Division of Economics and Business
Working Paper Series

Natural Gas Contract Decisions for Electric Power

Matthew Doyle
Ian Lange

Working Paper 2016-05
http://econbus.mines.edu/working-papers/wp201605.pdf

Colorado School of Mines
Division of Economics and Business
1500 Illinois Street
Golden, CO 80401

June 2016

Colorado School of Mines
Division of Economics and Business
Working Paper No. **2016-05**
June 2016

Title:
Natural Gas Contract Decisions for Electric Power*

Author(s):
Matthew Doyle
Division of Economics and Business
Colorado School of Mines
Golden, CO 80401-1887
matdoyle@mymail.mines.edu

Ian Lange
Division of Economics and Business
Colorado School of Mines
Golden, CO 80401-1887
ilange@mines.edu

ABSTRACT

Natural gas power plants can further specify their procurement contracts with pipeline distributors using a firm contract option that guarantees delivery at an additional cost. Using transaction level data from 2008-2012 we empirically test what characteristics lead to use of firm contracts and how the premium for firm contracts changes with these characteristics. Using variation in power plants technology type (combined vs. simple cycle) and electricity market structure (restructured vs. regulated), we generally find support for transaction cost theory in the data. Smaller plants, plants located in states with more variance in electricity demand, and plants in states with more inflow pipeline capacity are statistically less likely to use a firm contract. Firm contracts are on average 2.5% (14 cents per Mcf) more expensive and this premium increases as the weather is colder and the state a plant is located in has less inflow capacity.

JEL **classifications: Q40, L94, L95, L14**
Keywords: Natural Gas, Procurement Contracts, Pipelines, Electricity

*The authors wish to thank Harrison Fell, Pete Maniloff, Kanishka Kacker, and seminar participants at the Colorado School of Mines.

1 Introduction

Procurement contracts are written to divide up gains from trade between the two parties while balancing upfront costs of further specification against the possibility that the distribution of gains from trade *ex-post* vary from the party's expectations. Contract specification for natural gas as an input purchased by electricity producers often takes on several dimensions that are common to most contracts: the unit price, the quantity and the duration in which gas can be extracted from the pipeline. An additionally important measure of contract specificity in the case of natural gas is the priority for delivery. One option for the power plant is to increase contract specificity is by paying a *reservation price* premium for a guaranteed delivery of gas. These contracts are known as *firm transportation capacity*, hence referred to as firm contracts, and act as a guarantee for transportation through a pipeline. The alternative contract type is known as *interruptible transportation service*, hence referred to as interruptible contracts. We consider a firm contract as an increase in specification relative to an interruptible contract in that the parties have specified what the terms of trade will be in all contingencies.

Transactions cost theory suggests that contract specification will increase when there are fewer alternative options outside the contract (from either the buyer's perspective or the seller's perspective) (Klein et al. 1978) and when the value of the product contracted is more uncertain (Bajari and Tadelis 2001)(Crocker and Reynolds 1993). This paper tests whether the observed contracts signed between power plants and pipeline companies match the predictions of transactions cost theory using natural gas transaction data.[1] While trans-

[1] There is little reason to believe that asymmetric information is a concern in these contracts as natural gas is a relatively homogeneous product and once gas is put in the pipeline it is not clear whom will get those specific molecules.

actions cost theory has largely been supported in empirical tests (Allen and Lueck 1995), a majority of the tests in energy markets come from time periods when the market was heavily regulated, such as Masten and Crocker (1985) and Mulherin (1986). In the 1990's, natural gas pipelines and part of the electricity generation industry was deregulated and vertically integrated firms were broken up. These changes had profound impacts on how these industries operated as deregulation allowed market mechanisms to guide behavior. This paper specifically tests what factors lead to the further specification of contracts through the firm delivery option and empirically measures the price premium paid for a firm contract.

A probit model on contract choice finds that larger plants and plants in states with less pipeline capacity, measures of a reduced availability of alternatives, are statistically more likely to sign firm contracts. Additionally, plants under cost-of-service regulation generally have a "regulatory compact" with the state to meet demand in exchange for a guaranteed profit. This reduced flexibility in production decisions leads to larger gas plants in regulated electricity markets to be more likely to sign a firm contract. When the value of natural gas is more uncertain due to larger variation in temperature, firms are less likely to sign a firm contract. Electricity and natural gas demand increase as temperature extremes are reached due to increased demand for heating and cooling. Additionally, a hedonic price model is estimated to determine how contracts are priced and what characteristics alter the premium that firm contracts pay. On average, firm contracts are about 2.5% more expensive than interruptible contracts. This premium increases as the weather is colder and when the plants are located in a state with less pipeline inflow capacity. Both of these results confirm that when pipeline space is more scarce, the firm contract premium increases.

These results are novel in that prior literature has mainly focused on contract specifications for natural gas during the time period when natural gas delivery was heavily regulated and often vertically integrated with production. Masten and Crocker (1985) established that the "take-or-pay" provision, which requires the pipeline to take the contracted gas quantity or pay a penalty up to the price of breaching the contract, can be efficient but will be distorted by regulation of wellhead prices. Crocker and Masten (1988) examine how deviations from the contract shortens the length of subsequent contracts. Mulherin (1986) empirically tests three measures of the transaction costs hypothesis for upstream contracts between the gas wells and pipeline distributors. One measure Mulherin (1986) examines are price adjustment provisions and finds that these price previsions are less specified as the number of pipelines in the field increases (a measure of alternative buyers), but are more specified with increases in contract length. These findings support the transaction cost hypothesis as further contract specification is preferred when alternative options are fewer.

