)

As discussed by [Marmer, Shapiro and MacAvoy \(2007\)](#), the possibility for arbitrage could imply that the entire pipeline network is treated as intermediaries buy gas from unaffected regions (here, the West Coast) and sell it in affected regions (the Deep South). However, such arbitrage would increase demand at unaffected hubs and raise gas prices. We do not see a large price rise at unaffected hubs such as Malin and PG & E City gate (which serves San Francisco). Just as [Marmer et al. \(2007\)](#) found, there are likely important bottlenecks in the system preventing arbitrage between regions far away from each other. While the El Paso pipeline is a larger pipeline system than the GTN pipeline, the average percentage of capacity from the capacity release market is similar across both pipelines.

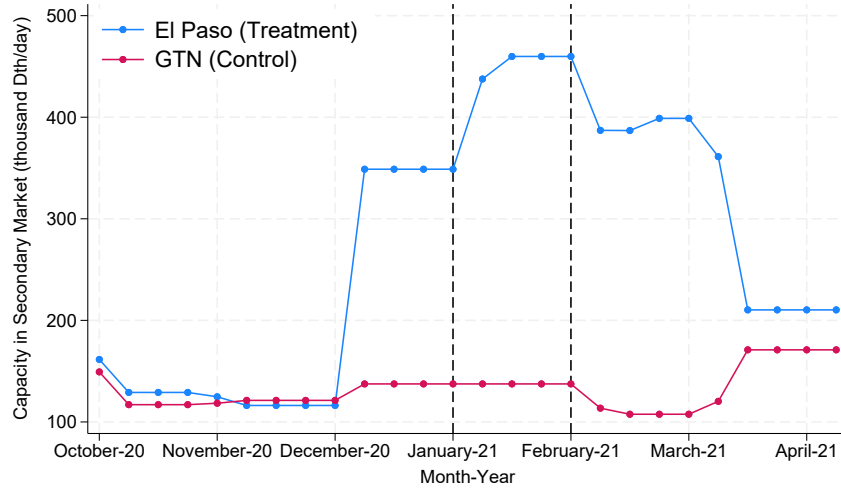
## 4.2 Difference-in-Difference Analysis

We perform a difference-in-difference event study with a single treated pipeline and a single control pipeline, allowing us to investigate the effect using a parsimonious two-way fixed-effects specification. We cannot rule out anticipation as shippers try to predict adverse weather events. Such extreme events may be correlated with temperature patterns over an extended period, such as an abnormally cold winter. We also cannot rule out persistent effects because shippers make decisions on capacity release without knowing the end date of



the demand shock and may want to air on the side of caution in the aftermath of the cold wave. Polar vortices can last from a few days to multiple months.

We allow for anticipation and persistence by investigating the effect in a larger window around the cold wave. As Figure 7 suggests, capacity released in the secondary market during the cold wave significantly increased in the El Paso pipeline (by 30% immediately following the beginning of the cold wave). It did not increase in the GTN pipeline. However, there was also a significant increase in capacity release for El Paso relative to GTN one month prior to the cold wave, which persisted up to one month after the cold wave.



**Figure 7:** Total Capacity in Secondary Market by Pipeline

*Notes:* The outcome variation displayed in this figure is the total capacity available in the secondary market each week. It is constructed by aggregating all contracts signed on previous dates with contracted capacity released during the current week. In the time axis, each month's tick corresponds to the end of the month. The dashed black lines correspond to the cold wave's beginning and end.

We also need to account for important seasonal variations across both pipelines. A careful look at the time series of capacity released in the secondary market outside of the window around the cold wave suggests a very distinct time series across pipelines. Much of the variation around the cold wave may obfuscate important seasonal patterns. Much of this variation can be attributed to pipeline-specific seasonal variation, in which different shippers make recurring contracts with each other. For example, utilities may lease some of their capacity to power plants every summer.

As shown in the main specification below, we allow for heterogeneous seasonal variation across pipelines to account for this rich heterogeneity. To study the causal effect of the 2021 cold wave on capacity released, we then propose the following two-way fixed effects specification:

$$y_{it} = \alpha_i + \alpha_t + q_{it}^T \delta + \sum_{m=-5}^{10} \beta_m D_{i,t-m} + \epsilon_{it} \quad (1)$$

Where  $i$  indexes pipeline,  $t$  indexes weeks.  $y_{it}$  is the log of capacity available in week  $t$  from the secondary market.  $q_{it}$  are pipeline-specific seasonality controls. These include week of the year (1-52) and year of observation.  $D_{i,t-m}$  is a treatment indicator defined as follows:

$$D_{i,t-m} = \begin{cases} 1 & \text{if } i \text{ is treated and we are } t-m \text{ weeks relative to start of cold wave} \\ 0 & \text{otherwise} \end{cases}$$

The outcome variable  $y_{it}$  aggregates all contracts signed at previous dates  $t-k$  that have contracted capacity to be released at  $t$ . Since most contracts are signed for one month, there is mechanically a lot of auto-correlation in  $y_{it}$ . We cluster standard errors at the monthly level to conduct autocorrelation-robust inference within 30-day periods.

To visualize the results, we follow the approach of [Freyaldenhoven, Hansen and Shapiro \(2019\)](#) by normalizing the treatment effect one week before the shock, plotting the cumulative treatment effect in a window around treatment. Under a null hypothesis that the cold wave was not anticipated, lasted throughout February (4 weeks), and did not have persistent effects, the cumulative treatment effect would be defined as:

$$\gamma_k = \begin{cases} 0 & \text{for } k < 0 \\ \sum_{m=0}^k \beta_m & \text{for } 1 \leq k \leq 4 \\ 0 & \text{for } k > 4 \end{cases}$$

However, as discussed earlier, shippers may anticipate an abnormally cold winter as they predict natural gas requirements before the winter starts. As discussed previously, there is likely much persistence in these treatment effects since contracts are signed without knowing when the cold wave will end. For these reasons, we plot an estimate of the cumulative effect up to five weeks before and ten weeks after the beginning of the cold wave, along with 95% confidence intervals. We then define estimates of the cumulative event path as follows:

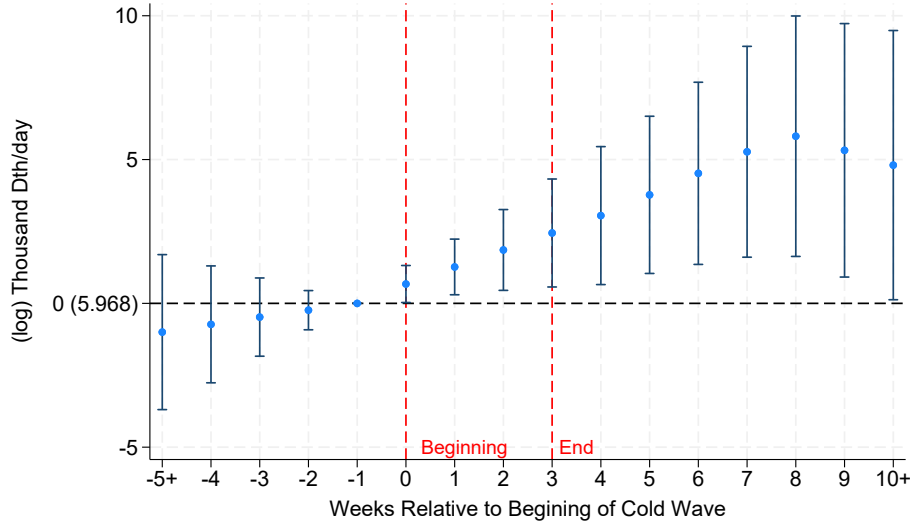
$$\hat{\gamma}_k = \begin{cases} \sum_{m=-k}^{-1} \hat{\beta}_m & \text{for } -5 \leq k < 0 \\ \sum_{m=0}^k \hat{\beta}_m & \text{for } 0 \leq k \leq 10 \end{cases} \quad (2)$$

To investigate anticipation and persistence more formally, we also present the results from a specification that aggregates the effect up to 2 months prior to the cold wave and

two months after the cold wave using the following specification:

$$\begin{aligned}
y_{it} = & \alpha_i + \alpha_t + q_{it}^T \delta + \underbrace{\beta_d D_{i,t \in \text{dec}20} + \beta_j D_{i,t \in \text{jan}21} + \beta_f D_{i,t \in \text{feb}21}}_{\text{Treated pipeline two months before}} \\
& + \underbrace{\beta_m D_{i,t \in \text{mar}21} + \beta_a D_{i,t \in \text{apr}21}}_{\text{Treated pipeline two months after}} + \epsilon_{it}
\end{aligned} \tag{3}$$

### 4.3 Results — El Paso (treatment) and GTN (control)

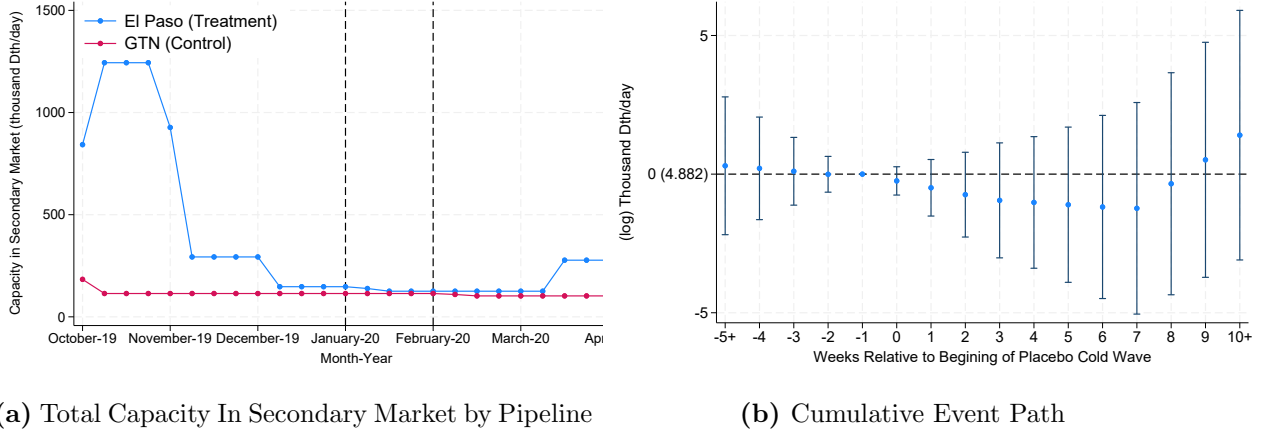


**Figure 8:** Baseline Cumulative Event Path

*Notes:* This figure plots the event path specified in equation 2 along with 95% confidence intervals. Specifically, we plot the cumulative effect of the February 2021 cold wave on the quantity of pipeline capacity contracted in the secondary market. Specifically, this quantity is defined as the total quantity released in the current week, aggregating all contracts signed prior to and up to the current week. We do so because many contracts are often signed weeks before the capacity is released. We exclude contracts that are signed for periods of one year or more.

Figure 8 shows the estimated cumulative event path from the main specification in Equation 1. While we do not find statistically significant violations of the pre-trend assumption, these results do not suggest a lack of anticipation. Rather, it should be interpreted as a lack of anticipation that the cold wave would start earlier than planned. Anticipation is directly embedded in the outcome variables, aggregating previously signed contracts. On the other hand, we find large and significant persistent effects many weeks after the cold wave, suggesting that shippers did not know when the demand shock would end. Overall, the cold wave caused an increase in capacity release by an average of 50% across the duration of the cold wave. See Table 9.

To further validate these findings, we performed a robustness check by imposing a placebo cold wave one year before, in 2020, and found no evidence of a placebo treatment effect.



**Figure 9:** Placebo Cold Wave (One Year Before)

**Table 9:** Main Results — Average Effect of Cold Wave on Capacity Release

	Real cold wave (log) Capacity	Placebo cold wave (log) Capacity
I(Two Months Before x Treated)	0.251 (0.376)	0.349 (0.405)
I(One Month Before x Treated)	0.215 (0.336)	-0.112 (0.331)
I(During x Treated)	0.579* (0.237)	-0.203 (0.242)
I(One Month After x Treated)	0.674* (0.280)	-0.130 (0.278)
I(Two Months After x Treated)	-0.266 (0.338)	0.624* (0.294)
$N$	1,278	1,278
adj. $R^2$	0.784	0.782

Notes: Standard errors in parentheses.  $^+ p < 0.10$ ,  $^* p < 0.05$ ,  $^{**} p < 0.01$ ,  $^{***} p < 0.001$

Notes: these results are exactly as specified in Equation 3. As such, they are not the cumulative treatment effects but the average treatment effect across the specified period. The first column presents results with the real cold wave whereas the second column presents results for the placebo cold wave (one year earlier), including two months before and after this placebo cold wave.

