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Dash for Gas: The Sequel

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Dash for Gas: The Sequel

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PRELIMINARY & INCOMPLETE—PLEASE DO NOT CITE

Abstract

We examine the environmental impact of the post-2005 natural gas glut in the United States due to the rapid development of technology related to hydraulic fracturing for extracting shale gas. We focus on fuel switching decisions by electric power plants, from coal to natural gas, due to rapidly falling natural-gas prices and steady and slightly-increasing coal prices. We categorize firms into four groups: utilities that operate in wholesale electricity markets; utilities that operate in traditional vertically-integrated regions; independent power producers; and, industrial and commercial firms that generate electricity for their own use. We investigate whether firms differ in their response to changes in natural gas and coal prices. We find that utilities that do not operate in wholesale markets are more sensitive to changes in input prices than utilities that operate in wholesale markets. One potential explanation for these differences is that savings in fuel costs by utilities that operate within wholesale power markets are more quickly absorbed into retail prices. We find that the comparisons of both types of utilities and Independent Power Producers are more mixed. These differences have large consequences on how environmental pollution responds to changes in fossil-fuel prices.

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"We are about halfway to the President's goal to cut greenhouse gas emissions and about half of that is because of the substitution of natural gas for coal in the power sector."

Ernest Moniz, August 26th, 2013 at Columbia University

"By the time natural gas has a net climate benefit you'll likely be dead and the climate ruined."

Joe Romm, February 19th, 2014, thinkprogress.org[1]

1 Introduction

Fossil fuel power plants burn coal, natural gas, or oil to generate electricity. In 2000, 52 percent of US electricity was generated using coal, while 16 percent used natural gas. By 2012, the use of coal fell to 37 percent of generation, while natural gas increased to 30 percent. One factor responsible for this change has been the change in relative prices of the two fuels. Recent advances in the ability to use hydraulic fracturing methods (fracking) have substantially increased natural gas production, altering the relative prices of natural gas and coal. On a per unit-of-energy basis, average prices for natural gas was nearly seven times the average price of coal at the beginning of 2006. By the end of 2012, this ratio had decreased to less than two.

There are a number of environmental benefits from shifting away from coal and into natural gas. Natural gas has roughly one-half of the greenhouse gas emissions per unit of energy. It also has significantly lower local-pollutant emissions, such as sulfur, nitrogen oxides, particulate matter, and mercury.

Within the power sector, electricity generation companies vary in terms of their ownership structure and the type of market in which they operate. Three broad types of companies exist. First, there are vertically integrated utilities that generate, transmit, and distribute the electricity. Some utilities operate in markets in which they are the only generation company; others sell into wholesale power markets. Second, some firms are independent power producers (IPPs), which solely generate electricity. Finally, many industrial firms and universities generate electricity for their own use. The market structure also varies. Some markets are organized such that the utility is the only generating company; in contrast, wholesale electricity markets have many electricity generation companies bidding their supply schedules—these include both utilities and IPPs.

[1] http://thinkprogress.org/climate/2014/02/19/3296831/natural-gas-climate-benefit/

In this paper, we estimate whether a firm's response to changes in natural gas and coal prices varies depending on the firm's type and the market structure in which it operates. We analyze a number of adjustments. We begin by focusing on power plants that have burnt both coal and natural gas at some point between 2003 and 2008. For these plants, we analyze how the share of natural gas energy (MMBtu) consumption varies with input prices. We dive deeper into what drives changes in the natural gas share by estimating fuel-specific demand curves, as well as the capacity factor of plants—total generation from the plant as a share of maximum generation. For the most part, these power plants have multiple "units"—individual electricity generators—where some of these units burn natural gas and some burn coal. Our data enable us to look at how the number of units burning each fuel changes over time. We augment the plant-specific results by looking at how the share of electricity coming from natural gas, as a share of fossil-fuel generation, varies with natural gas and coal prices at the firm level.

There may also be variation in the incentives of utilities to respond to changes in fuel prices. The typical utility is regulated such that it earns a required rate of return on its invested capital. Public Utility Commissions (PUCs) are tasked with adjusting retail prices such that the utility's rate of return does not differ from the required rate of return. Adjustments in retail rates as a result of changes in fuel prices can either be automatic—through what are known as automatic (fuel) adjustment clauses (AACs)—or can occur during rate hearings—quasi-judicial hearings in which the utility and the PUC present revenue and cost analysis. Because rate hearings are costly, long lags between rate hearings can occur. Between these rate hearings, the utility's rate of return can vary with changes in fuel prices. In contrast, AACs keep the utility's rate of return within a much narrower band.

When utility rates of return are always kept at the required rate of return, the utility will have very little incentive to adjust the relative use of coal and natural gas power plants in the face of changes in the fuels' relative prices. In contrast, as Joskow (1974) notes, when rate hearings are infrequent the utility will be the residual claimant to reductions in input costs. Therefore utility behavior may vary depending on whether a utility's rate structure is automatically adjusted to reflected changes in input prices. Because large industrial/commercial (IC) entities that produce power almost exclusively for their own use and IPPs are unregulated, they will also be the residual claimant to input cost reductions.

We find significant variation in how firms respond to changes in natural gas and coal prices across firm type and the market structures. When comparing utilities with non-utilities (both IC and IPPs). We find that among power plants that are capable of burning both coal and natural gas, the share of natural gas burned at utility-owned plants is less responsive to changes in coal and natural gas prices compared to non-utilities. The response to changes in natural gas prices for utilities is roughly one-half the response of non-utilities. We find a statistically insignificant response to changes in coal prices for utilities, but a positive and statistically significant response among non-utility plants; when coal prices increase non-utility plants burn more natural gas.

In particular, we find that utilities that do not operate within wholesale power markets—non-market utilities—are significantly more price sensitive to both natural gas and coal prices, compared to utilities that operate in wholesale power markets. IPPs are more price sensitive to changes in coal prices, but less price sensitive to changes in natural gas prices, compared to non-market utilities. ICs are more price sensitive than all of the other groups, however, these power plants vary considerably in terms of their observable characteristics. The results with respect to how plants respond to changes in natural gas prices are robust to identifying the coefficients using within-year variation in input prices; the coal coefficients are not robust with respect to the inclusion of year fixed effects. Coal prices increased fairly smoothly over our sample period, so we place less stock in our ability to identify the coefficients associated with coal prices apart from changes in environmental stringency. We also show that the observable characteristics of power plants operated by firms in the business of selling power (IPPs) are largely similar across a wide range of characteristics.

At the firm level, we find that utilities and non-utilities have similar responses to changes in coal prices, but non-utilities are more responsive to changes in natural gas prices. When we distinguish firm types further, we find that non-market utilities and IPPs behave similarly in response to changes in natural gas prices, while the coefficient associated with coal prices for IPPs is noisily estimated. In contrast, market utilities operating within wholesale power markets do not appear to respond to changes in natural gas prices, but their share of natural gas is responsive to changes in coal prices. IC entities continue to be sensitive to both input prices. The IPP results are not robust to the inclusion of fixed-year effects, but the general pattern of market and non-market utilities and utilities compared to non-utilities holds.

The differences in how firms respond to changes in input prices translate into meaningful differences in how emissions of greenhouse gases and local pollutants respond to changes in natural gas and coal prices. To illustrate this, we construct back-of-the-envelope calculations of how emissions evolve if "homogenize" the response of firms to changes in natural gas and coal prices. That is, we calculate the path of emissions if every firm responded in the same way that non-market utilities respond, a second path of emissions assuming that every firm responds in the same way market utilities respond, etc.

The remainder of the paper is organized as follows. We begin by providing a background on natural gas and coal including their properties, use, production, and prices in Section 2. We then provide an overview of gas and coal-fired electricity generation in Section 3. A discussion of wholesale electricity markets follows in Section 4. Those familiar with the markets for the two fuels, generation technologies, and the US wholesale electricity markets may skip the material in Sections 2–4. Section 5 contains a discussion of our data and the results of our empirical analysis. A preliminary back-of-the-envelope analysis is provided in Section 6. We finally conclude. The tables and figures are attached in the end of the paper.

2 Background on natural gas and coal

2.1 Natural gas

Natural gas is highly homogenous. It is primarily methane, a potent colorless, odorless, and tasteless greenhouse gas (GHG).[2] It is highly combustible with a BTU content of about 1.03 BTU per cubic foot (cf).[3] It occurs in geological formations in different ways: as a gas phase associated with crude oil, dissolved in the crude oil, or as a gas phase not associated with any significant crude oil. It is "rich" or "wet" if it contains significant natural gas liquids (NGLs) and is "lean" or "dry" if it does not contain NGLs. The NGLs may be processed out and sold separately. While natural gas is typically transported as a gas, it can be cooled to a liquid and transported in trucks or ships, which is a costly process. In this form, it is referred to as liquefied natural gas (LNG).

Most of the natural gas consumed in the US is produced domestically. Some is imported from Canada and shipped to the US in pipelines. A small amount of natural gas is shipped to the US as LNG. In 2012, about 25% of energy used in the US came from natural gas: a total of 25.46 trillion cubic feet (Tcf). The major consumers included the electric power sector (36%), industrial (28%), commercial (11%), and residential (16%).[4] It is often stored in large underground systems, such as old oil and gas wells or caverns formed in old salt beds. Inventories have been historically used to accommodate fluctuations in demand triggered largely by the demand for home heating.[5]

Burning natural gas results in much fewer emissions of nearly all types of air pollutants and CO_2 per unit of heat produced than coal or refined petroleum products. For example, 117

[2] This is the reason that mercaptan a chemical that smells like sulfur is added to it prior distribution.
[3] http://www.eia.gov/totalenergy/data/monthly/#appendices.
[4] http://www.eia.gov/energyexplained/index.cfm?page=natural_gas_use
[5] http://www.eia.gov/energyexplained/index.cfm?page=natural_gas_delivery

(over 200) lbs. of CO_2 are produced per million British Thermal Units (MMBtu) of natural gas (coal). These clean burning properties have contributed to an increase in natural gas use for electricity generation and as a transportation fuel.[6]

The US production of natural gas has increased considerably in the past 10 years. This increase is largely attributed to horizontal drilling—a technical innovation from the 1930s—and multistage hydraulic fracturing (fracking), which began in the 1950s. Fracturing refers to the process of using a water, sand and chemical composition, under pressure, to break open geological formations that are holding natural gas. The technique has allowed natural gas deposits captured in shale formations to be accessed; Figure 1 maps the known shale "play" in North America.

The process of hydraulic fracturing begins with drilling a vertical well several thousand feet down to a shale gas deposit. Then the drill bit is turned 90 degrees to follow the shale horizontally. This lateral well bore may run as far as 10,000 feet, with fracturing stages every 500-700 feet started by puncturing the well bore, allowing pressurized fracturing fluid (water, chemicals and sand) to enter the shale and crack it open.[7]

As Figure 2 shows, monthly gross withdrawals of natural gas exhibit a clear upward trend, which is more pronounced after 2006. They start at about 2 million MMcf in Dec-2003 and pick at around 2.5 million in Jan-2012. In 2007, gross withdrawals from shale gas were at about 2 tcf accounting for approximately 8% of total gross withdrawals. By 2010, the same fraction reached 35%.[8] The disruptive effect on offshore production by hurricanes Katrina and Rita in the fall of 2005 and Gustav and Ike in the fall of 2008 manifest themselves through the notable negative spikes.[9]

The top panel of Figure 3 shows monthly production in thousand cubic feet per day (mcf/d) for key US shale gas regions between Jan-2007 and Dec-2012—production in Jan-2007 is normalized to one.[10] The increase in production for the Marcellus shale has increased by a factor of about 8 during this period. The production in the Bakken, the epicenter of the recent oil rush, has also exhibited a very notable increase by a factor of about 5. The

[6] http://www.eia.gov/energyexplained/index.cfm?page=natural_gas_environment.

[7] See, e.g., Section 2 in FERC (2008). Recently, Covert (2013) studies firm learning behavior using their fracking endeavors in the Bakken shale of North Dakota using a very rich dataset of about 2,700 wells and 70 firms between 2005 and 2011. He does find that firms made more profitable input choices over time but did so slowly and incompletely capturing about 2/3 of possible fracking profits at the end of 2011. His findings are consistent with passive learning but not active experimentation. Additionally, firms seem to put more weight on their own information relative to observable information generated by others.

[8] http://www.eia.gov/dnav/ng/ng_prod_sum_dcu_NUS_a.htm.

[9] See EIA (2007) and EIA (2009a).

[10] http://www.eia.gov/petroleum/drilling/.

increase in production in the Eagle Ford shale is less dramatic, but still notable, by a factor of 3. For all three shales, the production seems to really take off in late 2009 and early 2010.[11]

Figure 10 shows the monthly natural gas price for the electric power sector from EIA and the NYMEX futures price (prompt month) for delivery at the Henry Hub in Louisiana, a widely used benchmark, from SNL Financial. The highly similar behavior of the two price series is rather obvious. After the frenzy of the commodity markets in the summer of 2008, both series exhibit a largely declining pattern until mid-2012 when they start bouncing back. Of course, for a good part of this period (fall 2008–fall 2009), the continued strong domestic production overlapped with sluggish demand due to the recession. Therefore, it is hard to tell how much of this decline was due to the positive (negative) shift in supply (demand). The last quarter of 2011 was the first time since the economic downturn that gas prices remained consistently below $4/MMBtu.[12] The bouncing back of the prices in the late 2012 has been attributed to an increased demand due to higher utilization of natural gas units, the potential for additional LNG exports, draw down in inventories as the country was marching towards a cold winter, and the diversion of rigs used in natural gas production towards the search of oil, among other factors.

2.2 Coal

Coal is less homogenous than natural gas with differences in energy, carbon, moisture, and ash characteristics playing an important role in its value, in transportation cost, and in the technology choice for electric power generation.[13] It is classified into four main types or ranks—lignite, subbituminous, bituminous, anthracite—depending on the amounts and types of carbon it contains and on the amount of heat energy it can produce.[14] The vast majority of the coal consumed in the US is produced domestically—on average 98% for 1995–2012. Figure 1 provides the major coal producing areas in the country, mamely, Appalachia, Interior, Illinois Basin, Uinta Basin, and the Powder River Basin.

Anthracite is the highest rank of coal, often referred to as hard coal, containing a high

[11]Hayensville and Barnett are generally considered dry plays because of the low levels of NGLs (ethane, propane, butane etc.). Since the NGLs are generally priced according to the price of the crude, as the price of oil increases while the price of natural gas remains at relatively low levels, operators target regions with wetter gas. For additional commentary see http://www.eia.gov/naturalgas/issuesandtrends/production/2013/.

[12]Macmillan et al. (2013).

[13]See Cicala (2013) and Hancevic (2013).

[14]The discussion in this section borrows from Campbell (2013), Campbell et al. (2013), the glossary in EIA (2010a), and MIT (2007a).

percentage of fixed carbon and a low percentage of volatile matter and is mined in the Appalachian region of Pennsylvania. It has a carbon content between 86% and 98%. The average heat content of anthractie consumed in the US of 25 MMBtu/short ton.[15]

Bituminous coal is the most abundant coal in active US mining regions with a carbon content between 25% and 45% and a heat content of 24 MMBtu/short ton. Subbituminous coal has properties that range from those of lignite to those of bituminous coal and an average heat content of 17–18 MMBtu/short ton. Subituminous coal is mostly found in the west part of the country (e.g., powder River basin in Wyoming and Montana).

Lignite, also known as brown coal, has the lowest carbon content of the four types of coal generally used for electric power generation, averaging between 25% and 35%, and a high moisture and ash content. It also has the lowest heat value, with an average of 13 MMBtu/short ton and is mined in Texas and North Dakota.[16]

Coals with a high heat content are generally priced higher and so do those with lower sulfur content; the former is obvious, the latter is a consequence of environmental regulations. Surface-mined coal (e.g., Powder River basin) is generally priced lower than underground-mined coal (e.g., Appalachia). Where coal beds are thick and near the surface, mining costs are low and, therefore, coal prices tend to be lower than where the beds are thinner and deeper, as in Appalachia. The higher cost of coal from underground mines reflects in part the more difficult mining conditions and the need for more miners. Generally, there is a positive relationship between heat and sulfur content.[17]

When coal is burned, it releases impurities including sulfur, which when combined with oxygen forms sulfur dioxide SO_2, that contributes to acid rain and respiratory illnesses. Other emissions resulting from coal combustion are: (i) nitrogen oxides NO_x, which contribute to smog and respiratory illnesses; (ii) particulates, which contribute to smog, haze, respiratory illnesses, and lung disease; (iii) CO_2; (iv) mercury and other heavy metals, which have been linked with both neurological and developmental damage in humans and animals.[18]

[15] Throughout this section, the heat content for various coal ranks is measured on an *as-received* basis, that is, containing both inherent moisture and mineral matter. We also refer to the heat content of coal consumed in the US.

[16] See also Table 3.2 in MIT (2007a) for typical energy, carbon, moisturem sulfur, and ash for typical US coal ranks.

[17] For example, SNL Financial reports prices for CAPP coal with a heat content are at or above 12,000 Btu/lb., and sulfur content in excess of 1.2 lbs./MMBtu. Prices for NAPP coal are quoted for heat content in the 12,000–13,500 Btu/lb. range with a sulfur content that may exceed 6 lbs./MMBtu. The same numbers for PRB coal are at or below 8,800 MMBtu/lb. and 0.8 lbs./MMBtu, respectively.

[18] Additionally, when coal is burned at power plants, residues such as fly and bottom ash are created. In the past, fly ash was released into the air through the smoke stack, but by law much of it now must be captured by pollution control devices, like scrubbers. Fly ash is generally stored at coal power plants or

Similar to our discussion of the previous section, we provide a brief commentary on the production and prices of coal during the period 2003–2012, the period used in our formal empirical analyses. As the bottom panel of Figure 2 illustrates, total US production exhibits a slight upward trend up until 2009, after which it starts declining, with the Appalachia and Western regions driving much of the decline. The downward trend post 2009 is largely consistent with the slow recovery of the economy, the changing landscape of electric power generation towards higher utilization of natural gas units, and increasing stockpiles of coal at the power plants. It seems to be the case that the only good news for coal producers in the country during this period was the increase in exports, which have been historically served with Appalachian coal, from around 80 million short tons in 2008 to almost 130 million short tons in 2012 before they dipped at 59 million short tons in 2009.

Panels (c) and (d) of Figure 10 provide monthly time series plots of the price of coal for the electric power sector from EIA and the NYMEX futures price (prompt Month) for Central Appalachian Coal (CAPP) with a heat content of 12,000 Btu/lb., a widely used benchmark, from SNL Financial.[19] When comparing the two price series, the reader should keep in mind the heterogeneity of coal used by power plants around the country—Appalachian coal accounts for about 35% per annum of the total US production (short tons) during 2003–2012. The price of coal for electric power plants almost doubled during this period, from about \$1.3/MMBtu to around \$2.5/MMBtu. After skyrocketing at about \$5MMBtu in the summer of 2008, the CAPP NYMEX price returned to levels of \$2.5/MMBtu in late 2012.During the same period, the prompt-month NYMEX price for PRB coal, with a heat content of 8,800 btu/lb was never priced above \$1/MMBtu. According to EIA, coal prices increases in 2008, were driven, in large part, by the international markets where US coal was in demand. Another factor that affected coal prices was the escalating delivery cost due to the growing fuel surcharges added by transportation companies in response to the unprecedented rise in oil prices experienced during the first half of the year.[20]

3 Natural gas and coal-fired electricity generation

Both natural gas and coal are used in the generation of electricity with a combined share (gigawatt per day) of 70% in 2012. Overall, there is a downward trend in the share of coal

placed in landfills. Pollution leaching from ash storage and landfills into groundwater has emerged as a new environmental concern. See http://www.eia.gov/energyexplained/index.cfm?page=coal_environment.

[19]The delivery prices reported by EIA are a weighted average of contract and spot prices with 80 percent of coal delivered under contract terms and 20 percent delivered under spot terms.

[20]Our commentary here follows EIA (2008) and EIA (2009b).

in electricity generation from 53% in 1995 to 39% in 2012. The share of natural gas in electricity generation, on the other hand has more than doubled during the same period; from 13% to 29%.[21]

Electric power generation accounts for the vast majority of the coal used in the country; on average 92% the last 20 years. This is in sharp contrast with natural gas, which has wide residential, industrial, and commercial uses. Between 1995 and 2012, electric power generation accounted for about 25% of natural gas use per annum.[22]

The majority of coal used for electric power generation is sold through long-term contracts, which provide some protection against price volatility, in conjunction with spot purchases to supplement additional needs. Furthermore, coal can be stored in vast quantities, providing protection against delivery disruptions.