Two related papers which analyzed the specifications of energy contracts after deregulation are Kozhevnikova and Lange (2009) and Hirschhausen and Neumann (2008), however these papers looked at contract duration exclusively. Kozhevnikova and Lange (2009) find that the duration of coal contracts decrease after deregulating the railroad industry, however, they do not find a significant effects of electricity market restructuring. Hirschhausen and Neumann (2008) examine a sample of international natural gas contracts and conclude that natural gas contract duration has significantly decreased in the European Union after restructuring the gas industry. Oliver et al. (2014) looks exclusively at the gas pipeline industry using a network model of gas transportation in the Rocky Mountain region and shows that prices rise as pipeline space becomes scarce. [2] This is consistent with our finding

[2]Additionally, there has been some literature related to the market integration of natural gas across

that the firm contract premium increases when the temperature is lower or when there is less pipeline inflow capacity.

Fuel is a critical input to electricity generation at gas-fired power plants. Unlike coal-fired power plants, it is not economical for gas-fired plants to maintain an on-site inventory of stored fuel from which they can withdraw if the plant's supply is interrupted.[3] Given the large increase in electricity generation from natural gas in the U.S., it is important to understand how plants procure their gas. The New England Independent Systems Operator will reimburse power plants for $2.6 million in expenses due to imports of natural gas that were purchased as insurance against a cold winter (Malik 2016). This insurance is needed as many power plants in New England do not purchase firm contracts and have found themselves without gas to generate when cold temperatures increases demand further up the pipeline.

The results of this analysis are useful for understanding how well the natural gas pipeline system is operating during a time of large increases in domestic natural gas production. The advent of hydraulic fracturing has allowed the U.S. to dramatically increase its natural gas production, often in regions that have not been traditional producers. This increased production has led to a large increase in natural gas use in electricity generation, as plants which had previously been uncompetitive with coal power plants began demanding more natural gas as the costs fell. In general, our results show that under these two large changes

different points in space. Oliver (2015) finds that pipelines don't necessarily have economies of scale over longer distances which may inhibit new pipelines from being built and lead to an inability to arbitrage prices in different regions. The results from Oliver (2015) support the work of Brown and Ycel (2008) who find a lack of market integration in natural gas transportation.

[3]At normal temperatures natural gas is too voluminous to store economically in above ground tanks. Natural gas can be cooled and liquefied to keep in holding tanks, but the cooling and un-cooling process comes at an additional cost. The most economic way to store natural gas is in underground geological formations, the most common are depleted oil reservoirs. The location of these geological formations does not often correlate with the location of power plants which is mainly determined by water availability, therefore storage capacity for natural gas is commonly owned and operated by gas distribution companies and then sold to the power producer.

to the energy industry, contracts for natural gas behave as theory would predict.

Section 2 of this paper summarizes the previous literature examining contract specification and the background regarding natural gas power plants. Section 3 presents descriptive statistics, discusses the data, and Section 4 lays out our empirical specifications and identification. Section 5 presents the results and Section 6 concludes.

2 Regulatory Framework

Prior to the early 1990's, pricing and transportation of natural gas was heavily regulated. In April of 1992 FERC issued order 636 which required pipeline companies to unbundle the price of delivered gas from transportation services. By separating the unit price of gas and the cost of gas transportation this regulation created transparency for transportation services. This shifted market power away from the pipeline companies who could no longer favor their own gas contract over other potential suppliers. Allowing open access to the interstate pipeline network promoted competition within the gas industry. In addition to unbundling gas and transportation prices, this order established a market for *firm* and *interruptible* contracts, with the intention that the pipeline could recover some of its fixed costs through a reservation price paid by customers who wanted to ensure delivery (i.e, those on a firm contract). Firm contracts receive a higher priority and are fulfilled prior to interruptible contracted quantities. In order to meet firm contract agreements the pipeline company must either reserve pipeline storage capacity for the firm contracted quantity or divert gas from other end users who did not pay the reservation price (i.e., customers purchasing interruptible contracts). Therefore, power plants contracting through interruptible contracts may benefit from a lower fuel price by avoiding the reservation price, but are subject to the risk of being cut off from their natural gas supply during peak demand or various other system capacity constraints. It is expected that the premium for firm contracts would vary with the underlying scarcity of the pipeline capacity. Figure 1 diagrams the general pipeline supply chain from suppliers to distributors to consumers.

One of the largest buyers of natural gas is the electricity industry. The U.S. electricity market has historically been regulated under cost-of-service regulation, where a state run Public Utility Commission (PUC) grants a natural monopoly to a utility to operate and supply electricity to an area at prices approved by the PUC. In the late 1990's, several states restructured the generation side of electricity, creating open access to wholesale markets that allowed for open competition among generation producers. The purpose of restructuring electricity was to use market incentives to decrease costs, encourage innovation and lower electricity rates. Importantly, plants no longer are required to run and must bid into a wholesale electricity market for the right to generate. Following the 2001-2002 electricity crisis in California's restructured market, several states indefinitely postponed any legislation to restructure their electricity markets with some states reverting to the traditional cost-of-service regulation. Since 2002 there has been very little change in each state's market structure.[4]

Another aspect that might alter decisions of whether to use a firm contract is the technology type of the power plant. There are two main types of natural gas generation technologies; simple cycle and combined cycle generators. Simple cycle generators use a single power cycle

[4]Borenstein and Bushnell (2015) gives a comprehensive review of the U.S. restructuring process and motivation. Roughly one third of the states still have restructured wholesale competitive markets while the rest retain a traditional cost-of-service regulation.

to spin a turbine to turn a generator to create electricity. Simple cycle units can be further classified as gas turbines and steam turbines depending on the technology.[5] Gas turbines flare the natural gas in order to compress air used to spin the turbine, where as steam turbines flare the gas to heat water creating steam to spin the turbine. Combined cycle units combines these two processes in order to recover the heat from the initial flaring and cycle it back to a boiler to produce steam and spin a second turbine.

