THREE EMPIRICAL ESSAYS ON POWER PLANT OPERATING DECISIONS

by

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ABSTRACT

Switching from coal-fired to natural gas-fired generation and increasing the thermal efficiency of fossil fuel fired generation plants have been identified as ways of achieving meaningful emission reductions. In chapter 2, we examine the fuel-price responsiveness across gas plant technologies and across the market structures in which the plants operate. We find that there are significant differences in the generation and efficiency responses of gas plants to fuel prices across generation technologies and market structures. Using the parameter estimates from our econometric models, we calculate emissions savings from efficiency improvements and fuel-switching possibilities.

The large and local economic and environmental footprint of power generation makes a salient target for state politicians when lobbying the electorate. Researchers have utilized the fact that many states have term limits for governors to determine how changes in electoral incentives alter state regulatory agency behavior. Chapter 3 asks whether the change in electoral incentives, and its impact on regulatory agencies, spillover into private sector decision-making? We find strong evidence that power plants invest less in water pollution abatement if the governor of the state where the plant is located is a democrat and term-limited. Furthermore, the difference in plant decision-making is strongest when the governor wins their term-limited term by a narrow margin. Finally, we show that the lack of investment has environmental impacts by increasing thermal pollution and chlorine use by the plant.

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. Chapter 4 uses transaction level data to empirically test what characteristics lead to use of *firm* contracts and how the premium for firm contracts changes with these characteristics. We find that 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% more expensive and this premium increases as the weather is colder and the state a plant is located in has less inflow capacity.

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CHAPTER 1
THESIS INTRODUCTION

The U.S. is currently undergoing a fundamental change in its electricity profile as both market forces and environmental regulation are causing a shift away from coal-fired generation to electricity produced from natural gas and renewable resources. In April 2015 total U.S. generation from natural gas power plants surpassed coal-fired generation.[1] The Energy Information Administration (EIA) projects this trend in fuel switching will continue and natural gas will be the primary fuel source in the U.S. for electricity generation in the coming years. Understanding the operating decisions of electricity producers becomes essential particularly for gas-fired generation as the electricity profile undergoes this transition. Chapters 2 and 4 specifically target and analyze the economic decisions of natural gas power plant.

In addition to gas plant decisions, chapter 2 and chapter 3 also examine pollution abatement at the plant level. The electricity sector is the largest source of greenhouse gases (GHG) in the U.S. Additionally, the electricity sector withdraws the most freshwater out of any other sector. Due to the large footprint of electricity generation, a small amount of pollution abatement can result in large impacts on the environment. The a following chapters research the pollution abatement at the power plant level along with the operating decisions for natural gas power plants.

Using annual plant level data, chapter 2 investigates both the generation and efficiency response of gas-fired power plants to changes in fuel prices, specifically natural gas and coal prices. We allow for these responses to vary across plant technology and electricity market structure. We find that all gas-fired generation responds to natural gas prices, however; only the more efficient combined cycle gas plants respond to changes in coal prices. Furthermore,

[1]Source: EIA report `http://www.eia.gov/todayinenergy/detail.cfm?id=27072`

there is no significant efficiency response to natural gas prices from any type of natural gas plant and only combined cycle plants in competitive generation markets exhibit a positive and significant efficiency response to changes in coal prices. From this analysis we simulate a carbon tax and its impact on carbon emissions savings.

The research question answered by chapter 3 examines the spillover effect into the private sector from changes in state electoral incentives, which in turn impact state regulatory agencies. We specifically examine pollution abatement investments of power plants in response to the state governor's eligibility for re-election. We find that power plants, located in a state where the governor is democrat and term-limited, will spend less on water and air pollution abatement. We extend this analysis to measure the impact of water abatement investment dollars on actual water pollution. Our results show evidence that decreasing abatement investment does lead to more thermal and chlorine pollution at a power plant.

The final research chapter analyzes the fuel procurement contracts of gas-fired power plant. Power plants can pay an additional cost which guarantees fuel delivery via pipeline. This is known as a *firm* contract. The alternative contract type, an *interruptible* contract is subject to interruption or curtailment if deemed necessary by the gas distributor. Here we analyze various time invariant characteristics of a power plant that determine the contract type decision. In addition to this analysis we also estimate the price differential between the two types of contracts.

The rest of this dissertation includes four additional chapters. The next three chapters are three empirical essays on power plant operating decisions titled as follows; chapter 2: *Fuel Prices, Restructuring and Natural Gas Plant Operations*; chapter 3: *Political Pressure and Power Plant Pollution Abatement*; and chapter 4: *Natural Gas Contract Decisions for Electric Power*. Chapter 5 summarizes the important findings and concluding remarks.

CHAPTER 2

FUEL PRICES, RESTRUCTURING, AND NATURAL GAS PLANT OPERATIONS

Switching from coal-fired to natural gas-fired generation and increasing the thermal efficiency (energy generated per unit of energy burned) of fossil fuel fired electricity generation plants have been identified as ways of achieving meaningful emission reductions. In this study, we examine the fuel-price responsiveness across gas plant technologies and across the market structures in which the plants operate. We find that there are significant differences in the generation and efficiency responses of gas plants to fuel prices across generation technologies and market structures. Specifically, our results indicate that, regardless of market structure, generation from natural gas combined cycle (NGCC) plants is responsive to both coal and gas prices, but that generation from simple cycle (NGSC) plants only respond to gas prices. On the other hand, with respect to efficiency, we generally find that only NGCC plants operating in deregulated regions show statistically significant efficiency improvements in response to coal price increases and that, generally, neither NGCC or NGSC plants, regardless of market structure, respond in any significant way to gas prices. Finally, using these parameter estimates, we calculate emissions savings from efficiency improvements and fuel-switching possibilities.

2.1 Introduction

Recent regional environmental regulations, such as the Regional Greenhouse Gas Initiative or California's AB32 regulations, and federally proposed regulations, such as the Clean Power Plan (CPP), have prompted regulators and state officials to consider ways to reduce the CO_2 emissions intensity of states' electricity generation sectors. Two possible ways that a state may reduce the emissions intensity of its electricity sector in a meaningful manner is by improving the thermal efficiency (electricity generated per unit of energy burned) of its fossil-fueled plants and by switching generation from coal-fired plants to natural gas-fired plants.

Indeed, the Environmental Protection Agency (EPA) has used the possibility for coal-to-gas switching and efficiency improvements in coal-fired plants as two of their "building blocks" to determine the CO_2 emissions intensity rates (emissions per MWh of generation) of states' electricity generation sectors under the proposed Clean Power Plan.

In terms of efficiency improvements, much of the EPA's attention, as well as that of several recent academic studies, has deservedly been focused on the potential for efficiency improvements in coal-fired plants. However, considerably less work has been directed toward incentives for efficiency gains from natural gas-fired plants. This may seem unnecessary given that gas plants have about half the CO_2 emissions intensity as coal plants and far less emissions of other regulated pollutants such as NO_X and SO_2. Despite lower emissions, relative to coal, gas plants do still emit roughly 0.5 tons of CO_2 per MWh. Additionally, the share of gas-fired generation has increased dramatically in the U.S. over the last several years, going from about 20 percent of total generation in the early 2000's to about 25 to 30 percent in recent years. We therefore take a focused look at drivers of thermal efficiency improvements among gas-fired plants in the U.S., paying particular attention to the impact of fuel prices across gas-fired technologies and regulatory status. Similarly, we also examine how fuel prices affect natural gas plant generation levels across technology types and regulatory status. We then use these estimates to shed light on how emissions pricing affects emission reductions via efficiency improvements and coal-to-gas switching and how market regulation and technology holdings across states may impact these reductions.

This paper is, of course, not the first to explore determinants of utilization rates and thermal efficiency. In particular, given the relatively recent fall in U.S. natural gas prices, several studies have explored how this price change has altered generation and emissions from the electricity sector. For example, Linn et al. (2014) use plant-level data to examine how generation responds to fuel prices, finding, as expected, that generally generation for coal-fired (gas-fired) plants increase (decrease) when gas prices increase and decrease (increase) when coal prices increase.[2] Relatedly, Knittel et al. (2015) examine how entities, considered at a plant and firm level, which operate both gas- and coal-fired units, alter their share of natural gas burned in response to coal and gas prices and how these results differ across entities operating in traditional cost of service regions and those with access to competitive wholesale markets. They find that natural gas shares in multi-fuel plants and for multi-fuel firms do respond in expected ways to coal and gas prices, though, somewhat surprisingly, they generally only find statistically significant price-responses in cost-of-service regulated regions.

Using higher frequency daily data, Fell and Kaffine (2014) and Holladay and LaRiviere (2014) find that coal plants' generation response to the coal-to-gas price ratio increases when wind generation increases and that during the hydraulic fracturing-induced low-gas price regime has led to some significant changes to the dispatch order of coal and gas generation in some regions, respectively. Similarly, Holladay and Soloway (2013) explore the effect of fuel-switching behavior of oil-fired plants in the New York City area, finding that when the diesel prices are approximately $4/MMBtu more than natural gas, oil-fired plants switch to burning natural gas.

Several other recent efforts have also explored the determinants of thermal efficiency in fossil-fuel power plants. Many of these studies explore the efficiency effects of electricity market deregulation. More specifically, in the 1990's many countries and several states in the U.S., began to dismantle large, integrated electric utilities that had delivered electricity as regulated monopolies under cost-of-service agreements. In the place of these integrated

[2] Fuel price effects are also examined on the dependent variables fuel consumption and CO_2 emissions in Linn et al. (2014). The general results for these dependent variables largely follow that for the corresponding regressions using generation as the dependent variable

utilities, regulators set up electricity markets where ostensibly independent generators bid power into markets and distribution companies purchased the power, eventually selling it to end consumers. Economist argue that this market-based system should incentivize efficiency in generators relative to traditional cost-of-service regulation. However, empirical evidence of this hypothesized efficiency improvement has been somewhat mixed, with some studies finding no evidence of efficiency improvements (Fabrizio et al. (2007)), and others finding small, but statistically significant deregulation impacts on efficiency (Bushnell and Wolfram (2005) and Chan et al. (2013)).

In addition to the impacts of market regulation on efficiency, there is also a long literature examining how input prices drive efficiency. Empirical examples of this type of literature fall largely outside the electric power generation industry (e.g. Dubin and McFadden (1984), Metcalf and Hassett (1999), Linn (2008), Alcott and Wozny (2014)), but Linn et al. (2014) provides an example more in line with this paper. Using panel data on coal-fired plant operations from 1985 – 2009, Linn et al. (2014) estimate the relationship between plant heat rates (the inverse of thermal efficiency) and coal prices over five-year intervals. They find, under some specifications, that a 1 standard deviation increase in coal prices decreases heat rates (improves efficiency) by about 1.5 percent.

Our study combines elements of the efficiency and generation response studies mentioned above, but differentiates itself from previous efforts in several key ways. First, unlike those focusing directly on coal-fired plants or inclusive of all plants, we focus on the price responses of gas-fired plants, an increasingly important source of generation in the U.S. This helps remove possible confounding factors and, as we show is important, avoids over aggregation of responses that one may encounter if one is forcing common responses across all fossil-fuel plants or even if aggregating responses within generators that burn a common fuel type.[3] The focus on gas-fired plants and on technology- and market-disaggregated responses also differentiates us from most previous efforts exploring plant-level thermal efficiency. Given the possibility for general difference in operation costs across technologies and different incentives for efficiency across regulation structures, allowing for such response flexibilities is key to understanding gas plants' price responsiveness. Finally, by looking at both generation and efficiency price-responsiveness using the same data set and similar techniques, we can further highlight that while generation responses are largely as expected, efficiency responses have some less intuitive outcomes - a point we examine in our theoretical modeling framework.

Using annual plant-level data from 2002 - 2012, our results indicate that there is a generation and efficiency responsiveness to input-fuel prices for gas-fired plants and that there are considerable differences in the responses across natural gas generation technologies. More specifically, we find, similar to Linn et al. (2014), when estimating a restrictive model that forces the responsivenesses of net generation to natural gas and coal prices to be the same across generation technologies and regulatory structures that the responses are as expected; net generation negatively responds to increasing natural gas prices and positively responds to coal prices. When we allow for different responses across natural gas combined cycle (NGCC) and natural gas simple cycle (NGSC) technologies, we do find net generation of NGCC plants responds positively to rising coal prices and negatively to rising gas prices, both at statistically significant levels, whereas NGSC respond (negatively) only to gas prices.

[3] Note that Linn et al. (2014) and Knittel et al. (2015), the papers most similar to our with respect to exploring generation responses to fuel prices, do not disaggregate the results with respect to gas-fired technology.

With respect to thermal efficiency improvements, the results are perhaps less aligned with general expectations. We find that increasing coal prices drive efficiency improvements among NGCC plants in deregulated regions and, under some specifications and to a slightly lesser extent, among NGCC plants in regulated regions. This incentive for efficiency improvements does not appear to be present for NGSC plants in traditional cost of service regions or in more competitive markets as we find no statistically significant improvements to thermal efficiency in response to coal price increases. We also find that neither NGCC or NGSC plants, regardless of the regulatory status, have consistently significant thermal efficiency responses to changes in natural gas prices. This may seem odd as we often expect to see efficiency improvements across a wide range of industries in response to an increase in the price of a production input. However, as we show below in the basic model of efficiency choice, the somewhat unique set up of electricity supply leads to an ambiguous response of gas-fired plants' efficiency decisions with respect to gas price changes. The general intuition behind this result comes from the ability of an efficiency improvement to increase the number of inframarginal operating hours for a plant. When coal prices increase, lower cost gas plants, such as NGCC plants, have an incentive to increase efficiency in order to potentially become inframarginal during hours when coal plants are marginal. However, when gas prices increase, the ability to become inframarginal during periods when coal is on the margin is diminished even with heat rate improvements. Additionally, if the gas price increase is felt by all gas-fired plants and electricity demand is relatively inelastic, the period over which a plant is inframarginal when a gas-fired plant is on the margin will remain relatively constant even if the plant does not improve its heat rate. Both factors diminish the responsiveness of gas plant efficiency to natural gas prices.

Finally, to help put our estimates in context, we calculate implied net generation, efficiency, and emission changes under various CO_2 emissions taxes, which can equivalently be viewed as altering the cost of burning various fuels (see Cullen and Mansur (2014)). Our simulation results indicate that carbon taxes would increase generation from NGCC plants, both in regulated and deregulated regions, and decrease generation from NGSC plants, particularly in deregulated regions. A carbon tax also significantly improves thermal efficiency of NGCC plants in restructured regions, with our results implying a 10 percent improvement in thermal efficiency resulting from a $\$20/tCO_2$ tax. In terms of emission reductions, as one may expect, the increased generation from NGCC plants, assuming it displace coal generation, is the channel that leads to the most significant emission reductions. However, for NGCC plants in restructured regions, emission reductions due to efficiency improvements account for about 30 percent of the total NGCC-based emissions reductions.

The rest of the paper is organized as follows. In the next section, we present a basic model to help build intuition about expected price responses. In Section 3, we discuss the data and empirical methods employed. Section 4 reviews the data and section 5 presents the results from our main specification and across a variety of robustness checks, as well as explores policy implications through simple back-of-the-envelope type calculations. Concluding remarks are given in section 6.

2.2 Expected Responses

To begin, we construct a graphical representation of an electricity market model to gain simple insights into what we may expect to occur to net generation of different technologies given changes in input prices. Consider a simple electricity market with three generators;

a coal-fired generator, a NGCC generator and NGSC generator, each with marginal costs of production (MC_i) such that our original setting is one where $MC_{coal} < MC_{NGCC} < MC_{NGSC}$. Consider also two different demand levels; high demand (D_H) and low demand (D_L). This market setting is represented in panel (a) of Figure Figure 2.1 and labeled as our base case. Note under the low demand case, NGCC is the marginal generator and NGSC does not produce and under high demand NGSC is on the margin and NGCC produces its maximum level (i.e., NGCC is inframarginal).

Let us now consider what happens when natural gas prices drop. Holding all other factors constant, this natural gas price decrease lowers the MC's of NGCC and NGSC. The market clearing quantities under these lower MC's will move to the right of our base case scenario as shown in panel (b) of Figure Figure 2.1 (the intersections of demand and the supply curve are to the right of the dashed vertical line which represents the equilibrium quantities under the base case). This then implies that if data was aggregated temporally such that it included both the high and low demand states, the net generations' of both NG technologies will appear to positively respond to a decrease in natural gas prices. Similarly, it is straightforward to show under this set up that an increase in natural gas prices, and thus increases in MC_{NGCC} and MC_{NGSC}, will lead to reduction in generation from NGCC and NGSC.[4]

If instead, coal prices increase such that $MC_{NGCC} < MC_{coal}$, as we show in panel (c) of Figure Figure 2.1, then NGCC will become inframarginal under both high and low demand states. Again, if the temporal aggregation of data includes both demand states, then the

[4]Note that in this setting if we have perfectly inelastic demand, natural gas price changes will not affect the generation levels of NGCC or NGSC.