Setting aside its heterogeneity, which drives the commodity cost, coal delivery prices vary considerably due to variations in distance between the power plants and the coal producing areas; transportation costs have historically been a major consideration in the choice of coal as a fuel. Although barge transport is used when possible, rail transportation is the most common mode of transportation due to the ability to carry large shipments to power plants on a regular basis. As a result coal-fired power plants are exposed to diesel fuel price fluctuations. Coal-fired plants receive more than 2/3 of their coal by rail and, while, on average, transportation costs account for approximately 20% of total delivered costs, they can be as high as 60% on shipments of coal originating in the Powder River Basin.[23]

By contrast, natural gas is a homogenous product. Since it is delivered by a national network of pipelines that maintain pressure throughout the grid, transportation costs are essentially zero. Under business-as-usual conditions, prices for natural gas around the country do not deviate substantially from the benchmark price at the Henry Hub in Louisiana. Contracts for natural gas are typically shorter than those for coal, and gas is harder to store in bulk near power plants, making them dependent on natural-gas pipelines that sometimes have delivery issues. In New England, for example, pipeline capacity has not kept up with the growth in natural-gas demand, which has led to increased volatility and numerous price

[21] http://www.eia.gov/forecasts/steo/query/.

[22] Industrial and commercial uses of natural gas include the production of fertilizers, plastics, fertilizers, and dyes, to only name a few examples. Setting aside exports for metallurgical and steam (power generation) use, the rest of the coal is used as a basic energy source in many industries including steel, cement, and paper.

[23] http://www.eia.gov/coal/transportationrates/. Transportation costs are cited as a major reason why many utilities in the New England states have chosen to generate electricity with natural gas, or import coal from overseas as a lower cost alternative.

spikes in the area recently.[24]

3.1 Natural gas-fired power plants

Natural-gas fired power plants employ three major technologies: steam boilers, combustion turbines also known as simple-cycle or gas turbines, and combined cycle generators. Figure 4 provides the location of gas-fired power plants around the country and Figure 5 serves as a simple schematic of the various generation technologies discussed below.

The steam boiler technology is an older design that burns gas in a large boiler furnace to provide heat for turning water into steam at both high pressure and a high temperature. The steam is then run through a turbine that is attached to a generator, which spins and produces electricity. Typical plant size ranges from 300 MW to 1,000 MW. Because of their size and the limited flexibility that is inherent in the centralized boiler design, these plants require fairly long start-up times to become operational and are limited in their flexibility to produce power output outside a certain range. Furthermore, these plants are not as economical or easy to site as newer designs, which explains why none has been built in recent years. Older steam boilers were originally built for oil or dual fuels. Because these units have lower efficiency and higher operating costs than combined-cycle units, they are typically utilized at lower rates.[25]

When a combustion turbine is put into operation, air is pulled in from outside and is compressed. This compressed air is ignited by burning natural gas and expands. The resulting combustion generates 300,000 horsepower. The expanding air pushes the turbine generators much like steam does in a steam-electric station. The turbines then turn the electric generators. In simplest terms, a turbine is a series of many long, thin blades similar to propeller blades. Two-thirds of the horsepower generated rotates the air-compressor turbine. The remaining energy spins the electric generator. CTs operate differently from coal-fired plants. Rather than using steam to drive a turbine, they harness the nature of air to expand when it is heated.[26] CTs are small, quick-start units similar to an aircraft jet engine. CT plants are relatively inexpensive to build, but are expensive to operate because

[24] http://www.eia.gov/naturalgas/issuesandtrends/deliverysystem/2013/. According to EIA, "since 2012, limited supply from the Canaport and Everett (LNG) terminals coupled with congestion on the Tennessee and Algonquin pipelines has led to winter natural gas price spikes in New England. The problem continued in the winter of 2013–14, as indicated by New England's forward basis for January 2014 reaching $17.41. Pipeline expansions could ease price spikes, but their cost-effectiveness, including their ultimate cost to consumers, remains a challenge."

[25] See pages 50–52 in FERC (2012). See also pages 40–41 in MIT (2007b).

[26] http://www.duke-energy.com/about-energy/generating-electricity/oil-gas-fired-how.asp.

they are relatively inefficient, providing low power output for the amount of gas burned, and have high maintenance costs. They are not designed to run on a continuous basis and are used to serve the highest demand during peak periods, as well as to provide operating reserves.

The natural gas combined cycle technology employs two stages, namely a gas turbine generator and a steam turbine that recovers waste heat from the gas turbine cycle. The gas turbine compresses air and mixes it with natural gas. The natural gas is burned and the hot air-gas mixture is expanded through turbine blades, making them spin. The spinning turbine drives a generator which converts the spinning energy into electricity. Exhaust heat from the gas turbine is sent to a heat recovery steam generator (HRSG). The HRSG turns the gas turbine exhaust heat into steam and feeds it to the steam turbine. The steam turbine delivers additional energy to the generator drive shaft. The generator converts the energy into electricity. The NGCC fleet is highly efficient with heat rates of 7,500 Btu/kWh, capable of operating at high utilization rates with capacity factors of up to 85%, and they are relatively new.

Overall gas-fired generation is more flexible when it comes to changes in output and is the primary option used to meet the variable portion of the electricity load and typically supplies peak power. However, the increased natural gas supply and relatively low natural gas prices, have resulted in more gas being utilized as base load energy. All three technologies are capable of "cycling"—ramping production levels up or down to meet changes in electricity demand. CTs have the greatest cycling flexibility and thus are mainly employed during periods of peak demand, which may occur for only several hours of the day. Combined-cycle technology and steam-turbine technology also can be cycled, but the steam cycle typically requires more time to ramp up and down; see MIT (2007b).

3.2 Coal-fired power plants

Most of the coal-fired plants in the US are owned by traditional utility companies with the Southeast and the Midwest portions of the country being the strongholds of coal-fired generation; see Figure 4. They supply base-load electricity, the portion of electricity loads which are continually present, and typically operate throughout the day.

Pulverized-coal plants (PC) account for the great majority of existing coal-fired generating capacity in the US. Coal is ground to fine powder and injected through burners into the furnace with combustion air. The fine coal particles heat up rapidly, undergo pyrolysis and ignite. Pipes filled with water run through the burners and the heat turns the water to steam, which is used to rotate a turbine and generate electricity.

For the last decade or so, most new PC plants have been *supercritical* designs that gain efficiency by operating at higher steam temperature and pressure relative to *subcritical* designs. Subcritical steam generation units operate at pressures such that water boils first and then is converted to superheated steam. At supercritical pressures, water is heated to produce superheated steam without boiling. Due to the improved thermodynamics of expanding higher pressure and temperature steam through the turbine, a supercritical steam generating unit is more efficient than a subcritical unit. Ultra-supercritical steam generation is the most efficient technology for producing PC-fueled electricity enabling operation at even higher steam temperature and pressure reducing fuel consumption, and, hence, emissions, solid waste, water use and operating costs. While PC units are most common in the US, coal-fired power plants use other technologies to burn coal including cyclone-fired boilers, fluidized bed combustion, and integrated coal gasification combined cycle (IGCC) technologies.[27]

Fluid bed combustion is a variation on PC combustion in which coal is burned with air in a fluid bed, typically a circulating fluid bed (CFB), which consists mainly of lime. The CFB technology is best suited to low-cost waste fuels and low quality or low heating value coals. The steam cycle can be subcritical and potentially supercritical, similar to the PC combustion, and efficiencies are similar. CFB technology offers the capability to capture SO_2 in the bed and is flexible to a wide range of coal properties such as low heating value, high ash, and low volatility.

IGCC technology produces electricity by first gasifying the coal to produce synthesis gas (syngas), a mix of hydrogen and carbon moNO_xide. The syngas after cleanup is burned in a gas turbine that drives a generator. Turbine exhaust goes to HRSG to raise steam which drives a steam turbine generator. The technology is similar to that used in NGCC plants. IGCC plants are more expensive to build than PC plants, but proponents believe they have compensating advantages, including: lower emissions of air pollutants (NO_x, SO_2), lower heat rates, and the syngas that results from the gasification process can be processed to convert the carbon in the gas into a concentrated stream of CO_2. The syngas can then be processed, before it is burned, to remove the CO_2.[28]

Overall the efficiency of coal-fired power plants depends on a number of unit designs and operating parameters including the coal type, steam temperature and pressure, and

[27]See Section 3 in MIT (2007a), Kaplan (2010), Campbell (2013), and Campbell et al. (2013) for an informative discussion.

[28]An example of such a plant is the 618MW Edwardsport of Duke Energy in KNO_x county, IN, with a commercial data of 2013, described as “one of the cleanest and most efficient coal-fired power plants in the world.” See https://www.duke-energy.com/power-plants/coal-fired/edwardsport.asp

condenser cooling water temperature. The efficiency of coal-fired power plants also decreases with age. While good maintenance practices can keep power plant efficiency high in the early years of life, as the plant ages, power plant performance and efficiency erode after about 25 to 30 years of operation, and substantial work may be required to keep the plant operating efficiently and economically. Higher sulfur content reduces PC generating efficiency due to additional energy consumption to remove SO_x from the flue gas (smoke). High-ash coal requires PC design changes to manage erosion. Coal types with lower energy content and higher moisture content significantly affect capital costs and generating efficiency. A unit in Florida will generally have a lower operating efficiency than a unit in Northern New England, due to higher cooling water temperature in Florida—the difference could be 2-3 percentage points. Units operating at near capacity exhibit highest efficiency; cycling and below-capacity operation results in lower efficiency.[29]

Since large coal-based generation sources typically have low variable costs and incur performance and economic penalties in transient operation, they operate as base load units. The service life for coal-fired plants is somewhere between 35 and 50 years, and varies according to boiler type, maintenance practices, and the type of coal burned, among other factors. According to EIA, approximately 73% of U.S. coal-fired power plants were age 30 years or older at the end of 2010. The fraction of gas-fired plants in the same age range was about 27%.[30]

4 Wholesale electricity markets

4.1 Overview

Historically, the US electric industry developed as a loosely connected structure of individual monopoly utility companies, each building and operating power plants and transmission and distribution lines to serve its franchise area. The utilities were overseen by regulators aiming to protect consumers from unfair pricing and other undesirable behavior/

Retail electricity prices were regulated by the states, generally through state public utility commissions (PUCs). States retained regulatory authority over retail sales of electricity, construction of transmission lines within their boundaries, and intrastate distribution. Generally, states set retail rates based on the utility's cost of production plus a fair rate of return. PUCs also approved plans and spending for building new power plants to serve

[29]See Section 3 in MIT (2007a).

[30]http://www.eia.gov/todayinenergy/detail.cfm?id=1830

regulated customers. In contrast, wholesale electricity pricing and interstate transmission were regulated by the federal government, principally FERC.

In the 1990s, the federal government took a series of steps to restructure the wholesale electricity industry with an emphasis on unbundling of generation from transmission and distribution. Efforts were also put on the promotion of competitive retail markets. For the first time in the history of the industry, retail customers in some states were given the choice to pick their power suppliers. High cost states, like California and Northeastern States, were in the forefront of retail competition. A number of factors contributed to this shift towards a more competitive landscape over the course of several years for a big part of the country.

Technological advances in generation, especially the use of combined-cycle technology by gas-fired plants, and transmission, which made possible the transmission of electricity over longer distances, changed the economics of power production. Increases in both residential and industrial electricity prices triggered by utility investments on new capacity and fuel costs raised concerns about the regulatory status quo. The Public Utilities Regulatory Policies Act (1978) allowed non-utility facilities that met criteria set by FERC to enter the wholesale markets for selling electricity with an emphasis on "green" energy. The Energy Policy Act of (1992) expanded FERC's authority to order vertically integrated IOUs to open their transmission grid to non-utility power producers, which proved to be slow and cumbersome. EPACT also created a new category of wholesale producers (exempt wholesale generators), which did not sell retail electricity and did not own transmission facilities, and could charge market-based rates.

FERC issued Order 888 in April 1996 requiring all vertically integrated IOUs to file an open-access transmission tariff that would grant universal access to their transmission grid for qualified users. To eliminate any lingering discriminatory practices regarding access to the transmission grid, FERC issued Order 2000 in December 1999 that paved the way for the formation, initially of Independent System Operators (ISOs), and subsequently, of Regional Transmission Organizations (RTOs); see Figure 8. These were intended to be independent entities running the grid on a non-discriminatory basis. Eventually, RTOs did more than operate the transmission system and dispatch generation, however. They developed markets in which buyers and sellers could bid for or offer generation. The RTOs used the bid-based markets to determine economic dispatch.[31] Major parts of the country were not exposed to the restructuring wave just described and operate under more traditional market structures.

Twenty years later, electricity is sold either in traditional regulated markets in areas of

[31] According to FERC (2012), there is little practical distinction between ISOs and RTOs; see page 63.

the country that did not opt for restructuring, or in wholesale ISO/RTO markets in parts of the country that did. ISOs/RTOs use their markets to make operational decisions, such as generator dispatch. Traditional systems rely on management to make those decisions, usually based on the cost of using the various generation options. Power trading occurs via bilateral transaction and transactions in RTO markets.[32]

Pricing in both RTO and traditional market entails both cost-of-service and market-based rates. FERC grants market-based rates to suppliers that have adequately mitigated horizontal and vertical market power. Cost-based rates are used when FERC determines market-based rates are not appropriate or when the entity does not seek market-based rate; they entail a fair RoR on capital. Load serving entities (LSEs), typically utilities, cover their needs through a combination of self-supply, bilateral, and market purchases. In ISO-NE, NYISO, and CAISO, the LSEs divested much or all of their generation during restructuring. In PJM, MISO, and SPP, LSEs own significant generation either directly or through affiliates.

Traditional wholesale electric markets exist primarily in the Southeast, Southwest and Northwest serving roughly 40 percent of all US retail customers; see Figure 9. Utilities, which are very often vertically integrated are responsible for system operations and management, and, usually for serving the retail consumers. They may also include federal utilities like the Bonneville Power Administration, and the Tennessee Valley Authority. Wholesale electricity is bought and sold in bilateral markets.[33]

Electricity markets run by ISOs/RTOs deliver electricity through competitive market mechanisms.[34] More specifically, RTOs use a series of markets to provide electric service to customers, which usually include the following: a forward (day-ahead or hour-ahead) energy market, a spot (real-time) energy market, capacity markets, which are designed to ensure resource adequacy, and ancillary-services (reserves) market. They also allow their market participants to hold financial transmission rights, contracts that allow them to hedge against congestion-driven price increases. Virtual bids and offers are also allowed and used by market

[32] Bilateral transactions take place also in RTO markets. See FERC (2012) for additional details.

[33] The Southeast electric market is a bilateral market and encompasses all or part of the Florida Reliability Coordinating Council (FRCC) and the Southeastern Electric Reliability Council (SERC). Major trading hubs include Entergy, Southern, and TVA. Long-term transactions of year or more dominate the Southeast. The Western markets are also almost exclusively bilateral markets. They include the Northwest Power Pool (NWPP), the Rocky Mountain Power Area (RMPA), and the Arizona, New Mexico, Southern Nevada Power Area (AZ/NM/SNV). The Intercontinental Exchange (ICE) has four trading points in the Northwest: Mid-Columbia (Mid-C), California-Oregon Border (COB), Nevada-Oregon Border (NOB) and Mona (Utah). See FERC (2012) for details.

[34] Although ISOs/RTOs have operational control of the transmission system, they do not own transmission or generation assets, perform the actual maintenance on generation or transmission equipment; or directly serve end use customers.

participants to arbitrage differences between day-ahed and real-time prices.

4.2 Entities

Generation facilities around the country are either utility- or non-utility owned. Their major difference is that non-utilities do not transmit and do not distribute electricity. The growth of non-utility ownership took off following the restructuring of the electricity industry and the divestiture of generation assets by utilities, especially, investor-owned utilities (IOUs). Those assets were transferred to another company or to an unregulated subsidiary with its own holding company structure. By the late 1990s, the numbers of IOUs were decreasing, non-utilities were expanding by buying utility divested generating assets, increasing their share of generation and the addition of new capacity.

Utilities in general are either private (investor-owned) companies or public agencies engaged in the generation, transmission, and/or distribution of electric power for public use. As the simple schematic in Figure 6 indicates, the are 5 distinct groups within utilities: IOUs, federally owned, other publicly owned (POUs), and rural electric cooperatives (co-ops), and power marketers. Under the traditional system, utility are given a monopoly franchise in return for regulation by state and federal agencies. Many utilities are exclusively distribution utilities, purchasing wholesale power from others to distribute it, over their own distribution lines, to the ultimate consumer. These are primarily the utilities owned by state and local governments and co-ops.

i. Utilities

There are two basic forms of IOUs with individual corporations being the most prevalent one. The second common form is the holding company, in which a parent company is established to own one or more operating utility companies that are integrated with one another. Most of the IOUs sell power at retail rates to different classes of consumers and at wholesale rates to other utilities. Pacific Gas & Electric, Southern California Edison, Florida Power & Light, Georgia Power Co, Virginia Electric & Power were the top 5 IOUs in terms of revenues in 2012; all in excess of $6.8 billion.[35]

There are nine federal electric utilities, which mainly sell electricity produced at hydroelectric projects around the country. Consumers of federal power are usually large industrial consumers or federal installations. Most of the remaining energy generated by *non-profit* federal utilities is sold in the wholesale market to POUs and co-ops for resale at cost. IOUs

[35] Based on data from forms EIA-861-schedules 4A & 4D and EIA-861S.

are the residual claimants of energy generated by non-profit federal utilities.[36]

POUs may or may not own generating assets. This is in sharp contrast with IOUs that largely own and operate generating capacity. Those that own and operate generating capacity supply some or all of their load; some of them supplement their production through purchases. The non-generators rely exclusively on purchases to serve demand and distribution is their main line of business and account for over half of the total number of POUs. POUs include municipal and states authorities, public power districts, irrigation districts, and other organizations. State authorities function in a manner similar to federal utilities: they generate or purchase electricity from other utilities and market large quantities in the wholesale market to groups of utilities within their states at lower prices than the individual utilities would otherwise pay. Large concentrations of publicly-owned power districts are in the Midwest and Eastern regions of the country. In general, POUs tend to have lower costs than IOUs because they often have access to tax-free financing and do not pay certain taxes or dividends.[37]

Most rural co-ops are formed and owned by groups of residents in rural areas to supply power to those areas. Some cooperatives may be owned by a number of other cooperatives. There are really three types of cooperatives: distribution only, distribution with power supply, and generation and transmission. Most distribution cooperatives resemble municipal utilities in that they often do not generate electricity, but purchase it from other utilities. The other type (generating and transmission cooperatives) are usually referred to as power supply cooperatives. These cooperatives are usually owned by the distribution cooperatives to whom they supply wholesale power. Distribution cooperatives are similar to federal utilities—they supply electricity to other utility consumers from their generation.[38]

The introduction of the competitive wholesale market for electricity introduced a fifth

[36] There are 4 entities operating federal hydro plants: USACE, USBR, US Bureau of Indian Affairs, and the Department of State's International Water and Boundary Commission. In addition, there are 4 federal Power Marketing Administrations (PMAs) that sell electricity produced at federal hydroelectric projects: the Bonneville Power Administration (BPA), the Western Area Power Administration (WAPA), the Southeastern Power Administration (SEPA), and the Southwestern Power Administration (SWPA), which marketed 42% of the nation's hydroelectricity in 2012, representing 7% of total generation in the United States. The ninth federal utility is the Tennessee Valley Authority (TVA), the largest federal power producer, which operates its own power plants and sells the power in the Tennessee Valley region in both the wholesale and retail markets. The TVA generates electricity from coal, gas, oil, and nuclear power as well as hydropower.

[37] In 2011, the New York Port Authority, the South Carolina Public Service Authority, CPS Energy, and the Salt River Project were the top 5 POUs in terms of net generation (MWhs). See the directory and statistical report at http://www.publicpower.org/.

[38] See http://www.nreca.coop/ for additional details. Pedernales Electric Coop, Jackson Electric Member Corp, Withlacoochee River Elec Coop, Lee County Electric Coop, Cobb Electric Membership Corp, and Middle Tennessee E M C were the top 5 co-ops in terms of customers served (all in excess of 190,000 customers) Based on data from forms EIA-861-schedules 4A & 4D and EIA-861S for 2012.

subcategory of electric utilities—power marketers. They are classified as electric utilities because they buy and sell electricity at the wholesale and retail levels. However, they do not own or operate generation, transmission, or distribution facilities. Examples include Dominion Energy Marketing, Duke Energy Trading and Marketing, Cargill Power Markets, Con Agra Energy Sevices.

ii. Non-Utilities

Non-utility electric power plants are operated by entities in one of the following sectors: independent power producers (IPPs), commercial, and industrial. Entities in the last two sectors produce electricity primarily for their own use.