Due to the secondary heat capture system combined cycle units produce more electricity per unit of natural gas (i.e. better efficiency) and these units are often larger and require a high initial capital cost relative to simple cycle units. In addition combined cycle units take longer to ramp up and down and incur larger start up and shut down costs. Therefore; combined cycle units run more often and are dispatched to meet base-load electricity demand, where as, simple cycle units are primarily "peaker" units and run only a few hours a day in order to meet peak electricity demand.

The difference in electricity market structure and plant technology type may provide different incentives when a power plant owner is deciding to pay extra for guaranteed delivery of natural gas. In this analysis, we empirically test the contract decisions made by these different plant types. Additionally we examine two measures of the availability of alternative suppliers are utilized: 1) the amount of pipeline capacity in the state that a plant is located in and 2) size of the plant, as larger plants may have a more difficult time fulfilling their needs when pipeline space is more scarce. Further, variation in the weather leads to variation in the value of the natural gas which can be used to determine contract choice. We test these predictions using data described in the following section.

[5]Combustion engines also used for generation but are a lot less common.

3 Data

Our dataset uses transaction level data for power plants owned by electric utilities and independent power producers from 2008 through 2012. We subset the data to use only power plants classified as "Electric Utility" (EIA sector #1) or "IPP Non-combined Heat and Power" (EIA sector #2). Each transaction includes the delivered price, quantity contracted, and whether the the contract is firm or interruptible. In addition we also use plant and prime mover level data to classify technology type, plant capacity and plant location. We consider a power plant to be combined cycle if more than 25% of its total capacity is combined cycle.[6] Based on plant location we use state level data to identify market structure, population weighted heating degree days (HDD) and state level inflow pipeline capacity. Figure 2 maps out each power plant along the gas pipeline network and the plant's most common contract type decision.

Data on fuel costs is collected and provided by the EIA 923 form through a non-disclosure agreement. Data on various other plant and generation unit characteristics are publicly available through the EIA 860 form and EIA 923 form. State HDD is collected from the National Oceanic and Atmospheric Administration (NOAA).[7] Data on state inflow pipeline capacity is collected by state and federal agencies, but is publicly available through the EIA website.[8] We use the EIA's classification of states that are restructured and regulated.[9]

[6]Only about 8.5% of the plants in our sample have both simple cycle and combined cycle capacity.

[7]`http://www7.ncdc.noaa.gov/CDO/CDODivisionalSelect.jsp#`. HDD is measured in *degree days* (dd), refer to the NOAA website for a more detailed description of HDD.

[8]`http://www.eia.gov/naturalgas/data.cfm`.

[9]The EIA classification can be found at `http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html` We slightly adjust this classification by classifying Oregon as regulated since producers still sell to residential customers under a traditional cost-of-service. Additionally we classify plants operating in the California ISO (CAISO) as restructured and plants located in Texas but operating outside of ERCOT as regulated.

Figure 3 shows the average price path from 2008 through 2012 for each contract type throughout our data set. Anecdotal accounts suggest that a firm contract should equal the price of an interruptible contract plus the reservation price. Over the majority of our dataset the firm contracted price is greater than the interruptible contracted price, but several factors, such pipeline capacity constraints or short run demand shocks, can cause this reservation price to fluctuate and even be negative causing the interruptible price to be higher than the firm price.

Table 1 shows some summary statistics by plant and regulatory type; combined cycle in regulated states (CC×REG), combined cycle in restructured states (CC×RST), simple cycle in regulated states (SC×REG) and simple cycle in restructured states (SC×RST).We have 721 gas power plants in our analysis.

Using our transaction level data from 2008-2012, we examine the within plant time varying contract decisions. About 70% of gas-plants never change their choice in contract type, strictly purchasing either a firm or interruptible contract. We extend the range and find that over four-fifths of the power plants in our sample choose a single type of contract for 90% of the fuel purchased.[10] Figure 4 depicts this plant level binary choice using a histogram showing the quantity weighted percentage of transactions purchased as a firm contract at each power plant from 2008-2012. The fact that the majority of power plants do not change their choice in contract type gives evidence that these contract decisions are more dependent on time invariant factors, such as location, market structure or technology type than market fluctuations. The methodology for identifying these important factors is described in the next section.

[10]These percentages are calculated using quantity weighted percentages.

4 Methodology

The first part of our analysis measures the reservation price a power plant pays for a firm contract using a hedonic price model. Our estimation model is given by equation 1;

$$y_{i,t} = \beta_0 + \beta_1 Firm_i + \boldsymbol{x'_{i,t}\beta} + \alpha_p + \theta_m + \delta_y + \epsilon_i \quad (1)$$

The subscript i indicates a individual transaction and t indicates time. The dependent variable, y_i is the unit cost for natural gas (cents per Mcf) for transaction i and β represents the slope coefficients of explanatory variables. $Firm_i$ is a dummy variable equal to one if transaction i is purchased under a firm contract and zero otherwise. Transaction, plant, and state level covariates are included in the vector $\boldsymbol{x'_i}$. These covariates include the quantity per transaction (MMcf), population weighted heating degree days for the state (HDD), and state pipeline inflow capacity ($^{MMcf}/_{day}$). For one specification we interact the firm dummy variable with heating degree days and the firm dummy with state pipeline inflow capacity ($Firm\times$HDD; $Firm\times$State Inflow Cap.). For each of our specifications we use plant level fixed effects (α_p), month fixed effects (θ_m) and year fixed effects (δ_y). ϵ_{it} is the stochastic error term. The data we use for the hedonic model is at the transaction level, however it is possible for a power plant to make multiple transactions or zero transactions within a single month, making the data an unbalanced panel.