### Secondary Market and Search Costs

To investigate trade-offs associated with a deregulated secondary market, we first provide evidence that the cold wave, interpreted as a demand shock, increased the search cost

between a releasing and a replacement shipper. As argued previously, the secondary market provides a mechanism to reduce these search costs by fostering the formation of long-term relationships. Indeed, more than 95% of contracts in the secondary market are private arrangements between shippers, and shippers often use these private arrangements to form long-term relationships. We now argue that these long-term relationships are crucial when shippers face large unexpected demand shocks such as the cold wave of 2021.

To be consistent with our classification in Section 3, we group all contracts from the secondary market into two categories: contracts between shippers that met less than five times in the past (which we call new relationships) and contracts between shippers that met more than five times in the past (which we call long-term relationships). Below is the distribution of relationship frequency between shippers:

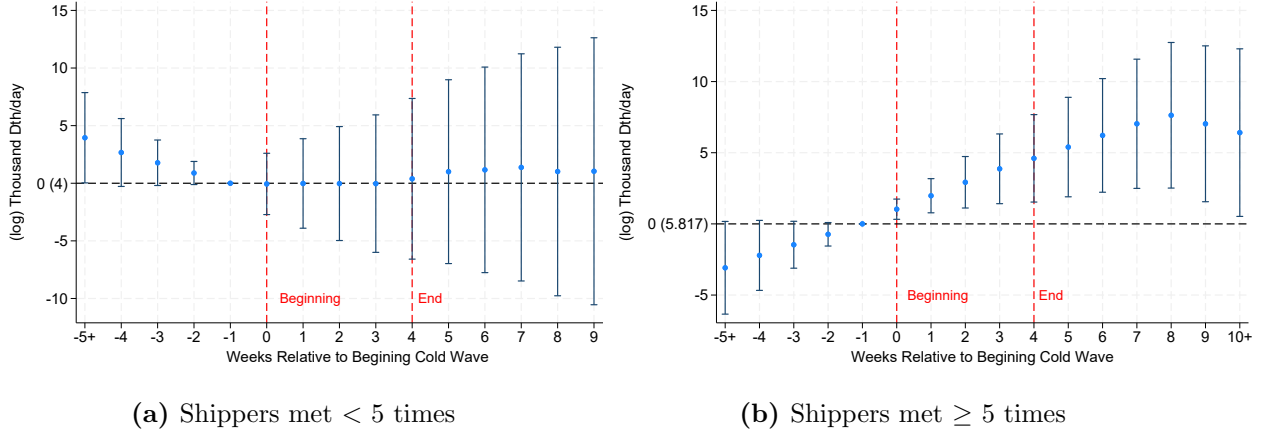
**Table 10:** Distribution of Relationship Frequency by Pipeline

Frequency of Identical Shippers Signing Contracts	El Paso (Treatment) <i>Percentage (%) of Contracts</i>	GTN (Control) <i>Percentage (%) of Contracts</i>
Never met	1	2
Met $> 0$ but $\leq 5$ times	22	9
Met $> 5$ but $\leq 10$ times	18	16
Met $> 10$ but $\leq 15$ times	15	10
Met $> 15$ but $\leq 20$ times	8	5
Met $> 20$ but $\leq 25$ times	9	25
Met $> 25$ but $\leq 30$ times	7	5
Met $> 30$ times	20	28
Total	100	100

*Notes:* The distribution corresponds to the percentage of unique contracts signed between shippers.

We then re-estimate the two-way fixed effects regression of equation 1 separately by groups. When grouping the contracts by relationship frequency in Figure 10, we find that the effect of the cold wave on capacity released is overwhelmingly driven by long-term partners. Moreover, the effect nearly doubles when narrowing down on long-term partners. On average, we find that the cold wave caused an increase in capacity between long-term partners by approximately 90%.

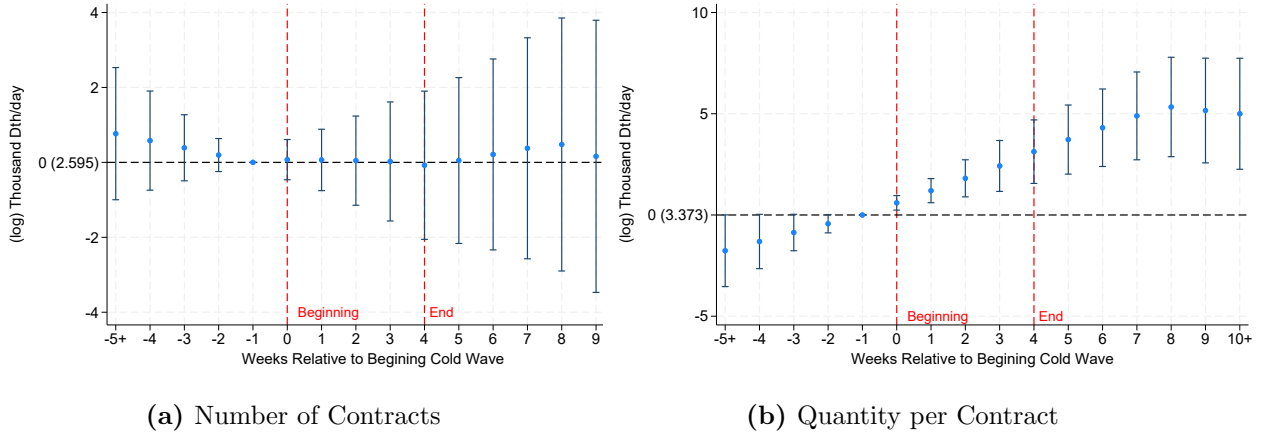
Finding new partners has a high search cost, and in times of unexpected shock, the opportunity cost of searching is high. For this reason, shippers reduce the search cost by leveraging their existing relationships. Moreover, the secondary market provides a platform for shippers to form new relationships during normal times, which can be leveraged during shocks. In this context, the secondary market provides a mechanism to reduce the search cost. Due to the FERC regulation, which mandates that all contracts be posted on public



**Figure 10:** Cumulative Event Path by Relationship Length

platforms, the secondary market fosters the formation of long-term relationships by providing shippers with daily information on the key players in each market.