An IPP owns or operates facilities for the generation of electricity for use primarily by the public that is not an electric utility. The major difference between utilities and IPPs is that utilities have distribution facilities while IPPs do not.[39]

The commercial sector consists of service-providing facilities and equipment of businesses, federal, state, and local governments, as well as other private and public organizations. It includes institutional living quarters and sewage treatment facilities. Common uses of energy associated with this sector include space heating, water heating, air conditioning, lighting, refrigeration, cooking, and running a wide variety of other equipment. The sector includes generators that produce electricity and/or useful thermal output primarily to support the activities of commercial establishments.[40]

The industrial sector consists of all facilities and equipment used for producing, processing, or assembling goods (e.g., manufacturing facilities with NAICS 31–33). Overall, energy use in this sector is largely for process heat and cooling and powering machinery, with lesser amounts used for facility heating, air conditioning, and lighting. The sector includes generators that produce electricity and/or useful thermal output primarily to support the above-mentioned industrial activities.[41]

[39]FirstEnergy Generation, Allegheny Energy Supply, NRG Texas Power, GenOn Northeast Management Company, Dynegey Midwest Generation, PPL Montana are among the top 10 IPPs in terms of net generation in 2012 using EIA-923 data.

[40]We see entities such as Los Angeles County Sanitation, Michigan State University, Iowa State University, University of Michigan, US Air Force Base-Eielson in this sector.

[41]For example, we see power plants operated by Archer Daniels Midland, Dow Chemical, International Paper, Weyerhaeuser, ExxonMobil Oil.

5 Empirical analysis

5.1 Nomenclature

Our goal is to understand how power plants adjust their use of inputs to changes in input prices, and how these responses vary by ownership and market types. We classify power plants into four groups. The first category consists of plants operated by utilities not participating in ISO/RTO (henceforth, ISO) wholesale markets. This category consists of plants owned by utilities in traditional markets described in Section **??**. Potentially abusing language, we refer to this group as plants operated by non-market utilities. The second group consists of plants operated by utilities participating in ISO wholesale markets. In our nomenclature, these are plants operated by market-utilities. The third group consists of plants by industrial and commercial entities that produce electricity primarily for their own use. Consistent with our discussion in the previous section, we will refer to this group as industrial/commercial (IC). The fourth group contains plants operated by IPPs selling power in ISO wholesale markets. This classification is summarized in the table below.

	Utilities	
Wholesale Markets	Yes	No
No	1. Non-market utilites	3. ICs
Yes	2. Market utilites	4. IPPs

5.2 Data

The vast majority of the data used in our analyses are publicly available from the US Energy Informtion Administration (EIA) and the Environmental Protection Agency (EPA). Monthly data for net generation (MWh) at the prime-mover level are available from the EIA-906, EIA-920, EIA-923 (schedules 3A and 5A) surveys.[42] Monthly data for total fuel consumption (electricity plus thermal output) in physical units and associated heat content by fuel are available from the same surveys. In the case of EIA-906 and EIA-920, the data are available at the prime mover level. In the case of EIA-923, the data are available at the boiler level. The EIA-906 and EIA-920 surveys cover the period 2003–2007, while EIA-923

[42] Prime mover is the engine, turbine, water wheel, or similar machine that drives an electric generator; or, for reporting purposes, a device that converts energy to electricity directly. See, e.g., the glossary in the EIA Monthly Energy Review for April 2013.

covers the period 2008–2012.[43] These three surveys contain information for the sector of the plants' operators, which allows us to distinguish between utilities and non-utilities.[44]

Monthly fuel receipts in physical units and delivery costs ($/MMBtu) for utility plants are available from the FERC-423 survey prior to 2008 and from the EIA-923 (Schedule 2) survey from 2008 onwards forms.[45] Monthly fuel receipts for non-utility plants are available from EIA-423 prior to 2008 and from EIA-923 beginning in 2008. The same reports also contain information regarding heat content for the fuel receipts. The data in EIA-423 pertain to plants for IPPs and commercial and industrial CHP producers whose total fossil-fueled nameplate generating capacity is 50 MW or more. The data from FERC-423 refer to plants with a total steam-turbine generating capacity and/or combined cycle (gas turbine with associated steam turbine) generating capacity of 50 MW or more. Finally, the EIA-923 data are for plants with a nameplate capacity of 50 MW or more burning fossil fuels.[46]

We imputed fuel delivery costs for non-utility plants in every month, and for utility plants during months with no fuel receipts, using fuel delivery costs from the closest plant that reported delivery costs during that month. Using the Harvershine formula that accounts for the Earth's curvature, and power-plant latitude and longitude coordinates, we calculated the distance between every pair of power plants in our data. One advantage of this method is that it accounts for unobserved factors that affect input costs and are spatially correlated.[47]

Nameplate operating capacity (MW) is available at the generator level on annual frequency from EIA-860—all existing plants that have a total generator nameplate capacity of one MW file EIA-860. The same survey reports up to six energy sources for each generator.

[43]http://www.eia.gov/electricity/data/eia923/. The EIA-906 survey covers all non-CHP power plants with a generating capacity of one MW or higher. The CHP plants above the same generating capacity threshold are covered by the EIA-920 survey for 2004–2007. The two surveys were superseded by EIA-923 in 2008.

[44]The databases contain a `sectorname` field that contains the following values: COMMERCIAL NAICS COGEN, COMMERCIAL NAICS NON-COGEN, ELECTRIC UTILITY, INDUSTRIAL NAICS COGEN, INDUSTRIAL NAICS NON-COGEN, NAICS-22 COGEN, NAICS-22 NON-COGEN. COGEN cogenerators, also known as combined heat and power (CHP) generators, facilities that utilize heat for electricity generation and for another form of useful thermal energy (steam or hot water), for manufacturing processes or central heating.

[45]http://www.eia.gov/electricity/data/eia423/.

[46]Pages 59–61 in EIA (2010b) provide a succinct yet informative description of all three surveys that are related to cost and quality of fuels. Using the databases described above, we calculated annual generation, fuel consumption for electricity only in physical units, and fuel receipts in physical units, for coal and natural gas for the period 2001–2012. We then compared these annual figures with the corresponding ones in Tables Tables 3.1.a, 5.1.a, 5.4.a, and 7.2 in EIA (2013). The maximum percentage difference is around 5% and is associated with natural gas fuel receipts for years between 2008 and 2012.

[47]We collected power plant coordinates from the EPA National Electric Energy Data System (NEEDs) v410 and v513 databases, from the SNL Financial power plant database, and from EIA at http://www.eia.gov/state/notes-sources.cfm#maps.

We use the primary energy source to come up with a measure of coal- and natural gas-fired nameplate operating capacity. For example, for a generator with nameplate operating capacity of 50MW for which the primary energy source is coal while the secondary source is natural gas, the coal-fired nameplate operating capacity is 50MW while the natural gas-fired nameplate operating capacity is zero.

Using information from EIA-860, the EPA E-GRID 2012 database, and the SNL Financial power plant database, we were able to check whether plants fall within ISO areas. As an additional, albeit imperfect check, we compared monthly total net generation and loads for 2007–2012 across six ISOs (CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM). Their absolute percentage difference never exceeded 5%. The generation/load comparison at the ISO level.[48]

Annual information for environmental controls at the generator level are available from the EPA Air Markets Program Data (AMPD) database for facility attributes. The AMPD data contain also information on annual and ozone (May–September) season programs at the generating unit level. The *annual* programs include the Acid Rain Program (ARP), the Clean Air Interstate Rule (CAIR) NO_x program, the Cross-State Air Pollution Rule (CSAPR) annual NO_x (TRNO_x), and phase I (TRSO2G1) and phase II (TRSO2G2) SO2 programs, and the Regional Green House Gas Initiative (RGGI). The ozone season programs include the CSAPR ozone season NO_x program (TRNO_xOS), the CAIR ozone season NO_x program (CAIROS), the State-Implementation-Plan NO_x program (SIPNO_x), and the NO_x Budget Program (NBP). Finally, the same database indicates whether a unit is subject to New Hampshire's NO_x program (NHNO_x). [49]

We obtained daily NYMEX futures CAPP coal and Henry Hub natural gas from SNL Financial. For the NYMEX futures market, coal contracts specify delivery by seller to the buyer at barge terminals on two limited sections near the confluence of the Big Sandy and the Ohio Rivers. The sections are a 12-mile stretch of the Ohio River and the adjoining Big Sandy River (where coal barge terminals are within the lowermost nine miles). The actual origins of the coal are not defined, but the coal must meet a set of specifications as to heat (12,000 Btu/lb.), ash, moisture, sulfur, volatile matter, hardness or grind ability, and sizing

[48] The date range is currently dictated by the fact that our current load data are from SNL and they don't extend before 2007. To our surprise, assigning plants to ISOs prior to 2010 (this is the 1st year for which the information is available in EIA-860 is rather difficult. For, example, although PJM provides a list of plants in its area, MISO informed us that treat such a list as confidential. FERC-714 would allow us to match exactly plants to ISOs but it has two problems: (i) it lacks EIA plant codes, (ii) its electronic filing started in 2005.

[49] See http://ampd.epa.gov/ampd/. Note that CSAPR is also known at the Transport Rule. The Appendix provides an overview of the various programs. Additional details for NHNO_x are available at: http://des.nh.gov/organization/divisions/air/tsb/tps/aetp/categories/overview.htm

and must be delivered in 1,550 ton trading units.[50] In the case of the natural gas NYMEX futures contracts, the delivery point is the Henry Hub which refers to piping and related facilities owned and/or leased by Sabine Pipe Line LLC near Erath, Louisiana.[51]

Finally, we obtained daily settlement SO_2 and seasonal NO_x (SNO_x) permit prices from Evolution Markets, an allowance broker we identified through EPA's website.[52] It is worth mentioning that although the prices of the SO_2 permits were constantly in the range \$100–\$200/ton during the first 10 years of ARP, the situation changed when it became clear that more stringent caps would be put into place following CAIR in 2005 (see Figure 10). CAIR essentially required some states to reduce the amount of permits by two thirds, which increased substantially the price of the remaining allowances (Schmalensee and Stavins (2012)). The upward pressure on SO_2 prices was magnified by hurricanes Katrina and Rita in the fall of 2005; in fact, prices exceeded \$1,000 per ton in 2005. Furthermore, the delivery of low-sulfur PRB coal to the Midwest was disrupted by UP and BNSF track failures in the Spring of 2005, which triggered switching to high-sulfur Eastern coal increasing the demand for allowances. The spike in prices prompted EPA's announcement to re-examine the program. That, together with some legal challenges in court started creating doubts on the viability of the permits market and pushed its prices downwards. When the DC Circuit Court of Appeals decided in 2008 against CAIR, the market price went back to the historic low of roughly \$100/ton. CSAPR essentially contributed to the disappearance of the market by eliminating inter-state transactions. The NO_x prices followed a similar pattern falling from around \$800/ton in 2007–2008 to essentially zero by 2012.[53]

5.3 A preliminary comparison of plants across observables

We provide summary statistics for a set of observable characteristics for the power plants used in our formal econometric analysis below in Table 1. We also provide pairwise comparisons across the same set of characteristics focusing on plants other than those in the industrial/commercial (IC) sector, since the latter group of plants serves almost entirely

[50]http://www.eia.gov/coal/nymex/. Additional details regarding contract specifications are available at http:http://www.cmegroup.com/rulebook/NYMEX/2/260.pdf.

[51]http://www.cmegroup.com/rulebook/NYMEX/2/220.pdf.

[52]http://www.epa.gov/airmarkets/trading/buying.html. Additional information about Evolution Markets is available at http://www.evomarkets.com/environment/emissions/˙markets.

[53]EIA attributes the dramatic drop in SO_2 and seasonal NO_x prices after July 2008, when CAIR was struck down by the DC Court of Appeals, which continued well in 2011 to the following factors: (i) post-CAIR ruling regulatory changes, (ii) installation of FGD and SCR technology by coal plants in anticipation of new environmental policies, (iii) lower coal generation due to the recession and warm weather in 2011, as well as the increased use of natural gas, which created a surplus of allowances. See http://www.eia.gov/todayinenergy/detail.cfm?id=4830.

their operators' own needs for power (Table 2). The gray shading indicates statistically significant differences at the 5% level with p-values based on clustered (by plnat) standard errors. For the remainder of our discussion, the reader should keep in mind that the number of observations is not necessarily the same across variables.

The statistics in Tables 1–2, as well the results of the econometric analysis that follow are based on samples that span the period 2003–2012 with an observation defined as a plant-month combination. There is an additional filter that we impose on the data: we focus on plants that burned both coal and natural gas at some point between 2003 and 2012 (dual-fuel plants).[54] The full sample, when limited to such dual-fuel plants, consists of 39,648 observations, which translates to about 2,900 plants and more than 3,500 observations per year. There are 25,598 (14,050) observations associated with plants operating outside (outside) ISO wholesale markets. The observations for plants associated with non-utilities and utilities are almost equally split: 20,004, and 19,644. The observations across the four groups of plants is as follows: 12,131 (non-market, utilities), 7,513 (market, utilities), 13,467 (ICs), and 6,537 (IPPs). The number of plants across the four groups is 111, 69, 139, and 60, respectively and remains relatively constant during the period of our analysis. On average, we track a plant for about 108 months (96 months) in the case of non-IPPs (IPPs).

We begin by comparing the share of fuel consumption in MMBtu (input energy) from natural gas across groups. This share will be the dependent variable in the first set of empirical models, which we discuss in detail below.[55] The share of natural gas is not statistically different between market and non-market utilities. There is some evidence that IPPs have lower natural gas shares compared to both groups of utilities. This difference is statistically significant when comparing IPPs with non-market utilities, and marginally significant when comparing IPPs with market utilities. It is difficult to draw too strong of conclusions from this comparison since this is one of our independent variables.

Next, we compare the two input prices measured in \$/MMBtu. The two utility groups have similar natural gas and coal prices, however, IPPs appear to pay higher prices for both. Although we find no statistical differences in natural gas prices across any of the groups, we do find that IPPs tend to have higher coal prices.[56] Subsequently, we compare plant

[54] Prior to conditioning on dual-fuel plants, the total number of observations is 256,626 with the number of observations almost uniformly split across the 10-year window.

[55] The breakdown of observations across different groups in the previous paragraph is conditional on the natural-gas share of input energy being defined.

[56] We note that the natural gas and coal prices for IPPs are all imputed as discussed above. Therefore, comparisons between IPPs and other groups are really a comparison of whether the geographic distribution of IPP power plants is similar to each group. Cicala (2013) finds that IPPs pay less for each input fuel. This is a motivating factor for our instrumental variables approach described below.

heat rates (the ratio of heat input to electricity generated) and the average age of the plants' generating units.[57] Heat rates do not vary across the three groups, while non-market utilities appear to have plants with less aged generating units compared to both market utilities and IPPs—the age difference is roughly five years.

The next set of comparisons refer to variables that we include as covariates in our econometric models. There are two main groups of variables here, both exhibiting variation only by year within a plant. The first group tracks the number of units within plant equipped with a particular pollution-abatement technology; e.g., the number of units with Selective Catalytic Reduction (SCR) technology installed. The second group tracks the number of units within a plant under the umbrella of an EPA program; e.g., the number of units under ARP. Power plants emit a variety of pollutants, and, in general, the emissions from natural-gas firing are lower compared to those from coal firing. Therefore, power plants that face severe regulatory restrictions may choose to rely more on natural gas as an input instead of coal. Similarly, the installation of additional abatement equipment, such as a Flue Gas Desulfurization (FGD) unit ("scrubber"), allows a power plant to increase their coal consumption, all else equal.

We obtain our information on the pollution-abatement technology for each unit within a plant from the EPA AMDP facility attributes database. In this draft, we focus on technologies aimed to reduce NO_x and $S0_2$ emissions, and particulate matter (PM). In the case of NO_x, we focus on Selective Catalytic Reduction (SCR) and Selective Non-catalytic Reduction (SNCR). For SO_2, we focus on dry- or wet-lime flue-gas desulfurization (FGD) equipment. Reducing PM relies on installing PM bags at the flue stack, essentially directing the exhaust through air filters. As Table 2 indicates, the three groups of plants do not differ in their average number of units with NO_x SCR and SNCR technology, PM controls, and SO_2 wet-lime FGDs. The number of units with SO_2 dry-lime FGDs is higher for non-market utilities compared to IPPs, but does not differ across market utilities and IPPs.

Moving to the set of variables related to EPA's environmental programs, the average number of units within a plant operating under the annual NO_x CAIR (CAIRNO_x), the ozone-season CAIR NO_x (CAIROS), and the annual SO_2 CAIR do not differ across the three groups. We do find that a larger number of market-utility units fall under ARP and fewer "market" plants (both utilities and IPPs) operate under NBP. We find some evidence that the number of units operating under NO_x SIP (SIPNO_x) differs across market utilities and IPPs, but the p-value exceeds 0.08. The number of units operating under the annual NO_x

[57]A plant may contain multiple generating units. We calculate the average age across units within a plant before we proceed with the comparisons.

CSAPR (TRNO_x) does appear to vary significantly across the groups, but the differences are small.[58] Furthermore, we find some evidence that market utilities have fewer units subject to the seasonal NO_x CSAPR (TRNO_xOS). Finally, more market-utility units are under the phase-1 annual SO_2 CSAPR (TRSO2G1), but fewer are under the phase-2 annual SO_2 CSAPR (TRSO2G2), compared to non-market utilities. Once again, the Supreme Court ruling on the CSAPR implementation is pending.

Overall, we take these comparisons as fairly strong evidence that the power plants in each group are similar on observables. Of course, a major concern will be that they differ in terms of *un*observables. We come back to this after we present the results of our econometric models.

5.4 Econometric models

5.4.1 Input share of natural gas

We begin by examining the sensitivity of the natural-gas share of plant's fuel consumption in MMBtu to coal and natural-gas prices. For the remainder of our discussion, the use of the term price is equivalent to delivery cost. Using i to denote the plant and t to denote the month, we estimate models of the form:

$$ln\left(s_{ng_{it}}\right) = \beta_{ng} ln(P_{ng,it}) + \beta_{coal} ln(P_{coal,it}) + f(lnetgen_{it}) + \mathbf{X'_{it}}\gamma + \eta_i + \eta_t + \epsilon_{it}, \qquad (1)$$

$$with \;\; s_{ng,it} \equiv \frac{MMBtu_{ng,it}}{MMBtu_{coal,it} + MMBtu_{ng,it}}.$$

Other than the logarithms of the fuel prices, $ln(P_{coal,it})$ and $ln(P_{coal,it})$, Our specifications include plant fixed effects (η_i) to control for time-invariant plant characteristics and month fixed effects (η_t) to account for seasonality in the share of natural gas. We also include a third-degree polynomial in the logarithm of the plant's net generation from the two fuels, $f(lnetgen_{it})$, to allow for flexibility in the plant output expansion path. We do so because although standard production functions, such as the linear, the Cobb-Douglas and the Leontief produce output expansion paths that are rays from the origin, the output expansion paths may take a variety of forms.

The vector $\mathbf{X_{it}}$ includes various covariates that fall within the following groups: (i) SO_2 and seasonal NO_x permit prices, (ii) the plant's natural-gas plus coal-fired operating capacity, (iii) the number of generating units with various type of pollution abatement technologies,

[58] Recall from our earlier discussion that CSAPR is also known as Transport Rule.

and (iv) the number of generating units under the various EPA programs. While the permit prices that exhibit variation only by time, the controls in (ii)–(iv) exhibit variation only by year within a plant. Unless stated otherwise, we estimate all our models for dual-fuel plants—namely, plants that consumed both natural gas and coal between 2003–2008—and report heteroskedasticity robust standard errors. Furthermore, since we use alternative dependent variables in our models, we will use DV (dependent variable) in our table captions to ease the reader.

Our modeling approach addresses two econometric issues. First, although we focus on dual-fuel plants, there are time periods during which that natural gas share may be zero. As a result, the distribution of the natural-gas share is a combination of a discrete distribution (at zero) and a continuous distribution. Therefore, we will use a Tobit, to address the cutoff (censoring) from above at 0 implied by the logarithmic transformation of the natural gas share. In future versions of the paper, we plan to incorporate more general double-hurdle models, such as Cragg's and its extensions that accommodate correlation in the participation and outcome equations.