The second part of our analysis aims to answer which power plant characteristics influence a plant manager's choice of contract type. Using a probit model we estimate the impact of various characteristics on the likelihood of a plant owner choosing a firm contract. Different from the hedonic model, the probit model is run at the plant level. Due to the within plant binary nature of these contract decisions (illustrated by Figure 4) there is little within plant variation of the dependent variable over time. Therefore, we collapse the dataset to make it cross-sectional and use the average of any time variant data within our sample at the plant level. Our estimation model is given as;

$$Pr(y_j = 1|x_j) = \Phi(\beta_1 CC_j + \beta_2 RST_j + \beta_3 CC \times RST_j + \boldsymbol{x_j'\beta}) \tag{2}$$

where the individual power plant is subscripted by index j. y_j is equal to one if the plant chooses a firm contract over fifty percent of the time within our sample and zero otherwise.

$\Phi()$ is the likelihood function using several plant characteristics of interest. We use two dummy variables and their interaction term to distinguish between the different plant and regulatory types; RST_j is equal to one if the plant is located within a restructured state and is zero otherwise; CC_j is equal to one if the plant is a combined cycle plant and is zero otherwise; and $CC \times RST_j$ is equal to one if the plant is a combined cycle in a restructured state and is zero otherwise.[11] $\boldsymbol{x_j'\beta}$ is comprised of other explanatory variables which could include; state pipeline inflow capacity; the minimum distance to the closest natural gas hub (an alternative measure of access to pipelines); power plant capacity and the standard deviation of state monthly heating degree days over our sample as a measure of variance in weather.[12]

[11] This means that the excluded plant category is simple cycle located in regulated states.

[12] The measurement for minimum distance to the closest natural gas hub is measured as the crow flies. A more accurate measure would be the actual pipeline distance to the closest hub, however; our measure is a good proxy variable for pipeline distance. We also examined the following variables in our analysis, but each proved to be statistically insignificant; a dummy variable indicating if the plant has on-site coal generation; heating degree days; quantity of fuel purchased; average heat rate($^{mmbtu}/_{MWh}$); and pipeline density measured as total length of pipeline within a forty square area block centered around the power plant.

5 Results

Three primary specifications for the hedonic model are shown by Table 2 using transaction level data with fuel cost (¢/Mcf) as the dependent variable. Each specification in Table 2 uses plant, month and year fixed effects. We present robust standard errors in parentheses below the coefficients. Specification (1) excludes any pipeline network characteristics. For both specification (2) and (3) we add state pipeline inflow capacity as a control variable. In specification (3) we add two interactions terms; Firm×HDD and Firm×State Inflow Cap. The coefficient on the "Firm" indicator variable represents the reservation price of natural gas (¢/Mcf) an average power plant must pay for guaranteed delivery conditional on the covariates.

Column (2) is the preferred specification when identifying the average reservation price across all power plants. The interpretation of β_1 from Equation 1 is that on average a gas power plant will pay roughly 14 cent more per Mcf for a guaranteed delivery. This is statistically significant at a one percent level. This is roughly 2.5% of the average fuel cost from 2008-2012.

In addition to identifying the reservation price we also examine several other variables. We find a negative and significant effect of our "Quantity" variable meaning that gas plants which purchase larger amounts of natural gas (MMcf) per transaction benefit from a lower price. We cannot determine the mechanism for this lower price, but it may come from a "buying-in-bulk" discount offer by the supplier or larger transaction provide more incentive for gas plants to negotiate better. We also find that the price of natural gas increases by about 12 cents for every 100 heating degree days increase per month (i.e., weather gets colder). This is reasonable as colder weather increases residential and commercial demand for natural gas used for heating. In specification (2) we see that power plants in states with larger inflow gas capacity experience lower prices.[13] Increasing state inflow capacity reduces pipeline space scarcity which lowers the equilibrium price.

Specification (3) uses interaction terms to see how the reservation price changes under various conditions. The coefficient for Firm×HDD is positive and statistically significant. This is evidence that when demand for natural gas is high, pipeline space becomes more scarce which increases the reservation price for guaranteed delivery. For every 100 degree day increase per month the reservation price increases by roughly one cent per Mcf. The coefficient for Firm×State Inflow Cap. is negative and significant. This means that as a state increases it's inflow pipeline capacity the reservation price for a firm contract decreases. This result is sensible as increasing pipeline capacity decreases the likelihood of running of out space in the pipeline.

Table 3 shows the results of our probit model. Here we examine various plant level characteristics that determine the type of contract a power plant's manager will choose to purchase natural gas. Columns (1) and (2) includes all gas power plants. We use dummy variables to separate the effects of market structure (RST), power plant technologies (CC) and the interaction effect (RST×CC). Columns (3) and (4) subset the model to examine only combined cycle power plants and columns (5) and (6) subset the model to examine only simple cycle power plants. We use two measures of pipeline network characteristics; state inflow capacity and minimum distance to the closest natural gas hub. We separate these two

[13] The state pipeline inflow capacity is time variant. Plant fixed effects do not prevent us from using them, but over our four year sample changes in pipeline capacity occur infrequently.

measures by specification due to a collinear relationship between these variables.

We calculate the marginal effects in Table 4 for specifications (1) and (2) from Table 3 to clearly see the effect of market and plant technology types on the propensity to have a firm contract. As expected combined cycle plants in regulated markets are more likely to purchase natural gas under a firm contract when compared to combined cycle plants in restructured markets. This difference across market structure can be attributed to the regulatory compact in regulated states to supply enough electricity in order to meet demand. Combined cycle plants regulated by the state are more likely to pay the extra reservation price in order to guarantee demand is meet, relative to combined cycle in restructured states. Additionally, the reservation price is a cost tied directly into the fuel cost in which these regulated combined cycle plants can use to justify higher electricity rates to the state PUC. The reservation price is more likely to be passed through to retail customers in a regulated market than a restructured market.