We further substantiate this narrative that the cold wave is associated with a higher opportunity cost of searching by looking at the characteristics of contracts during the cold wave. Indeed, what drives the main result is not an increase in the number of contracts, which would be costly, but rather an increase in the average quantity released by contract.



**Figure 11:** Event Path – Number of Contracts and Quantity per Contract

While this narrative on search costs is broadly consistent with the literature, there is one key difference. In the literature on intermediation with search costs (Spulber, 1996; Gehrig, 1993), it is often assumed that parties on two sides of a market can either engage in search or go through an intermediary to avoid search costs. In our case, the margin to reduce search cost is forming relationships between an intermediary (the replacer) and a releaser. This means that the presence of an intermediary does not eliminate search costs. We also argue that both releasers and replacers engage in search. The replacers search for available

**Table 11:** Average Effect of Cold Wave — Extensive and Intensive Margins

	(log) Number of Contracts	(log) Average Quantity per Contract
I(Two Months Before x Treated)	1.146*** (0.141)	-0.895** (0.290)
I(One Month Before x Treated)	-0.194 (0.125)	0.409+ (0.229)
I(During x Treated)	0.003 (0.126)	0.577*** (0.166)
I(One Month After x Treated)	0.084 (0.152)	0.589** (0.174)
I(Two Months After x Treated)	-0.229 (0.160)	-0.037 (0.210)
$N$	1,278	1,278
adj. $R^2$	0.726	0.860

Notes: Standard errors in parentheses. +  $p < 0.10$ , \*  $p < 0.05$ , \*\*  $p < 0.01$ , \*\*\*  $p < 0.001$

capacity when they face arbitrage opportunities between hubs. Releasers search for buyers when they do not need capacity to avoid paying reservation fees for unused capacity.

### Market Power

While the secondary market provides a platform for shippers to reduce search costs of releasing capacity, it is also largely unregulated. For the majority of contracts signed, releasing and replacement shippers can freely negotiate a contract rate, which can be below, equal, or above what the releaser pays to the pipeline.<sup>8</sup> Deregulation can incentivize market participants to engage in the secondary market but can also introduce market power, causing friction. We now investigate market concentration across different pipelines and zones. We find evidence that some markets have more concentrated releasers, while some have more concentrated replacers, and some have both. We relate this variation in market concentration to capacity release prices and find that releasers (replacers) with a higher market share tend to charge higher (lower) prices.

Table 12 summarizes market concentration across selected pipelines with considerable activity on the secondary market. We find substantial variation in market power across pipelines. For example, the Great Lakes (GL) pipeline has a high concentration of replacers and releasers, whereas El Paso has a low concentration of replacers but a high concentration of releasers. We also find lots of variation in average tariffs relative to the tariffs. Since the

<sup>8</sup>There are some exceptions. Certain contracts cannot have a rate above some maximum threshold the FERC sets. This constraint is based on the contract duration. Tariffs on capacity released for 31 days or less or one year or more can vary freely. Tariffs on capacity released between 31 days and one year cannot exceed the maximum tariffs. As Figure 3 suggests, the vast majority of contracts fall within the fully deregulated time constraints.



**Table 12:** Summary Statistics – Market Power and Prices (Secondary Market)

	Replacer HHI	Releaser HHI	$P < Max$	$Price = Max$	$P > Max$	$P = 0$
El Paso	1,660	4,821	0.81	0.15	0.04	0.21
GTN	1,723	4,746	0.21	0.75	0.04	0.03
GL	5,366	5,491	0.48	0.51	0.01	0.33
NGPL	1,529	1,769	0.68	0.24	0.08	0.09
Texas Eastern	2,708	1,586	0.50	0.42	0.08	0.32
Transwestern	1,889	2,685	0.95	0.03	0.02	0.15

*Notes:* In this Table,  $P$  refers to the tariff charged for a specific section of a contract in the secondary market, and always has two parts: a reservation fee and a volumetric charge based on gas flown. For example, a shipper can release capacity between delivery point  $A$  and receipt point  $B$  and between delivery point  $B$  and receipt point  $C$ . In this case, there would be four prices.  $Max$  corresponds to the maximum tariff set by the FERC for those four prices.  $HHI$  refers to the Herfindahl–Hirschman index.

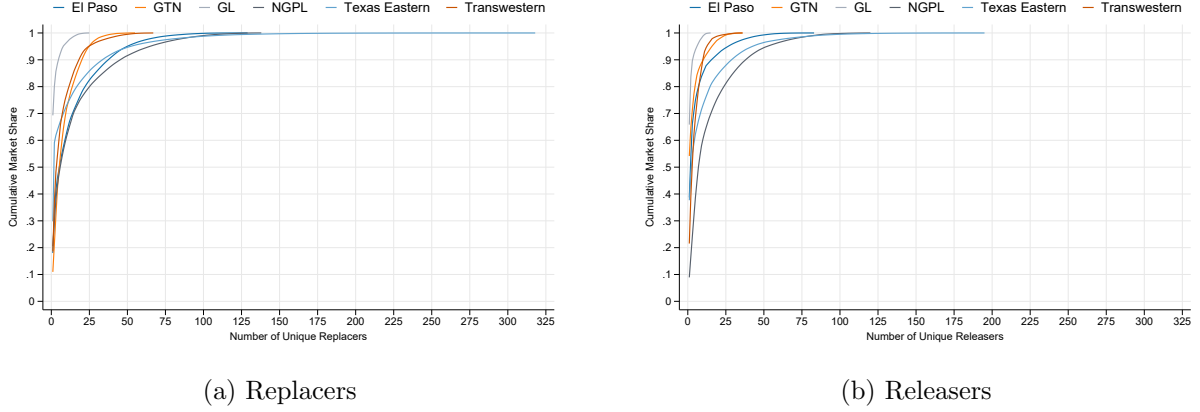
FERC sets these maximum tariffs specific to delivery and receipt points, they vary widely across contracts and provide a benchmark for comparing tariffs. However, Table 12 does not suggest a monotonicity between releaser/replacer market power and prices. For example, both El Paso and GTN have a high concentration of releasers relative to replacers, and tariffs are significantly more likely to be below the maximum in El Paso.