The second econometric issue is endogeneity due to measurement error and buyer power. The measurement error is a (direct) implication of our fuel delivery cost imputation. Recall, that our original data do not contain cost information for utility plants that did not have fuel receipts during a particular month, as well as for non-utility plants despite fuel receipts in EIA-423 since this is considered confidential information. In both instances, we imputed monthly cost information from the closest (in terms of distance) plant. Buyer power that exhibits variation over time is a concern if, for example, larger plants or plants that belong to large fleets, such as those of large utilities, are able to secure better prices. We instrument both coal and natural-gas prices using prompt-month NYMEX futures for Henry Hub and Central Appalachia, respectively. We introduce cross-sectional variation to the NYMEX prices by interacting them with NERC-region fixed effects. Note that with the data currently in hand, the use of instrumental variables compromises the sample size since SNL Financial does not track these futures prices prior to July 2004.

i. Pooling across all power plants

We report results for all power plants in Table 3, which shows the impact of accounting for the the censoring and instrumenting for the input prices. The first column provides OLS estimates. The coefficients of two input prices have the expected sign and they are highly significant. Higher coal prices increase the share of input fuel coming from natural gas, while higher natural gas prices have the opposite effect. The second column provides 2SLS estimates instrumenting for the input prices. As expected, the coefficients for natural gas and coal prices increase in magnitude with the coal price coefficient increasing the most. Furthermore the statistical significance of the price coefficients remains intact. The third column provides estimates from a Tobit model accounting for the censored nature of the data. The coefficients are highly comparable to their OLS counterparts of the first column. The fourth column provides estimates from an IV Tobit using the 2-step estimator in Newey (1987).[59] The input price coefficients increase in magnitude compared to the simple Tobit, they have the correct signs, and maintain their statistical significance. We delay discussing the coefficients associated with the remaining covariates until we present our results split by ownership and market structure.

ii. IV Tobit by plant type

Table 4 reports IV Tobit results split by our four groups using. We find considerable variation in the sensitivity to natural gas prices. We first compare utilities with non-utilities. We find that non-utilities are more price sensitive to both input prices. When we dig deeper into the four groups, utilities that do not operate in wholesale power markets are much more sensitive to movements in both natural gas and coal prices, compared to utilities operating in wholesale power markets; in fact, the coefficients associated with market-utilities are of the wrong sign. Non-market utilities have a larger natural-gas coefficient than IPPs, but a smaller coefficient associated with coal prices. For non-market utilities (and non-censored observations) a one-percent increase in the price of natural gas reduces the natural gas share by 0.63 percent. Industrial/commercial (IC) entities are also more price sensitive compared to these latter groups, but given that their power plants differ on a number of observable dimensions, we do not focus on these comparisons. The natural gas coefficient for utilities operating in wholesale power markets is positive and the 95% confidence interval is well outside of the coefficient associated with non-market utilities. A one-percent increase in natural gas prices reduce the natural gas share for IPPs by .05 percent—however, this effect is not statistically significant. Although, the 95 percent confidence interval for the natural gas coefficient for IPPs falls outside of the coefficient for non-market utilities.

The coefficients associated with the price of coal for non-market utilities suggests that a one-percent increase in coal prices increases the input share of natural gas by 0.58 percent, essentially equal in magnitude to the natural gas coefficient. Once again, the market utility coefficient has the opposite sign as we would expect. IPPs are more sensitive to movements in coal prices, compared to non-market utilities. A one-percent increase in coal prices increases the natural gas share by 1.79 percent. IC entities are also very price responsive, with a one-percent increase in coal prices increasing the natural gas share by 1.31 percent.

[59] We make no adjustment to the standard errors when we estimate IV Tobit models.

Combined, these results suggest that non-market utilities are more sensitive to movements in natural gas prices compared to both market utilities and IPPs. Non-market utilities are also more sensitive to movements in coal prices compared to non-market utilities, but IPPs are responsive to changes in coal prices.

The signs of the coefficients associated with the other covariates largely fit with our priors. However, we note that some of these covariates may be endogenous, leading to bias in their coefficients.[60] Theory does not predict the sign and shape of the response to total generation or total capacity. We would expect higher NO_x and SO_2 permit prices to increase the natural gas share given that gas firing is "greener" than coal firing. However, these prices also show a strong downward trend over time (see Figure 10) and, therefore, may capture industry trends toward natural gas. With that said, the majority of coefficients that are significant at the 5 percent level, across the four power plant ownership/market types, are positive (four of six).

We would expect that plants with pollution abatement equipment would tend to use less natural gas since the abatement equipment reduced the marginal environmental costs of using coal. However, it might also be the case that greater pollution abatement equipment is correlated with more stringent environmental regulations (Abito (2014)). With the exception of the SCR-related variable, the majority of the other coefficients, when statistically significant, have negative signs (seven out of eight). The coefficients on variables that pertain to EPA programs are more mixed. Here we would expect these coefficients to be positive. However, of the statistically significant coefficients, there is roughly equal numbers of positive and negative coefficients (12 and 15, respectively). The negative coefficients are predominantly associated with the the ARP and SO_2 CAIR. These negative coefficients may be capturing an omitted-variable bias; those regions burning a lot of coal are more likely to be operating under either of these programs.

iii. IV Tobit by plant type: propensity scores

A natural concern is that power plants of utilities operating within ISO wholesale markets differ from those utility plants outside ISO wholesale markets. While our comparison of observables in Table 1 suggests this is not the case, we investigate the robustness of the relative size of the natural gas coefficient using a variant of propensity score matching. In particular, we use a Probit to model the probability that a power plant operates within an ISO wholesale power market as a function of the plant's natural-gas plus coal-fired operating capacity, net generation from the two fuels, the plant heat rate (MMBtu/Mwh), and year

[60] The reader may be concerned that this bias may also bias our coefficients of interest. We would expect our instrumental variables approach to correct for any indirect bias created.

fixed effects. We use the predicted probability as a propensity score by excluding power plants with predicted probability above 0.85 and below 0.15. These results are presented in Table 5. As we can see, the change in the number of observations for the utility plants is negligible. The change in the number of observations, however, for the non-utility plants is dramatic; the sample size is reduced by a factor of 3. The coefficient associated with natural gas prices for IPPs becomes more noisy, but the 95-percent confidence interval for the natural gas prices falls outside that of the non-market utility coefficient. The coefficient associated with coal prices grows considerably for the IPP plants.

iv. IV Tobit by plant type: non-linearities

In our analysis so far we have assumed that changes in fuel prices have a linear effect on the input share of natural gas. This linear effect may not necessarily hold. To a first-order approximation, we can assume that a particular generating unit has a relatively constant heat rate. While heat rates can vary within a plant depending on the level of generation, they are roughly constant over a range of output levels. Consider now a power plant with one coal and one natural gas unit. Given the heat rates, the prevailing prices for coal and natural gas, and any *additional* environmental costs associated with the coal unit, one of the units will have a lower marginal cost than the other for producing 1 Kwh of electricity up to that unit's maximum output. Changing one of the input prices will have no effect until the change (in the correct direction) is large enough to reorder the marginal costs of the two units. At this point, the plant operator will have an incentive to decrease generation from the high-cost unit and increase generation from the low-cost unit. Therefore, changes in the relative use of the two inputs will be non-linear.

We investigate whether, somehow, these non-linearities are driving the results above by allowing the effect of the two input prices to vary depending on the relative marginal costs of the coal and natural gas units at each plant for generating 1 Kwh of electricity. Specifically, for each plant we construct the average heat rate of the coal and natural gas units across the entire sample. We then construct the following ratio of marginal costs:[61]

$$Relative\ MC = \frac{\overline{HR}_{i,coal} \times P_{it,coal}}{\overline{HR}_{i,ng} \times P_{it,ng}}. \tag{2}$$

Our first step to introduce non-linear effects of fuel prices on the input share of natural gas is the construction of three indicator variables that will dissect the distribution of the relative marginal costs. More specifically, these three indicator variables, represent the bottom 30%,

[61] Notice that the heat rate is measured in Btu/Kwh, while prices are measured in \$/Btu. Therefore, the marginal cost is measured in \$/Kwh.

the middle 40$, and the top 30% of the distribution of the distribution.[62] The second steps translates into interacting these three indicator variables with the coal and natural gas prices. Table 6 reports the results of this richer specification that allows for the presence of non-linear effects.

Non-market utilities conform to our intuition of how input prices should affect the input share of natural gas. The effect of both coal and natural gas prices is much stronger when the relative marginal costs are in the middle of the distribution. This holds for movements in both coal and natural gas prices. A one-percent increase in the price of coal leads to a 5.15 percent increase in the natural gas share when the relative fuel marginal costs are in the middle of the distribution. In the other two groups, a one-percent increase leads to a 1.5 percent increase in the natural gas share. A one-percent increase in the price of natural gas leads to a 3.21 percent decrease in the share of energy coming from natural gas when relative fuel-marginal costs are in the middle group, but a 1.52 percent decrease when this ratio is in the first bin and a 2.75 percent decrease when the ratio is greatest.

Utilities operating in markets continue to appear insensitive to changes in input prices regardless of the relative levels of fuel-related marginal costs. The only statistically significant coefficient for these plants actually has the wrong sign (coal prices when relative marginal costs are in the middle 40 percent). Five of the six coefficients have the wrong sign. Interestingly, IPPs also exhibit a non-linear response, but their "switch point" is in the top bin of the relative marginal cost measure instead of the middle bin; this is in a region where the ratio is closer to one. IPPs are incentive to changes in prices when the relative fuel-related marginal costs are in the first two bins, but become very large in the last bin.

5.4.2 Within-year variation

A number of other changes in the regulatory structure of the US electricity markets took place over our sample. Many of these center around a variety of environmental programs that negatively affected the use of coal. While our base specification controls for these environmental programs, an obvious concern is that our estimates are picking up industry-level trends taking place. We investigate whether this is the case by estimating Equation 1 including year fixed effects (Table 7). The non-market and market-utility results are robust

[62]The middle-40% of the distribution has marginal cost ratios that are well below one, suggesting that non-market utilities are switching over to natural gas despite the fuel-marginal cost being cheaper for the coal units; in fact, the 95th percentile of this ratio is below one (0.82). We do not find this to be inconsistent since the environmental-marginal costs are greater for coal, compared to natural gas. That is, there will be an incentive to switch from coal to natural gas even when the marginal cost of the *fuels* are such that coal is cheaper, if the marginal costs associated with environmental compliance is sufficiently high for coal.

to the inclusion of year fixed effects. In fact, the coefficients for non-market utilities increase considerably for coal prices (from 0.80 to 1.42) and increase slightly for natural gas prices (from 0.77 to 0.89). The coefficients for market utilities continue to be small and statistically insignificant.

Our base-case results for IPPs are not robust to the inclusion of fixed year effects. In fact, the coefficient for both the coal and natural gas prices have counterintuitive signs. The coefficient on the coal price is also highly significant.

5.5 Sources for the change in natural gas share

We next investigate *how* power plants are altering their natural gas share when input prices change. A power plant can alter it's share of natural gas consumption in a variety of ways. First, it may reduce the use of coal, holding fixed it's use of natural gas. Given the majority of the plants in our sample have both coal and natural gas units, this would occur by simply reducing the generation of the coal units. Second, the plant can increase the use of natural gas, holding constant its use of coal. This would be possible by increasing the generation from their natural gas plants. The plant operators could also employ a mix of the two. We next look at these different channels. First, we estimate how changes in coal and natural gas prices affect the percentage of maximum electricity coming from the plant as a whole—the capacity factor. We then turn to individual input demand curves for coal and natural gas.

5.5.1 Capacity factors

We estimate how capacity factors are affected by input prices. Our empirical model is similar to our previous model. We make the following changes. First, because the dependent variable is not censored, we estimate a standard linear instrumental variables model. Second, the dependent variable is net generation divided by capacity; therefore, we omit generation and capacity as covariates. This yields:

$$ln(CF_{it}) = \beta_{ng} ln(P_{ng,it}) + \beta_{coal} ln(P_{coal,it}) + \mathbf{X'_{it}}\gamma + \eta_i + \eta_t + \epsilon_{it}. \quad (3)$$

The results from this empirical model are presented in Table 8. Interestingly, we find that decreases in coal prices increase capacity factors, while decreases in natural gas prices *decrease* capacity factors. This suggests that when natural gas prices fall firms decrease the amount of generation coming from the coal units within the plant. This may occur because pure-natural gas plants that are not in this sample increase their generation, prompting a reduction in coal generation from the plants in the sample. This effect seems to be fairly constant across non-market utilities, market utilities, and IPPs. Self generating units do reduce their capacity factor when natural gas prices fall.

All four groups reduce their capacity factors when coal prices increase. The magnitude of this reduction is similar across the non-self-generating plants, and roughly half the size for the self generation plants. Taken together, these result suggest that generation from the coal units within the plant seem to respond most to changes in natural gas and coal prices, although they can't rule out changes in both occurring simultaneously.

5.5.2 Input demand functions

Our final set of empirical models estimate explicit demand curves for each fuel. Changes in the share of fuel coming from natural gas can arise from changing either the level of natural gas or coal fuel. By estimating the explicit demand curves, we can measure which effect is strongest. We estimate:

$$ln(BTU_{j,it}) = \beta_{ng} ln(P_{ng,it}) + \beta_{coal} ln(P_{coal,it}) + X_{it}\gamma + \eta_i + \eta_t + \epsilon_{it}, \quad (4)$$

where j indexes either energy coming from natural gas or coal. In this draft, we estimate these two demand curve separately; in future versions we will account for any correlation that might exist across the error terms. Tables 9 and 10 report the results for natural gas and coal demands, respectively. Once again we focus on comparing the sensitivity to input prices across ownership and market types.

As an initial data exploration, we plot non-parametric Lowess lines scatter plots of the share of input fuel coming from either natural gas or coal moves with natural gas and coal prices for each of the four groups in Figure 11. The smoothed lines in the top panel are how the share of input energy coming from natural gas moves with natural gas prices. The slopes of the lines suggest that non-market utilities are most responsive to changes in natural gas prices. For coal prices, both non-market utilities and self-generating firms are more responsive than the two other groups.[63]

Table 9 reports the results for the natural gas demand curves. These results mirror the natural gas share results above. Of the non-self generating power plants, we find that demand for natural gas for non-market utilities is most sensitive to changes in natural gas

[63] Coal prices rarely exceed $/MMBtu, so the upward sloping portions of these curves likely have large confidence intervals associated with them.

prices. The natural gas coefficient for IPPs is negative, but small and statistically significant, while the coefficient for market utilities is positive (and marginal significant). The natural gas demand for IPPs is more the most sensitive to changes in coal prices, although the 95 percent confidence interval includes the coefficient for non-market utilities. Again, the coefficient associated with coal price has the wrong sign for market utilities.

Table 10 reports the coal demand results. Here, the coefficients on prices are all statistically significant and of the right sign for each of the four groups. Non-market utilities are most sensitive to changes in natural gas prices, with a coefficient nearly twice as large compared to market utilities and 50 percent larger than the IPP coefficient. Market utilities have the largest coal coefficient, but not statistically so.

Both of these empirical models corroborate the previous results; non-market utilities shift out of coal to a greater degree and into natural gas when natural gas prices rise market utilities increase their natural gas consumption to a lower degree and do not alter their coal consumption when natural gas price fall. When coal prices increase, IPPs increase their natural gas consumption the greatest, but decrease their coal consumption to a lower degree compared to both utility groups. These results are consistent with our share regressions which suggested that non-market utilities were much more sensitive to changes in natural gas prices, while there was some evidence that IPPs responded more to changes in coal prices. What appears to be the main driving these differences is how the use of natural gas changes across these plants, not differences in how the use of coal responds.

5.5.3 Response at the extensive margin

The above empirical results capture changes at both the intensive and extensive margins. That is, firms can keep the same capital stock at a given power plant and adjust which units they dispatch. Firms may also make long-run investments in the types of units at a given power plant. We next estimate how the number of natural gas and coal units, as well as the ratio of these, changes with input prices.

As an initial investigation, we first look at the average number of natural gas and coal units at a given power plant both across time and ownership/market structure. Figure 12 plots the average number of natural gas units for non-market utilities, market utilities, and IPPs. The average non-market utility plant in our sample increased the number of natural gas units by slightly less than 0.7 units. The average market utility increased the number of natural gas units by 0.27. IPPs increased the number of natural gas units by 0.28.

The number of coal units fell over the sample for non-market utilities, but not by as large as the increase in natural gas units. Non-market utilities reduced the number of coal units by roughly 0.2. Market utilities reduced the number of coal units by 0.5, more than their increase in the number of natural gas units. IPPs, over this sample, *increased* the number of coal units by 0.19.

We add a little more structure to these summary statistics by estimating instrumental variables regressions similar to the above, with the number of units as the dependent variable. These decisions are inherently forward looking and the dependent variable is clearly a count variable. Future versions of the paper will treat these decisions in a more structural way, but as an initial starting power we estimate linear instrumental variable models using concurrent input prices. Table 11 reports the results with the number of generating units burning natural gas as the dependent variable. We would expect that as natural gas prices raise, the number of natural gas units falls, while coal prices have a positive impact on the number of natural gas units. The empirical results are very noisy, perhaps reflecting the simplistic empirical model. The results with the number of coal-fired generating units are also noisy (Table 12), but despite the simplistic nature of the model we see statistically significant effects of coal and natural gas prices for non-market utilities. The coefficients for the other firm and market categories are not statistically significant.

5.6 Responses at the firm level

The preceding analysis was based on a sample of power plants that were capable of burning both natural gas and coal. It may be the case that a given firm does not adjust the relative use of natural gas in these plants, but does adjust across power plants. We repeat our analysis of the relative share of input fuel coming from natural gas at the firm level. For each firm·state in our sample, we generate the share of input fuel coming from natural gas and coal across all of their power plants. We then construct the relative share for the firm. We aggregate the other covariates in a similar fashion. Because we have a number of firms that either always use natural gas or always use coal, we restrict our sample to those firms that have used both fuels for at least half of the periods in which they appear; however, our results are robust to this cut off.

Our empirical model is nearly identical to equation 1, but includes fixed firm·state fixed effects given the aggregation. Table 14 reports the results for the IV Tobit specification.

The results mirror those for the plants that can use both coal and natural gas. At the firm level, non-market utilities are sensitive to both natural gas and coal prices. Market utilities appear to respond to changes in coal prices, but not to changes in natural gas prices. The response to coal prices is not statistically different across the two utility groups, but the 95 confidence interval for the market utilities' response to natural gas prices lies outside of the natural gas coefficient for market utilities. IPPs increase their natural gas share when natural gas prices decrease, but the coefficient on coal is statistically insignificant. Self-generating firms continue to be price sensitive to both input prices.

5.7 Discussion

What can explain the differences across firm and market structure? Admittedly, we have not constructed a set of testable implications that can yield a definitive answer to this. What is clear is that utilities operating within wholesale power markets, at both the plant- and firm-level, do not respond to changes in natural gas prices as much as non-market utilities. When comparing the two types of utilities, the results for coal prices are more mixed. The plant-level results suggest that among plants capable of burning both fuels, market utilities do not respond like non-market utilities. The firm-level results suggest that their response to coal prices is on par with non-market utilities. These results are robust to the inclusion of fixed-year effects. The results for IPPs are also more mixed. At the plant-level, IPPs appear responsive to changes in coal prices, but not natural gas prices under our base specification. However, once we include fixed year effects, they seem unresponsive to either input prices. While not the focus of the paper, self-generating firms are responsive to both input prices throughout the models that we estimate.

One potential answer to the question posed at the beginning of this section is a divergence in the incentive to reduce fuel costs across market and non-market utilities. The key difference between market and non-market utilities is that market utilities both generate electricity and purchase electricity through a wholesale power market. In contrast, non-market utilities, for the most part, generate all of the electricity that they sell. Because wholesale power prices can vary considerably over time, many public utility commissions have institute adjustment clauses, or riders, that automatically adjust retail prices when the prices that utilities pay for power changes, and these often include changes to the utility's own costs.[64]

Discussions with one person in the industry corroborate this explanation. This person represents a utility that has operations in both wholesale power markets and in traditional markets. He explained that in wholesale market, his company is able to keep a share of cost

[64]Automatic fuel adjustment clauses are new, or unique, to utilities operating in wholesale power markets. Fuel adjustment clauses were originally adopted during in the late 1970s and early 1980s when oil and coal prices increased rapidly

savings for power plants that generate in excess of their required demand, and cost savings at power plants selling to their customers are passed directly to the customer.[65] In contrast, in more traditional markets, the utility is the residual claim to any costs savings taking place between rate hearings.

This can explain the results comparing market and non-market utilities, but does not explain would not explain differences in the sensitivity to input prices across non-market utilities and IPPs. IPPs are clearly the residual claimant to any cost reductions. We note, here, that we find mixed evidence in terms of the relative sensitivity to input prices, at least with respect to the share of input energy coming from natural gas. While non-market utilities are more sensitive to changes in natural gas prices, there is some evidence that IPPs appear to be more sensitive to changes in coal prices, at least when fixed-year effects are omitted. The mechanism for this is seen from our input demand functions. We find that IPPs' use of natural gas is much more sensitive to changes in coal prices, whereas changes in coal prices have a similar affect across non-market utilities and IPPs. Furthermore, non-market utility and IPP use of coal respond similarly to changes in natural prices, but we do not find that IPPs alter their natural gas use to when natural gas prices changes.

One possible explanation for this is an Averch-Johnson-type effect may be present. However, we have yet to confirm this given the simplistic nature of our investment models.

5.8 Extensions of the baseline plant-level model

5.8.1 Futures and lagged prices

The discussion of capital investments made in response to fuel prices make it clear that some of the plant-level changes may be forward looking; that is, expectations of the futures prices may affect the share of natural gas burned at a power plant. In addition, some plant-level changes, such as adjusting contracts, may take time to implement suggesting that lagged input prices may be relevant. We analyze the extent to which futures and lagged prices affect the share of natural gas burned at power plants.