The results for simple cycle plants, however are unexpected. Simple cycle plants in regulated states are less likely to purchase gas under a firm contract when compared to simple cycle plants in restructured markets. Comparing all four types, simple cycle plants in restructured states are even more likely to purchase firm contracts than combined cycle in restructured states. This seems counter intuitive as combined cycle plants run infra-marginal more often and the opportunity cost of shutting down due to a interruption in fuel is larger. Some mechanism of a competitive market is incentivizing these simple cycle plants in restructured states to purchase gas under firm contracts.[14]

[14] Attempts to rationalize the results by comparing the age, size, or region of simple cycle plants in restructured states do not reveal any differences that could account for the unexpected result.

Despite the conflicting results for simple cycle plants in restructured states, the other variables of interest fall in line with our expectations. Plants located in states with more inflow pipeline capacity are less likely to utilize the firm contract option as inflow capacity is a proxy for ease of access for natural gas. This result is negative and statistically significant for both types of plant technologies.

Using specification (2) the minimum distance to the closest natural gas hub is positive and statistically significant meaning that as the plants are locate further away from the hub plants are more likely to purchase firm contracts. If we assume that two plants are purchasing interruptible contracted gas and the plant closer to the natural gas hub will be serviced first, the plant located further away is more at risk of having the gas supply interrupted during high demand periods. Power plants further away can mitigate this risk through the firm contract option. Comparing across technology types (columns (4) and (6)), we find that this result is only significant for simple cycle plants.

The coefficient for plant capacity is positive and significant for specifications (1) and (2), implying larger power plants are more likely to pay the reservation price for guaranteed delivery. This is reasonable, considering larger power plants face a higher opportunity costs if forced to shut down. In addition, under an interruptible contract, a large plant is at more risk of not having their individual demand completely supplied. Although this effect is positive for both combined cycle and simple cycle, it is larger and statistically significant for combined cycle plants.

We use the standard deviation of heating degree days over our four year sample as a measure of variation in the weather for a given state. This variation in weather is a good proxy for demand uncertainty and therefore uncertainty in the value of natural gas to the plant. We see that plants located in a more volatile climates are less likely to utilize the firm contract option. Using an interruptible contract, the power plant has the flexibility to response to changes in price caused by shifts in demand. This result is consistent with those of Bajari and Tadelis (2001) and Crocker and Reynolds (1993) who find that a larger variance in value of the product leads to less contract specification.

5.1 Robustness Checks

We run several robustness checks for both our hedonic model and probit model shown by Table 5 and Table 6, respectively. For column (1) in Table 5, we cluster the standard errors at each individual month (i.e., 60 clusters from 2008-2012). By doing this we account for any within month serial correlation across transactions.[15] Column (2) we replace year and month fixed effects with year-by-month fixed effects. This is a more restrictive specification, but we still identify the reservation price through variation within and across power plants. Column (3) subsets the model with high fuel price transactions (the top 50^{th} percentile) and in column (4) we subset the model to low fuel price transactions (the bottom 50^{th} percentile). Comparing these two columns, the reservation price is larger when gas prices are higher indicating that the reservation price is likely proportional to the gas prices rather than a fixed cost.

Column (5) uses a log-linear specification where we regress the natural log of fuel costs on the "Firm" dummy variable and the natural log of the other independent continuous variables. Using the log-linear model the coefficient on the "Firm" dummy variable can

[15]Cameron and Miller (2015) argue that there is no definition of "too few" clusters but that more is better. Generally above 50 has been accepted as "large enough."

be interpreted as the reservation price adding an additional 2.6 percent to the fuel cost. Column (6) uses state fixed effects instead plant fixed effects. By using state fixed effects we can include plant capacity and additional time invariant measures regarding the pipeline network specific to the plant and examine their impact on fuel costs. We find that larger power plants typical pay less per Mcf of natural gas. This is likely due to similar reasons as the mechanisms causing our quantity measure to be negative and significant. Fuel cost increase by rough 4 cent for every 100 kilometers increase in distance from a natural gas hub. Another measure of pipeline access is the total density of pipelines within a forty square area block centered around the power plant. We find that as pipeline density increases fuel costs decrease (negative level term) at a decreasing rate (positive squared term). This result is consistent with an increased value of pipeline scarcity.

In our primary results for the probit model we narrowed down the data to a cross sectional dataset at the power plant level averaging time variant plant and state measures. We did this due to the lack of variation in our dependent variable (i.e., the contract choice) within plant, however; there is a small amount of variation in these plant level contract decisions month to month. Column (1) of Table 6 uses a monthly data at the plant level to run to our probit model.[16] Column (2) runs the cross sectional data using a logit model.

Column (3) runs our primary probit model, but drops any power plants that have quantity weighted percentage of natural gas purchased under a firm contract between 40%-60% over our sample. This drops any plants that are not regularly purchasing natural gas using one type of contract. Column (4) runs our probit model but drops any gas power plants

[16]Whether a plant chooses a firm or interruptible contract is still a binary variable at a monthly level based on the rounded quantity weighted percentage of natural gas a plant purchases under a firm contract.

with both combined cycle and simple cycle capacity. All of Table 6 shows the robustness results where we use the state inflow capacity as our pipeline characteristic. Table 7 shows the same robustness checks using minimum distance from the closet gas hub. Across all robustness checks our coefficients are relatively stable and convey the same results as our primary regressions.

6 Conclusion

Transactions cost theory says that contract specification will increase as the alternative options decrease. We test the predictions of transaction costs theory using contracts between gas-fired power plants and natural gas pipelines. We consider a firm contract as an increase in specification relative to an interruptible contract in that the parties have specified what the terms of trade will be in all contingencies. Our paper differs from the previous literature testing transactions cost theory through a number factors. First, the previous literature examines natural gas contracts when the industry was heavily regulated. Second, we empirically measure the reservation price premium paid for a firm contract. Third, we further test the difference across market structures on contract specification through variation in contract type. Fourth, we examine if the technology used at the power plant influences the generation plant's contract type decision.