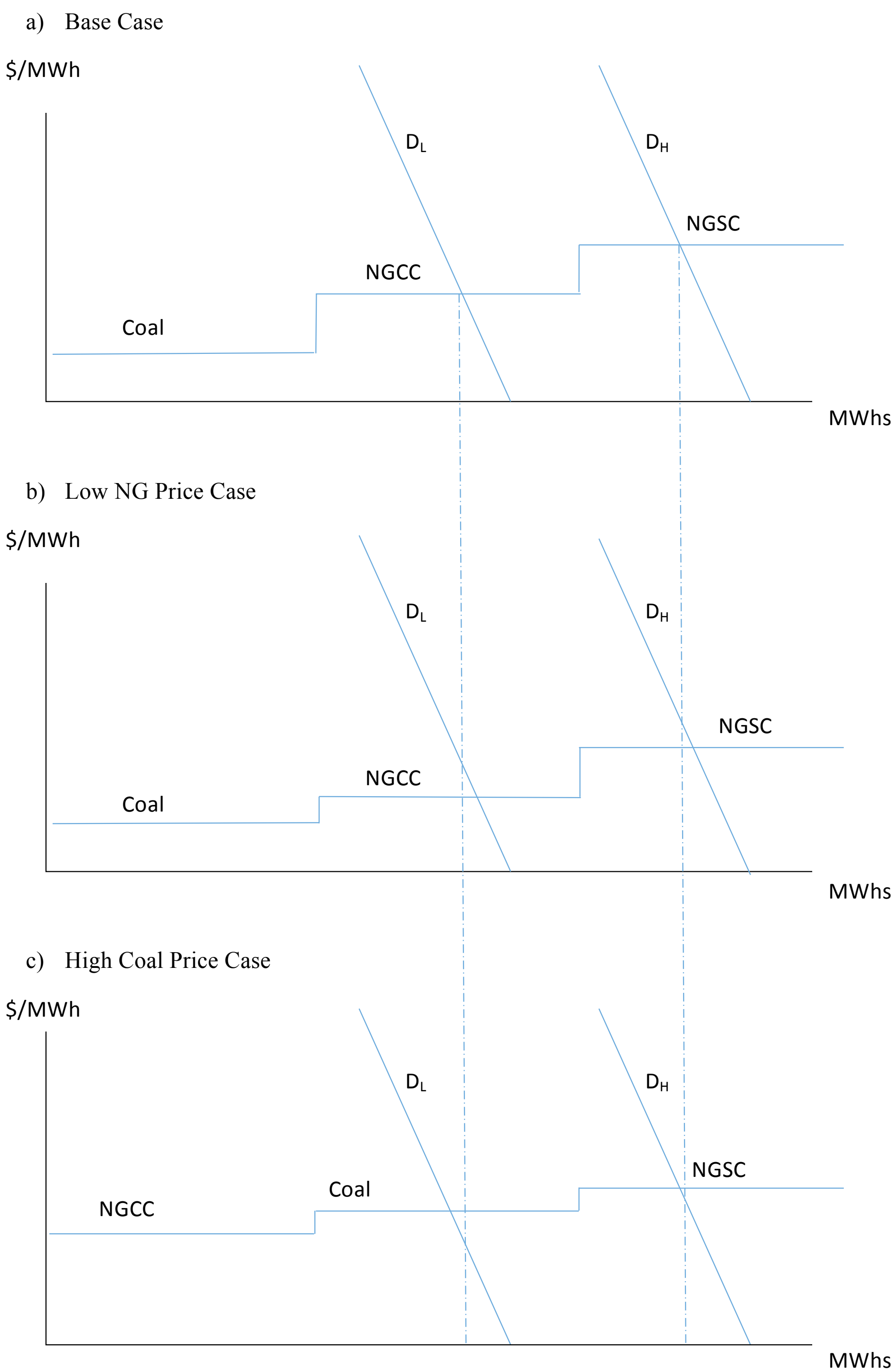


Figure 2.1: Net Generation Responses

net generation of NGCC will appear to have a positive response to increases in coal prices.[5] NGSC plants, on the other hand, will not appear responsive to coal prices.

This simple illustration thus shows that the net generation of some low-cost NG technologies (e.g. NGCC plants) may be responsive to both coal and natural gas prices, while other, more high-cost types (e.g. NGSC plants), may only be responsive to its own input price. Additionally, the setting for this simple illustration is a competitive supply and demand model, but is still relevant for those plants operating in a traditional cost-of-service regulated environment. More specifically, if the regulated utility has a mandate to provide power in a low-cost manner, they will set the dispatch order based on marginal cost of generation. If this is the dispatch ordering decision for the regulated utility, the responses will be the same as described above.

Next, we develop a simple model of plant-level efficiency investment for a natural gas-fired plant in a competitive wholesale electricity market with the goal of displaying how fuel price changes affect incentives for a firm's efficiency. In competitive industries with approximately equivalent producers, we generally think of higher input prices as driving efficiency in the use of these inputs. The model below shows the result is not so simple within the context of electricity production.

We consider the behavior of a given natural gas plant. The plant chooses its change in thermal efficiency, measured as the change in heat rates as $\Delta HR = HR_0 - HR_1$ where HR_0 is the heat rate before any heat rate changes and $HR_1$is the ending heat rate, that will hold

[5] If coal prices decreased in this setting, the NG generators would have no change in production. However, in a system that has a supply curve that does not so discretely jump from one producer type to another and one that allows more demand states it would possible that a drop in coal pries could lower generation from lower cost NG-fired generators.

over some pre-determined planning horizon.[6] In this setting, $\Delta HR > 0$ is an improvement in efficiency as lower heat rates are associated with more efficient fuel use (more MWh's per MMBtu of fuel burned). The changing heat rate, along with natural gas prices, affects the plant's marginal cost of generation, $MC\left(\Delta HR, C^{NG}\right)$ where C^{NG} is the plant's per-unit cost of natural gas over the planning horizon and with $\frac{\partial MC}{\partial \Delta HR} < 0$, $\frac{\partial MC}{\partial C^{NG}} > 0$, and $\frac{\partial MC}{\partial \Delta HR \partial C^{NG}} < 0$.[7] While efficiency improvements can lower marginal costs of generation, heat rate alterations come at a cost, $C(\Delta HR)$ with $C'(\Delta HR) > 0$ and $C''(\Delta HR) \geq 0$.

Natural gas prices and heat rates also affect the generation level chosen by the firm. We assume that the firm chooses hour i production such that:

$$q_i = \begin{cases} q^m & \text{if } p_i \geq MC \\ 0 & \text{otherwise} \end{cases} \tag{2.1}$$

where q^m is the capacity production at the gas power plant and p_i is hour i's electricity price.[8] Let us further assume that $H\left(C^C, C^{NG}, \Delta HR\right)$ is the number of operating hours over some evaluation horizon such that $H\left(C^C, C^{NG}, \Delta HR\right) = \sum_{i=1}^{N} 1(p_i \geq MC)$, where N is some number of hours over which a plant evaluates heat rate alterations, $1(\dot{})$ is an indicator function equal to one if $p_i \geq MC$, and C^C is the average cost of coal for competing plants over the evaluation horizon. These operating hours for a gas plant are a function of the plant's heat rate decisions, natural gas costs and coal costs, such that, ${}^{\partial H}/_{\partial C^C} \geq$

[6]Choosing heat rate levels over some planning horizon seems a reasonable assumption if efficiency improvement come largely in the form of capital improvements and/or contracted labor agreements.

[7]For example, a reasonable formulation such as$MC(\Delta HR, p^{NG}) = (HR_0 - \Delta HR) \times C^{NG}$ will lead to the partials described here. Note also we assume that marginal cost is constant with respect to generation levels. This omission is not relevant to the simple model here, but we do consider impacts that generation levels may play in heat rates, and thus marginal costs, in the empirical analysis.

[8]Note if $p_i = MC$ the firm may not be able to produce at its maximum level and still have the market clear, but without much loss of generality we ignore this possibility. We also ignore ramping constraints that may make it prohibitively expensive to go from zero production to q^m on an hourly basis. While this omission may be a considerable diversion from reality, adding more realistic ramping conditions appear unlikely to affect the general point of the model below.

0, ${\partial H}/{\partial C^{NG}} \leq 0$, ${\partial H}/{\partial \Delta HR} \geq 0$, ${\partial^2 H}/{\partial \Delta HR \partial C^C} \leq 0$ and ${\partial^2 H}/{\partial \Delta HR \partial C^{NG}} \geq 0$.[9] Finally, let us define the average electricity price over the hours the plant is operating as $p(C^C, C^{NG})$, specifically $p(C^C, C^{NG}) = \frac{1}{H}\sum_{i=1}^{N} 1(p_i \geq MC)p_i$ with reasonable partials of ${\partial p}/{\partial C^C} \geq 0$ and ${\partial p}/{\partial C^{NG}} \geq 0$.[10]

Given these definitions, we can define the firm's maximization problem as:

$$\underset{\Delta HR}{max} \pi = q^m \Big[p(C^C, C^{NG}) - MC(\Delta HR, C^{NG})\Big] H(C^C, C^{NG}, \Delta HR) - C(\Delta HR) \tag{2.2}$$

The first order condition for maximization then implies:

$$\frac{\partial \pi}{\partial \Delta HR} = q^m \Big[(p - MC)\frac{\partial H}{\partial \Delta HR} - \frac{\partial MC}{\partial \Delta HR} H\Big] - \frac{\partial C}{\partial \Delta HR} = 0 \tag{2.3}$$

To assess the effect of an increase in coal prices on efficiency improvements we can differentiate the left hand side of (2.3) with respect to C^C to explore how NGCC plants may react to increasing coal prices. This leads to:

$$\frac{\partial^2 \pi}{\partial \Delta HR \partial C^C} = q^m \Big[\frac{\partial p}{\partial C^C}\frac{\partial H}{\partial \Delta HR} + (p - MC)\frac{\partial^2 H}{\partial \Delta HR \partial C^C} - \frac{\partial MC}{\partial \Delta HR}\frac{\partial H}{\partial C^C}\Big] > 0 \tag{2.4}$$

[9] A functional form for $H(\dot{})$ is difficult to specify exactly, but these partial seem reasonable. For example, if a plant is just off the margin in some hours, increasing ΔHR should increase hours of operation. If a plant is near cost competitive with coal plants then an increase in coal prices should increase H. If a plant is the marginal plant some hours or inframarginal when coal is on the margin, gas price increases would lower H. The marginal benefit of improving heat rate in terms of increasing H seems likely to diminish as gas prices increase. Finally, the marginal benefit of improving heat rate in terms of increasing H seems likely to increase as coal prices increase, particularly for plants that are initially near cost-competitive with coal plants.

[10] Technically, p would also be a function of ΔHR. More specifically, we would expect ${\partial p}/{\partial \Delta HR} \leq 0$ because as effiency increases the plant is infra-marginal more hours and therefore adds more relatively low-priced hours to the average price calculation that defines p. However, if we assume a relatively continuous electricity supply curve, then ${\partial p}/{\partial \Delta HR} \approx 0$ because the prices added to the average price calculation will be similar to those already included. We make such an assumption and ignore the affect of heat rate improvements on average electricity prices. One however could add this to the model and the results below will hold so long certain reasonable assumptions about marginal effects hold.

If we assume $\partial p/\partial C^C > 0$, $\partial H/\partial \Delta HR > 0$, $\partial H/\partial C^C > 0$, and $\partial^2 H/\partial \Delta HR \partial C^C > 0$, (2.4) implies that an increase in coal prices would increase the left-hand side of (2.3). Assuming a convex cost function for $C(\Delta HR)$ then we must also have ΔHR increase (i.e. efficiency increase) in response to an increase in coal prices to maintain the equality in (2.3). Of course, if the given plant has relatively high MC, as we generally assume is the case for NGSC plants, then the average price received by the plant and hours that the plant is operating will be unaffected by coal prices. In this case, the heat rates will appear largely unresponsive to coal price changes.

To evaluate the impact of a change in natural gas prices on efficiency investments we can similarly differentiate (2.3) with respect to C^{NG}. This gives us:

$$\begin{aligned}\frac{\partial^2 \pi}{\partial \Delta HR \partial C^{NG}} =& q^m \Bigg[\left(\frac{\partial p}{\partial C^{NG}} - \frac{\partial MC}{\partial C^{NG}} \right) \frac{\partial H}{\partial \Delta HR} + (p - MC) \frac{\partial^2 H}{\partial \Delta HR \partial C^{NG}} \\ & - \frac{\partial^2 MC}{\partial \Delta HR \partial C^{NG}} H + \frac{\partial MC}{\partial \Delta HR} \frac{\partial H}{\partial C^{NG}} \Bigg] \gtrless 0 \end{aligned} \tag{2.5}$$

Signing this cross-partial is not straightforward. Examining the first two terms in parentheses there is a positive subtracted from another positive. This first set of terms creates an ambiguous sign. We might assume that the electricity price change due to a change in natural gas costs might exactly off set the change in marginal costs, if a gas fired plant is on the margin and setting the market price for electricity. In this case, the first set of terms would become zero, however, even with this assumption the sign of the equation is still ambiguous.

The reason for this ambiguous sign is created by two opposing incentives faced by the power plant. The final two terms of (2.5) are the standard partial effects of the increase in an input fuel on the marginal benefit of increasing efficiency and are, as usual, positive.[11] However, the if marginal value of an efficiency improvement in terms of hours operating is declining as natural gas prices increase, so $\frac{\partial^2 H}{\partial \Delta HR \partial C^{NG}} < 0$ and, thus, the term $(p - MC) \frac{\partial^2 H}{\partial \Delta HR \partial C^{NG}} < 0$. To put it another way, this effect implies that with higher natural gas prices, improving efficiency is not going to be as effective in increasing the number of infra-marginal hours for the plant, so there is a diminished incentive to increase efficiency in this case. These two opposing forces, the value of improving efficiency in terms of its impact on marginal costs increases as natural gas prices go up and the value of improving efficiency in terms of its impacts on hours operating decreases as natural gas prices go up, is the root of the ambiguous sign impact of a natural gas price increase on the plant's incentive to increase efficiency. Note also that, unlike responses to the coal price changes, the described ambiguity in response to the natural gas price changes holds more generally for all types of natural gas plants.

2.3 Empirical Methodology

While the previous section lays out plausible responses of net generation and heat rates to changes in input prices across the two types of natural gas generation technologies, it remains an empirical question as to the magnitudes of these responses. Additionally, the previous theoretic section was largely set up in the framework of plants in a competitive market structure, but much of the electricity generation sector in the U.S. operates as regulated monopolies. Plants in these cost-of-service territories could have different incentives for efficiency and possibly for generation more generally. Thus, the aim of our empirical investigation is to identify the impacts of input fuel prices on both generation and efficiency

[11] Again, assuming $\frac{\partial^2 MC}{\partial \Delta HR \partial C^{NG}} < 0$ and noting that both $\frac{\partial MC}{\partial \Delta HR}$ and $\frac{\partial H}{\partial C^{NG}}$ are negative leads to an overall positive sign on the last two terms of (2.5).

decisions at natural gas power plants, allowing these responses to vary by generation technology and regulatory status.

We use a panel dataset with prime mover specific data on heat rates and net generation, plant level natural gas prices, regional coal prices, and various other prime mover, plant and regional characteristics. Our estimating equations can be encompassed in the general form as follows:

$$y_{it} = \sum_{j \in J} \beta_j D_i^j P_{it}^C + \sum_{j \in J} \theta_j D_i^j P_{it}^G + \boldsymbol{x'_{it}\gamma} + \alpha_i + \delta_t + \epsilon_{it} \tag{2.6}$$

The dependent variable y_{it} represents the log of net generation or log of heat rate. P_{it}^C, P_{it}^G are the logged values of coal and natural gas prices. Other time variant observable covariates are represented by the matrix $\boldsymbol{x'_{it}\gamma}$. We add in α_i and δ_t as plant and year fixed effects, respectively. ϵ_{it} is the stochastic error term.

Responsiveness of various technologies and market structures are incorporated through interaction dummies, D_i^j. In our most restrictive modeling form (Specification 1), we force the price responsiveness of all prime movers to be the same regardless of technology or market structure. In this case, $J = All$ is a single element set (i.e., $D_i^{All} = 1 \ \forall i$) and coal and gas price responsiveness measures are picked up by β_{All} and θ_{All}, respectively. Next (Specification 2), we allow for differing responses across technologies, broadly defined as CC and SC prime mover. In this case, $J = [CC, SC]$, with $D_i^{CC} = 1$ if plant i is an NGCC plant and 0 otherwise and $D_i^{SC} = 1$ if plant i is an NGSC plant and 0 otherwise. For Specification 3, we differentiate responses by technology class *and* market structure, defined as regulated (i.e. cost-of-service region) and restructured (i.e. competitive electricity market region). For this specification $J = [CC \times RST, CC \times REG, SC \times RST, SC \times REG]$, where $D_i^{CC \times RST} = 1$

if the NGCC plant is in a restructured region, $D_i^{CC\times REG} = 1$ for NGCC plants is in a regulated region, $D_i^{SC\times RST} = 1$ for NGSC plants in restructured regions, and $D_i^{SC\times REG} = 1$ for NGSC plants in regulated regions.

2.4 Data

For our analysis, we use a panel data set consisting of 756 natural gas power plants from 2002-2012, allowing us identification through variation cross-sectional plant differences and changes in operations within a plant over time. The data set is annual prime mover level data for gas-fired power plants in the contiguous United States. Additionally, we limit our analysis to power plants classified as "electric non-utility", "electric utility", or "NAICS-22 non-cogen." This excludes any co-generation power plants (i.e. combined heat and power) and any industrial or commercial power plants, for example, power plants owned and operated by one company for an internal purpose. We drop these power plants as their objective function may involve alternative motives other than selling generated electricity to the grid.[12]

We aggregate the data to an annual level for three main reasons. First, the cost data is split into monthly and annual respondents. Only gas plants with a nameplate capacity greater than 200 megawatts are required to report monthly. A monthly level analysis would exclude many of the small to medium sized gas plants from the analysis. Second, by using annual data we avoid gaps in the data at the monthly level, such as missing data due to a plant maintenance shut down or missing cost data if a plant did not receive any fuel deliveries for that month. Lastly, it would seem unlikely that plants are making many substantial short

[12]Note all non-binary variables described below are log-transformed in our analysis.

term (less than year) changes to heat rates and therefore the aggregation would be needed for identification.