Table 13 reports these results. We discuss each firm type in order. When lagged and futures prices are included, the contemporaneous prices are no longer statistically significant for non-market utilities. The previous effect of contemporaneous coal prices for non-market utilities seem to now be captured in how coal prices are expected to change. The coefficient

[65] Fabra and Reguant (2013) find an almost complete pass-through in their study of the Spanish wholesale electricity market.

on the 12-month future coal prices is now positive and statistically significant. Lagged coal prices are statistically insignificant. In contrast, lagged natural gas prices affect natural gas shares, while the natural gas futures price coefficient is small and statistically insignificant. These results suggest that near-term natural gas prices matter for non-market utilities, while expectations about *future* coal prices matter.

The results for market utilities continue to be puzzling. The contemporaneous natural gas price has statistically significant coefficient that is the wrong sign and is roughly the size of the lagged and futures price coefficients combined. The contemporaneous coefficients for coal prices also has the wrong sign and is larger than the correct-sign coefficient on lagged prices. For IPPs, contemporaneous price for coal appears to be driving their positive response to coal prices while the remaining coefficients are noisily estimated.

6 Back-of-the-envelope calculations

Our econometric analysis identifies differences in fuel cost sensitivities across different types of generators. It is, therefore, natural to ask: what is the impact of those differences upon the emission of air pollutants? In particular, we are interested in quantifying the effect on total emissions of carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrogen oxides (NO_x).

We simulate emissions under three extreme cases, in which all generators operate as (i) market utilities; (ii) non-market utilities; (iii) market non-utilities (or IPPs). We then compare the pattern of emissions over time with the baseline scenario (in which each plant is assigned to its current type). Importantly, in each of the simulated scenarios, we assume that all plant characteristics remain constant, except for the sensitivity to the cost of coal and natural gas.

In principle, we could use the results of our baseline models, which uses the log of the share of natural gas as the dependent variable, to compute the back-of-the-envelope. However, we would still need to make assumptions regarding how to translate different input combinations into emissions of the different pollutants.[66] Moreover, we would restrict our analysis to the impact of fuel cost changes over time on the emissions coming from coal and natural gas alone. For those, reasons, we instead estimate directly the impact of fuel costs on the emissions of CO_2, SO_2, and NO_x.

[66]For example, the model would predict the ratio of natural gas to coal usage but say nothing about its absolute values.

Our specification here is similar to the one that was used in the main empirical section:

$$ln(emiss_{it}^{gas}) = \beta_{ng}^{gas} ln(P_{ng,it}) + \beta_{coal}^{gas} ln(P_{coal,it}) + \\ + X_{it}^{gas}\gamma + \eta_i^{gas} + \eta_t^{gas} + \epsilon_{it}^{gas}, \quad (5)$$

where gas stands for CO_2, SO_2, and NO_x.

We estimate the above model separately for each of the three groups of firms. Therefore, we obtain different cost coefficients for each combination of fuel, air pollutant and plant type. The focus of the exercise is to recover percentage changes in the dependent variable under different scenarios. Therefore we normalize emissions in the first year to one.

Let A' denote the variable A at some point in the future. Then, for a fixed value of $\beta_{ng}^{gas}, \beta_{coal}^{gas}$, we can write the following:

$$\frac{emiss_{it}^{'gas}}{emiss_{it}^{gas}} = exp\left[\beta_{ng}^{gas}\left(ln(P'_{ng,it}) - ln(P_{ng,it})\right) + \beta_{coal}^{gas}\left(ln(P'_{coal,it}) - ln(P_{coal,it})\right)\right]. \quad (6)$$

This exercise yields a time series of relative emissions for each of the three pollutants. We can translate the relative reduction across the three groups of firms into the dollar value of reductions. In principle, we can do this for each of the pollutants, however the external costs associated with the local pollutants (SO_2 and NO_x) have significant geographic variation. This is not the case for CO_2. For CO_2 we quantify the reductions using the social cost of carbon used by the Federal government for cost benefit analysis: \$37/ton. This step requires an additional assumption: what share of power plants do we apply the differences in the coefficients associated with natural gas and coal prices. Our estimation strategy restricted the sample to those firms that have burned both natural gas and coal in at least half of the sample. For the back-of-the-envelope calculations we take the *extreme* assumption that the differences in coefficients affect all, which is unlikely to occur, since this demand for electricity would have to be met. A full understanding of the general equilibrium effects requires a more structure model; this is the topic of current research. However, we believe that they are important benchmarks in helping us to understand the impact of market structure on the emission of air pollutants, but we stress that these estimates should be viewed as a strict upper bound.

Figure 13 summarizes the results of this exercise. The first three panels plot back-of-the-envelope emissions assuming that all plants in the same have the same response to changes in natural gas and coal prices. We plot three different series: all plants respond the way that market utilities respond, all plants respond the way non-market utilities respond, and all plants respond the way IPPs respond. Panel (a) mirrors the results above: the natural gas share of non-market utilities is most responsive to changes in fuel prices and this translates into the largest reduction in CO_2 emissions. If all plants behaved in a way consistent with how non-market utilities respond, by the end of the sample CO_2 would have fallen by 55 percent. In contrast, if all plants respond in the way that market utilities respond, CO_2 would have fallen by roughly 35 percent. If plants behaved as IPP plants behave, emissions would have fallen by 23 percent.

For the local pollutants, the largest reductions do not come from non-market utilities and the heterogeneity is much smaller than for CO_2 emissions. By the end of the sample, each group reaches a similar reduction for SO_2 emissions with the relative rankings of the three groups flipped. For SO_2 the non-market parameters lead to the smallest reduction in SO_2 emissions. Reductions in NO_x emissions are more varied than the reductions in SO_2 emissions. Market utilities and IPPs lead to similar reductions, roughly 65 percent by the end of the sample. Using the non-market utility responses to input prices leads to roughly a 50 percent reduction.

Finally, we value the reductions in CO_2. As noted above we take the extreme assumption that all power plants behave in a way consistent with the regression coefficients. When we do this, the reductions in external costs are substantial for each group. The value of the CO_2 reductions if all plants behaved in a way consistent with how IPP plants behave is roughly \$20B. However, the value of the reductions if instead plants behaved in a way consistent with non-market utilities is nearly \$50B. Using the coefficients from the market utility regression translates to a reduction in external costs of roughly \$30B.

7 Conclusions

The wide use of hydraulic fracturing techniques to capture natural gas from shale formations has fundamentally changed the relative prices of coal and natural gas. This change in relative prices can have large impacts on both greenhouse gas emissions, but also the emissions of local pollutants such as nitrogen oxides, sulfur dioxides, and mercury. However, electricity generating firms differ considerably in their ownerships structure and the types of markets in which they operate. These differences may lead to differences in how firms respond to changes in the prices for natural gas and coal.

We study whether differences in ownership structure and the type of market firms operate within correlate with differences in the sensitivity to changes in input fuel prices. Significant differences in the response to changes in input prices exist across firm type and the market structure. Among power plants that are capable of burning both coal and natural gas, the share of natural gas burned at utility-owned plants is less responsive to changes in coal and natural gas prices compared to non-utilities. We find a statistically insignificant response to coal prices for utilities, but a positive and statistically significant response among non-utility plants.

Differences also exist within utilities. When we focus on plants that can burn both natural gas and coal, non-market utilities are significantly more price sensitive to both natural gas and coal prices, compared to utilities that operate in wholesale power markets. IPPs are more price sensitive to changes in coal prices, but less price sensitive to changes in natural gas prices, compared to non-market utilities. Throughout our analysis there is robust evidence that companies that generate their own electricity are sensitive to changes in natural gas and coal prices.

Many of these differences exist when we look at firm-level input decisions. Utilities and non-utilities have similar responses to changes in coal prices, but non-utilities are more responsive to changes in natural gas prices. When we split firms into finer groups, we find that non-market utilities and IPPs behave similarly in response to changes in natural gas prices, while the coefficient associated with coal prices for IPPs is noisily estimated. In contrast, market utilities operating within wholesale power markets do not appear to respond to changes in natural gas prices, but their share of natural gas is responsive to changes in coal prices.

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Tables and Figures

Table 1: Plant-level covariates I (top: mean; bottom: std.deviation)

	ALL			UTILITIES			Non-UTILITIES		
VARIABLES	ALL	NMKT	MKT	ALL	NMKT	MKT	ALL	IC	IPP
NG share of fuel consumption	0.142	0.174	0.083	0.142	0.103	0.106	0.142	0.238	0.056
	0.283	0.303	0.230	0.283	0.247	0.261	0.283	0.333	0.184
Fuel delivery cost (coal)	1.889	1.887	1.893	1.889	1.837	1.822	1.889	1.932	1.975
	0.564	0.562	0.569	0.564	0.560	0.555	0.564	0.560	0.574
Fuel delivery cost (NG)	7.269	7.294	7.223	7.269	7.151	7.151	7.269	7.425	7.308
	3.328	3.435	3.123	3.328	3.302	3.130	3.328	3.548	3.113
Net generation	172,059	118,250	269,302	172,059	220,819	274,387	172,059	24,955	263,387
	268,330	227,255	306,764	268,330	285,221	275,703	268,330	79,712	339,263
Coal plus NG op. capacity	488.406	375.599	667.399	488.406	600.691	711.521	488.406	86.562	611.204
	608.777	571.792	622.869	608.777	656.849	577.836	608.777	210.578	672.307
Heat rate	18.547	22.367	12.026	18.547	12.253	12.085	18.547	32.876	11.957
	12.560	14.018	4.926	12.560	3.130	5.891	12.560	13.183	3.459
Generating unit age	34.905	31.854	38.081	34.905	32.618	38.438	34.905	29.557	37.632
	14.111	13.450	14.088	14.111	12.431	14.063	14.111	15.937	14.120
# of units with SCR	0.267	0.191	0.405	0.267	0.330	0.449	0.267	0.066	0.355
	0.764	0.700	0.851	0.764	0.898	0.870	0.764	0.414	0.827
# of units with SNCR	0.164	0.126	0.233	0.164	0.174	0.200	0.164	0.082	0.271
	0.601	0.574	0.640	0.601	0.649	0.646	0.601	0.494	0.631
# of units with dry-lime FGD	0.105	0.124	0.070	0.105	0.155	0.099	0.105	0.096	0.036
	0.588	0.689	0.329	0.588	0.458	0.381	0.588	0.844	0.251
# of units with wet-lime FGD	0.094	0.068	0.141	0.094	0.142	0.101	0.094	0.000	0.188
	0.505	0.394	0.658	0.505	0.563	0.648	0.505	0.000	0.668
# of units with PM controls	0.397	0.328	0.524	0.397	0.446	0.461	0.397	0.221	0.596
	0.956	0.922	1.002	0.956	0.878	0.909	0.956	0.948	1.095
# of units in ARP	1.901	1.393	2.824	1.901	2.809	3.158	1.901	0.115	2.439
	2.235	2.239	1.910	2.235	2.510	1.657	2.235	0.641	2.101
# of units in CAIRNOX	0.891	0.672	1.289	0.891	1.392	1.252	0.891	0.023	1.330
	2.232	2.298	2.051	2.232	3.179	1.996	2.232	0.201	2.114
# of units in CAIROS	0.927	0.747	1.255	0.927	1.239	1.198	0.927	0.304	1.320
	2.235	2.306	2.061	2.235	3.088	2.026	2.235	1.051	2.102
# of units in CAIRSO2	0.705	0.538	1.010	0.705	1.115	0.974	0.705	0.016	1.052
	2.023	2.073	1.892	2.023	2.898	1.840	2.023	0.169	1.951
# of units in NBP	0.918	0.719	1.281	0.918	0.953	0.889	0.918	0.508	1.734
	2.347	2.430	2.143	2.347	3.127	1.924	2.347	1.523	2.289
# of units in SIPNOX	0.034	0.047	0.012	0.034	0.003	0.000	0.034	0.087	0.025
	0.444	0.542	0.146	0.444	0.069	0.000	0.444	0.743	0.214
# of units in TRNOX	0.180	0.141	0.252	0.180	0.290	0.276	0.180	0.006	0.225
	1.045	1.066	1.003	1.045	1.531	1.034	1.045	0.098	0.968
# of units in TRNOXOS	0.135	0.117	0.166	0.135	0.243	0.115	0.135	0.004	0.225
	0.971	1.033	0.847	0.971	1.488	0.723	0.971	0.078	0.968
# of units in TRSO2G1	0.115	0.063	0.210	0.115	0.132	0.221	0.115	0.001	0.196
	0.864	0.816	0.939	0.864	1.181	0.974	0.864	0.029	0.898
# of units in TRSO2G2	0.046	0.051	0.038	0.046	0.104	0.046	0.046	0.003	0.029
	0.519	0.589	0.360	0.519	0.849	0.345	0.519	0.066	0.377

Table 2: Plant-level covariates II (p-values in squared brackets)

Variable	Comparisons			
	Market Utilities vs. Non-Market Utilities	Market Utilities vs. IPPs	Non-Market Utilites vs. IPPs	Utilites vs. Non-utilities
NG share of fuel consumption	0.31%	5.02%	4.71%	-7.46%
	[0.9151]	[0.0798]	[0.0199]	[0.0010]
Fuel delivery cost (coal)	-0.015	-0.152	-0.137	-0.114
	[0.7494]	[0.0005]	[0.0006]	[0.0001]
Fuel delivery cost (NG)	-0.001	-0.157	-0.156	-0.235
	[0.9970]	[0.3810]	[0.3683]	[0.0868]
Net generation	53,568	11,000	-42,567	138,216
	[0.1977]	[0.8374]	[0.4019]	[0.0000]
Coal plus NG op. capacity	111	100	(11)	353
	[0.2432]	[0.3666]	[0.9221]	[0.0000]
Heat rate	-0.168	0.129	0.297	-13.284
	[0.8214]	[0.8747]	[0.5785]	[0.0000]
Generating unit age	5.821	0.807	-5.014	0.391
	[0.0032]	[0.7369]	[0.0233]	[0.8324]
# of units with SCR	0.119	0.094	-0.025	0.215
	[0.3628]	[0.5229]	[0.8515]	[0.0057]
# of units with SNCR	0.025	-0.072	-0.097	0.040
	[0.7733]	[0.4815]	[0.2773]	[0.4851]
# of units with dry-lime FGD	-0.056	0.063	0.119	0.057
	[0.3342]	[0.1588]	[0.0114]	[0.3518]
# of units with wet-lime FGD	-0.042	-0.087	-0.045	0.065
	[0.6573]	[0.4313]	[0.6293]	[0.2034]
# of units with PM controls	0.016	-0.135	-0.151	0.108
	[0.9065]	[0.4429]	[0.3593]	[0.2819]
# of units in ARP	0.348	0.719	0.370	2.067
	[0.2661]	[0.0345]	[0.3138]	[0.0000]
# of units in CAIRNOX	-0.139	-0.078	0.061	0.887
	[0.5580]	[0.6969]	[0.8044]	[0.0000]
# of units in CAIROS	-0.041	-0.122	-0.081	0.587
	[0.8666]	[0.5557]	[0.7426]	[0.0001]
# of units in CAIRSO2	-0.142	-0.078	0.064	0.706
	[0.4598]	[0.6283]	[0.7475]	[0.0000]
# of units in NBP	-0.064	-0.845	-0.781	0.019
	[0.8211]	[0.0008]	[0.0079]	[0.9170]
# of units in SIPNOX	-0.003	-0.025	-0.022	-0.065
	[0.3173]	[0.0851]	[0.1349]	[0.0300]
# of units in TRNOX	-0.014	0.051	0.065	0.207
	[0.0000]	[0.0000]	[0.0000]	[0.0000]
# of units in TRNOXOS	-0.128	-0.110	0.018	0.117
	[0.0071]	[0.0044]	[0.7260]	[0.0001]
# of units in TRSO2G1	0.090	0.025	-0.065	0.101
	[0.0452]	[0.5352]	[0.1507]	[0.0002]
# of units in TRSO2G2	-0.058	0.018	0.075	0.071
	[0.0364]	[0.3711]	[0.0095]	[0.0000]

Table 3: A first pass on estimation at the plant level (DV: NG input share)

VARIABLES	(1) OLS	(2) 2SLS	(3) Tobit	(4) IV Tobit
log coal delivery cost	0.2704***	0.7885***	0.2654***	0.8981***
	(0.0524)	(0.1674)	(0.0548)	(0.1795)
log NG delivery cost	-0.4296***	-0.4498***	-0.4484***	-0.4590***
	(0.0252)	(0.0505)	(0.0289)	(0.0538)
log net generation	0.4269***	0.3909***	0.5559***	0.5048***
	(0.0366)	(0.0347)	(0.0500)	(0.0453)
log net generation (sq.)	-0.1040***	-0.0932***	-0.1462***	-0.1298***
	(0.0063)	(0.0069)	(0.0085)	(0.0076)
log net generation (cb.)	0.0029***	0.0023***	0.0048***	0.0039***
	(0.0003)	(0.0004)	(0.0004)	(0.0004)
coal plus NG op. capacity	0.0013***	0.0011***	0.0015***	0.0013***
	(0.0001)	(0.0001)	(0.0001)	(0.0001)
SO2 permit price	-0.0853***	0.1534***	-0.0988***	0.1518***
	(0.0326)	(0.0570)	(0.0346)	(0.0588)
SNOX permit price	0.0121	0.0149	0.0150	0.0281
	(0.0087)	(0.0280)	(0.0091)	(0.0292)
# of units with SCR	1.0222***	1.1240***	1.2399***	1.4592***
	(0.0381)	(0.0487)	(0.0617)	(0.0547)
# of units with SNCR	0.0715**	0.0742**	0.0553*	0.0649*
	(0.0330)	(0.0357)	(0.0331)	(0.0387)
# of units with dry-lime FGD	0.1809***	0.1459**	0.1216**	0.0440
	(0.0600)	(0.0572)	(0.0556)	(0.0673)
# of units with wet-lime FGD	-0.1510***	-0.1486**	-0.1814***	-0.1936***
	(0.0484)	(0.0599)	(0.0583)	(0.0541)
# of units with PM controls	-0.4102***	-0.3774***	-0.4305***	-0.3948***
	(0.0401)	(0.0492)	(0.0466)	(0.0456)
# of units in ARP	-0.3234***	-0.3473***	-0.4217***	-0.4042***
	(0.0335)	(0.0375)	(0.0413)	(0.0425)
# of units in CAIRNOX	0.0016	-0.0043	0.0103	0.0028
	(0.0158)	(0.0157)	(0.0158)	(0.0175)
# of units in CAIROS	-0.0332**	-0.0323**	-0.0443***	-0.0436***
	(0.0148)	(0.0149)	(0.0151)	(0.0164)
# of units in CAIRSO2	-0.0444***	-0.0439***	-0.0518***	-0.0517***
	(0.0111)	(0.0105)	(0.0103)	(0.0123)
# of units in NBP	-0.0270***	-0.0204**	-0.0325***	-0.0257**
	(0.0099)	(0.0099)	(0.0097)	(0.0109)
# of units in SIPNOX	0.0859***	-0.1551***	-0.1791***	-0.1607***
	(0.0325)	(0.0321)	(0.0333)	(0.0333)
# of units in TRNOX	0.0033	0.0560*	0.0915***	0.0562
	(0.0204)	(0.0288)	(0.0302)	(0.0343)
# of units in TRNOXOS	-0.0581**	0.0277	0.0123	0.0387*
	(0.0265)	(0.0206)	(0.0223)	(0.0216)
# of units in TRSO2G1	-0.0146	-0.0586**	-0.0716***	-0.0711**
	(0.0291)	(0.0230)	(0.0235)	(0.0277)
# of units in TRSO2G2	-0.1239***	-0.0180	-0.0091	-0.0159
	(0.0397)	(0.0243)	(0.0258)	(0.0306)
Observations	28,310	24,307	28,310	24,307
R-squared	0.7275	0.7372		