Consistent with contract theory we find that firms are more likely to increase contract specification when their options are limited (e.g. less inflow pipeline capacity or larger plant capacity). Combined cycle plants in regulated states are more likely to pay the reservation price relative to combined cycle plants in restructured states and simple cycle plants in regulated states. This is consistent with our expectations. Inconsistent with our expectations is the behavior of simple cycle plants in restructured states which typically purchase more firm contract gas relative to simple cycle plants in regulated states and combined cycle plants in the regulated states. Further, we estimate the premium paid for a firm contract and show that it varies with measures of pipeline space scarcity.

It is important to note that natural gas power plant contracting is consistent with economic theory even though our sample includes large changes in the amount and spatial distribution of natural gas production and a the large increase in use of natural gas by the power sector.

References

Allen, D. and D. Lueck (1995). Risk preferences and the economics of contracts. *The American Economic Review 85*(2), 447–451.

Bajari, P. and S. Tadelis (2001). Incentives versus trasactions costs: A theory of procurement contracts. *The RAND Journal of Economics 32*(3), 387–40.

Borenstein, S. and J. Bushnell (2015). The us electricity industry after 20 years of restructuring. Technical report, National Bureau of Economic Research.

Brown, S. and M. Ycel (2008). Deliverability and regional pricing in u.s. natural gas markets. *Energy Economics 30*(5), 2441 – 2453.

Cameron, A. C. and D. L. Miller (2015). A practitioner's guide to cluster-robust inference. *Journal of Human Resources 50*(2), 317–372.

Crocker, K. and S. Masten (1988). Mitigating contractual hazards: Unilateral options and contract length. *The RAND Journal of Economics 19*(3), 327–343.

Crocker, K. and K. Reynolds (1993). The efficiency of incomplete contracts: An empirical analysis of air force engine procurement. *The RAND Journal of Economics 24*(1), 126–146.

Hirschhausen, C. and A. Neumann (2008). Long-term contracts and asset specificity revisited: An empirical analysis of producer–importer relations in the natural gas industry. *Review of Industrial Organization 32*(2), 131–143.

Klein, B., R. G. Crawford, and A. A. Alchian (1978). Vertical integration, appropriable rents, and the competitive contracting process. *The Journal of Law & Economics 21*(2), 297–326.

Kozhevnikova, M. and I. Lange (2009). Determinants of contract duration: Further evidence from coal-fired power plants. *Review of Industrial Organization 34*(3), 217–229.

Malik, N. (2016, April). The u.s. has more natural gas than it needs and boston's importing. Bloomberg Online; posted April 13, 2016.

Masten, S. and K. Crocker (1985). Efficient adaptation in long-term contracts: Take-or-pay provisions for natural gas. *The American Economic Review 75*(5), 1083–1093.

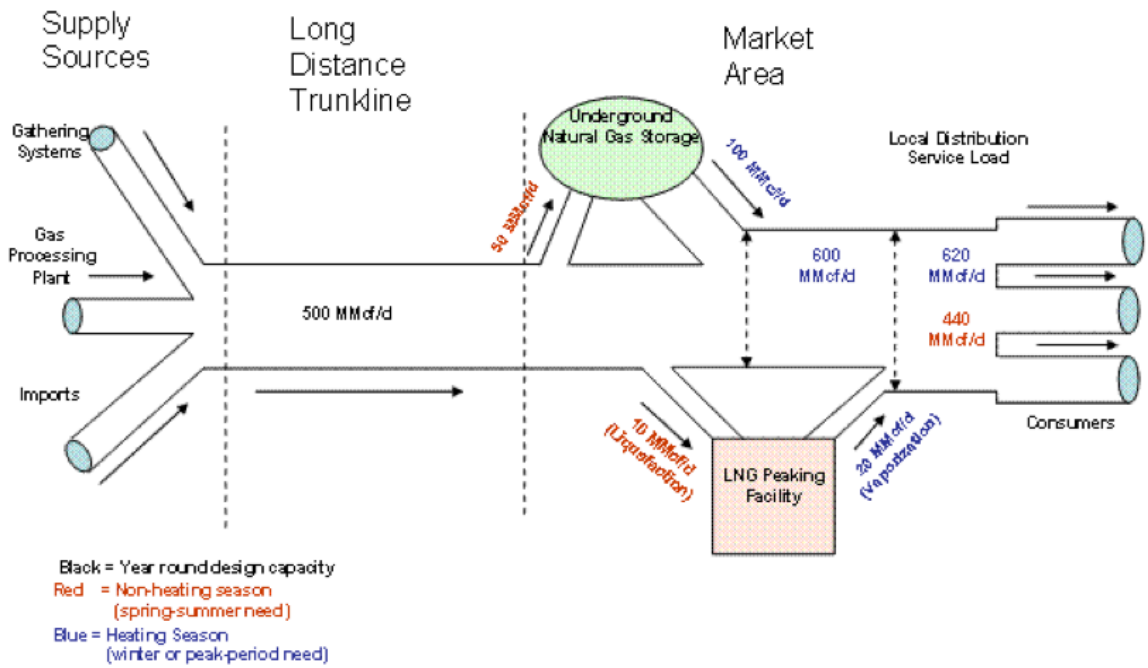
Mulherin, J. H. (1986). Complexity in long-term contracts: An analysis of natural gas contractual provisions. *Journal of Law, Economics, & Organization 2*(1), 105–117.

Oliver, M. (2015). Economies of scale and scope in expansion of the u.s. natural gas pipeline network. *Energy Economics 52*(B), 265 – 276.

Oliver, M., C. F. Mason, and D. Finnoff (2014). Pipeline congestion and basis differentials. *Journal of Regulatory Economics 46*(3), 261–291.