To form our data set, we first designate generation technologies as NGCC and NGSC generators. The technology, designated as the "prime mover", of the generating units, along with the fuel burned by the units, within a given plant are listed in the EIA-923 and EIA-860 forms. To form the various variables taken from these forms for a given "NGCC plant" we sum the variable in question across the units within a plant for the given time period that have a NGCC prime mover code.[13] A similar aggregation is done over the simple cycle prime movers to form NGSC plant observations.[14] This type of within-plant summing is used to form all the variables described below.

We also must designate the market structure for the given plant. To determine the market structure, we used information from the EIA's website on market restructuring. A total of 15 states in our sample are consider to have restructured competitive markets, based on the EIA's designation.[15] It is also important to recall that since our sample begins in 2002, which is post implementation of new market systems for all states that restructured, we avoid any ambiguity of when legislation was passed and the appropriate timeframe when

[13]The prime mover codes in the EIA data that signify a combined cycle generating unit are CA (combined cycle steam part), CT (combined cycle combustion turbine part), CS (combined cycle single shaft), and CC (combined cycle - total unit).

[14]Generating units that form our NGSC plant observations have the following prime mover code designations: ST (steam turbine) or GT (combustion gas turbine). For our sample, combustion gas turbine are by far the most common simple cycle prime mover.

[15]Based on the EIA-generated map provided at `http://www.eia.gov/electricity/policies/restructuring/restructure_elect.html`, we consider CA, CT, DE, IL, MA, MD, ME, MI, NH, NJ, NY, OH, PA, RI & TX as restructured electricity markets. We do not consider Oregon to be restructured because their residential electricity services are still provided under a traditional rate of return regulation. We do consider power plants operating within California's ISO (CAISO) as restructured since CAISO runs a day ahead and real time markets which generators can sell power. Other than California, states that started restructuring and ultimately suspended their restructuring legislation are considered regulated.

power plants react to market restructuring.[16] In our robustness checks, discussed in more detail below, we also consider specifications where a restructuring designation as one where the plant in question falls under the service territory of an Independent System Operator (ISO) or Regional Transmission Operator (RTO) as has been done in other related works (e.g. Knittel et al. (2015) and Savage and Craig (2014)).

In some robustness specifications we also control for ownership type. We distinguish between plants being investor owned or publicly owned, which includes ownership by a municipality, state, or federal government. Ownership information for the plants was taken from the EIA-860 form data.

To form our dependent variables, net generation and heat rate, we gather data on net generation and fuel consumption from the EIA-923 form. This data is monthly and is therefore aggregated to the annual level. The heat rate variable is then formed by the annual fuel consumption (in MMBtu's) divided by annual net generation (in MWh's).

The key independent variables in all of our specifications are fuel cost. This cost information is currently collected by the EIA-923 form, however, prior to 2008, cost data for utilities was collected primarily by the FERC-423 form and cost data for non-utilities was collected by the EIA-423 form. Cost data for non-utilities across all years is not publicly available, but has been provide by the EIA for this research through a non-disclosure agreement. This data is given in terms of monthly or annual deliveries of fuel, broken down by fuel type and reported in MMBtu's, to the plant and the cost of the deliveries. We therefore form a given year's delivered natural gas price for the plant in question as the total annual cost of natural

[16]Additionally, most of the NGCC capacity entered in 2000 and 2001, so we have a more balanced panel by starting our analysis with year 2002 data.

gas deliveries divided by the sum of MMBtu's delivered.[17] To get the coal price for a given plant we use the average quantity weighted delivery cost for coal to power plants within the balancing authority area (BAA) of the NGCC- or NGSC-plant in question.[18] Figure Figure 2.2 shows a map of the BAA in the U.S. We choose to aggregate coal cost to this level since power plants within a BAA compete most directly with each other, however if aggregation at the BAA is unavailable, for example if there are no coal plants within the BAA, then a state average is used.[19]

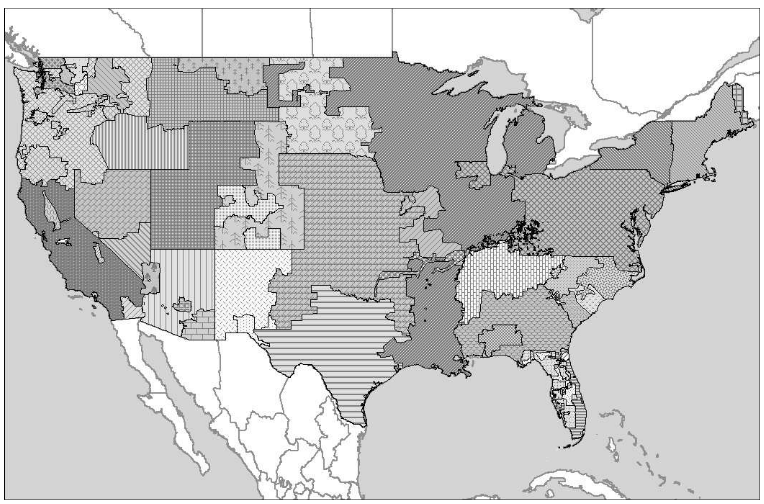


Figure 2.2: U.S. Balancing Authority Areas

The remaining regressors, included in $\boldsymbol{x_{it}}$ in regression equation (2.6), vary across dependent variable specification. For regressions using heat rate as the dependent variable, we

[17]Note that this data is given at the plant level, not generating unit level. Therefore if a plant has both NGCC prime mover and NGSC prime movers the NGCC-plant observation and NGSC-plant observation derived from this plant will be assigned the same fuel prices. In addition, using delivered prices further distinguishes our work from that of Linn et al. (2014) who use regional average input prices for both coal and gas. While they give several reasons for this choice a clear reason for using the delivered price where possible is that it reduces the measurement error that may be associated with a regional average price.

[18]A BAA is defined as an electric power system or systems to which a common automatic control scheme is applied to match generation supply to power demand.

[19]With the exception of plant fuel cost data, which was provided by the EIA through a non-disclosure agreement, all other EIA & CEMS data used for this paper is provided by ABB through their Velocity Suite software.

control for the number of starts (the number of times in a year a generating units gross generation goes from zero one hour to a positive value the next) a plant has in a year. Starting a plant after it has been shutdown generally consumes some energy and thus lowers a plant's efficiency. To the extent that a plant has more starts due to, for instance, more variable intermittent generation (e.g. wind and solar) or more variable load, then its thermal efficiency will decrease. Capacity utilization can also affect the thermal efficiency of a plant, so we include the plant's log of net generation and log of capacity.[20] However, including the net generation variable may create an endogeneity issue due the simultaneity of net generation and heat rates - higher net generation may increase plant efficiency, but more efficient plants have lower operating costs and are therefore reasonably dispatched more frequently which leads to higher net generation levels. Similarly, the number of starts may be endogenous due to simultaneity - less efficient plants are more likely to be pushed off the margin and thus may have more starts in a year. To instrument for net generation, we include demand shifting variables, including state-level cooling and heating degree days (CDD and HDD) and gross state product (GSP), that are likely to increase a plant's net generation, but are generally exogenous to a plant's efficiency choice.[21] To instrument for starts, we include standardized load variability in a plant's transmission zone and the plant's state-level wind generation.[22]

[20] We include these terms separately as it provides more flexibility than including the log of capacity utilization itself. Additionally, there is sufficient variation in capacity to identify its effect within a plant-FE estimation framework.

[21] State CDD and HDD are collected by the National Oceanic and Atmospheric Administration (NOAA) at `http://www7.ncdc.noaa.gov/CDO/CDODivisionalSelect.jsp#`. Data for GSP is publicly available from the Bureau of Economic Analysis website at `http://www.bea.gov/itable/iTable.cfm?ReqID=70&step=1#reqid=70&step=1&isuri=1`.

[22] A transmission zone is defined by the data-aggregation firm ABB and refers to a geographic "load pocket" that is highly correlated with the plant's generation. ABB calculates the standardized load volatility from data reported from FERC Form 714. State-level wind generation is available through the EIA at `https://www.eia.gov/electricity/data/state/`. We include wind generation because the increase in

For the net generation equations, our $\boldsymbol{x}'_{it}$ vector includes a control for generation capacity (summed MW of nameplate capacity for units with the same prime mover classification within the plant). We also control for regional demand conditions. Specifically, we include annual load at the North American Electric Reliability Council (NERC) subregion level.[23] A map of the subregions is given in Figure Figure 2.3. Because the subregions are of varying size and populations we normalize the load from each subregion by its mean over the sample observed.[24]

Figure 2.3: NERC Subregion Map

the major intermittent source of generation in the US likely increases net load (load minus wind generation) volatility in the region.

[23]We also considered specifications that controlled for load at the geographically broader NERC-region level and the geographically narrower transmission zone level. Results from these specifications are similar, both in terms of marginal effect magnitudes and statistical significance, to what is presented below.

[24]One might still be concerned that there are other time-varying plant-specific unobservables that could be correlated with generation or heat rate and the gas prices plants receive, such as managerial quality. For example, better managers may be more effective bargainers for fuel prices and may also get more generation out of their plants. While this seems plausible, Cicala (2015) shows no discernible difference in the natural gas purchase price of plants across regulated and deregulated plants, a distinction where we would expect the managers of deregulated plants to have more incentive to bargain for lower prices. Cicala asserts that this result is a product of the relative homogeneity of natural gas as input fuel. This suggests that the potential for bargaining in gas prices is not as possible as it is for coal or other similarly heterogenous inputs.

Across both dependent variable specifications we also include time-varying plant level characteristics. These include average-unit age, emissions control equipment dummies, and dummies controlling for enrollment in NOx emissions regulation.[25] This plant level data is taken from EIA-860 form data.

Table Table 2.1 provides mean statistics for the NGCC and NGSC power plants across the two market structures. From these statistics it is clear that NGCC plants are more efficient with a mean heat rate a little under 8,000 btu's per kWh. Simple cycle plants have a mean heat rate of roughly 12,500 btu's per kWh. Plants located in restructured states are slightly more efficient for both types of technology. Summed combined cycle prime mover capacity are about two times larger than NGSC capacity. This is not surprising since by definition combined cycle plants combine a both a gas turbine and steam turbine to generate electricity. In conjunction with higher nameplate capacities NGCC plants also produce much more electricity. NGCC capacity factors are also much higher than NGSC. This is expected and supports the fact that NGSC plants are mainly used to meet peak demand. It should also be noted that NGSC plants are usually older as measured by their average generating units age. This is due to the fact that combined cycle technology is relative new and has had a lot of investment over the pass 20 years.

We do face a few data limitations. First, the cost data prior to 2008 only required power plants with a nameplate capacity greater than 50 megawatts to report fuel costs. Therefore, several plants enter our analysis in 2008 as a result of the stricter response requirements. Additionally the CEMS data only monitors generating units over 25 megawatts. Due to

[25] The nameplate capacity variable is the sum of capacity from all generating units within a plant and are of the same generation technology, NGCC or NGSC. The average unit age is the average age of the units that are summed to make the "plant" observation. Emission control dummies are set to one if any of the units within the "plant" observation have emissions control equipment.

Table 2.1: Summary Statistics

	NGCC		NGSC	
	Restructured	Regulated	Restructured	Regulated
Net Generation (GWh)	2,214	2,223	313	307
	(17,932)	(24,408)	(5,428)	(6,556)
Heat Rate ($\frac{btus}{KWh}$)	7,859	7,925	12,574	12,815
	(1,080)	(1,246)	(3,041)	(3,024)
NG Cost ($\frac{cents}{mmbtu}$)	609	600	642	613
	(206)	(207)	(226)	(233)
Coal Cost ($\frac{cents}{mmbtu}$)	212	204	191	191
	(66)	(76)	(54)	(74)
Nameplate Capacity (MW)	682	710	481	374
	(394)	(512)	(430)	(364)
Capacity Factor (%)	36.1	33.5	7.0	7.7
	(20.1)	(20.1)	(8.5)	(9.8)
Average Unit Age (years)	7.4	7.9	25.6	24.0
	(6.8)	(7.6)	(18.)	(18.4)
Starts	144	122	220	149
	(151.)	(143.6)	(329.5)	(241.)
Plant Count	123	165	203	316

Notes: Standard deviations are given in the parentheses below the means. "Plant Count" includes plants that have both CC and SC prime movers.

this, we do not have start data on power plants that utilize units under 25 megawatts, even if the summed nameplate capacity of the units is above 25 megawatts for the whole power plant. Due to these limitations, several plants, typically small NGSC plants, are dropped from the analysis. Additionally, in calculating price and heat rate variables we observed many extreme outliers that are likely data entry errors. We therefore drop observations with heat rates and natural gas price values in the extreme percentiles (1 and 99) and those with capacity factors greater than 1.20.

2.5 Results

To begin, we present the various marginal effects of natural gas and coal prices on net generation estimated from variations of equation (2.6).[26] Table Table 2.2 gives the price responses based on the specification that estimates common responses for all gas plants (row labeled "Combined"), where the responses are broken out by technology types NGCC and NGCS (rows labeled "CC" and "CS", respectively), and, finally, where responses are further broken out by technology and market structure (rows labeled "CC×RST" and "SC×RST" for NGCC and NGSC plants, respectively, in restructured regions and those labeled "CC×REG" and "SC×REG" for NGCC and NGSC plants, respectively, in regulated regions).

Table 2.2: Marginal Effects of Fuel Prices on Net Generation

	NG Price Responses			Coal Price Responses		
Combined	-0.734***			0.379**		
	(0.070)			(0.154)		
CC		-0.738***			0.651***	
		(0.080)			(0.164)	
SC		-0.720***			0.231	
		(0.073)			(0.168)	
CC×RST			-0.758***			0.572***
			(0.097)			(0.217)
CC×REG			-0.722***			0.618***
			(0.084)			(0.167)
SC×RST			-0.640***			-0.006
			(0.082)			(0.191)
SC×REG			-0.773***			0.293
			(0.082)			(0.186)

*Notes: *, **, *** denote statistical significance at at least the 10, 5, and 1 percent levels, respectively. Standard errors are given in parentheses below the parameter estimates. All specifications have 5,895 observations.*

[26] The full set of parameter estimates from these base specifications with the log of net generation as the dependent variable, as well as those with log of heat rate as the dependent variable, are given in Table Table A.1 and Table Table A.2 in Appendix A.

When the responses are restricted to be fixed across all plants, we find that plants respond significantly (both statistically and economically) to gas prices, with a parameter estimate that implies about a seven percent increase in net generation given a 10 percent decline in gas prices. The net generation response to coal prices is also statistically significant, though at about half the magnitude of the gas price response with marginal effects implying a 10 percent increase in coal prices lead to almost a four percent increase in net generation from gas plants in aggregate.[27]

When we further break the response out by technology type, both CC and SC plants respond similarly to gas prices, with parameter estimates again implying about a seven percent increase in net generation from both types given a 10 percent decline in prices. However, by allowing for heterogenous fuel-price responses by technology our estimates now show that CC plants respond in a statistically significant fashion to coal prices, with a parameter estimate that implies about a 6.5 percent increase in CC net generation given a 10 percent increase in coal prices, while SC plants have a smaller and statistically insignificant response to coal prices. This is as the simple dispatch exposition described above would predict.

Finally, when breaking out responses by technology and market type, we find that the market-type distinction matters little - responses to gas prices across technologies and market structure varies somewhat, though not at statistically significant levels, and the response to coal prices by NGCC plants in regulated and deregulated regions is approximately equivalent. This suggests that dispatching decisions, at least with respect to gas plants, are similar across

[27] As a point of comparison, Linn et al. (2014) find that gas plants in aggregate respond to both gas and coal prices in a statistically significant fashion.

market structures.

The response of heat rates with respect to fuel prices are given in Table Table 2.3. The format of this table is similar to that of Table Table 2.2. Here we find when the thermal efficiency response to coal and gas prices are constrained to be constant across technologies and market structures ("Combined" row) estimated marginal responses to coal prices is small in magnitude and statistically insignificant. The response to gas prices is also small, but positive and significant at the 10 percent level. This result that higher gas prices leads to lower thermal efficiency of gas plants seems somewhat counterintuitive. This may occur, however, if higher cost plants do, for example, ramp capacity utilization rates up and down more frequently in high gas-price periods due to their position on the supply curve.[28]

Table 2.3: Marginal Effects of Fuel Prices on Heat Rate

	NG Price Responses			Coal Price Responses		
Combined	0.042*			-0.035		
	(0.023)			(0.062)		
CC		0.046			-0.093	
		(0.040)			(0.068)	
SC		0.036*			-0.008	
		(0.021)			(0.065)	
CC×RST			0.049			-0.197**
			(0.041)			(0.095)
CC×REG			0.044			-0.066
			(0.040)			(0.061)
SC×RST			0.038			-0.011
			(0.025)			(0.066)
SC×REG			0.033			-0.029
			(0.024)			(0.072)

*Notes: *, **, *** denote statistical significance at at least the 10, 5, and 1 percent levels, respectively. Standard errors are given in parentheses below the parameter estimates. All specifications have 5,895 observations.*

[28] Ramping production or "cycling" is known to affect the thermal efficiency of power plants (see Kumar et al. (2012)). While we attempt to proxy for ramping through including the number of "starts" a plant has in a year, effectively capturing the degree of ramping using annual data is not straightforward.