Table 4: Plant-level IV Tobit (DV: NG input share)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	ALL			UTILITIES			Non-UTILITIES		
VARIABLES	ALL	NMKT	MKT	ALL	NMKT	MKT	ALL	IC	IPP
log coal delivery cost	0.8981***	1.2670***	0.8747***	-0.0737	0.5840**	-1.1996***	1.8448***	1.3113***	1.7921***
	(0.1795)	(0.2331)	(0.2942)	(0.2281)	(0.2975)	(0.3645)	(0.2640)	(0.3521)	(0.4388)
log NG delivery cost	-0.4590***	-0.7544***	0.1341	-0.2805***	-0.6309***	0.2584**	-0.6462***	-0.8755***	-0.0493
	(0.0538)	(0.0674)	(0.0944)	(0.0728)	(0.0959)	(0.1167)	(0.0813)	(0.0949)	(0.1447)
log net generation	0.5048***	0.5763***	0.5416	-2.3692***	-2.6879***	-0.1633	0.4820***	0.4016***	0.8175
	(0.0453)	(0.0481)	(0.3688)	(0.2649)	(0.3633)	(0.4660)	(0.0526)	(0.0557)	(0.6088)
log net generation (sq.)	-0.1298***	-0.1595***	-0.0893**	0.1798***	0.1879***	-0.0015	-0.0508***	-0.0030	-0.1159*
	(0.0076)	(0.0091)	(0.0415)	(0.0311)	(0.0431)	(0.0522)	(0.0110)	(0.0153)	(0.0688)
log net generation (cb.)	0.0039***	0.0059***	0.0012	-0.0068***	-0.0062***	-0.0022	-0.0009	-0.0046***	0.0020
	(0.0004)	(0.0005)	(0.0015)	(0.0012)	(0.0016)	(0.0019)	(0.0006)	(0.0010)	(0.0025)
coal plus NG op. capacity	0.0013***	0.0020***	0.0012***	0.0009***	0.0023***	0.0003*	0.0020***	0.0060***	0.0017***
	(0.0001)	(0.0003)	(0.0001)	(0.0001)	(0.0003)	(0.0002)	(0.0004)	(0.0013)	(0.0003)
SO2 permit price	0.1518***	0.3474***	-0.2595***	0.0418	0.3188***	-0.2972***	0.0950	0.2386**	-0.2709*
	(0.0588)	(0.0785)	(0.0924)	(0.0768)	(0.1049)	(0.1129)	(0.0905)	(0.1131)	(0.1570)
SNOX permit price	0.0281	0.0606	0.0377	-0.1528***	-0.0702	-0.2545***	0.2485***	0.1321**	0.2906***
	(0.0292)	(0.0373)	(0.0466)	(0.0355)	(0.0467)	(0.0526)	(0.0462)	(0.0581)	(0.0778)
# of units with SCR	1.4592***	1.0222***	1.6933***	1.5931***	0.7337***	2.5990***	1.5139***	2.4938***	1.1835***
	(0.0547)	(0.0794)	(0.0826)	(0.0642)	(0.0882)	(0.1146)	(0.1158)	(0.2213)	(0.1546)
# of units with SNCR	0.0649*	0.0096	0.1254**	0.1320***	0.1011*	0.1700	-0.0214	-1.7911***	0.0621
	(0.0387)	(0.0595)	(0.0529)	(0.0483)	(0.0588)	(0.1095)	(0.0658)	(0.4061)	(0.0684)
# of units with dry-lime FGD	0.0440	-0.2723***	0.2842***	0.0383	-0.1313	-0.0151	-0.1094	-2.6068***	-0.0123
	(0.0673)	(0.1005)	(0.0996)	(0.0800)	(0.1025)	(0.1780)	(0.1252)	(0.4141)	(0.1436)
# of units with wet-lime FGD	-0.1936***	-0.0754	-0.1792***	-0.6689***	-0.2690*	-1.3699***	0.1181		0.1698**
	(0.0541)	(0.1494)	(0.0597)	(0.0840)	(0.1594)	(0.1091)	(0.0734)		(0.0796)
# of units with PM controls	-0.3948***	-0.4373***	-0.3446***	-0.2777***	-0.1994**	-0.1781**	-0.2773***	-0.6216***	0.0076
	(0.0456)	(0.0779)	(0.0655)	(0.0564)	(0.0989)	(0.0906)	(0.0828)	(0.1548)	(0.1054)
# of units in ARP	-0.4042***	-0.3776***	-0.4818***	-0.3181***	-0.3217***	-0.2580***	-1.1616***	-6.6288***	-1.1065***
	(0.0425)	(0.0808)	(0.0549)	(0.0443)	(0.0789)	(0.0574)	(0.1249)	(0.7687)	(0.1328)
# of units in CAIRNOX	0.0028	0.0221	-0.0665**	0.0526**	0.0540*	0.0328	-0.1332***	0.1104	-0.0863*
	(0.0175)	(0.0214)	(0.0322)	(0.0241)	(0.0279)	(0.0555)	(0.0318)	(0.1418)	(0.0497)
# of units in CAIROS	-0.0436***	-0.0265	-0.0797***	-0.0854***	-0.0656**	-0.1109**	-0.0048	0.0385	-0.1110**
	(0.0164)	(0.0205)	(0.0291)	(0.0237)	(0.0280)	(0.0519)	(0.0275)	(0.0349)	(0.0458)
# of units in CAIRSO2	-0.0517***	-0.0184	-0.0384*	-0.0650***	-0.0398**	-0.0138	-0.0317	-0.6314***	-0.0257
	(0.0123)	(0.0156)	(0.0215)	(0.0141)	(0.0179)	(0.0262)	(0.0289)	(0.1484)	(0.0413)
# of units in NBP	-0.0257**	0.0043	-0.0341**	-0.0630***	-0.0304*	-0.0475**	0.0535**	0.0902***	-0.0236
	(0.0109)	(0.0143)	(0.0173)	(0.0125)	(0.0165)	(0.0203)	(0.0239)	(0.0305)	(0.0398)
# of units in SIPNOX	-0.1607***	-0.1638***	0.0452	12.8455	12.7298		-0.0807*	-0.0334	0.0598
	(0.0333)	(0.0373)	(0.1066)	(735.1554)	(160.6245)		(0.0413)	(0.0472)	(0.1230)
# of units in TRNOX	0.0562	0.0512	0.0601	0.1064***	0.1126**	0.0414	-0.6850**	0.4611*	0.0269
	(0.0343)	(0.0474)	(0.1090)	(0.0337)	(0.0474)	(0.1046)	(0.3137)	(0.2430)	(0.0544)
# of units in TRNOXOS	0.0387*	0.0092	0.0141	0.0122	-0.0149	0.0027	-0.3280	-1.1819***	
	(0.0216)	(0.0376)	(0.0286)	(0.0212)	(0.0373)	(0.0334)	(0.2338)	(0.3228)	
# of units in TRSO2G1	-0.0711**	-0.0296	-0.0524	-0.0806***	-0.0621**	0.0441	0.9813***	-0.3851	-0.0188
	(0.0277)	(0.0299)	(0.1062)	(0.0269)	(0.0295)	(0.1012)	(0.2103)	(0.5365)	(0.0598)
# of units in TRSO2G2	-0.0159	-0.0101	0.0245	-0.0316	-0.0335	0.1076	0.9900***		
	(0.0306)	(0.0330)	(0.1107)	(0.0298)	(0.0323)	(0.1119)	(0.2147)		
Observations	24,307	14,621	9,686	13,874	8,185	5,689	10,433	6,436	3,997

Table 5: Plant-level IV Tobit: propensity scores (DV: NG input share)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		ALL			UTILITIES			Non-UTILITIES	
VARIABLES	ALL	NMKT	MKT	ALL	NMKT	MKT	ALL	IC	IPP
log coal delivery cost	0.8153***	1.1237***	0.9594***	-0.0736	0.5840**	-1.1997***	1.5785***	0.2653	2.5775***
	(0.2004)	(0.2750)	(0.3063)	(0.2282)	(0.2977)	(0.3646)	(0.4176)	(0.5986)	(0.6179)
log NG delivery cost	-0.2902***	-0.6618***	0.1915**	-0.2802***	-0.6305***	0.2584**	-0.1660	-0.5743***	0.3869*
	(0.0628)	(0.0850)	(0.0973)	(0.0728)	(0.0959)	(0.1167)	(0.1532)	(0.1980)	(0.2077)
log net generation	-2.3849***	-2.9667***	0.0173	-2.3698***	-2.6896***	-0.1633	1.9077	0.4141	0.4996
	(0.2399)	(0.3375)	(0.4591)	(0.2650)	(0.3636)	(0.4661)	(1.1749)	(1.4733)	(1.9252)
log net generation (sq.)	0.1934***	0.2474***	-0.0409	0.1799***	0.1882***	-0.0015	-0.2582*	0.0455	-0.1293
	(0.0279)	(0.0401)	(0.0500)	(0.0311)	(0.0431)	(0.0522)	(0.1338)	(0.1807)	(0.2144)
log net generation (cb.)	-0.0076***	-0.0090***	-0.0003	-0.0068***	-0.0062***	-0.0022	0.0072	-0.0084	0.0034
	(0.0010)	(0.0015)	(0.0018)	(0.0012)	(0.0016)	(0.0019)	(0.0049)	(0.0071)	(0.0077)
coal plus NG op. capacity	0.0014***	0.0023***	0.0013***	0.0009***	0.0023***	0.0003*	0.0006	0.0067***	-0.0014
	(0.0001)	(0.0003)	(0.0001)	(0.0001)	(0.0003)	(0.0002)	(0.0008)	(0.0014)	(0.0010)
SO2 permit price	0.1281*	0.3648***	-0.2652***	0.0420	0.3191***	-0.2972***	-0.1825	-0.0383	-0.7135***
	(0.0655)	(0.0953)	(0.0939)	(0.0768)	(0.1050)	(0.1129)	(0.1597)	(0.2211)	(0.2429)
SNOX permit price	0.0047	0.0263	0.0289	-0.1528***	-0.0703	-0.2545***	0.3011***	0.0740	0.4893***
	(0.0321)	(0.0427)	(0.0480)	(0.0355)	(0.0467)	(0.0526)	(0.0767)	(0.0981)	(0.1156)
# of units with SCR	1.4877***	1.0561***	1.6895***	1.5933***	0.7340***	2.5991***	1.5131***	-0.5376	2.4002***
	(0.0542)	(0.0788)	(0.0825)	(0.0642)	(0.0882)	(0.1146)	(0.2875)	(0.3632)	(0.3835)
# of units with SNCR	0.1062***	0.0826	0.1290**	0.1320***	0.1012*	0.1700	-0.3134	-2.1652	-0.2944
	(0.0389)	(0.0601)	(0.0531)	(0.0483)	(0.0588)	(0.1095)	(0.2526)	(56.3957)	(0.3795)
# of units with dry-lime FGD	0.0060	-0.3229***	0.2572**	0.0383	-0.1313	-0.0151	-1.3118***		-0.3032
	(0.0677)	(0.1009)	(0.1001)	(0.0801)	(0.1025)	(0.1780)	(0.2947)		(0.4210)
# of units with wet-lime FGD	-0.2072***	-0.2691*	-0.2063***	-0.6689***	-0.2688*	-1.3699***	-0.0922		-0.0121
	(0.0543)	(0.1513)	(0.0605)	(0.0840)	(0.1595)	(0.1091)	(0.1240)		(0.3717)
# of units with PM controls	-0.3219***	-0.2285***	-0.3617***	-0.2777***	-0.1994**	-0.1782**	-0.0995	-0.3053*	-0.1638
	(0.0463)	(0.0822)	(0.0658)	(0.0565)	(0.0990)	(0.0906)	(0.1048)	(0.1837)	(0.1431)
# of units in ARP	-0.3993***	-0.3811***	-0.4667***	-0.3181***	-0.3216***	-0.2580***	-0.7253***	-18.8124	-0.8734***
	(0.0424)	(0.0805)	(0.0551)	(0.0443)	(0.0790)	(0.0574)	(0.1553)	(225.5826)	(0.1743)
# of units in CAIRNOX	-0.0150	0.0263	-0.1158***	0.0526**	0.0540*	0.0328	0.0089	0.3027	-0.0767
	(0.0206)	(0.0263)	(0.0353)	(0.0241)	(0.0279)	(0.0555)	(0.1266)	(0.1974)	(0.4976)
# of units in CAIROS	-0.0353*	-0.0374	-0.0358	-0.0854***	-0.0656**	-0.1109**	-0.0777	-0.3006*	-0.0654
	(0.0198)	(0.0262)	(0.0323)	(0.0237)	(0.0280)	(0.0519)	(0.1236)	(0.1751)	(0.4935)
# of units in CAIRSO2	-0.0533***	-0.0418**	-0.0405*	-0.0650***	-0.0398**	-0.0138	-0.2890***	-0.6864***	-0.0768
	(0.0130)	(0.0169)	(0.0218)	(0.0141)	(0.0179)	(0.0263)	(0.0613)	(0.1534)	(0.0809)
# of units in NBP	-0.0421***	-0.0255	-0.0393**	-0.0630***	-0.0304*	-0.0475**	-0.2483***	-0.4552***	-0.0746
	(0.0115)	(0.0156)	(0.0174)	(0.0125)	(0.0165)	(0.0203)	(0.0541)	(0.1488)	(0.0748)
# of units in SIPNOX	-0.1198	-0.3988**	0.6203**	11.4853	10.2431		0.3151		0.5445
	(0.1529)	(0.1852)	(0.2709)	(735.4301)	(160.7153)		(0.3030)		(0.3330)
# of units in TRNOX	0.0850**	0.0828*	0.0725	0.1064***	0.1127**	0.0414	-0.5550	0.2570	0.2702
	(0.0345)	(0.0480)	(0.1091)	(0.0337)	(0.0475)	(0.1046)	(0.3891)	(0.2411)	(0.2398)
# of units in TRNOXOS	0.0225	-0.0139	0.0161	0.0122	-0.0150	0.0027	-0.0855	-0.7258**	
	(0.0216)	(0.0378)	(0.0286)	(0.0212)	(0.0373)	(0.0334)	(0.3231)	(0.3065)	
# of units in TRSO2G1	-0.0851***	-0.0436	-0.0656	-0.0806***	-0.0622**	0.0441	0.6753***		-0.2257
	(0.0277)	(0.0300)	(0.1063)	(0.0270)	(0.0295)	(0.1013)	(0.2220)		(0.2412)
# of units in TRSO2G2	-0.0235	-0.0216	0.0218	-0.0316	-0.0336	0.1076	0.8325***		
	(0.0305)	(0.0329)	(0.1108)	(0.0298)	(0.0323)	(0.1119)	(0.3084)		
Observations	19,872	10,446	9,426	13,861	8,173	5,688	3,617	1,473	2,144

Table 6: Plant-level IV Tobit: non-linear effects (DV: NG input share)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	ALL			UTILITIES			Non-UTILITIES		
VARIABLES	ALL	NMKT	MKT	ALL	NMKT	MKT	ALL	IC	IPP
log coal delivery cost tier 1	2.2518***	2.2727***	0.7674	1.8451**	1.5472*	0.9425	1.4446*	3.9969***	1.6218
	(0.5439)	(0.5941)	(1.1821)	(0.8622)	(0.8467)	(1.8199)	(0.7719)	(0.8883)	(1.5558)
log coal delivery cost tier 2	4.4271***	1.5136	0.2759	7.3414***	5.1541***	-7.1486**	-6.2050***	-1.4464	0.1123
	(1.5570)	(1.5026)	(1.9370)	(1.4647)	(1.3299)	(3.4179)	(1.9019)	(1.2889)	(3.5479)
log coal delivery cost tier 3	2.0504***	2.2961***	0.0256	0.2270	1.4988**	-1.1120	4.4667***	2.0638***	7.7647***
	(0.4663)	(0.5418)	(1.0391)	(0.6021)	(0.7182)	(1.2407)	(0.8482)	(0.6372)	(2.0917)
log ng delivery cost tier 1	-1.4059***	-1.2180***	0.1964	-1.8201***	-1.5245***	0.3277	0.3423	-1.4699***	0.3422
	(0.2770)	(0.2934)	(0.5526)	(0.3531)	(0.3353)	(0.7472)	(0.4425)	(0.3462)	(1.0623)
log ng delivery cost tier 2	-2.6797***	-1.3595*	0.0942	-4.3975***	-3.2124***	2.4105	2.9003***	-0.0218	0.4627
	(0.7124)	(0.7101)	(1.0259)	(0.6595)	(0.4970)	(1.5583)	(0.9858)	(0.6010)	(2.2006)
log ng delivery cost tier 3	-2.6755***	-2.1039***	0.7702	-2.8181***	-2.7476***	1.3486	-0.8310*	-1.4243***	-3.6657*
	(0.3994)	(0.3918)	(1.1120)	(0.5147)	(0.5162)	(1.1978)	(0.5028)	(0.3927)	(1.9282)
log net generation	0.0027	0.1850***	-0.0964	-0.5375***	-0.3016**	-0.6416	0.3211***	-0.0040	-1.0067
	(0.0694)	(0.0694)	(0.3590)	(0.1203)	(0.1230)	(0.4897)	(0.0883)	(0.0879)	(1.1503)
log net generation (sq.)	-0.0654***	-0.1055***	-0.0193	-0.0083	-0.0580***	0.0366	-0.0299**	0.0745***	0.0787
	(0.0104)	(0.0110)	(0.0398)	(0.0168)	(0.0179)	(0.0556)	(0.0146)	(0.0199)	(0.1230)
log net generation (cb.)	0.0019***	0.0041***	-0.0006	-0.0002	0.0024***	-0.0024	-0.0009	-0.0077***	-0.0035
	(0.0005)	(0.0005)	(0.0014)	(0.0007)	(0.0008)	(0.0020)	(0.0008)	(0.0012)	(0.0042)
coal plus NG op. capacity	0.0007***	0.0022***	0.0010***	0.0005***	0.0018***	0.0005**	0.0008***	0.0047***	0.0003
	(0.0001)	(0.0003)	(0.0002)	(0.0002)	(0.0003)	(0.0002)	(0.0002)	(0.0012)	(0.0003)
SO2 permit price	-0.1013	0.1297	-0.1289	-0.1335	0.0514	-0.0625	0.2306*	0.2340*	-0.5723*
	(0.0785)	(0.0898)	(0.1483)	(0.1031)	(0.1239)	(0.1650)	(0.1286)	(0.1286)	(0.3377)
SNOX permit price	0.0607	0.0723	-0.0693	-0.0416	-0.0329	-0.3435***	0.0589	0.1710**	0.0985
	(0.0446)	(0.0463)	(0.0661)	(0.0525)	(0.0569)	(0.1166)	(0.0690)	(0.0693)	(0.1192)
# of units with SCR	0.7539***	0.4976***	1.0069***	0.8803***	0.5347***	1.4280***	0.4258***	2.3585***	-0.1576
	(0.0641)	(0.1067)	(0.0935)	(0.0839)	(0.1156)	(0.1468)	(0.1630)	(0.5473)	(0.3425)
# of units with SNCR	-0.0078	-0.0968	0.0093	0.0105	-0.1064	-0.1793	-0.1363	-1.8441***	-0.0174
	(0.0429)	(0.0648)	(0.0711)	(0.0588)	(0.0688)	(0.1748)	(0.1023)	(0.3949)	(0.1120)
# of units with dry-lime FGD	0.1760**	-0.2693**	0.2572**	0.1997*	-0.1554	0.3462	-0.1928	-2.4178***	-0.1996
	(0.0809)	(0.1065)	(0.1239)	(0.1026)	(0.1154)	(0.2239)	(0.1601)	(0.6446)	(0.2321)
# of units with wet-lime FGD	-0.3707***	-1.2054***	-0.2550***	-0.9820***	-1.3726***	-0.8662***	0.1938		0.1939
	(0.0766)	(0.2494)	(0.0733)	(0.1372)	(0.2474)	(0.1479)	(0.1377)		(0.1488)
# of units with PM controls	-0.3042***	-0.2423***	-0.4174***	-0.3118***	-0.2611**	-0.3673***	-0.1223	-0.1579	0.1368
	(0.0548)	(0.0882)	(0.0732)	(0.0754)	(0.1300)	(0.1110)	(0.1029)	(0.1676)	(0.1551)
# of units in ARP	-0.3183***	-0.3020***	-0.2812***	-0.3231***	-0.2985***	-0.2038***	-0.7841***	-5.3685	-0.4707***
	(0.0429)	(0.0941)	(0.0517)	(0.0500)	(0.1079)	(0.0717)	(0.1214)	(478.2757)	(0.1809)
# of units in CAIRNOX	0.0087	0.0337	-0.0606*	0.0270	0.0347	0.1386*	-0.0043	-0.0366	-0.0474
	(0.0194)	(0.0226)	(0.0341)	(0.0294)	(0.0323)	(0.0790)	(0.0392)	(0.1786)	(0.0655)
# of units in CAIROS	-0.0689***	-0.0648***	-0.0431	-0.0836***	-0.0758**	-0.2484***	-0.0308	0.0429	-0.1305
	(0.0198)	(0.0226)	(0.0355)	(0.0294)	(0.0327)	(0.0747)	(0.0352)	(0.0369)	(0.0835)
# of units in CAIRSO2	-0.0364**	-0.0335*	-0.0858***	-0.0219	-0.0458*	-0.0753**	-0.0952**	-0.2997	-0.0865
	(0.0169)	(0.0189)	(0.0293)	(0.0210)	(0.0269)	(0.0342)	(0.0447)	(0.1979)	(0.0639)
# of units in NBP	-0.0661***	-0.0403**	-0.0591*	-0.0481**	-0.0600*	-0.1424***	-0.0315	0.0781**	-0.2379***
	(0.0165)	(0.0190)	(0.0302)	(0.0242)	(0.0310)	(0.0396)	(0.0320)	(0.0323)	(0.0843)
# of units in SIPNOX	-0.6128***	-0.5988***	0.8379	3.6977***	2.8231***		-0.3917***	-0.2144***	-3.1127**
	(0.0573)	(0.0605)	(0.8294)	(0.6662)	(0.6369)		(0.0705)	(0.0788)	(1.5154)
# of units in TRNOX	-0.0090	0.0936**	0.0363	0.0162	0.1068*	0.0905	0.5487	0.5195**	-0.2626*
	(0.0385)	(0.0469)	(0.1457)	(0.0494)	(0.0591)	(0.1670)	(0.3491)	(0.2360)	(0.1533)
# of units in TRNOXOS	-0.0003	-0.0860**	0.0527	0.0168	-0.0849**	-0.0346	-0.8428***	-0.5669	
	(0.0226)	(0.0346)	(0.0440)	(0.0247)	(0.0370)	(0.0485)	(0.2450)	(0.3632)	
# of units in TRSO2G1	-0.0142	0.0051	0.0220	-0.0148	-0.0064	0.0117	0.2114	-0.4905	-0.0532
	(0.0274)	(0.0288)	(0.1088)	(0.0322)	(0.0344)	(0.1293)	(0.2552)	(0.5220)	(0.0767)
# of units in TRSO2G2	-0.0354	-0.0400	-0.0102	-0.0578*	-0.0657*	0.0908	0.1972		
	(0.0308)	(0.0307)	(0.1150)	(0.0351)	(0.0346)	(0.1397)	(0.2612)		
Observations	21,983	12,531	9,452	13,650	8,036	5,614	8,333	4,495	3,838