7 Tables and Figures

Figure 1: Generalized Natural Gas Pipeline Capacity Design Schematic



Note: MMcf/d = million cubic feet per day. Areas shown are not proportional to capacity volumes indicated. Other natural gas transmission pipelines may interconnect with and supplement the supplies of the mainline transmission or local distribution company in the market area to meet peak period demands.
Source: Energy Information Administration, Office of Oil and Gas

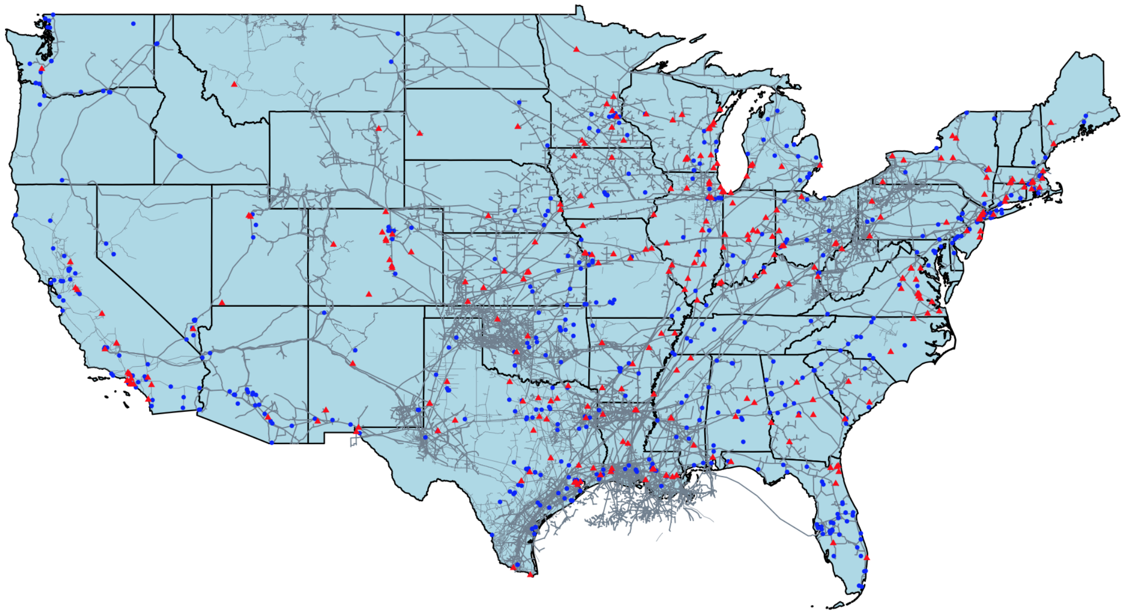


Figure 2: Red triangles are the interruptible contracts, blue circles are firm contracts.

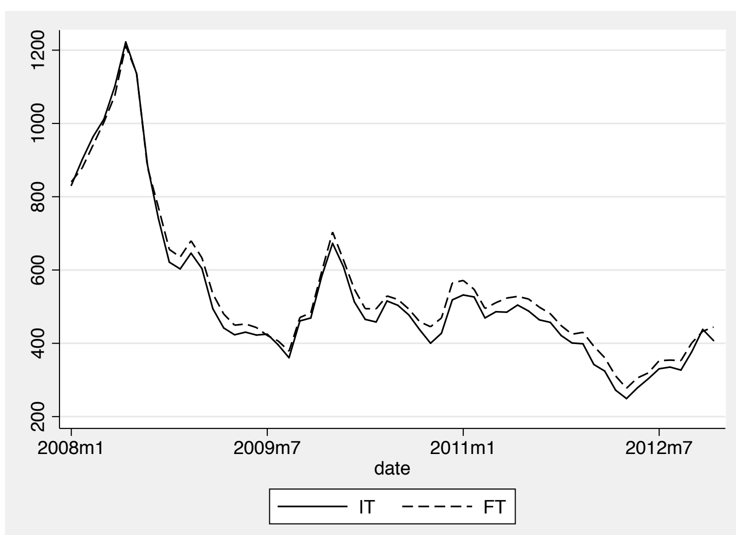


Figure 3: Average Transaction Price by Contract Type

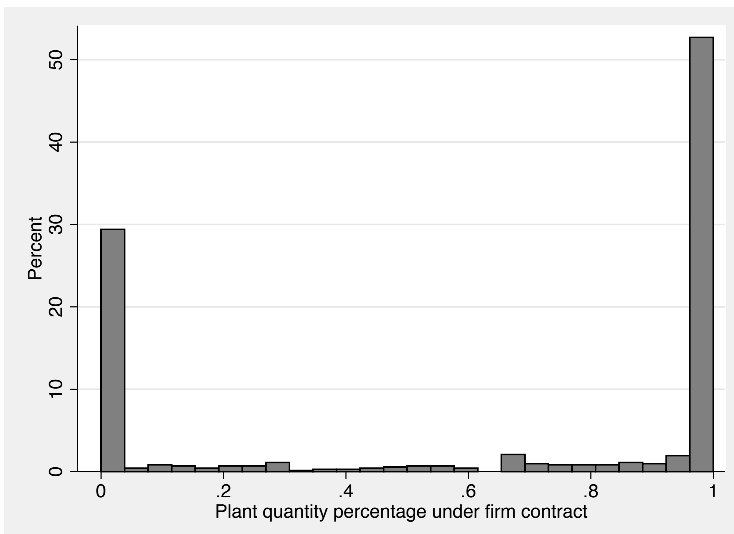


Figure 4: Quantity Weighted Percent Purchased as Firm Contract within Plant

Table 1: Descriptive Statistics by Power Plant Type

	Percentage of All Transactions	Quantity Weighted Percentage of All Transactions	Number of Plants	Average Quantity per Transaction (Mcf)	Average Capacity (MW)	Firm Contracts	Interruptible Contracts
CC×REG	36.8	51.6	170	641.0	742	81.9 %	18.1 %
CC×RST	24.0	28.3	119	538.3	664	52.8 %	47.2 %
SC×REG	27.8	12.8	282	210.5	363	52.8 %	47.2 %
SC×RST	11.4	7.2	150	289.4	490	71.3 %	28.7 %