Breaking the heat rate responses out by technology we find that NGCC plants again appear unresponsive to fuel prices. NGSC plants are also unresponsive to coal prices and somewhat positively responsive to gas prices. Given that we find slight significance in the gas-price responsiveness of only the NGSC plants, this would lend support to the idea that as gas prices increase the higher cost plants (i.e., NGSC plants) in high gas price periods will be pushed off the margin or running at inefficient capacity utilization levels more frequently leading to a positive relationship between heat rates and gas prices.

Finally, when we further disaggregate responses across technologies and market structures we find that NGSC plants in both restructured and traditionally regulated regions, as well as NGCC plants in regulated regions, have small and statistically insignificant responses to fuel prices. Heat rates of NGCC plants in restructured regions are also unresponsive to gas prices. However, NGCC plants in restructured regions do respond, at a statistically significant level, to coal prices such that increases in coal prices *increase* the thermal efficiency of these plants.

The estimated response of restructured NGCC plants to coal prices is also relatively large in magnitude, with our estimates implying a 10 percent increase in coal prices reduces heat rates by about two percent. Or, to put this in a similar context to that of Linn et al. (2014), who found that a 1-standard deviation increase in coal prices decreased heat rates of coal plants by 1.5 percent, our estimates imply a 1-standard deviation increase in coal prices decreases heat rates of NGCC plants in restructured regions by about six percent.[29]

[29] This calculation is based off of the observation that in our data set a one standard deviation increase in coal prices relative the the mean price is equivalent to an approximate 33 percent increase in prices. This calculation appears to be similar to how Linn et al. (2014) derive their 1.5 percent value.

2.5.1 Robustness Checks

To assess the robustness of our primary results, we run our analysis on a number of different data restrictions and variable assignments, presented in Tables Table 2.4 and Table 2.5. In the first of these robustness checks we restrict our sample to those plants that are investor-owned plants ("IOU" column), as opposed to plants that are owned by municipal, state, or federal governments. One may want to exclude these publicly owned plants from the sample because in many instances, even when operating in restructured regions, these plants may operate in a way more consistent with those operating within a traditional vertically integrated utility. The second data restriction we apply is to look at the sample for the years 2006 - 2012 ("2006-2012" column). We consider this cut of the data because in the early years of our whole sample, a large amount of NGCC capacity was still coming into operation. By restricting the sample to later years we are able to get a more balanced sample while still retaining a large cross-sectional dimension. The third robustness check presented ("NERC×Year" column) removes several of the control variables and replaces them with more general NERC×Year fixed effects.[30] The final robustness check we present ("ISO" column) considers a re-assignment of the restructuring dummy. More specifically, we consider a plant as operating in a restructured region if it falls within a region with a grid managed by an Independent System Operator (ISO) or Regional Transmission Organization (RTO). A map of these ISO/RTO regions is included in Figure Figure 2.4. One may consider this a more appropriate designation of restructuring because these ISO and RTO managed regions do typically operate wholesale electricity markets even though they may span regions with

[30]For this robustness check, beyond the fuel prices, plant and NERC×Year fixed effects, we control for participation in RGGI and the NO_x trading programs and capacity across both equations. Additionally we control for net generation in the heat rate equation.

states that still operate under more traditional cost-of-service regulations.[31] Also, as noted above, this designation of restructuring is more in line with the work of Knittel et al. (2015) and Dean and Savage (2013).

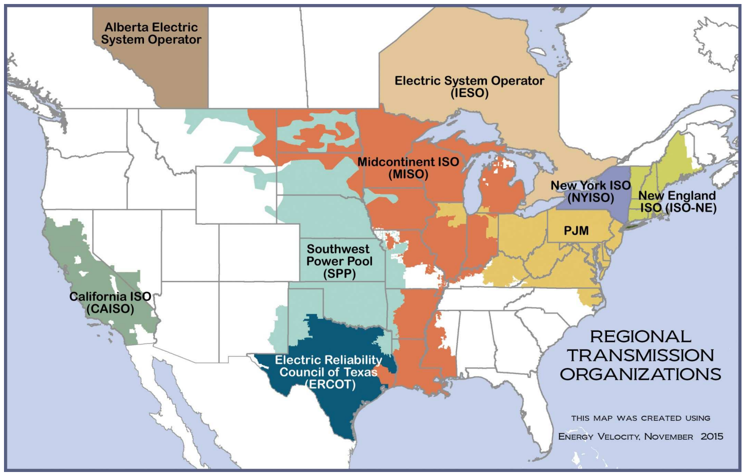


Figure 2.4: ISO/RTO Map

For each of these different estimations, we present results based on the model specification that allows for fuel price responses to vary by technology and market structure. Table Table 2.4 presents the marginal responses of net generation to gas and coal prices for the different groups. In each of these robustness checks we again find that both plant technologies across both market structures have a negative and significant response to gas prices. The magnitude of these responses to gas prices are also quite similar across the different checks, as well as close to those presented in our base specification. With respect to coal prices, we again find that the net generation of NGCC plants respond positively in both regulated and restructured across these various robustness checks. NGSC plants have statistically signif-

[31] For example, Minnesota falls within the Midcontinent Independent System Operator (MISO) territory, though Minnesota still operates as a rate-regulated region with a largely regulated, vertically-integrated utility, Xcel.

Table 2.4: Robustness Checks - Net Generation

NG Price Responses

	IOU	2006-2012	NERC×Year	ISO
CC×RST	-0.745***	-0.835***	-0.640***	-0.754***
	(0.112)	(0.117)	(0.116)	(0.089)
CC×REG	-0.631***	-0.791***	-0.497***	-0.679***
	(0.104)	(0.095)	(0.085)	(0.082)
SC×RST	-0.701***	-0.687***	-0.494***	-0.644***
	(0.098)	(0.102)	(0.100)	(0.076)
SC×REG	-0.723***	-0.718***	-0.530***	-0.822***
	(0.103)	(0.101)	(0.084)	(0.092)

Coal Price Responses

	IOU	2006-2012	NERC×Year	ISO
CC×RST	0.444**	0.221	0.572**	0.692***
	(0.221)	(0.253)	(0.265)	(0.178)
CC×REG	0.536***	0.414**	0.683***	0.559***
	(0.176)	(0.195)	(0.195)	(0.164)
SC×RST	0.035	-0.178	-0.625**	0.117
	(0.199)	(0.237)	(0.245)	(0.166)
SC×REG	0.343	0.262	-0.183	0.329*
	(0.215)	(0.253)	(0.228)	(0.183)
Obs	4530	4186	5895	5895

*Notes: Results display marginal responses of net generation to natural gas (NG) and coal prices. Column headers "IOU", "2006-2012", "NERC× Year", and "ISO" refer to models that only consider IOU plants, restrict the sample to years 2006-2012, drop most controls and include NERC-by-year fixed effects, and designate plants as being in a restructured region if they fall within an ISO or RTO region, respectively. *, **, *** denote statistical significance at at least the 10, 5, and 1 percent levels, respectively. Standard errors are given in parentheses below the parameter estimates. "Obs" provides the number of observations for each specification.*

Table 2.5: Robustness Checks - Heat Rate

NG Price Responses

	IOU	2006-2012	NERC×Year	ISO
CC×RST	0.048	0.029	0.029	0.059
	(0.054)	(0.023)	(0.039)	(0.039)
CC×REG	0.057	-0.015	0.004	0.013
	(0.050)	(0.026)	(0.037)	(0.034)
SC×RST	0.031	0.004	0.046	0.033
	(0.027)	(0.021)	(0.032)	(0.022)
SC×REG	0.033	-0.007	0.029	0.038
	(0.028)	(0.021)	(0.038)	(0.025)

Coal Price Responses

	IOU	2006-2012	NERC×Year	ISO
CC×RST	-0.210**	-0.163*	-0.195**	-0.135*
	(0.106)	(0.097)	(0.097)	(0.074)
CC×REG	-0.050	-0.124*	-0.086	-0.079
	(0.065)	(0.063)	(0.076)	(0.059)
SC×RST	0.011	0.013	0.012	-0.009
	(0.064)	(0.088)	(0.082)	(0.061)
SC×REG	0.016	-0.065	0.001	-0.008
	(0.076)	(0.060)	(0.081)	(0.069)
Obs	4530	4186	5895	5895

*Notes: Results display marginal responses of net generation to natural gas (NG) and coal prices. Column headers "IOU", "2006-2012", "NERC× Year", and "ISO" refer to models that only consider IOU plants, restrict the sample to years 2006-2012, drop most controls and include NERC-by-year fixed effects, and designate plants as being in a restructured region if they fall within an ISO or RTO region, respectively. *, **, *** denote statistical significance at at least the 10, 5, and 1 percent levels, respectively. Standard errors are given in parentheses below the parameter estimates. "Obs" provides the number of observations for each specification.*

icant responses to coal prices in some specifications (positively for regulated NGSC plants when considering the "ISO" specification and negatively for NGSC plants in restructured regions for the "NERC×Year" specification) though these responses are not consistent across specifications.

Table Table 2.5 presents the robustness checks for the heat rate equations. Here we again find that natural gas prices have small and statistically insignificant effects on thermal efficiency of gas plants across technology types and market structures. With respect to coal prices, we continue to find negative and statistically significant impacts for NGCC plants across specifications that are similar in magnitude to our base results. The one exception may be the case where restructuring is defined as being in an ISO/RTO region where we find a somewhat smaller-in-magnitude effect. This may be expected as some plants in ISO/RTO regions are still operating under traditionally-regulated, vertically-integrated utilities that may lack some incentives for efficiency improvements. Additionally, in our "2006-2012" specification, we find that NGCC plants in regulated regions have a statistically significant (10 percent level) and negative response to coal prices. It should be noted that there was expansion of some ISO/RTO territories into regions that are traditionally regulated toward the later part of our sample, which may have led to increased competition in these regions and greater incentive for efficiency improvements. Overall, these robustness checks largely align with our base specification results. This provides additional evidence of a consistent pattern of generation and efficiency price responsiveness across gas generators.

2.5.2 Policy Implications

To help put our estimates in context, we explore implications of various CO_2 taxes on generation, thermal efficiency, and emissions savings. More specifically, as pointed out in Cullen and Mansur (2014) one can view imposing a carbon tax as changing the implicit cost of coal and gas since burning both fuels emit CO_2, though an MMBtu of coal is roughly twice as carbon intensive as that for natural gas.[32] We can therefore calculate how a carbon tax changes the implicit \$/MMBtu costs of coal and natural gas. Based on our parameter estimates we can determine how these price changes change NGCC and NGSC net generation, heat rates, and, with some assumptions, electricity sector emissions relative to a no-carbon pricing baseline.

With a carbon tax of P^{CO_2}, the modified effective coal price would be $P^C_{tax} = P^C + P^{CO_2} \times 0.1028$ and, similarly, the modified natural gas price would be $P^G_{tax} = P^G + P^{CO_2} \times 0.0585$. Given these implicit tax-induced changes in fuel prices, we can calculate a change in net generation or heat rates relative to a no-carbon-pricing baseline. More specifically note that for generator j with $j \in [NGCC, NGSC]$ changes in the dependent variables can be written as:

$$\begin{aligned}&\bar{Y}_j(P^C_{tax}, P^G_{tax}) - \bar{Y}_j(P^C, P^G) = \\ &\qquad \left(\exp\left[\hat{\beta}_k\left(\log\left(P^C_{tax}\right) - \log\left(P^C\right)\right) + \hat{\theta}_k\left(\log\left(P^G_{tax}\right) - \log\left(P^G\right)\right)\right] - 1\right)\bar{Y}_j(P^C, P^G) \end{aligned} \tag{2.7}$$

where $\bar{Y}_j$ is some average net generation or heat rate value (in levels) for generator class j and $\hat{\beta}_k$ and $\hat{\theta}_k$ are the marginal responses to coal and natural gas prices, respectively, for

[32]Based on EIA estimates given at http://www.eia.gov/environment/emissions/co2_vol_mass.cfm and http://www.eia.gov/coal/production/quarterly/co2_article/co2.html, bituminous coal, the most common coal burned, has an average emissions factor of 0.10285 tons of CO_2 per MMBtu, while carbon intensity of natural gas is only 0.0585 tons of CO_2/MMBtu.

generator-market structure k with $k \in [NGCC\times RST, NGCC\times REG, NGSC\times RST, NGSC\times REG]$.[33] Thus in this specification we are essentially examining how a carbon price would change generation or heat rates for an average NGCC or NGSC plant if it were in a restructured region and if it were in a regulated region.

We base our carbon tax exploration on 2012 averages. To begin, we take 2012 average \$/MMBtu prices of coal and gas, P^C and P^G respectively.[34] Similarly, $\bar{Y}_j$ is formed as the 2012 average net generation or heat rate (in levels) for technology j based on plants in our sample. Note that (2.7) is a nonlinear transformation of random variables $\hat{\beta}_k$ and $\hat{\theta}_k$. Therefore to get confidence intervals for our estimated changes in dependent variables, we numerically simulate these distributions. To do this we first take 10,000 draws of $\hat{\beta}_k$ and $\hat{\theta}_k$ values from the assumed multivariate normally distributed parameters estimated in our base specification that breaks out responses by technologies and market structures. From each of these draws, and given the average price levels, tax level, and net generation or heat rate levels, we can calculate 10,000 differences in dependent variables. These simulated differences are then used to form our confidence intervals.

The top panel of Table Table 2.6 reports the average per-plant percent changes in net generation $\left(\left(\bar{Y}_j(P^C_{tax},P^G_{tax})-\bar{Y}_j(P^C,P^G)\right)/\bar{Y}_j(P^C,P^G)\right)$ by technology and market structure for various emission taxes. As one would expect given the parameter estimates, the NGCC plants are expected to increase generation and NGSC plants are expected to decrease generation in response to a carbon pricing scheme. Across market structures we see that the NGCC

[33]Equation (2.7) is based off the assumption that $\bar{Y}_j(P^C_{tax}, P^G_{tax})$ and $\bar{Y}_j(P^C, P^G)$ have the same values for all non-fuel-price variables.

[34]Note that these average prices are formed as the averages across all plants in our sample regardless of generation technology or market structure. We did this so that one could more directly compare outputs across plant types based on differences in fuel-price responses. Additionally, from Table Table 2.1 that fuel prices across technologies and market structures are quite similar.

plant responses are quite similar, but the NGSC-restructured plants appear to turndown generation more aggressively than NGSC-regulated plants do in response to the carbon tax. However, with across all plant types our 95 percent confidence intervals, shown in brackets below the mean estimates, indicate that none of the expected responses to the taxes are significant at the five percent significance level. This is due to the tax creating opposing incentives on generation - the tax increases implied coal prices which, at least among NGCC plants, increases net generation, but it also somewhat increases gas prices which drives down generation across all gas plant types.

Table 2.6: Carbon Tax Impacts

% Change in Generation

Tax ($^{\$}/_{tCO_2}$)	NGCC-RST	NGCC-REG	NGSC-RST	NGSC-REG
10	8.91	11.18	-9.33	-1.49
	[-7; 26]	[-1; 25]	[-21; 4]	[-14; 12]
20	14.76	18.87	-16.46	-3.76
	[-13; 48]	[-4; 46]	[-34; 5]	[-24; 20]
30	18.86	24.48	-22.16	-6.21
	[-18; 66]	[-6; 63]	[-44; 6]	[-31; 25]

% Change in Heatrate

Tax ($^{\$}/_{tCO_2}$)	NGCC-RST	NGCC-REG	NGSC-RST	NGSC-REG
10	-5.88	-1.60	0.23	-0.47
	[-12; -0.16]	[-5; 2]	[-4; 5]	[-5; 5]
20	-9.88	-2.67	0.50	-0.70
	[-19; -0.23]	[-9; 4]	[-7; 9]	[-9; 8]
30	-12.85	-3.45	0.80	-0.83
	[-25; -0.21]	[-11; 5]	[-10; 13]	[-12; 11]

Notes: Taxes are in $\$/tCO_2$. All other reported values are per plant average changes relative to a case with no carbon price and using 2012 average prices and 2012 average production or heat rates for NGCC or NGSC plants for the baselines. The 95% confidence bands are shown in brackets below the mean estimate.

The bottom panel of Table Table 2.6 presents the average per-plant percentage changes in heat rates for the various tax levels. The carbon tax results in rather large efficiency improvements (heat rate decreases) for the NGCC plants, particularly the NGCC plants in restructured regions and effectively no changes in efficiency for NGSC plants. Additionally, the calculated 95 percent confidence intervals indicate that the expected heat rate decrease brought on at each tax level examined is statistically different from zero at the five percent significance level.

Finally, to further put these generation and heat rate changes into an environmental context, we calculate per-plant average emission savings from the different channels under the various carbon taxes. With respect to the changes in net generation channel, we assume that the increased generation from NGCC plants displaces generation from coal plants. We also assume that reductions in generation from NGSC plants represent changes in quantity demanded and are therefore not compensated for by generation from other technologies. For the heat rate channel, we calculate emissions savings from NGCC plants, the only plants that showed non-neglible heat rate responses, as the difference between what emissions would have been under generation levels (including the tax-induced generation increases) and at the no-tax heat rate levels (i.e. 2012 average heat rates) and the emissions under those same generation levels but at the tax-adjusted heat rates.