Table 7: Plant-level IV Tobit: within-year variation (DV: NG input share)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	ALL			UTILITIES			Non-UTILITIES		
VARIABLES	ALL	NMKT	MKT	ALL	NMKT	MKT	ALL	IC	IPP
log coal delivery cost	0.7941*	1.3668**	0.8213	-0.7295*	0.3931	-0.2466	1.6474**	0.9307	-3.7827***
	(0.4241)	(0.5747)	(0.5726)	(0.4432)	(0.6428)	(0.6039)	(0.6537)	(0.9066)	(1.0170)
log NG delivery cost	-0.2876***	-0.6298***	0.0840	-0.0873	-0.5901***	0.2216	-0.4823***	-0.5312***	0.4522*
	(0.0858)	(0.1083)	(0.1379)	(0.1077)	(0.1352)	(0.1608)	(0.1294)	(0.1504)	(0.2381)
log net generation	0.4927***	0.5663***	0.5558	-2.3424***	-2.6235***	-0.1524	0.4772***	0.3990***	1.4638**
	(0.0453)	(0.0482)	(0.3670)	(0.2630)	(0.3613)	(0.4603)	(0.0524)	(0.0562)	(0.6277)
log net generation (sq.)	-0.1272***	-0.1576***	-0.0893**	0.1789***	0.1817***	-0.0031	-0.0500***	-0.0046	-0.1821***
	(0.0076)	(0.0091)	(0.0414)	(0.0309)	(0.0428)	(0.0517)	(0.0110)	(0.0156)	(0.0707)
log net generation (cb.)	0.0038***	0.0058***	0.0011	-0.0068***	-0.0060***	-0.0021	-0.0009	-0.0044***	0.0042
	(0.0004)	(0.0005)	(0.0015)	(0.0012)	(0.0016)	(0.0019)	(0.0006)	(0.0010)	(0.0026)
coal plus NG op. capacity	0.0013***	0.0020***	0.0012***	0.0009***	0.0022***	0.0005***	0.0019***	0.0054***	0.0014***
	(0.0001)	(0.0003)	(0.0001)	(0.0001)	(0.0003)	(0.0002)	(0.0003)	(0.0013)	(0.0004)
SO2 permit price	-0.0078	0.1950**	-0.2583**	-0.0425	0.2417*	-0.2562*	-0.1079	0.0865	0.4359*
	(0.0750)	(0.0980)	(0.1193)	(0.0959)	(0.1278)	(0.1370)	(0.1291)	(0.1482)	(0.2416)
SNOX permit price	-0.0799**	-0.0720	-0.0940*	-0.1646***	-0.1183**	-0.2423***	0.0073	-0.0242	0.1473
	(0.0348)	(0.0457)	(0.0530)	(0.0440)	(0.0586)	(0.0630)	(0.0549)	(0.0679)	(0.0910)
# of units with SCR	1.4559***	1.0173***	1.7122***	1.5719***	0.7336***	2.5934***	1.5202***	2.5548***	0.9811***
	(0.0549)	(0.0794)	(0.0851)	(0.0643)	(0.0896)	(0.1161)	(0.1164)	(0.2226)	(0.1644)
# of units with SNCR	0.0673*	0.0258	0.1186**	0.1401***	0.1145*	0.2606**	-0.0219	-1.5362***	-0.0428
	(0.0392)	(0.0611)	(0.0572)	(0.0488)	(0.0607)	(0.1202)	(0.0671)	(0.4081)	(0.0749)
# of units with dry-lime FGD	0.0278	-0.2800***	0.2513**	0.0087	-0.1341	-0.0505	-0.1259	-2.7191***	0.1768
	(0.0672)	(0.1004)	(0.0999)	(0.0804)	(0.1021)	(0.1773)	(0.1247)	(0.4376)	(0.1493)
# of units with wet-lime FGD	-0.1995***	-0.0942	-0.1919***	-0.6931***	-0.3034*	-1.3688***	0.1187		0.2353***
	(0.0542)	(0.1503)	(0.0597)	(0.0850)	(0.1636)	(0.1084)	(0.0727)		(0.0813)
# of units with PM controls	-0.3885***	-0.4172***	-0.3343***	-0.2741***	-0.1878*	-0.2077**	-0.2629***	-0.6638***	-0.0018
	(0.0456)	(0.0792)	(0.0655)	(0.0568)	(0.0988)	(0.0900)	(0.0827)	(0.1557)	(0.1084)
# of units in ARP	-0.3957***	-0.3625***	-0.4592***	-0.3060***	-0.3038***	-0.2147***	-1.1544***	-7.0381***	-0.9716***
	(0.0426)	(0.0807)	(0.0548)	(0.0445)	(0.0791)	(0.0573)	(0.1256)	(0.8478)	(0.1375)
# of units in CAIRNOX	0.0021	0.0207	-0.0736**	0.0336	0.0452	-0.0086	-0.1255***	0.1756	0.0193
	(0.0179)	(0.0218)	(0.0343)	(0.0259)	(0.0307)	(0.0590)	(0.0319)	(0.1549)	(0.0534)
# of units in CAIROS	-0.0386**	-0.0256	-0.0789***	-0.0695***	-0.0597**	-0.0992*	0.0053	0.0386	-0.1589***
	(0.0166)	(0.0208)	(0.0291)	(0.0247)	(0.0297)	(0.0518)	(0.0278)	(0.0347)	(0.0486)
# of units in CAIRSO2	-0.0456***	-0.0115	-0.0357	-0.0529***	-0.0302	-0.0179	-0.0325	-0.6774***	-0.0056
	(0.0130)	(0.0162)	(0.0265)	(0.0153)	(0.0191)	(0.0341)	(0.0293)	(0.1504)	(0.0455)
# of units in NBP	-0.0222**	0.0075	-0.0308*	-0.0603***	-0.0271	-0.0430**	0.0576**	0.0892***	-0.0705*
	(0.0111)	(0.0148)	(0.0173)	(0.0128)	(0.0175)	(0.0201)	(0.0242)	(0.0311)	(0.0416)
# of units in SIPNOX	-0.1641***	-0.1623***	0.0499	13.1545	12.7301		-0.0853**	-0.0494	0.2955**
	(0.0335)	(0.0384)	(0.1103)	(733.7411)	(160.3271)		(0.0413)	(0.0486)	(0.1290)
# of units in TRNOX	-0.0031	0.0040	0.0113	0.0101	0.0436	-0.0600	-0.8040**	0.4030	-0.1018
	(0.0376)	(0.0531)	(0.1123)	(0.0402)	(0.0591)	(0.1076)	(0.3155)	(0.2479)	(0.0642)
# of units in TRNOXOS	0.0641***	0.0328	0.0206	0.0543**	0.0183	0.0110	-0.2714	-1.1750***	
	(0.0223)	(0.0394)	(0.0290)	(0.0229)	(0.0408)	(0.0334)	(0.2383)	(0.3280)	
# of units in TRSO2G1	-0.0541*	-0.0166	-0.0376	-0.0414	-0.0377	0.0702	1.0229***	-0.3806	0.0740
	(0.0291)	(0.0325)	(0.1067)	(0.0294)	(0.0340)	(0.1006)	(0.2091)	(0.5297)	(0.0634)
# of units in TRSO2G2	-0.0094	-0.0040	0.0252	-0.0145	-0.0207	0.1073	1.0305***		
	(0.0307)	(0.0337)	(0.1104)	(0.0305)	(0.0338)	(0.1111)	(0.2144)		
Observations	24,307	14,621	9,686	13,874	8,185	5,689	10,433	6,436	3,997

Table 8: Plant-level 2SLS (DV: capacity factor)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		ALL			UTILITIES			Non-UTILITIES	
VARIABLES	ALL	NMKT	MKT	ALL	NMKT	MKT	ALL	IC	IPP
log coal delivery cost	-0.9911***	-0.8545***	-1.3048***	-1.0168***	-0.9112***	-1.1512***	-0.6411***	-0.5109***	-0.9821***
	(0.0746)	(0.0902)	(0.1337)	(0.1043)	(0.1316)	(0.1909)	(0.0950)	(0.1080)	(0.1814)
log NG delivery cost	0.2847***	0.2519***	0.3647***	0.4571***	0.5429***	0.3393***	0.1255***	0.0070	0.3774***
	(0.0238)	(0.0292)	(0.0428)	(0.0374)	(0.0481)	(0.0581)	(0.0305)	(0.0352)	(0.0609)
SO2 permit price	0.0324	0.0602*	0.0284	-0.0191	-0.0364	-0.0105	0.0945***	0.1491***	0.0458
	(0.0252)	(0.0316)	(0.0431)	(0.0360)	(0.0468)	(0.0563)	(0.0342)	(0.0409)	(0.0640)
SNOX permit price	-0.0883***	-0.0683***	-0.1368***	-0.0727***	-0.0485**	-0.1018***	-0.0654***	-0.0532***	-0.1086***
	(0.0116)	(0.0146)	(0.0194)	(0.0157)	(0.0205)	(0.0255)	(0.0160)	(0.0193)	(0.0292)
# of units with SCR	0.0429*	0.2087***	-0.1694***	0.0231	0.1690***	-0.2180***	0.2676***	0.6149***	0.0147
	(0.0234)	(0.0275)	(0.0364)	(0.0271)	(0.0317)	(0.0469)	(0.0569)	(0.0702)	(0.0726)
# of units with SNCR	0.0337**	0.0301	0.0256	-0.0024	0.0312	-0.1284***	0.1325***	0.1547***	0.1307***
	(0.0162)	(0.0217)	(0.0265)	(0.0189)	(0.0224)	(0.0424)	(0.0322)	(0.0449)	(0.0343)
# of units with dry-lime FGD	-0.1153***	-0.1650***	-0.0376	0.0066	-0.1053***	0.3018***	-0.3104***	-1.0687***	-0.1697*
	(0.0333)	(0.0352)	(0.0587)	(0.0290)	(0.0363)	(0.0626)	(0.0751)	(0.1310)	(0.0875)
# of units with wet-lime FGD	0.0545***	0.0507	0.1284***	0.0337	0.0698	0.1693***	0.0719***		0.1061***
	(0.0134)	(0.0547)	(0.0162)	(0.0267)	(0.0644)	(0.0334)	(0.0131)		(0.0226)
# of units with PM controls	0.0552***	-0.0035	0.0807***	0.0961***	0.0323	0.0800**	-0.0019	-0.0840*	0.0184
	(0.0173)	(0.0281)	(0.0270)	(0.0225)	(0.0368)	(0.0368)	(0.0283)	(0.0503)	(0.0360)
# of units in ARP	0.0731***	-0.0134	0.0848***	0.0572**	0.0067	0.0567*	0.0589	0.0783	0.0755
	(0.0216)	(0.0303)	(0.0321)	(0.0233)	(0.0325)	(0.0343)	(0.0770)	(0.1199)	(0.0793)
# of units in CAIRNOX	-0.0235***	-0.0481***	0.0461***	-0.0571***	-0.0836***	0.0289	0.0033	0.1273***	0.0271
	(0.0080)	(0.0095)	(0.0151)	(0.0131)	(0.0151)	(0.0191)	(0.0095)	(0.0402)	(0.0195)
# of units in CAIROS	0.0245***	0.0573***	-0.0570***	0.0535***	0.0858***	-0.0531***	0.0004	0.0064	-0.0353*
	(0.0075)	(0.0088)	(0.0149)	(0.0128)	(0.0147)	(0.0176)	(0.0089)	(0.0095)	(0.0191)
# of units in CAIRSO2	-0.0235***	-0.0298***	-0.0049	-0.0059	-0.0012	-0.0076	-0.0237***	-0.0800*	-0.0060
	(0.0056)	(0.0067)	(0.0105)	(0.0077)	(0.0091)	(0.0148)	(0.0085)	(0.0430)	(0.0136)
# of units in NBP	-0.0239***	-0.0120**	-0.0472***	-0.0151**	-0.0003	-0.0549***	-0.0136*	-0.0023	-0.0361***
	(0.0050)	(0.0059)	(0.0089)	(0.0066)	(0.0079)	(0.0118)	(0.0073)	(0.0085)	(0.0133)
# of units in SIPNOX	-0.0211***	-0.0075	-0.0858**	-0.3872	-0.3573		-0.0242***	-0.0101	-0.1003**
	(0.0071)	(0.0078)	(0.0423)	(0.2444)	(0.2405)		(0.0086)	(0.0095)	(0.0434)
# of units in TRNOX	0.0152	-0.0342	0.0994***	0.0342*	0.0178	0.0060	-0.1338	-0.0659	-0.0019
	(0.0173)	(0.0220)	(0.0329)	(0.0184)	(0.0236)	(0.0319)	(0.0934)	(0.0569)	(0.0246)
# of units in TRNOXOS	0.0233*	0.0613***	-0.0043	0.0192	0.0347*	0.0373**	0.1007*	0.0003	
	(0.0120)	(0.0173)	(0.0181)	(0.0124)	(0.0178)	(0.0187)	(0.0515)	(0.0922)	
# of units in TRSO2G1	-0.0388***	-0.0234*	-0.0954***	-0.0364***	-0.0412***	-0.0086	-0.0626	-0.6442***	-0.0534
	(0.0129)	(0.0134)	(0.0300)	(0.0139)	(0.0150)	(0.0285)	(0.0802)	(0.1302)	(0.0329)
# of units in TRSO2G2	-0.0551***	-0.0493***	-0.0873**	-0.0533***	-0.0537***	0.0183	0.0135		
Observations	25,557	15,628	9,929	14,271	8,782	5,489	11,286	6,846	4,440
R-squared	0.5496	0.6003	0.4423	0.5813	0.6359	0.4297	0.4927	0.4969	0.4878

Table 9: Plant-level 2SLS (DV: natural gas demand)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	ALL			UTILITIES			Non-UTILITIES		
VARIABLES	ALL	NMKT	MKT	ALL	NMKT	MKT	ALL	IC	IPP
log coal delivery cost	0.5896***	1.0047***	0.4331	-0.4266**	0.2635	-1.4827***	1.6354***	1.4590***	1.5147***
	(0.1674)	(0.2194)	(0.2724)	(0.2123)	(0.2743)	(0.3297)	(0.2552)	(0.3441)	(0.4301)
log NG delivery cost	-0.4134***	-0.6824***	0.1594*	-0.1851***	-0.4516***	0.2541**	-0.7513***	-0.9968***	-0.0306
	(0.0519)	(0.0643)	(0.0911)	(0.0688)	(0.0890)	(0.1160)	(0.0817)	(0.0980)	(0.1414)
coal plus NG op. capacity	0.0012***	0.0026***	0.0010***	0.0007***	0.0025***	0.0000	0.0016***	0.0050***	0.0015***
	(0.0001)	(0.0003)	(0.0001)	(0.0001)	(0.0003)	(0.0002)	(0.0002)	(0.0012)	(0.0002)
SO2 permit price	0.1745***	0.3572***	-0.1897**	0.0308	0.2484**	-0.2520**	0.1779**	0.3452***	-0.1829
	(0.0577)	(0.0760)	(0.0948)	(0.0756)	(0.1006)	(0.1199)	(0.0906)	(0.1133)	(0.1616)
SNOX permit price	-0.0102	0.0331	-0.0274	-0.1833***	-0.0857*	-0.3134***	0.1939***	0.1049*	0.2531***
	(0.0280)	(0.0352)	(0.0462)	(0.0338)	(0.0442)	(0.0504)	(0.0451)	(0.0557)	(0.0821)
# of units with SCR	0.9970***	0.6755***	1.1376***	1.1812***	0.6488***	1.4872***	0.9296***	1.0573***	0.8732***
	(0.0482)	(0.0767)	(0.0715)	(0.0634)	(0.0997)	(0.0895)	(0.0862)	(0.1161)	(0.1253)
# of units with SNCR	0.0744**	0.0207	0.1060**	0.1032**	0.1111*	-0.2215**	0.0450	-2.5750***	0.1311**
	(0.0362)	(0.0606)	(0.0436)	(0.0524)	(0.0606)	(0.1077)	(0.0562)	(0.3587)	(0.0529)
# of units with dry-lime FGD	0.1385**	-0.1413*	0.3014***	0.1611**	-0.0747	0.6170***	0.0804	-0.7698**	0.0445
	(0.0578)	(0.0827)	(0.0854)	(0.0715)	(0.0871)	(0.1720)	(0.1079)	(0.3108)	(0.1058)
# of units with wet-lime FGD	-0.1138*	-0.0564	-0.0791	-0.5229***	-0.2368	-0.7974***	0.1334**		0.1779***
	(0.0587)	(0.2056)	(0.0636)	(0.0848)	(0.2053)	(0.0596)	(0.0623)		(0.0670)
# of units with PM controls	-0.3618***	-0.3868***	-0.3024***	-0.2395***	-0.1740	-0.3099***	-0.2643***	-0.5253**	0.0172
	(0.0495)	(0.0915)	(0.0651)	(0.0658)	(0.1103)	(0.1037)	(0.0824)	(0.2140)	(0.0775)
# of units in ARP	-0.2196***	-0.3844***	-0.2435***	-0.2339***	-0.3978***	-0.2257***	-0.5177***	-7.8223***	-0.4897***
	(0.0387)	(0.0968)	(0.0467)	(0.0412)	(0.0981)	(0.0500)	(0.1440)	(0.3424)	(0.1467)
# of units in CAIRNOX	-0.0036	0.0088	-0.0617**	0.0224	0.0011	0.0466	-0.1339***	0.0683	-0.1221***
	(0.0156)	(0.0192)	(0.0280)	(0.0217)	(0.0235)	(0.0606)	(0.0300)	(0.1313)	(0.0384)
# of units in CAIROS	-0.0302**	-0.0090	-0.0671***	-0.0467**	-0.0097	-0.1072*	0.0146	0.0372	-0.0591
	(0.0148)	(0.0187)	(0.0255)	(0.0215)	(0.0239)	(0.0579)	(0.0259)	(0.0357)	(0.0366)
# of units in CAIRSO2	-0.0491***	-0.0275**	-0.0359*	-0.0630***	-0.0425***	-0.0429*	-0.0036	-0.5541***	0.0117
	(0.0105)	(0.0131)	(0.0193)	(0.0124)	(0.0155)	(0.0235)	(0.0276)	(0.1248)	(0.0376)
# of units in NBP	-0.0220**	0.0030	-0.0410***	-0.0669***	-0.0383**	-0.0762***	0.0926***	0.1321***	0.0006
	(0.0100)	(0.0130)	(0.0154)	(0.0117)	(0.0156)	(0.0178)	(0.0225)	(0.0304)	(0.0364)
# of units in SIPNOX	-0.1574***	-0.1900***	0.1690**	4.6055***	4.4340***		-0.0660*	-0.0242	0.2076**
	(0.0323)	(0.0402)	(0.0815)	(0.2944)	(0.3509)		(0.0387)	(0.0439)	(0.0892)
# of units in TRNOX	0.0631**	0.0970**	-0.0209	0.1291***	0.1734***	0.0376	-0.5848	0.4293	0.0430
	(0.0313)	(0.0452)	(0.1286)	(0.0322)	(0.0463)	(0.1267)	(0.3702)	(0.3230)	(0.0434)
# of units in TRNOXOS	0.0196	-0.0492	0.0100	-0.0106	-0.0780**	-0.0301	-0.3079	-1.0517**	
	(0.0211)	(0.0381)	(0.0285)	(0.0216)	(0.0388)	(0.0371)	(0.2695)	(0.4186)	
# of units in TRSO2G1	-0.0612**	-0.0150	0.0375	-0.0791***	-0.0554**	0.0560	0.8544***	0.3966	-0.0283
	(0.0260)	(0.0270)	(0.1266)	(0.0262)	(0.0271)	(0.1239)	(0.2548)	(0.5995)	(0.0551)
# of units in TRSO2G2	-0.0274	-0.0368	0.1163	-0.0485*	-0.0565**	0.1312	0.8693***		
	(0.0271)	(0.0287)	(0.1304)	(0.0278)	(0.0287)	(0.1368)	(0.2560)		
Observations	24,743	14,930	9,813	14,111	8,363	5,748	10,632	6,567	4,065
R-squared	0.7029	0.7052	0.7006	0.7518	0.7555	0.7371	0.6252	0.6173	0.6307