Table 2: Hedonic FT Premium

	(1)	(2)	(3)
Firm	13.172***	13.900***	20.892***
	(2.505)	(2.492)	(4.707)
Quantity (MMcf)	-0.036***	-0.036***	-0.036***
	(0.002)	(0.002)	(0.002)
HDD	0.122***	0.125***	0.120***
	(0.005)	(0.005)	(0.006)
Firm×HDD			0.011**
			(0.005)
State Inflow Cap. ($\frac{MMcf}{d}$)		-0.018***	-0.017***
		(0.001)	(0.001)
Firm×State Inflow Cap.			-0.001***
			(0.000)
Observations	59702	59702	59702

Robust standard errors in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

Table 3: Probit Model

	All Plants		CC Plants		SC Plants	
	(1)	(2)	(3)	(4)	(5)	(6)
CC	0.402***	0.465***				
	(0.142)	(0.142)				
RST	0.317**	0.432***	-0.461***	-0.423**	0.338**	0.492***
	(0.135)	(0.142)	(0.165)	(0.174)	(0.136)	(0.146)
CC×RST	-0.763***	-0.781***				
	(0.211)	(0.211)				
State Inflow Cap. ($\frac{bcf}{d}$)	-0.025***		-0.029**		-0.023***	
	(0.007)		(0.012)		(0.008)	
Min Distance to NG Hub (Mm)		0.813***		0.137		1.137***
		(0.306)		(0.488)		(0.379)
Plant Capacity (GW)	0.352***	0.316**	0.563***	0.509***	0.185	0.180
	(0.132)	(0.129)	(0.205)	(0.189)	(0.179)	(0.175)
HDD std. (00 dd)	-0.233***	-0.195***	-0.217***	-0.180***	-0.250***	-0.212***
	(0.044)	(0.043)	(0.072)	(0.068)	(0.057)	(0.055)
Observations	721	721	289	289	432	432

Standard errors clustered at the state are in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

Table 4: Marginal Effects

	(1)	(2)
CC×REG	1.461***	0.875***
	(0.224)	(0.212)
CC×RST	1.015***	0.527**
	(0.231)	(0.213)
SC×REG	1.059***	0.410**
	(0.208)	(0.193)
SC×RST	1.376***	0.842***
	(0.235)	(0.207)
Observations	721	721

Standard errors clustered at the state are in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

Table 5: Robustness Checks Hedonic FT Premium

	SE: Month Cluster	FE:Month×Year	High NG Price	Low NG Price	Log-log	FE: State
	(1)	(2)	(3)	(4)	(5)	(6)
Firm	13.900***	16.217***	10.013*	2.280**	0.026***	23.635***
	(4.220)	(1.889)	(5.257)	(1.159)	(0.004)	(1.779)
Quantity (MMcf)	-0.036***	-0.031***	-0.031***	-0.009***	-0.031***	-0.009***
	(0.003)	(0.001)	(0.003)	(0.001)	(0.001)	(0.001)
HDD	0.125***	0.093***	0.028***	0.056***	-0.001	0.121***
	(0.018)	(0.005)	(0.009)	(0.002)	(0.001)	(0.006)
State Inflow Cap. ($\frac{MMcf}{d}$)	-0.018***	-0.019***	-0.022***	-0.006***	-0.434***	-0.017***
	(0.002)	(0.001)	(0.002)	(0.000)	(0.025)	(0.001)
Plant Capacity (MW)						-0.005***
						(0.002)
Min Distance to NG Hub (km)						0.038***
						(0.010)
Pipeline density						-0.043***
						(0.006)
(Pipeline density)^2						0.000***
						(0.000)
Observations	59702	59702	20039	39663	59702	59241

Standard errors in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

Table 6: Robustness Checks Probit Model

	Panel	Logit	One Contract Type	Single Cap.Type
	(1)	(2)	(3)	(4)
RST State	0.243	0.524	0.321	0.359*
	(0.255)	(0.327)	(0.214)	(0.203)
CC	0.490***	0.664***	0.372***	0.524***
	(0.116)	(0.206)	(0.126)	(0.147)
CC×RST	-0.788***	-1.269***	-0.727***	-0.876***
	(0.236)	(0.426)	(0.270)	(0.281)
State Inflow Cap. ($\frac{bcf}{d}$)	-0.019**	-0.040***	-0.025***	-0.024***
	(0.008)	(0.012)	(0.007)	(0.007)
Plant Capacity (GW)	0.286*	0.585**	0.374**	0.360*
	(0.151)	(0.278)	(0.173)	(0.201)
HDD (000 d)	-0.273***			
	(0.086)			
HDD std. (00 dd)		-0.004***	-0.002***	-0.003***
		(0.001)	(0.001)	(0.001)
Observations	29093	721	675	645

Standard errors clustered at the state in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

Table 7: Robustness Checks Probit Model

	Panel (1)	Logit (2)	One Contract Type (3)	Single Cap.Type (4)
main				
RST State	0.373	0.715**	0.436*	0.479**
	(0.253)	(0.365)	(0.235)	(0.223)
CC	0.537***	0.778***	0.450***	0.593***
	(0.132)	(0.222)	(0.142)	(0.167)
CC×RST	-0.812***	-1.301***	-0.756***	-0.899***
	(0.237)	(0.431)	(0.275)	(0.290)
Min Distance to NG Hub (Mm)	0.864**	1.388***	0.824**	0.870***
	(0.379)	(0.518)	(0.344)	(0.311)
Plant Capacity (GW)	0.250	0.514*	0.333*	0.304
	(0.157)	(0.283)	(0.179)	(0.207)
HDD (000 dd)	-0.220***			
	(0.080)			
HDD std. (00 dd)		-0.003***	-0.002***	-0.002***
		(0.001)	(0.000)	(0.000)
Observations	29093	721	675	645

Standard errors in parentheses

* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$