To understand this point better, we also show in Figure 12 that the cumulative distribution of market power in releasing shippers tends to be highly correlated with the cumulative distribution of market power for replacement shippers, which is likely to be correlated with market thickness. Great Lakes is the most concentrated in both releasers and replacers, whereas NGPL is the least concentrated. GTN and Transwestern are more concentrated in releasers and replacers than El Paso and Texas Eastern. For this reason, only looking at variation in market concentration may not provide enough variation to investigate its effect on tariffs.

Next, we investigate the role of releaser and replacer market power on tariffs in more detail. Specifically, we investigate variation in market power at the individual releaser/replacer level. We specified the following regression model, where we consider both the log of tariffs and the log of tariffs relative to maximum tariffs as outcome variables:

$$\ln Y_{pcit} = \alpha_t + \alpha_p + X_{it}^T \beta + z_{cpit}^T \gamma + \beta^{rep} \ln S_{rep,it} + \beta^{rel} \ln S_{rel,it} + \epsilon_{cpit}$$

Where  $p$  indexes a delivery and receipt point pair,  $c$  indexes a contract,  $i$  indexes a pipeline, and  $t$  indexes days. The main independent variables of interest are the market share of releasing and replacement shippers signing the contract,  $\ln S_{rep,it}$  and  $\ln S_{rel,it}$  respectively.



**Figure 12:** Market Concentration Across Pipelines

For robustness, I consider various specifications for this market share: (1) total pipeline market share (constant across all years); (2) annual pipeline market share; (3) total market share in pipeline-specific zones (constant across all years); and (4) annual market share in pipeline-specific zones.

$X_{it}$  are seasonal adjustments that vary by pipelines, and  $Z_{it}$  are control variables and include relationship length between shippers and other contract characteristics such as contract duration.  $\alpha_p$  are pipeline-specific delivery-receipt point fixed effects, so they absorb pipeline fixed effects, and  $\alpha_t$  are week fixed effects. Here,  $\beta^{rep}$  and  $\beta^{rel}$  capture variation in market share across shippers and within shippers over time because we omit shipper fixed effects.<sup>9</sup> All the results are robust to the inclusion/exclusion of all control variables, fixed effects, and seasonality.

The results in Table 13 suggest a strong relationship between market share and tariffs charged, both for replacers and releasers, suggestive of price-setting behavior. Moreover, this relationship is twice as large for releasers. Remembering that releasers benefit from higher tariffs (supply) and replacers benefit from lower tariffs (demand), a 1% increase in releaser market share is associated with a 0.09% increase in tariffs, whereas a 1% increase in replacer market share is associated with a 0.04% decrease in tariffs.

These results suggest two-sided market power. In such a context, it is unclear what the welfare implications of partially deregulating the natural gas transportation industry through its secondary market are. On the one hand, the secondary market allows tariffs to vary over time and respond to fluctuations in supply and demand. These tariffs are otherwise constant and set by long-term contracts in the primary market, which may prevent the efficient allocation of capacity, particularly during shocks. On the other hand, Deregulation

<sup>9</sup>We also tried including shipper fixed effects, but there is not enough remaining variation (e.g., only over time within shippers) because market shares tend to be fairly consistent over time.

**Table 13:** Estimation Results – log Tarrifs

	(1)	(2)	(3)	(4)
Releaser share	0.088*** (0.003)			
Replacer share	-0.040*** (0.001)			
Annual releaser share		0.063*** (0.003)		
Annual replacer share		-0.042*** (0.001)		
Zone releaser share			0.113*** (0.003)	
Zone replacer share			-0.037*** (0.001)	
Annual zone releaser share				0.103*** (0.003)
Annual zone replacer share				-0.040*** (0.001)
Time FE	Yes	Yes	Yes	Yes
Pipeline FE	Yes	Yes	Yes	Yes
Delivery and Receipt point FE	Yes	Yes	Yes	Yes
$N$	86,112	86,082	78,778	78,657
adj. $R^2$	0.777	0.773	0.726	0.721

Standard errors in parentheses

+  $p < 0.10$ , \*  $p < 0.05$ , \*\*  $p < 0.01$ , \*\*\*  $p < 0.001$ 

of pipeline capacity implies that market participants influence tariffs based on their market share, as seen in Table 13, which may restrict the allocation of capacity. Thus, the aggregate implications are unclear, and there may be significant variation across pipelines and regions. We plan to investigate these welfare implications in future research.

## 5 Model

## 5.1 Setup and Players

We consider a network with multiple origin-destination  $o - d$  points, which is organized as follows with three key players:

1. **Releasers:** There are releasers at each destination node. Releasers own pipeline capacity  $K_{od}$  between origin and destination points.
  - Releases  $q_{od}$  in secondary market
  - Consumes remaining  $c_{od} = K_{od} - q_{od}$  with utility function  $u^r(\sum_o c_{od}, x_d)$ , where  $x_d$  is a destination-specific demand shock.
2. **Replacers (marketers):** engages in arbitrage opportunities coming from price differentials across hubs.
  - buys capacity from releaser  $q_{od}$  and gas, then sell gas to consumers
3. **Consumers:** There are consumers at each destination node. Unlike releasers, consumers do not own pipeline capacity. Therefore, consumers need to go through marketers to consume natural gas.
  - buys gas  $Q_d = \sum_{o \neq d} q_{od}$  from marketer. Utility function  $u^c(\sum_o q_{od}, x_d)$

Lastly, there is a Fixed supply of gas to be dispatched from each origin point  $Q_o = \sum_{d \neq o} K_{od}$ . The key spatial friction we consider is the fact that total supply of gas is lower than total pipeline capacity:

$$\sum_d K_{od} < Q_o \quad \forall o$$

## 5.2 Market Structure

We are interested in comparing various market structures which we think represent different regions of the US. Critically, we seek to understand the implication of different market structures on the price differential across natural gas hubs as a measure of “efficiency” for the entire network. Price differentials reflect both physical capacity constraints and artificial/contractual constraints. Here, we are interested in the latter, which has received much less attention in the literature.