The results from these emissions reduction calculations are presented in Table Table 2.7. Note that these values, except for the "Total" column are based on average per plant changes. As one may suspect the biggest emission reductions from a carbon tax that occur via the natural gas generators comes from the coal-to-gas switching. The average NGCC plant in a restructured region will up its generation more than that same plant in a restructured region by a small margin, so consequently our estimates predict more emissions reductions from an NGCC plant due to coal-to-gas switching in regulated regions. On the other hand, the larger heat rate response of NGCC plants in restructured regions leads to significantly more tax-induced emission reductions from that channel in the restructured regions than in the regulated regions. The emission reductions due to heat rates are quite large. In fact, our estimates imply that with a $\$30/tCO_2$ emissions about 30 percent of the NGCC-related emission reductions in the restructured regions come via tax-induced heat rate improvements. With respect to the NGSC plants, we see that the tax-induced reduction in generation and thus emissions is relatively small. Totaling these reductions across all plants in the restructure and regulated regions, we see that the total gas-fired related emissions reductions are similar across the regions though slightly larger in the regulated regions. This is due to the fact that there are more NGCC and NGSC plants in the regulated regions relative the restructured regions.

Table 2.7: Carbon Emissions Saving (tons of CO_2 per plant)

	Tax ($^{\$}/_{tCO_2}$)	NGCC Coal Displacement	NGCC Effic Improvement	NGSC Gen. Reduction	Total (million tCO_2)
Restructured					
	10	118,147	65,752	883	24.7
	20	195,722	116,220	1,557	41.9
	30	249,987	156,629	2,096	54.7
Regulated					
	10	148,223	18,332	141	30.1
	20	250,141	32,563	356	51.2
	30	324,566	43,960	588	66.7

Notes: Taxes are in $\$/tCO_2$. Emissions savings for all columns except "Total (millioin tCO_2)" are average per-plant values relative to 2012 averages with no carbon price. The "Total (millioin tCO_2)" sums up the average per plant emissions savings across all plants in the given region, restructured or regulated. From our sample we have; 133 restructured NGCC; 181 regulated NGCC; 290 NGSC restructured; and 425 NGSC regulated plants. These counts are used to calculate total emissions savings (column "Total")

2.6 Conclusion

Natural gas-fired generation has rapidly gained market share in many parts of the U.S. such that it now represents roughly a third of total generation. It is therefore important to understand how input fuel prices affect operations of these increasingly important generation technologies to not only understand how future price movements may alter our generation mix and plant efficiency, but also to understand how various environmental policies that effectively change the cost of burning certain fuels will alter the electricity generation landscape. While others have looked at this question to some degree, our work distinguishes itself from the other related studies in that we pay particular attention to the difference in fuel-price responsiveness across different gas-fired generation technologies and across market structures.

Using a panel data set of gas-fired power plants from 2002 - 2012 that includes confidential cost information, our results indicate that there is substantial heterogeneity in response to coal and gas prices across generation technologies and across market structures. More specifically, we find that generation from NGCC plants responds at statistically significant levels to both coal and gas prices in ways one would expect - rising coal prices increases generation and rising gas prices decreases generation. On the other hand, NGSC plants' generation have stistically significant responses to gas prices only, such that increasing gas prices decrease NGSC production. These results are consistent for both restructured and traditionally regulated regions. Furthermore, our results show that restricting the net generation responses to be the same across all technology types, as others have done, obscures the more nuanced response to fuel price movements.

With respect to thermal efficiency improvements, our results are less obvious. More specifically we find that gas plants, regardless of generation technology and market structure, do not significantly alter their thermal efficiency in response to natural gas prices. However, we do find that the thermal efficiency of NGCC plants in restructured regions does respond to coal prices in a statistically significant manner, such that higher coal prices improves the efficiency of these NGCC plants. Again, this finding is lost if one confines the responses to be constant across technology and market structures.

To further put these results in context, we also use our parameter estimates to determine how a price on carbon would affect generation and efficiency of gas-fired plants and the implied emission reductions brought about by these changes. Our results indicate that the carbon price would increase NGCC generation and decrease NGSC generation, though generally not at statistically significant levels. On the other hand, we find that a carbon tax would increase the efficiency of NGCC plants in restructured regions and this results appears statistically significant at the 5 percent level. Calculating the implied emissions reductions from these changes we find that the largest gas-fired generation related emissions reductions would come from coal-to-gas switching brought about by tax-induced increases in NGCC generation. Although, our results also show that the emissions savings from improved thermal efficiency of NGCC plants in restructured regions also adds considerably to the emissions reductions generated by those plants. In fact, our simulation indicates that about a third of the tax-induced emissions reductions for NGCC plants in restructured regions are due to thermal efficiency improvements among those plants.

CHAPTER 3

POLITICAL PRESSURE AND POWER PLANT POLLUTION ABATEMENT

The large and local economic and environmental footprint of power generation make them a salient target for state politicians when lobbying the electorate. Researchers have utilized the fact that many states have term limits (as opposed to being eligible for re-election) for governors to determine how changes in electoral incentives alter state regulatory agency behavior. The research question here asks whether the change in electoral incentives, and its impact on regulatory agencies, spillover into private sector decision-making? We find strong evidence that power plants invest less in water pollution abatement, and similar but not as strong evidence for air pollution abatement investment, if the governor of the state where the plant is located is a democrat and term-limited. Furthermore, the difference in plant decision-making is strongest when the governor wins their term-limited term by a narrow margin. The effect is much weaker and statistically insignificant if variables relating to the make-up of the electorate are used instead of political party of the governor, implying the effects found here are not due to candidates desire to capture the environmental vote. Finally, we show that the lack of investment has environmental impacts by increasing thermal pollution and chlorine use by the plant.

3.1 Introduction

Modern democracies utilize the ballot box as an accountability mechanism to ensure politician's goals match well with the electorates. There are many instruments available to governors to achieve their goals, some more visible such as encouraging the enactment of new legislation and others less visible such as the goal setting of executive agencies. These executive agencies often have considerable flexibility in how they enforce regulations, which can provide relatively low transparency for how governors move their goals forward. The ability to attract voters by targeting specific policy issues, whether it be environmental concerns or gun control, creates the incentive for politicians to increase effort when they are eligible for re-election. However, most states have term limits for governors and the lack of re-election eligibility, also known as *lame duck* status, may alter their incentives in how they interact with regulated sectors. The notion that governors change their behavior based on electoral incentives may not be surprising, but does this change in behavior spillover into the private sector decision-making?

That is the question this analysis seeks to answer using plant level panel data from 1985-2005 on power plant abatement investments, collected by the Energy Information Administration. The large and usually local environmental footprint from power generation is an easy target for politicians in order to lobby the electorate.[35] Using data on both water and air pollution abatement investments, we find strong evidence that power plants are less likely to invest in water and air pollution abatement if the governor is a term-limited democrat. The re-election status and party of a particular state's governor is unlikely to be correlated with variables related to pollution abatement decisions, especially given that states hold elections on different cycles (1988, 1992... vs 1990, 1994...). To understand the relationship between re-election status and party of the governor better, a regression discontinuity design model is estimated where the discontinuity comes from the fact that a majority vote share

[35] The electricity sector withdraws more freshwater than any other sector in the U.S and is responsible for roughly one third of U.S. air emissions.

makes one party the winner of the election. For elections where the winner is re-electable, the winner's party makes no difference in the amount of pollution abatement plants investment during the governor's term. However, when the winner is term limited, a divergence in power plant pollution abatement investment occurs. Power plants invest more in pollution abatement when a lame duck republican wins by smaller vote margins and the plants invest less when a lame duck democratic governor wins by small vote margins.[36] Power plants in states with lame duck democratic or republican who win by a larger vote margins invest similar amounts. This suggests that power plants do in fact respond to the change in the governors' behavior depending on the political party and the re-election status, especially after close elections.

Next, we estimate whether less investment in water pollution abatement investment actually leads to more pollution. For water, there are three main ways in which a power plant contributes pollution: water withdrawal, thermal pollution and the addition of chlorine. Each outcome is estimated separately in model with the lag amount of investment as the explanatory variable. Results show that decreases in pollution abatement investment leads to more thermal pollution and higher chlorine levels, but does not have a significant effect on water withdrawal.

The impact of the re-electable status of politicians has previously focused on public sector outcomes. This analysis broadens the previous literature by showing that private sector decision making is can be altered by politician's re-election incentives. Previous work by Besley and Case (1995) has argued that there is a *accountability* effect of re-election by

[36]Small vote margins indicate similar constituents. That is, the constituents of a state where a republican wins by a small vote marginal is similar to a state where a democrat wins by a small vote margin. This allows us to conduct a regression continuity design

building a theoretical model of reputation that encourages the efforts of re-electable incumbents to create higher voter payoffs. Their model suggests that these efforts are diminished when the governor becomes term limited and no longer seeks to build their reputation.[37] They then empirically show that taxes and per capita government spending are higher when governors are term limited compared to their re-electable governors counterparts. They also find that this lame duck effect is present across political parties, but is larger in magnitude for Democratic governors.

Alt et al. (2011) reexamine the Besley and Case (1995) findings by arguing that there is a *competency* effect, where governors who are re-elected, have shown the electorate during previous terms that they are a competent head of the state executive branch, in addition to the accountability effect discussed by Besley and Case (1995). Using differences in the various state term limit legislation, they find evidence for both a competency and an accountability effect with respect to economic growth, taxes, spending and borrowing costs, but do not split this effect out by political party.

Closer to our analysis are two studies, List and Sturm (2006) and Fredriksson et al. (2011), that measure the effect of term limits on the budgets of state environmental agencies.[38] More specifically, List and Sturm (2006) use an interaction model and find a significant negative effect on environmental spending for lame duck governors located in *green* states. They argue that the governors in *green* states looking for re-election are more likely to favor environmental spending in order to ellicit votes from their *green* voters, but during a

[37] Besley and Case (1995) further discuss how party reputation, lack of gubernatorial discretion (i.e. the governors ability to effect policy), and career after gubernatorial office would reduce the lame duck effect.In other words, these are three arguments why a governor would <u>not</u> alter their behavior due to a being term limited.

[38] Each state has different names for their environmental agencies, but an example would be the Colorado Parks and Wildlife.

governor's lame duck term she or he will revert to pleasing the base constituents. Fredriksson et al. (2011) use a regression discontinuity design and find a significant negative effect on environmental spending for democratic (relative to republican) lame duck governors. Our study differs from the previous literature by showing that private sector decisions, specifically investment for pollution abatement, are altered by the political and re-election status of the state executive branch.

One possible mechanism for the results found here is that governors alter the magnitude and type of enforcement for environmental regulations. Governor's often appoint the director and other office positions to their environmental agencies. The leadership within these agencies sets the priorities and focus for the state's environmental policies. In conjunction with allocating money to environmental agencies, the appointment of specific offices can translate to stricter government oversight, which has been shown to affect private sector actions. Earnhart (2004) and Shimshack and Ward (2005) find that type of enforcement plays a significant role in the behavior of polluters. A fine given to one polluter generally alters the behavior of all polluters within the state. Our paper will not test these mechanisms, but simply turns to the data to see if the re-election status and party of a governor is in fact impacting power plant abatement decisions.

3.2 Empirical Model

In order to determine how party and re-election status of the governor affect power plant pollution abatement investment, two different estimation techniques are utilized. Our first technique estimates an interaction model of party and re-election status of the governor as determinants for the (log of the) amount invested in pollution abatement during that election cycle.[39] The interaction model is specified as follows:

$$\begin{aligned} log(j^{abate}\ invest)_{it} =& \beta_1 dem_{it} + \beta_2 duck_{it} + \beta_3 dem_{it} \times duck_{it} + \boldsymbol{x'_{it}\gamma} + \alpha_i + \epsilon_{it} \\ & \forall j = \{water, air\} \end{aligned} \tag{3.1}$$

where i indexes the individual power plant and t indexes a specific election cycle for that state's governor. The dependent variable, $log(j^{abate}\ invest)_{it}$, is the log of the amount invested in pollution abatement for j pollution during election cycle t at plant i. We run this specification for both water and air abatement investments. The variable dem_{it} is a dummy variable indicating if the governor is a democrat and $duck_{it}$ is a dummy variable indicating if the governor is a lame duck. The third term is an interaction term between the two previous dummy variables. Other time variant observable covariates are included by the matrix $\boldsymbol{x'_{it}}$. We use α_i as plant fixed effects and ϵ_{it} is the stochastic error term.[40]

Using the democrat lame duck governor interaction term as a treatment variable provides temporal and spatial variation that makes it unlikely that our treatment is correlated with unobservables. Gubernatorial elections occur every four years with the exception of New Hampshire and Vermont which have only two year terms. Additionally, about two-thirds of states hold elections for governor on one cycle of even number years (e.g., 1988, 1992, 1996 ...). Others hold elections on a different cycle of even number years (e.g., 1990, 1994, 1998..) and six states hold elections during odd number years.[41] Thirty-six states have term limit

[39] A linear and probit probability model with a binary outcome of whether plants invest is also estimated. These results are shown in appendix B.

[40] Year fixed effects are not utilized since the election cycles do not all fall within the same year. For robustness checks we drop the few states that have odd year elections and dummy out the two election cycle groups and interact them with a year fixed effect. This effectively adds in year fixed effects for the two groups.

[41] NJ and VA (1985,1989,...) and CA,KY,LA, and MS (1987,1991...). CA only joined the list of states with elections in odd years in 2003 when the state held a recall vote.

legislation for their governors and these are geographically spread across the U.S. Virginia is the only state that limits its governor to a single term. Figure Figure 3.1 shows which states do and do not have term limit legislation. Elections can have party waves to them but the different cycles of elections across states and the chance that the governor is of the same party to that wave make it unlikely that these waves are driving our results.

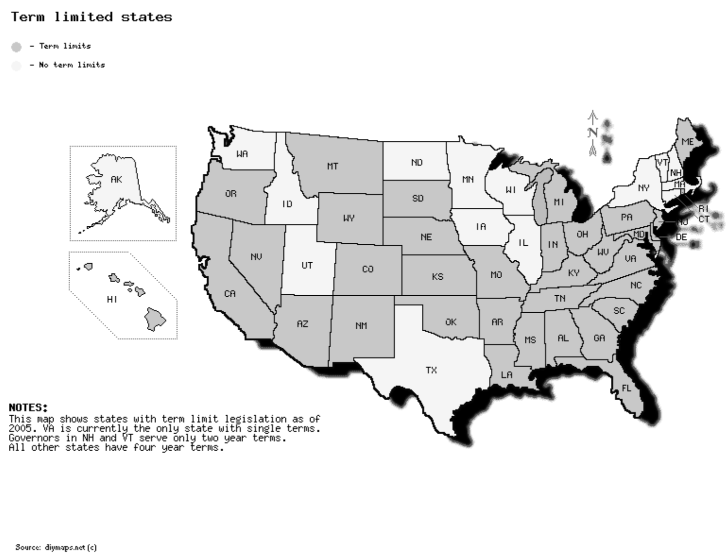


Figure 3.1: State term limit legislation

The covariates in the matrix $\boldsymbol{x}'_{it}$ include a number of control variables. Three dummy variables are used to indicate if the plant is located in a state that (1) has a restructured electricity market, (2) participates in the Regional Greenhouse Gas Initiative (RGGI), and (3) participates in the a NO_x trading program. Other controls are the share variable ranging from zero to one showing the portion of the election cycle that the majority party of the legislative branch is the same as the governors political party (e.g. 1 = same party throughout the governors term, 0 = split or opposing party throughout the governors term, .5 = same party for half of the governor's term) and the logged share of Sierra Club membership to state population. These two variables account for the ease of passing state regulatory legislation and as a control for the environmental conscience of the states' constituents.

An alternative model is to estimate a regression discontinuity design (RDD) where the assignment variable is democratic vote share. A vote share above 50% leads to a term as governor for the Democrat party and below 50% leads to a term as governor for the Republican party, thus there is a sharp discontinuity in earning a term as governor. The dependent variables is the same as in Equation 3.1. The advantage an RDD has over the model in Equation 3.1 is that the will of the electorate is fairly similar on either side of the 50% cutoff (either candidate could have been elected) and thus the amount invested in pollution abatement by power plants is unlikely to be driven by the electorates political views. Additionally, it can provide evidence of how the treatment effect varies by voting margins. The RDD model is:

$$\begin{aligned} log(j^{abate}\ invest)_{it} =& \alpha + \beta_1 \widetilde{v_{it}} + \cdots + \beta_k \widetilde{v_{it}}^k + \rho D_{it} + \boldsymbol{x'_{it}\gamma} + \epsilon_{it} \\ & \forall j = \{water, air\} \end{aligned} \tag{3.2}$$

where D is the treatment indicator that takes the value of 1 if the Democrat received above 50% of the vote and 0 otherwise, and $\widetilde{v} = v$–50 is the normalized vote share (i.e., centered around the cutoff).[42] A number of specifications of the functional forms on either side of the cutoff will be utilized to ensure any jump, ρ, estimated will be do to an actual jump in the data and not to a misspecification of the data (Lee and Lemieux (2010)). The rest of the variables are as given in Equation 3.1.

[42] The normalized voteshare, $\widetilde{v} = v$–50, gives a guarantee that the coefficient on D is still a causal effect even after these interactions ((Angrist and Pischke, 2009)).

In both Equation 3.1 and 3.2 the level to cluster standard errors at is not immediately clear. Generally, clustering would be at the level of the treatment (the state) as argued by Bertrand et al. (2004). However, it is likely that investment decisions will have significant plant-level autocorrelation. An additional concern with clustering at the state level is the possibility of too few clusters. Cameron and Miller (2015) argue that there is no definition of "too few" clusters but that more is better.