First, we use perfect competition on all sides of the market as a benchmark, where each player takes prices as given. In our context, perfect competition is also the solution to the planner's problem:

$$\begin{aligned}
\text{Releaser: } \pi_d^r &= \max_{\{q_{od}, c_{od}\}} \left\{ \underbrace{u^r \left( \sum_{o \neq q} (c_{od}), x_d \right)}_{\text{own consumption}} + \underbrace{\sum_{o \neq q} \tau_{od} q_{od}}_{\text{releases to marketer}} - \underbrace{\sum_{o \neq q} p_o(c_{od})}_{\text{buy unreleased gas}} \right\} \\
\text{Marketer: } \pi_d^m &= \max_{\{q_{od}\}} \left\{ \underbrace{p_d \sum_{o \neq q} q_{od}}_{\text{sell gas to consumer}} - \underbrace{\sum_{o \neq q} \tau_{od} q_{od}}_{\text{buy capacity from releaser}} - \underbrace{\sum_{o \neq d} p_o q_{od}}_{\text{buy gas from spot market}} \right\} \\
\text{Consumer: } \pi_d^c &= \max_{\{q_{od}\}} \left\{ u^c \left( \sum_{o \neq q} q_{od}, x_d \right) - p_d \sum_{o \neq d} q_{od} \right\}
\end{aligned}$$

Second, we consider the case where the marketer acts as a monopoly on consumers, but perfect competition remains in the upstream market (releasers and marketers). The only difference is that marketers now strategically take into account the decisions of consumers:

$$\text{Marketer } \pi_d^m = \max_{\{q_{od}\}} \left\{ \underbrace{p_d \left( \sum_{o \neq q} q_{od} \right) \sum_{o \neq q} q_{od}}_{\text{sell gas to consumer}} - \underbrace{\sum_{o \neq q} \tau_{od} q_{od}}_{\text{buy capacity from releaser}} - \underbrace{\sum_{o \neq d} p_o q_{od}}_{\text{buy gas from spot market}} \right\}$$

Third, we consider the case where the releaser is a monopoly to marketer, which is a monopoly to consumers (double marginalization). The only difference from the second case is that releasers now strategically take into account the actions of marketers:

$$\text{Releaser } \pi_{od}^r = \max_{\{q_{od}\}} \left\{ \underbrace{u^r \left( \sum_{o \neq q} (K_{od} - q_{od}), x_d \right)}_{\text{own consumption}} + \underbrace{\sum_{o \neq q} \tau_{od}(q_{od}) q_{od}}_{\text{releases to marketer}} - \underbrace{\sum_{o \neq q} p_o (K_{od} - q_{od})}_{\text{buy unreleased gas}} \right\}$$

Fourth and last, we consider the case where the marketer is a monopsony to releasers and a monopoly to consumers. In the upstream market, it is the opposite of the previous case:

$$\text{Marketer } \pi_d^m = \max_{\{q_{od}\}} \left\{ \underbrace{p_d \left( \sum_{o \neq q} q_{od} \right)}_{\text{sell gas to consumer}} \underbrace{\sum_{o \neq q} q_{od}}_{\text{buy capacity from releaser}} - \underbrace{\sum_{o \neq q} \tau_{od}(q_{od}) q_{od}}_{\text{buy gas from spot market}} \right\}$$

We think that all markets in the US feature a convex combination of the third and fourth case, with varying weights on the releaser having more market power vs. the marketer having more market power.

### 5.3 Simple Network — Price Arbitrage

For now, we will consider a simple network with three nodes: one origin node  $o$  and two destination nodes  $(a, b)$ . Much of the interesting results come from this simple network. There is a fixed total quantity of natural gas  $K_o$  that can be supplied from  $o$  to either  $a$  and/or  $b$ .

We assume that the total pipeline capacity is larger than the total quantity of gas available. Specifically,  $K_{od} = K_o$ ,  $\sum_{O=(A,B)} K_{od} = 2K_o$ . For simplicity, we also assume that the releaser and consumers have the same log utility  $u^r(c, x) = u^c(c, x) = \log(c)e^x$ . We then consider what happens in the competitive benchmark. Each player maximizes its objective function, taking all prices as given:

$$\begin{aligned} \text{Releaser: } \max_{c_{od}, q_{od}} & \left\{ \ln(c_{od})e^{x_d} + \tau_{od}q_{od} - p_o c_{od} \right\} \\ \text{s.t. } & q_{od} + c_{od} - k_o \leq 0 \end{aligned}$$

The problem of marketer and consumers is trivial to elaborate here. Let  $\lambda_d$  be the lagrangian multiplier. Each player's first-order condition is such that:

$$\begin{aligned} \text{Releaser: } & \frac{e^{x_d}}{c_{od}} - \lambda_d - p_o = 0 \\ & \tau_{od} - \lambda_d = 0 \\ & \lambda_d(k_o - q_{od} - c_{od}) = 0 \\ \text{Marketer: } & p_d = \tau_{od} + p_o \\ \text{Consumers: } & p_d = \frac{e^{x_d}}{q_{od}} \end{aligned}$$

Market clearing:

$$c_{oa} + q_{oa} + c_{ob} + q_{ob} = k_o$$

With perfect competition, we know that the marketer will only flow gas if transportation cost is zero  $\tau_{od} = 0$ . Any allocation in which the marketer does not flow gas is suboptimal for the consumer. In that case, let's set transportation costs to zero, and consequently all gas prices equal  $p_o = p_a = p_b$ , and a non-binding non-negative constraint for the consumer  $\lambda_a = \lambda_b = 0$ . In that case, market clearing becomes:

$$\begin{aligned} \frac{e^{x_a}}{p} + \frac{e^{x_a}}{p} + \frac{e^{x_b}}{p} + \frac{e^{x_b}}{p} &= k_o \\ p &= \frac{2(e^{x_a} + e^{x_b})}{k_o} \end{aligned}$$

*Intuition:*

Even though demand shocks may be different at  $a$  and  $b$ , we get full price arbitrage, necessary to flow any gas to consumers. The key is that, while prices are equal, they also equalize marginal utilities across both regions:

$$MU_a = p = MU_b$$

However, since demand shocks are different, quantities will adjust accordingly:

$$\begin{aligned} q_a = c_a &= \frac{k_o}{2} \frac{e^{x_a}}{(e^{x_a} + e^{x_b})} \\ q_b = c_b &= \frac{k_o}{2} \frac{e^{x_b}}{(e^{x_a} + e^{x_b})} \end{aligned}$$

## 6 Conclusion

This paper investigates a major deregulation effort in a highly regulated industry characterized by natural monopolies: the secondary market for natural gas capacity release. It is one of the first empirical investigations of a real Coasian market in which market participants can trade legal entitlements, allowing us to shed light on the resilience of supply chains, par-



ticularly on the supply of natural gas during periods of high demand. Our results highlight that the secondary market is an important market constituent during shocks, as evidenced by the large and persistent increase in capacity released in that market during the February 2021 cold wave in Texas. We argue that the secondary market improves the efficiency of capacity allocation by deregulating transportation tariffs and providing information to market participants, which fosters the formation of long-term relationships between releasers and replacers. However, deregulation comes at a cost, and we find evidence of market power that reflects price-setting behavior from both releasers and replacers.