Next we determine the relationship between the amount of water pollution abatement investment and pollution levels using annual plant level data. Our dataset only contains data on water pollution, so we restrict our analysis to water abatement investments. Furthermore there are three pollution categories; water withdrawal, thermal pollution, and chlorine levels. We do not observe which abatement investment dollars are spent for which type of pollution. To circumvent this issue we simply run our analysis on all three types of pollution. We also use lags of the logged water investment value. This avoids any confusion on the time of year the abatement technology was installed and started impacting pollution levels during the contemporary time period. The pollution model is specified as follows:

$$\begin{aligned} \ln(j^{pollution})_{it} = &\sum_{n=1}^{k} \beta_n L^n \ln(water\ invest)_{it} + \boldsymbol{g'_{it}}\boldsymbol{\gamma} + \alpha_i + \delta_t + \epsilon_{it} \\ &\forall j = \{withdrawal, thermal, chlorine\}; k = \{1, 2, 3\} \end{aligned} \tag{3.3}$$

where i indexes the power plant, t now indexes the year, j indexes the type of pollution, and k indexes the number lags included in the regression. L^n is the lag operator on the $\ln(water\ invest)$ and $\boldsymbol{g'_{it}}$ includes covariates; generation and generation squared. For this analysis we use plant and year fixed effects, α_i and δ_t, respectively and ϵ_{it} is a stochastic error term. For our specifications we choose a maximum of three lags.[43] Standard errors are clustered at the plant level.

3.3 Data

The analyses described above use data from the EIA-767 form, an annual-plant level panel dataset from 1985-2005. Given that our treatment is about the party and re-election status of the governor, we aggregate up to election cycles for the first analysis. These data contain plant level investment dollars on water and air abatement investments and is collected by the EIA-767 form. Other plant level characteristics are collected by the EIA-860 form.

The dependent variables for Equation 3.1 and 3.2 is the amount invested in water pollution abatement capital. The instructions for this entry in the EIA-767 read:

> report new structures and or equipment purchased to reduce, monitor, or eliminate waterborne pollutants, including chlorine, phosphates, acids, bases, hydrocarbons, sewage, and other pollutants. Examples include structures/equipment used to treat thermal pollution; cooling, boiler, and cooling tower blowdown water; coal pile runoff; and fly ash waste water.

Similarly, for investment in air pollution abatement capital the instructions read:

> report new structures and/or equipment purchased to reduce, monitor, or eliminate airborne pollutants, including particulate matter (dust, smoke, fly ash, dirt, etc.), sulfur dioxides, nitrogen oxides, carbon monoxide, hydrocarbons, odors, and other pollutants. Examples of air pollution abatement structures/equipment

[43] Since our data can be described as wide instead of long (i.e. we have 451 power plants and only 26 years worth of data) adding additional lags begins to shrink our sample, for each additional lag one early year is chopped off.

include flue gas particulate collectors, flue gas desulfurization units, continuous emissions monitoring equipment (CEMs), and nitrogen oxide control devices.

Sierra Club membership data comes from the Sierra Club.[44] We collect data for the league of conservation voters (LCV) which we use in alternative specifications. This data is publicly available on the LCV score card website.[45] Governor party affiliation, vote margin, state legislative party shares, and state term limit legislation is all publicly available. [46]

In the second step, three different dependent variables are utilized: water withdrawals, thermal pollution, and chlorine use. Water withdrawal is the average annual rate of withdrawal in cubic feet per second. Thermal pollution is the product of the annual average rate of discharge in cubic feet per second and the difference between the intake temperature and the outflow temperature. Chlorine use is the amount of chlorine added to the water in the year in thousands of pounds. These pollution data are available from the EIA-767 form .

3.4 Results

The results of the estimation for Equation 3.1 can be found in Tables Table 3.1 and Table 3.2. There are four specifications which differ depending on the inclusion of covariates, cluster level for the error term, and estimation specification. The first three columns are estimates from a fixed effects model and the fourth uses a panel tobit model to correct for possible truncation in the choice of amount invested. The omitted category in these regressions is first term republican. In specification (1) we exclude any control variables and cluster at the state level. In specification (2) we add in control variables and (3) shows

[44] Thank you to Daniel Kaffine for providing the data to us.
[45] `http://scorecard.lcv.org/`
[46] We thank Le Wang for providing the election data from their paper ((Fredriksson et al., 2011)). The rest of the data were collected ourselves.

standard errors clustered plant level.

Table 3.1: Log Water Pollution Abatement Investment

	(1) ln(water invest)	(2) ln(water invest)	(3) ln(water invest)	(4) ln(water invest)
democrat	0.498	0.732**	0.732***	0.139***
	(0.325)	(0.334)	(0.143)	(0.033)
lame duck	0.641	0.619	0.619***	0.120**
	(0.535)	(0.501)	(0.193)	(0.048)
democrat × lame duck	-1.213*	-1.321*	-1.321***	-0.242***
	(0.719)	(0.660)	(0.265)	(0.066)
Controls	No	Yes	Yes	Yes
Cluster Level	State	State	Plant	Plant
Observations	3139	3139	3139	3139

Standard errors in parentheses

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

Table 3.2: Log Air Pollution Abatement Investment

	(1) ln(air invest)	(2) ln(air invest)	(3) ln(air invest)	(4) ln(air invest)
democrat	0.252	0.738*	0.738***	0.072*
	(0.359)	(0.414)	(0.163)	(0.040)
lame duck	0.419	0.705	0.705***	0.049
	(0.643)	(0.698)	(0.224)	(0.059)
democrat × lame duck	-0.991	-1.314	-1.314***	-0.131*
	(0.895)	(0.891)	(0.299)	(0.079)
Controls	No	Yes	Yes	Yes
Cluster Level	State	State	Plant	Plant
Observations	3139	3139	3139	3139

Standard errors in parentheses

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

The results from Table Table 3.1 provide strong evidence that power plants invest less in water pollution abatement when the governor of the state they are located in is a lame duck democrat. The estimate is negative and statistically significant across all specifications. There is some evidence that power plants are more likely to invest in water pollution abatement when a democrat is in their first term, as compared to a republican, as the democrat estimate is statistically significant in three of the four specifications. The coefficient on lame duck governors is positive but only significant when clustering at the plant level. Turning to Table Table 3.2, the results are much less robust for the treatment (democrat interacted with lame duck). The estimate is only significant with a plant level cluster of the standard errors. The rest of the estimates, re-electable democrats and lame duck governors, are similar to that of water pollution abatement investment. Tables showing the results from the estimation of Equation 3.1 with a dependent variable that is a dummy indicating whether any investment is made can be found in Tables Table 3.3 and Table 3.4. Results are consistent with those given in Tables Table 3.1 and Table 3.2.

Table 3.3: Dummy Water pollution abatement -Probit

	(1) dum(water inv)	(2) dum(water inv)	(3) dum(water inv)	(4) dum(water inv)	(5) dum(water inv)
dum(water inv)					
democrat	0.187	0.266	0.266^{***}	0.320	0.320^{***}
	(0.157)	(0.169)	(0.068)	(0.211)	(0.079)
lame duck	0.241	0.243	0.243^{**}	0.241	0.241^{**}
	(0.230)	(0.228)	(0.096)	(0.228)	(0.096)
democrat × lame duck	-0.424	-0.459	-0.459^{***}	-0.447	-0.447^{***}
	(0.323)	(0.317)	(0.135)	(0.314)	(0.134)
democrat × south				-0.158	-0.158
				(0.203)	(0.103)
Controls	No	Yes	Yes	Yes	Yes
Observations	3139	3139	3139	3139	3139

Standard errors in parentheses
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

The estimates in Tables Table 3.1 and Table 3.2 provide an average treatment effect, however this specification assumes that a lame duck democrat winning election by a 25 percent vote margin is the same as those winning by 1 percent vote margin. Further, it may be difficult to compare the results from a republican winning election by a 25 percent vote margin to a democrat winning election by a percent vote margin as these scenarios may provide other reasons for power plants to change their investment behavior. To remedy these

Table 3.4: Dummy Air pollution abatement - Probit

	(1) dum(air inv)	(2) dum(air inv)	(3) dum(air inv)	(4) dum(air inv)	(5) dum(air inv)
dum(air inv)					
democrat	0.010	0.116	0.116*	0.247	0.247***
	(0.122)	(0.141)	(0.065)	(0.162)	(0.077)
lame duck	0.031	0.077	0.077	0.075	0.075
	(0.229)	(0.240)	(0.091)	(0.242)	(0.092)
democrat × lame duck	-0.134	-0.199	-0.199	-0.170	-0.170
	(0.324)	(0.330)	(0.132)	(0.335)	(0.133)
democrat × south				-0.391**	-0.391***
				(0.191)	(0.103)
Controls	No	Yes	Yes	Yes	Yes
Observations	3139	3139	3139	3139	3139

Standard errors in parentheses

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

concerns, the RDD model of Equation 3.2 is estimated with results given in Table Table 3.5. Here the functional form of the vote share is estimated using a triangular kernel. [47]

Equation 3.2 is run on a sample where the winning candidate is term limited and where the winning candidate can run for re-election at the next election. The coefficients given in Table Table 3.5 report the amount invested in water (or air, as given by the table) pollution investment under a term where the democrat just won the election (i.e., received greater than 50% of the vote) compared to a term where the republican just won the election. Three different bandwidths and two different standard error clusters are shown. Every specification is negative and statistically significant for the sample where the winner is a term-limited democrat. All but one of the nine coefficients is statistically insignificant when the winner is a re-electable democrat. Furthermore, the magnitude of the coefficients when the winner is re-electable are orders of magnitude smaller relative to the sample where the winner is term-limited. Tables Table 3.6 and Table 3.7 show the estimates of a parametric estimation of a modified equation 3.2 to include plant fixed effects. The results are quantitatively similar to

[47]The RD command in Stata written by Austin Nichols is utilized for this estimation.

Table 3.5: Non-parametric RDD Estimates of a Democratic Governor

	Elections where the Winner is Term Limited			
Bandwidth	Water Pollution Investment		Air Pollution Investment	
5 Percentage Points	-4.14***	-4.14***	-4.74***	-4.74***
	(0.90)	(1.10)	(0.79)	(1.11)
10 Percentage Points	-4.37***	-4.37***	-4.16***	-4.16***
	(0.68)	(0.71)	(0.68)	(0.73)
20 Percentage Points	-3.23***	-3.23***	-2.59***	-2.59***
	(0.78)	(0.56)	(0.98)	(0.62)
	Elections where the Winner is not Term Limited			
Bandwidth	Water Pollution Investment		Air Pollution Investment	
5 Percentage Points	0.65	0.65*	0.26	0.26
	(0.50)	(0.36)	(1.11)	(0.48)
10 Percentage Points	0.32	0.32	0.33	0.33
	(0.38)	(0.26)	(0.68)	(0.35)
20 Percentage Points	-0.01	-0.01	0.09	0.09
	(0.27)	(0.19)	(0.45)	(0.25)
Cluster Level	State	Plant	State	Plant

Notes: This table reports the estimated coefficients from local linear RDDs of the amount invested in water pollution abatement or air pollution abatement whether the Democratic candidate wins the election. Results are shown for triangular kernels with three different bandwidths (5, 10 and 20 percentage points). The optimal bandwidth is 10 for term limited water pollution investment and 5 for all other specifications according to the method devised by Imbens and Kalyanaraman (2012)). Standard errors in parentheses. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

that of Table Table 3.5 in that the coefficients on term limited democrats are large, negative, and statistically significant compared to those for re-electable democratic governors.

Table 3.6: Parametric RDD Estimates for Water Pollution Abatement

	Elections where the Winner is Term Limited			
Bandwidth	Linear	Linear w/Interaction	Quadratic	Quadratic w/Interaction
10 Percentage Points	-9.532***	-5.547***	-4.489	-4.449***
	(1.795)	(1.146)	(3.876)	(1.361)
15 Percentage Points	-2.917***	-3.411***	-3.436***	-6.588***
	(0.703)	(0.909)	(0.871)	(1.737)
	Elections where the Winner is not Term Limited			
10 Percentage Points	-0.072	-0.127	-0.098	-0.520
	(0.269)	(0.276)	(0.274)	(0.449)
15 Percentage Points	0.041	0.035	0.035	0.294
	(0.176)	(0.182)	(0.183)	(0.306)

Notes: This table reports the estimated coefficients from a parametric RDDs of the amount invested in water pollution abatement on whether the Democratic candidate wins the election. Results are shown for four different functional forms with two different bandwidths (10 and 15 percentage points). All regressions include plant fixed effects and standard errors are clustered at the plant. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$. Standard errors in parentheses

Figures Figure 3.2 to Figure 3.5 provide a graphical representation of the effect of the winning candidates vote margin on the amount of pollution abatement investment by power plants during the term. The x-axis shows the democratic vote share where a zero or above means the democrat won and a negative democratic vote share means the republican won. Figures Figure 3.2 and Figure 3.3 are for water abatement investment while Figures Figure 3.4 and Figure 3.5 are for air abatement investment. Figures Figure 3.2 and Figure 3.4 show the sample of governors able to be re-elected while Figure 3.3 and Figure 3.5 graphs show the sample of governors unable to be re-elected (lame duck). As the democratic vote share gets closer to zero (the winning candidate won by a smaller amount) from above and below zero, there is a divergence in outcomes for the term-limited sample. Republicans who win their term-limited term by smaller and smaller margins see increases in pollution abatement

Table 3.7: Parametric RDD Estimates for Air Pollution Abatement

	Elections where the Winner is Term Limited			
Bandwidth	Linear	Linear w/Interaction	Quadratic	Quadratic w/Interaction
10 Percentage Points	-10.052**	-6.643***	-23.752***	-9.625***
	(4.295)	(2.499)	(5.214)	(1.920)
15 Percentage Points	-2.764***	-4.039***	-3.965***	-8.375***
	(0.823)	(1.058)	(1.019)	(2.145)
	Elections where the Winner is not Term Limited			
10 Percentage Points	0.697**	0.649*	0.675**	1.416***
	(0.335)	(0.335)	(0.334)	(0.544))
15 Percentage Points	0.277	0.330	0.354	1.027***
	(0.227)	(0.231)	(0.232)	(0.369)

Notes: This table reports the estimated coefficients from a parametric RDDs of the amount invested in air pollution abatement on whether the Democratic candidate wins the election. Results are shown for four different functional forms with two different bandwidths (10 and 15 percentage points). All regressions include plant fixed effects and standard errors are clustered at the plant. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$. Standard errors in parentheses

investment while democrats who win their term limited term by smaller and smaller margins see decreases. The shape of the lines are very similar to that of Fredriksson et al. (2011), who use growth rate of the budget of the state environmental agency as their dependent variable. The Fredriksson et al. (2011) result hints at a mechanism for the effect found here, which will be discussed in the next section. For the sample of re-electable governors, the lines practically meet at the discontinuity (switch from republican to democrat).

3.4.1 Mechanism

The results discussed above show an effect of political party and re-election status of the governor on the amount of investment in pollution control by the power plants in that state. Is the effect inherent in the people who chose to run under that party's banner or does it come from something inherent in the electorate. To test this, three alternative treatments are used to replace democrat that attempt to proxy for the political leanings of the electorate. The first is the Sierra Club membership of the state, the second is a green

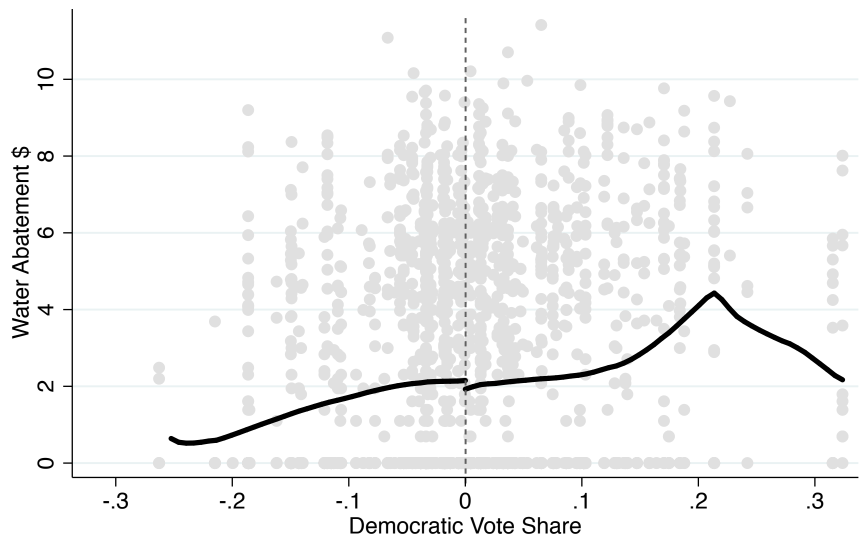


Figure 3.2: Water RDD Re-electable Governors
Bandwidth (optimal): .103

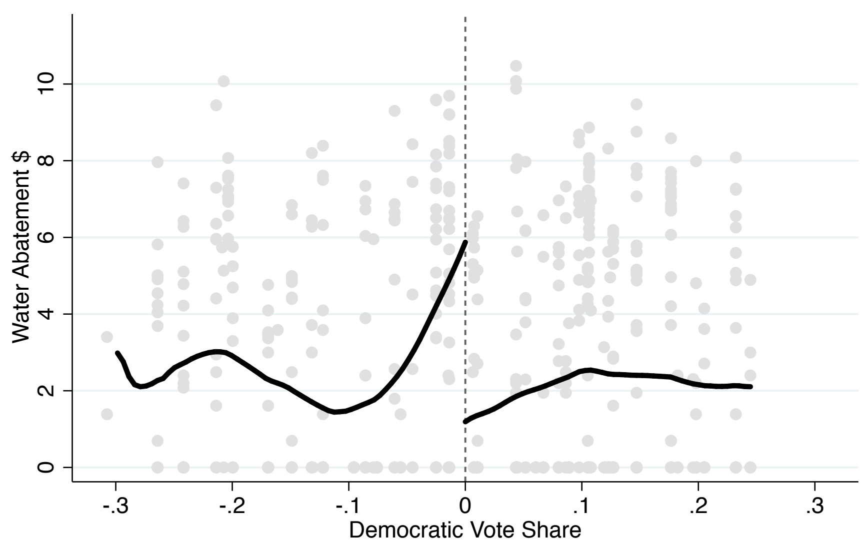


Figure 3.3: Water RDD Term Limited Governors
Bandwidth (optimal): .088

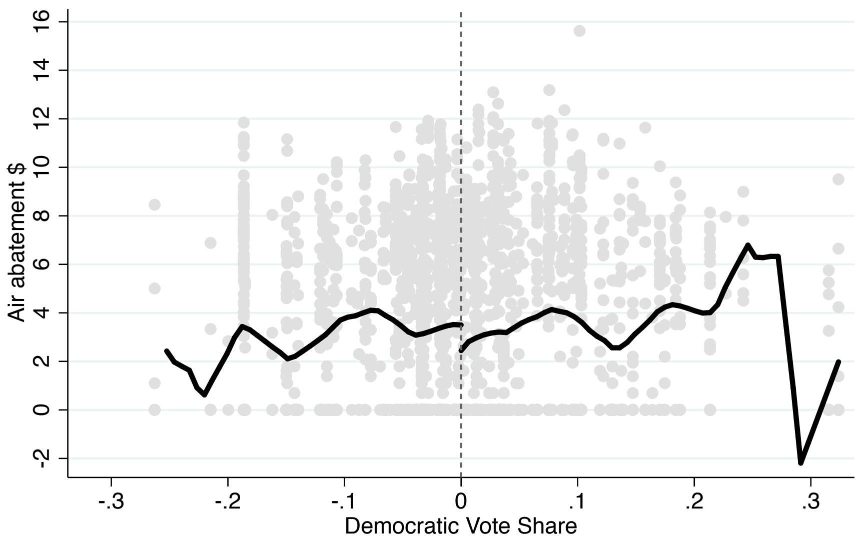


Figure 3.4: Air RDD Re-electable Governors
Bandwidth (optimal): .036

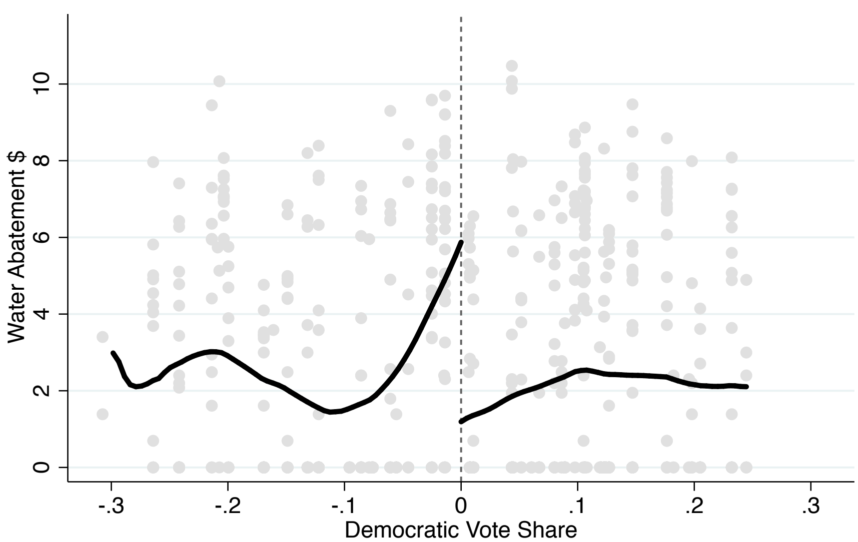


Figure 3.5: Air RDD Term Limited Governors
Bandwidth (optimal): .068

state dummy variable (as defined by List and Sturm (2006)), and the third is the League of Conservation Voters score for the US House of Representatives for that state. Each of these variables are interacted with the re-election status of the governor to form the alternative treatments. Tables Table 3.8 and Table 3.9 show the results of estimating Equation 3.1 with the alternative treatment variables. The specifications from left to right are a fixed effect model (columns 1, 2 & 3) and a probit model (columns 4, 5 & 6). The first three columns have the log of the abatement investment and the last three have a dummy variable indicating abatement investment. The results are much weaker than those with a democrat lame duck interaction treatment.

Table 3.8: Alternative Treatments- Water Pollution Abatement Investment

	(1)	(2)	(3)	(4)	(5)	(6)
		ln Water Inv			Dummy Water Inv	
Sierra club × lame duck	-0.319			-0.195		
	(0.340)			(0.127)		
Green State × lame duck		-0.234			-0.324	
		(0.703)			(0.262)	
LVC × lame duck			0.395			0.251*
			(0.283)			(0.143)
Controls	Yes	Yes	Yes	Yes	Yes	Yes
Observations	3139	3139	3132	3139	3139	3132

Standard errors in parentheses
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

It would seem that the make-up of the electorate is not the driving force behind the results found in Tables Table 3.1, Table 3.2, and Table 3.10. Another possibility is that the change in behavior found between re-electable and term limited governors is not due to their re-election status but to the fact that being elected to a second (or beyond) term implies that a governor has put in the effort that the electorate recognizes as being worthy of a second (or

Table 3.9: Alternative Treatments- Air Pollution Abatement Investment

	(1)	(2)	(3)	(4)	(5)	(6)
		Ln Air Inv			Dummy Air Inv	
Sierra Club × lame duck	-0.729			-0.296		
	(0.569)			(0.189)		
Green State × lame duck		-1.234			-0.524	
		(1.328)			(0.472)	
LCV × lame duck			-1.145*			-0.339**
			(0.649)			(0.166)
Controls	Yes	Yes	Yes	Yes	Yes	Yes
Observations	3139	3139	3132	3139	3139	3132

Standard errors clustered at the state level in parentheses
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

beyond) term. This is known as the competency effect in Alt et al. (2011). To test whether the above findings are due to competency, equation 3.2 is run on two samples. The first is governors in their second or beyond term (regardless of their re-election status) and the second is governors in their first term. Recall that fourteen states do not have term limits, thus these analyses essentially move the observations for governors in their second, third, or fourth term from non-term limit states to the sample with term limited governors. Results are shown in Table Table 3.10. Plants in states with democratic governors in their second or beyond terms (which still included lame duck governors) are still statistically different than plants in states with republican governors in their second or beyond term, but the coefficients are less negative relative to Table Table 3.10. This would imply that the competency effect from Alt et al. (2011) is not the mechanism for the difference in behavior of plants in states with re-electable governors relative to term limited governors.[48]

[48]If we thought the competency effect was the main driver of the gap in pollution abatement investment, we would expect these coefficients to become more negative when we add in non-term limited governors in their second or beyond term.

Table 3.10: Non-parametric RDD Estimates of a Democratic Governor

	Elections where Governor is serving second or more term			
Bandwidth	Water Pollution Investment		Air Pollution Investment	
5 Percentage Points	-1.94	-1.94**	-3.15***	-3.15***
	(1.58)	(0.92)	(1.22)	(0.90)
10 Percentage Points	-2.91***	-2.91***	-1.91	-1.91***
	(1.00)	(0.50)	(1.35)	(0.53)
20 Percentage Points	-2.62***	-2.62***	-1.58	-1.58 ***
	(0..77)	(0..36)	(0.98)	(0.41)
	Elections where Governor is serving first term			
Bandwidth	Water Pollution Investment		Air Pollution Investment	
5 Percentage Points	0.22	0.22	0.23	0.23
	(0.51)	(0.37)	(1.07)	(0.45)
10 Percentage Points	0.56	0.56*	0.28	0.28
	(0.42)	(0.29)	(0.84)	(0.32)
20 Percentage Points	0.39	0.39*	0.31	0.31
	(0.32)	(0.21)	(0.60)	(0.27)
Cluster Level	State	Plant	State	Plant

Notes: This table reports the estimated coefficients from local linear RDDs of the amount invested in water pollution abatement or air pollution abatement whether the Democratic candidate wins the election. Results are shown for triangular kernels with three different bandwidths (5, 10 and 20 percentage points). The optimal bandwith is 10 for term limited water pollution investment and 5 for all other specifications according to the method devised by Imbens and Kalyanaraman (2012)). Standard errors in parentheses. * $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$.

Shimshack and Ward (2005) show that a change in enforcement behavior by the state regulatory agency can have large impacts on the decisions of all polluters in that state. Should a term limited governor alter the goals set for the state regulatory agency, such as to enforce environmental regulations more stringently, it would lead to large overall changes in the decisions of polluters in the state.

3.4.2 Effect of Investment on Pollution

Finally, we investigate whether this change in the amount of investment leads to increases in pollution levels. Tables Table 3.11, Table 3.12, and Table 3.13 show the results from estimating Equation 3.3. For each pollution type we run three specifications starting with a single lagged variable, shown by specification (1). We increase the lags going from left to right and show a maximum of three lags used in specification (3). We use the Akiake information criterion (AIC) to choose the best lag length selections, which are noted in Tables Table 3.11, Table 3.12, and Table 3.13. The AICs can be found in Table Table 3.14.[49]

Table 3.11: Water withdrawal rates regressed on pollution abatement investments

	(1-Optimal) ln(withdrawal)	(2) ln(withdrawal)	(3) ln(withdrawal)
L.ln(water inv)	-0.003	-0.012**	-0.010
	(0.006)	(0.006)	(0.006)
L2.ln(water inv)		0.007	0.001
		(0.005)	(0.005)
L3.ln(water inv)			0.004
			(0.004)
FE Year	Yes	Yes	Yes
Observations	8051	7298	6603

Standard errors in parentheses
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

[49]It should be noted that in order to use the AIC as a lag length selection we must hold the number of observations constant across specifications. As observations are dropped as we add additional lags to the model, we only use the observations from specification (3) in the first two specifications.

Table 3.12: Thermal pollution rates regressed on pollution abatement investments

	(1) ln(thermal)	(2-Optimal) ln(thermal)	(3) ln(thermal)
L.ln(water inv)	-0.006	-0.012*	-0.014**
	(0.007)	(0.007)	(0.007)
L2.ln(water inv)		0.009	0.007
		(0.006)	(0.006)
L3.ln(water inv)			0.003
			(0.005)
FE Year	Yes	Yes	Yes
Observations	7510	6852	6237

Standard errors in parentheses
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

Table 3.13: Chlorine pollution rates regressed on pollution abatement investments

	(1) ln(chlorine)	(2) ln(chlorine)	(3-Optimal) ln(chlorine)
L.ln(water inv)	-0.015	0.004	0.011
	(0.013)	(0.012)	(0.013)
L2.ln(water inv)		-0.043***	-0.033***
		(0.015)	(0.012)
L3.ln(water inv)			-0.032*
			(0.017)
FE Year	Yes	Yes	Yes
Observations	6841	6240	5685

Standard errors in parentheses
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

Table 3.14: Optimal lag order selection using the Akaike Information Criterion (AIC)

Variable	One Lag	Two Lags	Three Lags
Water Withdrawls	11868.347	11870.113	11871.370
Thermal Pollution	13370.247	13370.207	13371.987
Chlorine Use	19211.430	19197.074	19190.663

Notes: This table reports the AIC statistics computed for each model presented in Table 3.3. The optimal lag order is the one with minimum AIC value. The number of observations for each set of regressions is 6603, 6237, 5685 for water withdrawals, thermal pollution, and chlorine use, respectively

The second step results do not show any significant change in water withdrawal in response to water abatement investment. There is a significant negative response in the first lag for thermal pollution and a significant negative response in the second and third lag for chlorine levels. The magnitudes of these coefficients are fairly small, but we can attribute this to the fact that we do not directly observe which investment dollars are being used for which type of abatement. From these results we can conclude that abatement investment does impact pollution output.

3.5 Conclusions

In the U.S. democracy, electoral incentives hold politicians accountable to theirs constituents. When these electoral incentives are diminished by term limits, politicians may alter their priorities and behavior. The results of this paper are compelling in the fact that they show how electoral incentives within the public sector spill over into private sector decisions. We specifically examine the electricity sector and water and pollution abatement investments. We further show that these investment decisions do impact pollution output at power plants. The scope of this concept is not limited to pollution abatement and further research can explore the links between term limits and various other private sector decisions.

CHAPTER 4

NATURAL GAS CONTRACT DECISIONS FOR ELECTRIC POWER

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.

4.1 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.[50] While transactions 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.

[50] 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.

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. [51] This is consistent with our finding 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.[52] Given

[51] Additionally, there has been some literature related to the market integration of natural gas across 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 Yücel (2008) who find a lack of market integration in natural gas transportation.

[52] 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 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.

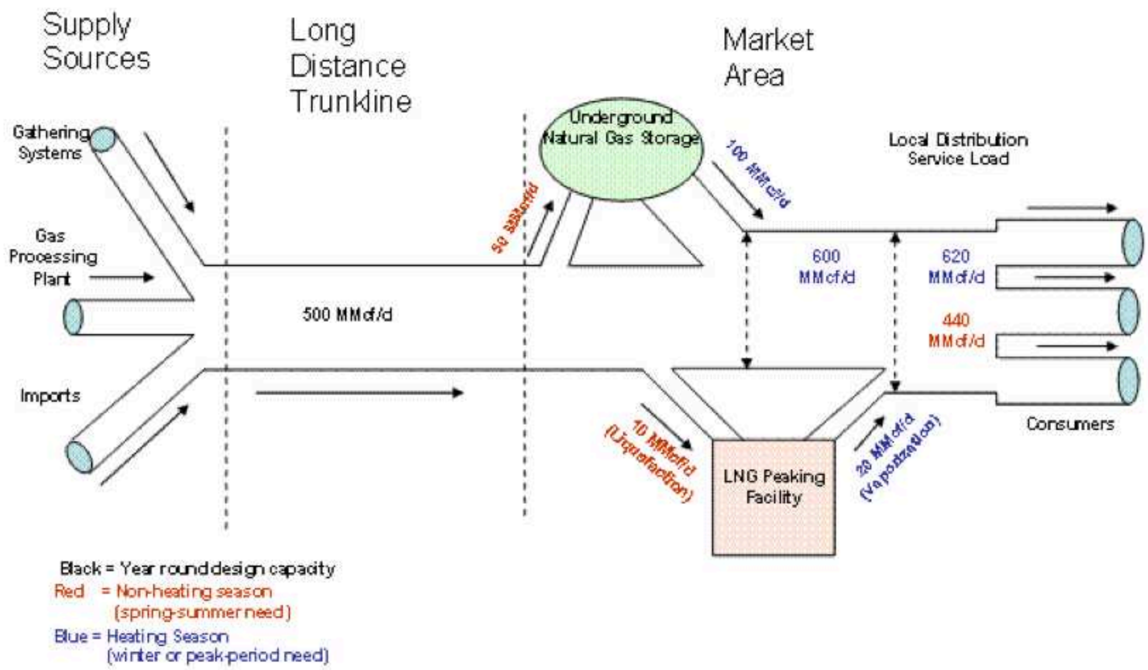
The results of this analysis are useful for understanding how well the natural gas pipeline system is operating during a time of large increases in domestic natural gas production. The advent of hydraulic fracturing has allowed the U.S. to dramatically increase its natural gas production, often in regions 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 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.

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.

4.2 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 Figure 4.1 diagrams the general pipeline supply chain from suppliers to distributors to consumers.



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 4.1: Generalized Natural Gas Pipeline Capacity Design Schematic

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.[53]

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 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.[54] 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

[53]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.

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

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.

4.3 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.[55] 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 Figure 4.2 maps out each power plant along the gas pipeline network and the plant's most common contract type decision.

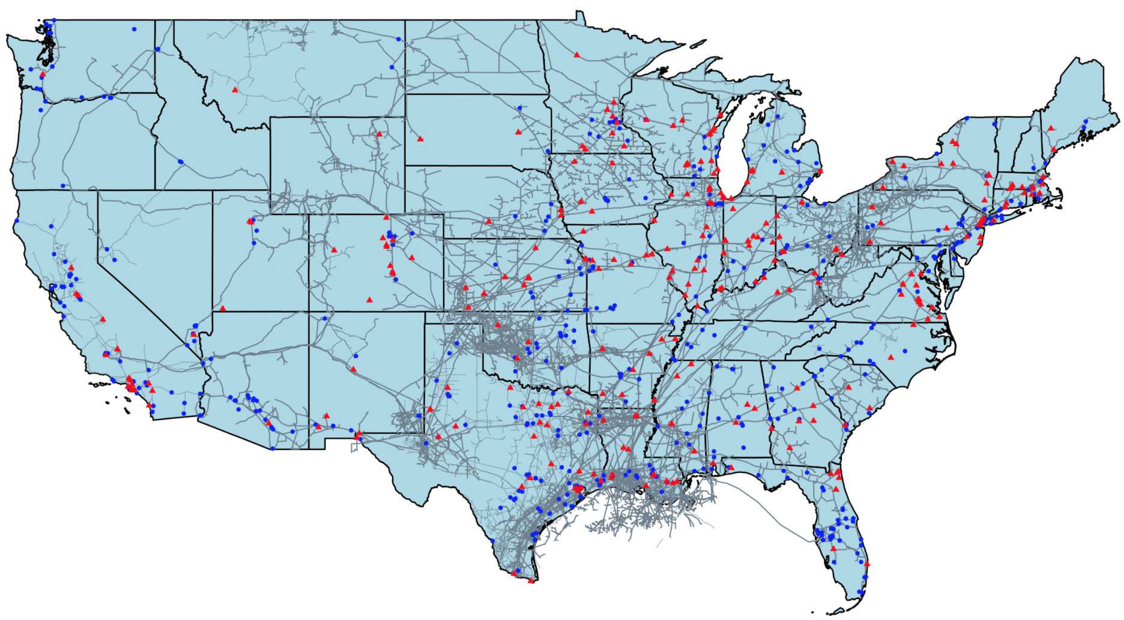


Figure 4.2: Red triangles are the interruptible contracts, blue circles are firm contracts.