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# Online Appendices: Not For Publication

## A Rate Regulation in the US Pipeline Industry

The United States pipeline regulatory authority, the Federal Energy Regulatory Commission (FERC), has both an established framework and legislation allowing it to approve pipelines of charging market-based rates. Much of this framework and legislation was developed in the late 80s and early 90s and today a handful of pipelines charge market-based rates, mostly oil pipelines. While the FERC grants oil and natural gas pipelines market-based rate authority under two separate pieces of legislation generally the following must be included by a pipeline as evidence to move towards market-based rates:

- Describe proposed service.
- Define relevant product and geographic markets.
- Provide applicant's ownership and then list affiliated energy companies, services provided, and their location. If an affiliate operates in the same geographic market, the market shares of the applicant and the affiliate should be combined.
- Identify good alternatives to the proposed service - which parties provide similar service within the same geographic market. List the applicant's competitors and location.
- Include market share and Herfindahl-Hirschman Index (HHI) calculations to measure market concentration. The Commission's traditional HHI threshold is 1,800.
- Discuss other relevant competitive factors such as ease of entry and excess capacity held by competitors.
- Describe how the applicant's rates compare to the competitors.

In addition to the evidence above some pipelines have also provided econometric analysis to show that its shippers have a relatively high elasticity of demand, as a means to quantify the competitive position these pipelines face. It has also been required that pipelines provide cross-price elasticities for different products transported in their pipeline or by competitors. For example, a liquids pipeline may be constructed to ship various types of petroleum products (heavy crude, light crude, condensate, refined products, etc.) vs. another pipeline within the same area only capable of transporting a single type of petroleum product. In that case the regulator does not seem the product transported through the pipeline as homogenous and may review cross-price elasticities.

The FERC also has authority to determine if only a certain portion of a system may be granted market-based rate authority. For example, the origin market for pipelines is often considered as the production areas, which often could be considered not sufficiently concentrated and may result in the pipeline having market power in the origin market. However, many pipelines, before reaching their ultimate destination, pass through storage hubs. These storage hubs often have many pipelines entering them and are seen as a more competitive market. Therefore, a pipeline may not be granted market-based rates for its

entire system but only a portion of its system, say from these storage hubs to its destination market.

As is evident the United States has a much more established framework for determining market-base rate authority. This is largely due to the more competitive nature of the pipeline industry in the United States in comparison to Canada. While this framework is established it is also important to note that this represents a relatively steep bar to cross and there are very few pipelines that are granted this authority.

## A.1 Throughput (Utilization Rate)

Most pipelines split pipeline flow into 4 nomination windows/cycles that create 3 periods of potentially unique flow conditions.

1. 7am – 12pm
2. 12pm – 4pm
3. 4pm – 7am (next day)

The scheduled capacity is what they are actually nominating to flow in any of these particular periods and the maximum capacity is essentially the size of their contract and available capacity is what they do not utilize. Note if these are firm contracts they still pay the full demand rate on the maximum capacity and pay variable charges (extremely small compared to the demand rate, essentially only fuel) on the scheduled capacity for that nomination window. However, lots of times the less sophisticated shippers will just set their scheduled capacity and leave it the same for all 4 windows, even set that for a full week or month and generally if there is no nomination the pipeline assumes it to be the previously nominated amount.

So taking the average of 4 nomination cycle scheduled capacity is a good proxy for daily flow of the contracts, with a few caveats:

1. The period of 12am – 6:59am of any given days capacity will be dependent on the intraday 2 nomination from the previous day, we could get around this by defining a day as 7am-7am (the next day).
2. When defining this utilization we want to be very specific of what we are saying here. Particularly this is utilization of an existing contract within a day/week. I think it would be too definitive of a statement to say this is the utilization of the entire pipeline because we do not have information on things like interruptible/ancillary service being sold by the pipeline after firm nominations are tallied.

## B Capacity Release Market

### B.1 How does Capacity Release Market Work?

We first explain in more detail the capacity release programs:

1. Capacity releases can be put forward by the pipeline or requested from shippers. Both get posted on the pipeline's website.
2. There are generally two types of capacity releases biddable and non-biddable. Biddable capacity releases are subject to an open season (bidding process) where the individual who bids the highest gets the capacity. Non-biddable capacity releases are generally agreements that are entered into before posting on the regulatory website and are only eligible for releases with contract lengths of 31 days or less, or more than 1 year. This is why we see most of the releases at 31 days in length or 1 year. Furthermore, capacity releases less than one year can be above the Tariff specified firm toll while those above a year cannot exceed the firm Tariff rate.
3. We discussed another very interesting feature the recall and reput options. Essentially if recall and reput conditions are included in a capacity release transaction then the original entitlement holder can at any time (within nomination window deadlines) "recall" that capacity and utilize it if they need it, this waives any tolls for the shipper that purchased the capacity release when it was recalled. Once the capacity is recalled the original entitlement holder can decide to "reput" that capacity if it no longer needs it and give it back to the shipper that originally purchased the capacity release. A recall/reput have to happen on separate days. From what Alan said this is a very common provision and we can see on the capacity release data from the pipeline whether these conditions are included in the contract.
4. Capacity release above the maximum tariff rate (releases less than or equal to 31 days, greater than or equal to 1 year, or bidded on).
5. The pipeline receives the same reservation charge whether it be from the releaser or the replacement shipper where they could potentially benefit is from the volumetric charge.

Below, we outline the timelines detailing the processes for conducting open season auctions for short-term and long-term releases, respectively.

#### Short Term Release (Less than 1 year)

1. The capacity release request is posted by 9:00am on a business day (the specific timing of which will vary depending on the pipeline to meet their nomination windows, I found 9am to be the most common).
2. The open season/auction period is held between 9:00-10:00am. This is a silent auction, no parties can see what others bid, and during this period bids can be withdrawn.