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

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

National Oceanic and Atmospheric Administration (NOAA).[56] Data on state inflow pipeline capacity is collected by state and federal agencies, but is publicly available through the EIA website.[57] We use the EIA's classification of states that are restructured and regulated.[58]

Figure Figure 4.3 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.

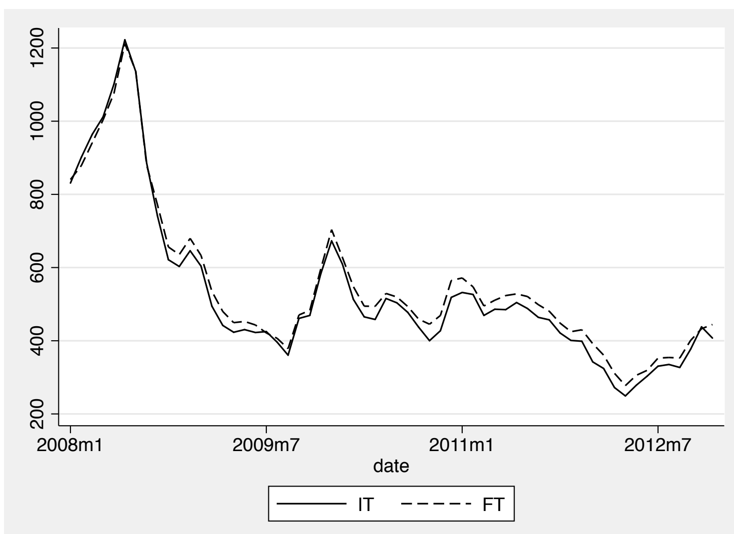


Figure 4.3: Average Transaction Price by Contract Type

[56]`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.

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

[58]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.

Table Table 4.1 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.

Table 4.1: 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 %

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.[59] Figure Figure 4.4 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.

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

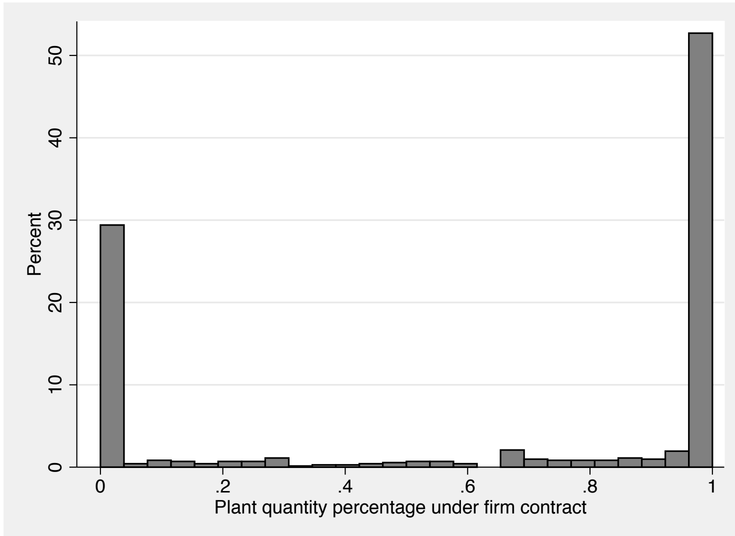


Figure 4.4: Quantity Weighted Percent Purchased as Firm Contract within Plant

4.4 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 4.1;

$$p_i = \beta_0 + \beta_1 Firm_i + \boldsymbol{x_i'\beta} + \alpha_p + \theta_m + \delta_y + \epsilon_i \tag{4.1}$$

The subscript i indicates a individual transaction. The dependent variable, p_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 Figure 4.4) 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;

$$Pr(y_j = 1|\mathbf{x_j}) = \Phi(\beta_1 CC_j + \beta_2 RST_j + \beta_3 CC \times RST_j + \boldsymbol{x_j'\beta}) \tag{4.2}$$

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 cummulative distribution 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.[60] $\boldsymbol{x_j'\beta}$ is comprised of other explanatory variables which could include; state pipeline inflow capacity; the minimum distance to the closest

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

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.[61]

4.5 Results

Three primary specifications for the hedonic model are shown by Table Table 4.2 using transaction level data with fuel cost ($^{\text{cents}}/_{Mcf}$) as the dependent variable. Each specification in Table Table 4.2 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 ($^{\text{cents}}/_{Mcf}$) 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 4.1 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.

[61]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.

Table 4.2: 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

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

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.[62] Increasing state inflow capacity reduces pipeline space scarcity which lowers the equilibrium price.

[62]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.

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 Table 4.3 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 measures by specification due to a collinear relationship between these variables.

We calculate the marginal effects in Table Table 4.4 for specifications (1) and (2) from Table Table 4.3 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

Table 4.3: 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

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

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-

Table 4.4: 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
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

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.[63]

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

[63] 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.

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.[64]

4.5.1 Robustness Checks

We run several robustness checks for both our hedonic model and probit model shown by Table Table 4.5 and Table Table 4.6, respectively. For column (1) in Table Table 4.5, we cluster the standard errors at each individual month (i.e., 60 clusters from 2008-2012). By

[64] We inspect the variation inflation factor (VIF) for each regressor to examine if multicollinearity among the independent variables is driving this result. Each VIF is well below 10, which is generally accepted as indicating a low amount of collinearity among the regressors.

doing this we account for any within month serial correlation across transactions.[65] 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.

Table 4.5: Robustness Checks Hedonic FT Premium

	SE: Month Cluster (1)	FE:Month×Year (2)	High NG Price (3)	Low NG Price (4)	Log-log (5)	FE: State (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

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

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

[65] 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.”

Table 4.6: Robustness Checks Probit Model

	Panel (1)	Logit (2)	One Contract Type (3)	Single Cap.Type (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

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

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 Table 4.6 uses a monthly data at the plant level to run to our probit model.[66] 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 with both combined cycle and simple cycle capacity. All of Table Table 4.6 shows the robustness results where we use the state inflow capacity as our pipeline characteristic. Table Table 4.7 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.

4.6 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

[66] 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.

Table 4.7: 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
* $p < 0.10$, ** $p < 0.05$, *** $p < 0.01$

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.

CHAPTER 5

THESIS CONCLUSION

This thesis presents three empirical papers on the operations of electric power plants. Each chapter uses data driven regression analysis to examine various aspects of economic decisions made at the plant level. The key findings of each chapter are summarized here.

Chapter 2, titled *Fuel Prices, Restructuring and Natural Gas Plant Operations*, finds that both combined cycle and simple cycle plants exhibit a negative generation response to changes in natural gas prices. Since natural gas is a critical input for these power plants, this response is consistent with economic theory. Only combined cycle power plants, which are more cost competitive with coal-fired generation relative to simple cycle plants, have a positive generation response to changes in coal prices. Furthermore, we find a positive and significant efficiency response (i.e., negative heat rate response) to changes in coal prices for combined cycle gas plants located in a restructured market.

Chapter 3, titled *Political Pressure and Power Plant Pollution Abatement*, examines the impact of a governor's electoral status and party affiliation on power plant investments in pollution abatement. We find that power plants invest less in pollution abatement when the governor of the state which they are located is a term-limited democrat. This gap in abatement investment becomes larger in states with close elections, as demonstrated through our RDD model results. We then use plant level data on water pollution abatement investment and water pollution and find that more investment leads to less water pollution.

Chapter 4, titled *Natural Gas Contract Decisions for Electric Power*, investigates the magnitude of the reservation price power plant must pay for a firm contract and the plant characteristics that would lead a power plant to choose a firm contract. Using a hedonic model we measure the reservation price for firm contracted natural gas to be roughly 14 cents per Mcf. We find that combined cycle plants in regulated states are most likely to procure their natural gas utilizing the firm option. Other determinants of contract specification (e.g., capacity, pipeline access, weather) fall in line with transaction cost theory.

These three essays give insight to the economic decisions of the agents operating electric power plants. Further research should continue to explore the dynamics of electricity markets as this type of empirical analysis will help inform and guide future electricity and environmental policy.

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APPENDIX A - FULL PARAMETER ESTIMATES

Table A.1: Net Generation

	(1)	(2)	(3)
NG Cost × (CC; CC × RST)	-0.734***	-0.738***	-0.758***
	(0.070)	(0.080)	(0.097)
NG Cost × SC		0.018	
		(0.058)	
NG Cost × CC × REG			0.036
			(0.088)
NG Cost × SC × RST			0.118
			(0.093)
NG Cost × SC × REG			-0.016
			(0.089)
Coal Cost × (CC; CC × RST)	0.379**	0.651***	0.572***
	(0.154)	(0.164)	(0.217)
Coal Cost × SC		-0.420***	
		(0.143)	
Coal Cost × CC × REG			0.047
			(0.177)
Coal Cost × SC × RST			-0.578***
			(0.200)
Coal Cost × SC × REG			-0.279
			(0.209)
Capacity	0.801***	0.760***	0.763***
	(0.117)	(0.116)	(0.115)
Age	0.403***	0.326***	0.326***
	(0.050)	(0.056)	(0.056)
NERC Sub-region Load	0.567***	0.561**	0.515**
	(0.220)	(0.219)	(0.216)
RGGI Dummy	0.102	0.066	0.075
	(0.074)	(0.075)	(0.079)
NO_x Dummy	0.308***	0.355***	0.365***
	(0.081)	(0.082)	(0.081)
FE Year	Yes	Yes	Yes
Observations	5895	5895	5895

*Notes: *, **, *** denote statistical significance at at least the 10, 5, and 1 percent levels, respectively. Standard errors are given in parentheses below the parameter estimates. provides the number of observations for each specification.*

Table A.2: Heat Rate

	(1)	(2)	(3)
NG Cost × (CC; CC × RST)	0.042*	0.046	0.049
	(0.023)	(0.040)	(0.041)
NG Cost × SC		-0.009	
		(0.040)	
NG Cost × CC × REG			-0.005
			(0.024)
NG Cost × SC × RST			-0.011
			(0.050)
NG Cost × SC × REG			-0.016
			(0.040)
Coal Cost × (CC; CC × RST)	-0.035	-0.093	-0.197**
	(0.062)	(0.068)	(0.095)
Coal Cost × SC		0.085**	
		(0.038)	
Coal Cost × CC × REG			0.131**
			(0.064)
Coal Cost × SC × RST			0.186**
			(0.081)
Coal Cost × SC × REG			0.168***
			(0.064)
Net Gen	-0.017	-0.017	-0.014
	(0.031)	(0.030)	(0.030)
Starts	-0.039	-0.044	-0.047
	(0.057)	(0.054)	(0.053)
Capacity	0.020	0.031	0.030
	(0.060)	(0.060)	(0.059)
Age	-0.050***	-0.033**	-0.032**
	(0.019)	(0.016)	(0.016)
RGGI Dummy	0.037	0.044	0.060
	(0.053)	(0.054)	(0.058)
NO_x Dummy	0.030	0.023	0.022
	(0.031)	(0.032)	(0.031)
FE Year	Yes	Yes	Yes
LMP	0.000	0.000	0.000
HJP	0.751	0.640	0.766
Observations	5895	5895	5895

*Notes: P-values are shown for the underidentification test in row "LMP" [Kleibergen-Paap rk LM statistic∼ $X(4)$] and overidenticifaction test in row "HJ" [Hansen J statistic∼ $X(3)$] for the excluded instrumental variables. *, **, *** denote statistical significance at at least the 10, 5, and 1 percent levels, respectively. Standard errors are given in parentheses below the parameter estimates. provides the number of observations for each specification.*

APPENDIX B - EXTENDED THEORY MODEL

In this appendix we expand upon the model in the paper. Here we recognize that the average electricity price a gas plant receives over it's evaluation horizon is not only a function of fuel costs, but also the heat rate a plant chooses. To analyze this effect we allow the average electricity price ($\bar{p}$) received by the gas plant to be a function of coal costs (C^C), natural gas costs (C^{NG}), and a plant's heat rate decision (ΔHR). Intuitively, as a gas plant improves it efficiency it moves further inframarginal and operates more hours. The additional operating hours gained are hours where lower costs firms on the margin are setting the market price, therefore, decreasing the overall average price ($\bar{p}$). This implies $\frac{\partial \bar{p}}{\partial \Delta HR} < 0$. All other partial derivatives for the average electricity prices are the same before, $\frac{\partial \bar{p}}{\partial C^C} \geq 0$ and $\frac{\partial \bar{p}}{\partial C^{NG}} \geq 0$.

The firm's maximization problem is as before, except for the modified ($\bar{p}$):

$$\begin{aligned} &\underset{\Delta HR}{max}\pi = q^m \left[\bar{p}(C^C, C^{NG}, \Delta HR) - MC(\Delta HR, C^{NG}) \right] H(C^C, C^{NG}, \Delta HR) - C(\Delta HR) \\ &\qquad s.t. : \Delta HR \leq \Delta HR^m \end{aligned} \tag{B.1}$$

The first order condition is now:

$$\frac{\partial \pi}{\partial \Delta HR} : q^m \left[(\bar{p} - MC) \frac{\partial H}{\partial \Delta HR} + \left(\frac{\partial \bar{p}}{\partial \Delta HR} - \frac{\partial MC}{\partial \Delta HR} \right) H \right] = C' + \lambda \tag{B.2}$$

where λ is the multiplier associated with the $\Delta HR \leq \Delta HR^m$ constraint. We can differentiate the left side of (B.2) with respect to C^C.

$$\frac{\partial^2 \pi}{\partial \Delta HR \partial C^C} : q^m \Big[(\bar{p} - MC) \frac{\partial^2 H}{\partial \Delta HR \partial C^C} + \frac{\partial \bar{p}}{\partial C^C} \frac{\partial H}{\partial \Delta HR} + \left(\frac{\partial \bar{p}}{\partial \Delta HR} - \frac{\partial MC}{\partial \Delta HR} \right) \frac{\partial H}{\partial C^C} + \frac{\partial^2 \bar{p}}{\partial \Delta HR \partial C^C} H \Big] > 0 \tag{B.3}$$

We can sign equation B.3 as greater than zero given two reasonable assumptions:

$$\begin{aligned} &(1) \qquad \left(\frac{\partial \bar{p}}{\partial \Delta HR} - \frac{\partial MC}{\partial \Delta HR} \right) > 0 \\ &(2) \qquad \frac{\partial^2 \bar{p}}{\partial \Delta HR \partial C^C} > 0 \end{aligned} \tag{B.4}$$

Both terms in assumption (1) are negative, however, the change in the average price must be less than the change marginal cost. Since the marginal power plant sets the price, anytime the power plant is infra marginal it receives a higher price than its marginal cost. Improving efficiency lowers the marginal cost and lowers the average price, however, higher prices when the plant is infra marginal causes the change in the average price to decrease less than the decrease in the marginal cost. Given this assumption (1) is positive.

For assumption (2), the change in average prices due to a change heat rates is negative. This effect diminishes as coal prices increase. This is because coal plants will be on the margin more often if coal prices increase setting a higher market price. This causes assumption (2) to be positive. With these two assumptions equation B.3 is positive.

Using this more generalized model, we show that the left hand side of equation (B.2) is increasing with coal prices. If this is the case the right and side must also be increasing in coal prices. If the constraint is non-binding and λ is zero, gas plants must be improving their efficiency.

We perform the same exercise to see the response to natural gas prices and differentiate the left hand side of (B.2) with respect to C^{NG}.

$$\frac{\partial^2 \pi}{\partial \Delta HR \partial C^{NG}} = q^m \Bigg[(\bar{p} - MC) \frac{\partial^2 H}{\partial \Delta HR \partial C^{NG}} + \left(\frac{\partial \bar{p}}{\partial C^{NG}} - \frac{\partial MC}{\partial C^{NG}} \right) \frac{\partial H}{\partial \Delta HR} + \left(\frac{\partial \bar{p}}{\partial \Delta HR} - \frac{\partial MC}{\partial \Delta HR} \right) \frac{\partial H}{\partial C^{NG}} + \left(\frac{\partial^2 \bar{p}}{\partial \Delta HR \partial C^{NG}} - \frac{\partial^2 MC}{\partial \Delta HR \partial C^{NG}} \right) H \Bigg] \gtrless 0 \tag{B.5}$$

Here we are unable to sign equation B.5 due to opposing incentives faced by the power plant. Intuitively, as gas prices increase the plant has an incentive to become more efficient in order to lower its marginal cost and save costs on each MWh generated. On the other, hand as gas prices increase it becomes less competitive with coal and is less likely to gain additional hours of operation through efficiency improvements.