3. The pipeline company begins evaluation of the bids at 10:00am, contingencies are cleared, and a determination of the best bid is made based on the process specified by the releaser/requester.
4. Both parties are notified by 11:00am and confirmed by 12:00pm. The capacity release contract is awarded within an hour.

### **Long Term Release (More than 1 year)**

1. The capacity release request is posted by 9:00am on a business day.
2. The open season/auction period is then held for three consecutive business days, such that the open season process ends at 10:00am three business days after the capacity release posting.
3. The pipeline company begins evaluation of the bids at 10:00am three days later, contingencies are cleared, and a determination of the best bid is made based on the process specified by the releaser/requester.
4. Both parties are notified by 11:00am and confirmed by 12:00pm. The capacity release contract is awarded within an hour.

## **B.2 Interviews with Practitioners**

Below we document our interviews with practitioners that participate in the capacity release market:

- Q: Why someone would not have an incentive to just nominate 100% of their firm contract?

A: This is due to there also being a certain amount of variable costs associated with transportation. We discussed these briefly before Yanyou. but I was not aware it could be such a factor, for example, pipeline abandonment surcharges or fuel costs for shipping on the pipeline. If you nominate a particular level of gas for that nomination window it is assumed you use up to 100% of the gas you nominated, therefore you incur variable costs on a volumetric basis equal to your nomination. While these are small in comparison to the overall demand charges (fixed costs) there is little to no incentive for certain types of customers (industrial user or a local distribution company) to incur those costs if they do not require the gas. Whereas marketers/natural gas traders will only choose to nominate their full amount of their contract if the contract path is “in the money”: price of natural gas at destination plus variable cost of transportation is greater than the price of natural gas at origin.

- Q: How often do people choose biddable agreement?

A: In terms of biddable or non-biddable he would be surprised if more than 1% of the capacity releases were the result of a biddable process. Most are prearranged deals where you have negotiated before posting it on the pipeline’s website. In particular, even in the US many relationships are established, and many players are aware of who to call if they need a capacity release.



- Q: What is the difference between a natural gas utility, marketer, and retailer?

A: A natural gas utility is a regulated entity that distributes natural gas, sometimes known as a local distribution company (LDC), to end use customers such as residential, commercial, and industrial customers. LDCs will often have an exclusive franchise area of a city or region and in turn their rates charged for their services are regulated by state regulatory authorities. Utilities source the transportation of their gas from interstate and intrastate pipelines which are in turn regulated by federal or state regulatory authorities, respectively. These utilities are required by their regulators to hold a certain percentage of their peak day demand requirements in long-term contracts on these pipeline systems. Utilities average day demand requirements are often much lower than their peak day requirements and therefore utilities hold excess transportation capacity on interstate and intrastate pipeline systems.

Natural gas marketers are unregulated companies that arrange for the purchase and sale of natural gas. Most typically marketers arrange for gas supply agreements with natural gas producers or purchase gas at trading hubs. They then sell this gas to end users or at other market hubs to earn profit based on the spreads between different prices of natural gas hubs. To transport natural gas marketers must also hold capacity on natural gas pipelines but are not required to hold any typical amount of capacity and often choose to be nimble in the amount of capacity they hold on pipeline systems. When arranging the supply of gas for an end user marketers will typically charge for the cost of gas, cost of transportation, and then a service fee for arranging the transactions.

Natural gas retailers are also unregulated companies that arrange for the purchase and sale of natural gas. However, the main distinction between them and marketers is that retailers typically hold capacity on natural gas distribution systems and sell to end users such as residential, commercial, and industrial customers. The distinction between retailers and LDCs is that the provision of natural gas distribution (responsibility of LDCs) is regulated but the retail sales of natural gas is often competitive. End use consumers can choose to purchase gas directly from the LDC, which offers a regulated rate, or from natural gas retailers which have competitive rates. Natural gas retailers typically source their natural gas from natural gas marketers or in certain circumstances are vertically integrated with a marketing company. Since both marketers and retailers are unregulated entities they do not require supply obligations and typically hold transportation or distribution capacity that is more in line with average day demand for natural gas, in contrast to peak day demand like utilities.

- Q: Why do we see a large portion of end users of natural gas utilize marketer's services instead of contracting for their own service on interstate natural gas pipelines?

A: A significant portion of end users of natural gas do not actually hold transportation capacity on interstate pipeline systems, or they are not connected to natural gas distribution utilities. These customers are often industrial facilities, agricultural operations, smaller power generation facilities, and natural gas retailers. Thus, a large amount of these end users of natural gas rely on natural gas marketers to meet their gas needs, both in terms of supply and transportation. The reason these end users do not hold

transportation capacity on pipelines is for two primary reasons: creditworthiness and balance sheet obligations.

The credit obligations that are necessary for a company to hold pipeline transportation service are often quite steep and that most companies could not meet. For example, a typical credit evaluation criteria for firm service on a natural gas pipeline is to provide security guarantees for three months of firm service at the maximum tariff rate for the entire volume of your contract. This requires companies to have large amounts of cash on hand (in the form of an advance deposit), a strong standing letter of credit from a financial institution, an acceptable security interest in collateral, or a guarantee from a more credit worthy parent company.

As for the balance sheet obligations, given the take or pay nature of natural gas transportation firm service contracts financial institutions view these transportation contracts as debt obligations. If a company were to take out large amounts of transportation capacity this would result in a large liability to appear on their balance sheet which may impact their own credit metrics, impacting their ability to secure their own financing and financial obligations.

Given these restrictive requirements many of these end users rely on the services of marketers to arrange for supply and transportation of their gas needs, since marketers require lower levels of credit requirements and the less restrictive outcomes on their balance sheet obligations. This comes at an increased cost to the end user as marketers often require a service fee or mark up for arranging supply and transportation of natural gas.

- Q: Why do we see natural gas marketers as replacers in the capacity release market?  
A: Since these end users rely on marketers to provide them service when unexpected shocks in demand happen either to end use residential, commercial, and industrial demand (increased demand for natural gas retailers) or unexpected shocks in their various industries that do not impact demand for gas utilities/retailers (for example an increase in demand for steel production) they often turn to marketers to supply them with additional natural gas. While the primary market for natural gas transportation is held largely by utilities, to meet their regulatory obligations, most periods of the year they do not require the full use of their transportation contracts and would prefer releasing that capacity to a marketer that will ultimately provide the transportation services to an end user.