Table 10: Plant-level 2SLS (DV: coal demand)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		ALL			UTILITIES			Non-UTILITIES	
VARIABLES	ALL	NMKT	MKT	ALL	NMKT	MKT	ALL	IC	IPP
log coal delivery cost	-0.9467***	-1.0070***	-0.9946***	-1.0088***	-1.0020***	-1.3067***	-0.8482***	-0.8750***	-0.6399***
	(0.0691)	(0.0926)	(0.1095)	(0.0958)	(0.1211)	(0.1762)	(0.0944)	(0.1377)	(0.1423)
log NG delivery cost	0.4285***	0.4488***	0.4112***	0.5145***	0.6145***	0.3424***	0.3409***	0.3045***	0.4449***
	(0.0229)	(0.0290)	(0.0391)	(0.0352)	(0.0462)	(0.0583)	(0.0299)	(0.0367)	(0.0515)
coal plus NG op. capacity	0.0003***	0.0005***	0.0003***	0.0002***	0.0004***	0.0001	0.0006***	0.0016***	0.0004*
	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0001)	(0.0002)	(0.0004)	(0.0002)
SO2 permit price	-0.0267	-0.0251	-0.0425	-0.0861***	-0.0988***	-0.1100**	0.0501	0.0533	-0.0017
	(0.0215)	(0.0292)	(0.0330)	(0.0289)	(0.0373)	(0.0476)	(0.0330)	(0.0470)	(0.0447)
SNOX permit price	-0.0743***	-0.0711***	-0.0950***	-0.0697***	-0.0670***	-0.0989***	-0.0733***	-0.0546**	-0.0765***
	(0.0105)	(0.0140)	(0.0158)	(0.0135)	(0.0176)	(0.0225)	(0.0157)	(0.0223)	(0.0225)
# of units with SCR	0.0415	-0.0144	0.1233***	0.0884**	0.0286	0.4324***	-0.0351	-0.2331***	0.0614
	(0.0324)	(0.0429)	(0.0352)	(0.0385)	(0.0448)	(0.0628)	(0.0451)	(0.0494)	(0.0522)
# of units with SNCR	0.0074	-0.0109	0.0169	-0.0422**	-0.0231	-0.2170***	0.1139***	0.2878***	0.1022***
	(0.0144)	(0.0203)	(0.0218)	(0.0178)	(0.0211)	(0.0405)	(0.0245)	(0.0500)	(0.0258)
# of units with dry-lime FGD	-0.0370	-0.1306***	0.0537	0.0598	-0.1170**	0.4422***	-0.1440**	-0.2576**	-0.1673**
	(0.0334)	(0.0487)	(0.0483)	(0.0393)	(0.0529)	(0.0622)	(0.0609)	(0.1171)	(0.0670)
# of units with wet-lime FGD	0.0706***	-0.0878	0.0789***	0.0005	-0.1588**	-0.1520***	0.0952***		0.0884***
	(0.0149)	(0.0610)	(0.0174)	(0.0263)	(0.0738)	(0.0386)	(0.0180)		(0.0193)
# of units with PM controls	0.0928***	0.2123***	-0.0225	0.1260***	0.2885***	-0.0616**	0.0507**	0.0578	0.0180
	(0.0185)	(0.0364)	(0.0219)	(0.0246)	(0.0504)	(0.0291)	(0.0253)	(0.0486)	(0.0311)
# of units in ARP	0.0916***	0.1283***	0.0247	0.1052***	0.1130***	0.0056	-0.1529***	1.2647***	-0.1484***
	(0.0243)	(0.0388)	(0.0287)	(0.0269)	(0.0385)	(0.0342)	(0.0517)	(0.1436)	(0.0538)
# of units in CAIRNOX	0.0070	-0.0140*	0.0404***	-0.0236**	-0.0442***	0.0309*	0.0240***	0.1072***	0.0124
	(0.0059)	(0.0074)	(0.0091)	(0.0095)	(0.0112)	(0.0159)	(0.0069)	(0.0374)	(0.0103)
# of units in CAIROS	-0.0120**	0.0152**	-0.0543***	0.0164*	0.0404***	-0.0486***	-0.0168***	-0.0074	-0.0266***
	(0.0057)	(0.0073)	(0.0085)	(0.0095)	(0.0113)	(0.0146)	(0.0059)	(0.0078)	(0.0091)
# of units in CAIRSO2	-0.0210***	-0.0235***	-0.0133	-0.0155**	-0.0112	-0.0193	-0.0048	0.0795**	0.0016
	(0.0050)	(0.0061)	(0.0089)	(0.0065)	(0.0076)	(0.0133)	(0.0069)	(0.0383)	(0.0096)
# of units in NBP	-0.0322***	-0.0223***	-0.0451***	-0.0254***	-0.0171**	-0.0504***	-0.0295***	-0.0285***	-0.0283***
	(0.0047)	(0.0058)	(0.0078)	(0.0060)	(0.0072)	(0.0110)	(0.0063)	(0.0084)	(0.0098)
# of units in SIPNOX	0.0024	0.0105	-0.0116	-0.4188	-0.3836		0.0029	-0.0022	-0.0279
	(0.0078)	(0.0087)	(0.0356)	(0.2890)	(0.2864)		(0.0082)	(0.0101)	(0.0364)
# of units in TRNOX	-0.0255	-0.0875***	0.1616***	-0.0182	-0.0686**	0.1243***	0.0277	-0.0719	0.0020
	(0.0225)	(0.0329)	(0.0328)	(0.0230)	(0.0335)	(0.0329)	(0.0957)	(0.0584)	(0.0216)
# of units in TRNOXOS	0.0093	0.0677***	-0.0171	0.0048	0.0572**	-0.0069	0.0746	0.1102	
	(0.0117)	(0.0257)	(0.0148)	(0.0117)	(0.0256)	(0.0175)	(0.0501)	(0.0992)	
# of units in TRSO2G1	0.0098	0.0192	-0.1635***	0.0141	0.0132	-0.1148***	-0.1498*	0.3622**	-0.0488*
	(0.0194)	(0.0205)	(0.0308)	(0.0199)	(0.0213)	(0.0305)	(0.0825)	(0.1495)	(0.0262)
# of units in TRSO2G2	0.0019	0.0063	-0.1253***	0.0044	0.0076	-0.0545	-0.1068		
	(0.0203)	(0.0218)	(0.0327)	(0.0208)	(0.0224)	(0.0336)	(0.0835)		
Observations	27,505	17,013	10,492	15,076	9,395	5,681	12,429	7,618	4,811
R-squared	0.8735	0.8719	0.8279	0.8487	0.8557	0.8157	0.8818	0.8411	0.8460

Table 11: Plant-level 2SLS (DV: natural gas generating units)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		ALL			UTILITIES			Non-UTILITIES	
VARIABLES	ALL	NMKT	MKT	ALL	NMKT	MKT	ALL	IC	IPP
log coal delivery cost	0.1627*	0.0947	0.2637***	-0.2713*	-0.2291	-0.3405**	0.3531***	0.1262***	0.3439***
	(0.0916)	(0.1025)	(0.0935)	(0.1474)	(0.1935)	(0.1670)	(0.0528)	(0.0488)	(0.1025)
log NG delivery cost	-0.0028	-0.0207	-0.0614**	0.0512	0.0529	-0.0344	-0.0455***	-0.0479***	-0.0966***
	(0.0414)	(0.0424)	(0.0303)	(0.0843)	(0.1028)	(0.0464)	(0.0147)	(0.0147)	(0.0356)
SO2 permit price	-0.0324	-0.0335	-0.0292	-0.1100	-0.1132	-0.0618	0.0273	0.0341*	0.0066
	(0.0358)	(0.0469)	(0.0299)	(0.0708)	(0.1032)	(0.0426)	(0.0194)	(0.0198)	(0.0390)
SNOX permit price	0.0079	-0.0020	0.0281**	-0.0371	-0.0363	-0.0202	0.0319***	0.0083	0.0194
	(0.0165)	(0.0202)	(0.0140)	(0.0276)	(0.0388)	(0.0204)	(0.0089)	(0.0091)	(0.0179)
# of units with SCR	0.7671***	0.5096***	0.8593***	0.6916***	0.2942***	1.1421***	0.9404***	1.6701***	0.4853***
	(0.0404)	(0.0520)	(0.0396)	(0.0431)	(0.0536)	(0.0388)	(0.0660)	(0.0808)	(0.0964)
# of units with SNCR	-0.0282	0.0026	-0.0300***	-0.0085	0.0382	-0.1189***	-0.0350***	-0.0264***	-0.0229*
	(0.0232)	(0.0433)	(0.0114)	(0.0331)	(0.0446)	(0.0231)	(0.0130)	(0.0085)	(0.0118)
# of units with dry-lime FGD	-0.2683***	-0.2766***	-0.1782***	-0.2765***	-0.1615***	-0.2991***	-0.4169***	-1.6459***	-0.1922***
	(0.0221)	(0.0248)	(0.0348)	(0.0249)	(0.0260)	(0.0587)	(0.0461)	(0.0794)	(0.0479)
# of units with wet-lime FGD	-0.0955***	0.1050**	-0.1023***	-0.2413***	0.2460***	-0.6773***	-0.0023		0.0475***
	(0.0234)	(0.0517)	(0.0305)	(0.0405)	(0.0611)	(0.0266)	(0.0044)		(0.0163)
# of units with PM controls	-0.1218***	-0.1999***	-0.0969***	-0.1413***	-0.3114***	-0.0501***	-0.0347*	-0.0116**	-0.0098
	(0.0124)	(0.0267)	(0.0131)	(0.0174)	(0.0378)	(0.0169)	(0.0191)	(0.0047)	(0.0234)
# of units in ARP	0.0185	0.4196***	-0.2205***	0.1039***	0.5105***	-0.1077***	-0.6351***	0.0981***	-0.5841***
	(0.0294)	(0.0470)	(0.0278)	(0.0320)	(0.0456)	(0.0288)	(0.0959)	(0.0218)	(0.0948)
# of units in CAIRNOX	0.0662***	0.0501*	0.0962***	0.1288***	0.1492***	0.0174	0.0414***	-0.0089	0.1435***
	(0.0202)	(0.0283)	(0.0208)	(0.0327)	(0.0385)	(0.0115)	(0.0130)	(0.0057)	(0.0263)
# of units in CAIROS	-0.0663***	-0.0455**	-0.1049***	-0.1379***	-0.1551***	-0.0367***	-0.0313***	0.0126***	-0.1371***
	(0.0142)	(0.0189)	(0.0203)	(0.0297)	(0.0361)	(0.0091)	(0.0096)	(0.0034)	(0.0251)
# of units in CAIRSO2	0.0354**	0.0542**	-0.0022	0.0595**	0.0653**	0.0422***	-0.0068	-0.0138***	-0.0330***
	(0.0179)	(0.0256)	(0.0077)	(0.0234)	(0.0276)	(0.0115)	(0.0067)	(0.0046)	(0.0084)
# of units in NBP	0.0023	0.0106	-0.0000	0.0168	0.0173	0.0359***	-0.0021	0.0045	-0.0184**
	(0.0095)	(0.0144)	(0.0069)	(0.0139)	(0.0188)	(0.0096)	(0.0046)	(0.0031)	(0.0080)
# of units in SIPNOX	-0.0042	0.0072	0.0321	0.0205	-0.0002		-0.0104*	0.0053	-0.0014
	(0.0104)	(0.0154)	(0.0451)	(0.0453)	(0.0529)		(0.0060)	(0.0044)	(0.0444)
# of units in TRNOX	-0.0015	-0.0161	0.1591***	0.0143	0.0154	0.2039***	-0.1555***	0.0175**	0.0322***
	(0.0161)	(0.0248)	(0.0253)	(0.0201)	(0.0296)	(0.0306)	(0.0285)	(0.0080)	(0.0118)
# of units in TRNOXOS	0.0226	0.0130	0.0053	0.0062	-0.0064	-0.0186	0.0471**	-0.0411***	
	(0.0137)	(0.0233)	(0.0110)	(0.0163)	(0.0245)	(0.0122)	(0.0223)	(0.0079)	
# of units in TRSO2G1	-0.0077	0.0170	-0.1617***	0.0074	0.0189	-0.1567***	0.0988***	-0.0314***	-0.0412***
	(0.0143)	(0.0202)	(0.0227)	(0.0182)	(0.0228)	(0.0283)	(0.0181)	(0.0095)	(0.0129)
# of units in TRSO2G2	0.0594***	0.0839***	-0.1721***	0.0563**	0.0722***	-0.2577***	0.1794***	-0.0184***	
Observations	33,909	21,924	11,985	16,706	10,280	6,426	17,203	11,644	5,559
R-squared	0.8288	0.8317	0.8169	0.8220	0.8184	0.8513	0.7778	0.8242	0.7255

Table 12: Plant-level 2SLS (DV: coal generating units)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	ALL			UTILITIES			Non-UTILITIES		
VARIABLES	ALL	NMKT	MKT	ALL	NMKT	MKT	ALL	IC	IPP
log coal delivery cost	-0.1653***	-0.1710**	-0.3385***	-0.6673***	-0.8412***	-0.5848***	0.2653***	0.4288***	-0.2324**
	(0.0585)	(0.0779)	(0.0870)	(0.0640)	(0.0739)	(0.1249)	(0.0905)	(0.1283)	(0.1120)
log NG delivery cost	0.1055***	0.1330***	0.0864***	0.1282***	0.1826***	0.0145	0.1090***	0.0987***	0.0944**
	(0.0160)	(0.0199)	(0.0262)	(0.0196)	(0.0246)	(0.0333)	(0.0240)	(0.0294)	(0.0379)
SO2 permit price	0.0096	0.0103	0.0212	-0.0348	-0.0638**	0.0191	0.0343	0.0796**	0.0017
	(0.0188)	(0.0253)	(0.0264)	(0.0212)	(0.0258)	(0.0345)	(0.0297)	(0.0400)	(0.0390)
SNOX permit price	-0.0255***	-0.0336***	-0.0349***	-0.0521***	-0.0972***	-0.0136	0.0009	0.0299	-0.0846***
	(0.0085)	(0.0113)	(0.0129)	(0.0095)	(0.0114)	(0.0170)	(0.0140)	(0.0189)	(0.0177)
# of units with SCR	-0.3429***	-0.2666***	-0.2201***	-0.3120***	-0.1927***	-0.1969***	-0.3401***	-0.6517***	-0.1806***
	(0.0220)	(0.0203)	(0.0211)	(0.0247)	(0.0210)	(0.0258)	(0.0343)	(0.0632)	(0.0391)
# of units with SNCR	-0.0671***	-0.0671***	-0.1074***	-0.0664***	-0.0595***	-0.0961***	-0.0998***	0.0262	-0.1214***
	(0.0094)	(0.0099)	(0.0159)	(0.0108)	(0.0103)	(0.0187)	(0.0224)	(0.0255)	(0.0241)
# of units with dry-lime FGD	0.0286	0.1922***	-0.1473***	0.0882***	0.2060***	-0.2613***	0.0253	0.6932***	0.0014
	(0.0214)	(0.0187)	(0.0309)	(0.0260)	(0.0203)	(0.0553)	(0.0365)	(0.0869)	(0.0371)
# of units with wet-lime FGD	0.0397***	-0.2744***	0.0854***	0.0385	-0.3849***	0.1784***	0.0005		0.0385**
	(0.0111)	(0.0356)	(0.0121)	(0.0280)	(0.0501)	(0.0154)	(0.0071)		(0.0171)
# of units with PM controls	0.1804***	0.3500***	0.1781***	0.2778***	0.4885***	0.2914***	-0.0430***	-0.0625**	-0.0698***
	(0.0128)	(0.0225)	(0.0176)	(0.0187)	(0.0318)	(0.0272)	(0.0104)	(0.0253)	(0.0131)
# of units in ARP	0.2939***	0.0092	0.5142***	0.2632***	-0.0546***	0.5388***	0.3310***	0.2112***	0.3338***
	(0.0270)	(0.0191)	(0.0340)	(0.0315)	(0.0185)	(0.0397)	(0.0507)	(0.0803)	(0.0519)
# of units in CAIRNOX	0.0226***	-0.0087	0.1053***	0.0187***	0.0018	0.0608***	0.0194	0.1514***	0.0646**
	(0.0075)	(0.0069)	(0.0194)	(0.0071)	(0.0075)	(0.0116)	(0.0142)	(0.0376)	(0.0270)
# of units in CAIROS	-0.0126*	0.0168**	-0.0870***	-0.0025	0.0094	-0.0183*	-0.0096	0.0222	-0.0628**
	(0.0076)	(0.0072)	(0.0194)	(0.0072)	(0.0075)	(0.0102)	(0.0126)	(0.0145)	(0.0263)
# of units in CAIRSO2	0.0099**	0.0308***	-0.0269***	0.0126***	0.0399***	-0.0485***	0.0324***	0.0370	0.0274*
	(0.0040)	(0.0044)	(0.0076)	(0.0041)	(0.0041)	(0.0099)	(0.0113)	(0.0266)	(0.0156)
# of units in NBP	0.0017	0.0256***	-0.0498***	0.0015	0.0316***	-0.0698***	0.0170	0.0212	0.0128
	(0.0043)	(0.0050)	(0.0070)	(0.0043)	(0.0040)	(0.0095)	(0.0110)	(0.0160)	(0.0142)
# of units in SIPNOX	0.0324***	0.0401***	0.1692***	-0.1718**	-0.0884		0.0354***	0.0268	0.1843***
	(0.0061)	(0.0063)	(0.0276)	(0.0866)	(0.0557)		(0.0122)	(0.0168)	(0.0296)
# of units in TRNOX	-0.0163*	0.0033	-0.1539***	0.0046	0.0322**	-0.1599***	-0.0293	0.9943***	0.0959***
	(0.0090)	(0.0152)	(0.0217)	(0.0091)	(0.0138)	(0.0268)	(0.0285)	(0.0355)	(0.0152)
# of units in TRNOXOS	0.0191***	0.0031	0.0399***	0.0042	-0.0189	0.0436***	0.0380**	-1.1044***	
	(0.0072)	(0.0145)	(0.0091)	(0.0071)	(0.0128)	(0.0128)	(0.0187)	(0.0324)	
# of units in TRSO2G1	-0.0104*	-0.0151***	0.1245***	-0.0068	-0.0111**	0.1401***	-0.0334	0.0521*	-0.1057***
	(0.0056)	(0.0047)	(0.0198)	(0.0059)	(0.0044)	(0.0254)	(0.0214)	(0.0306)	(0.0171)
# of units in TRSO2G2	0.0053	0.0014	0.1997***	-0.0013	0.0040	0.1725***	0.0888***	-0.8897***	
Observations	33,909	21,924	11,985	16,706	10,280	6,426	17,203	11,644	5,559
R-squared	0.9221	0.9313	0.8933	0.9217	0.9322	0.9158	0.9192	0.9291	0.8410

Table 13: Plant-level IV Tobit, partial adjustment & forward looking (DV: NG input share)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		ALL			UTILITIES			Non-UTILITIES	
VARIABLES	ALL	NMKT	MKT	ALL	NMKT	MKT	ALL	IC	IPP
log coal delivery cost	1.7935***	2.4215***	2.1706***	-0.8517	0.0812	-2.6414***	3.8336***	4.2233***	1.7506*
	(0.5346)	(0.7743)	(0.7295)	(0.7255)	(0.9842)	(0.9701)	(0.7424)	(1.1635)	(0.9707)
log NG delivery cost	0.2844*	-0.3854*	1.0838***	0.5969***	-0.2571	1.1370***	-0.3295	-0.5661*	0.1515
	(0.1691)	(0.2075)	(0.2779)	(0.2236)	(0.2756)	(0.3276)	(0.2491)	(0.3043)	(0.3836)
log NYMEX Coal CAPP 12m	-0.0470	0.0714	-0.1713	0.1756	0.3515**	0.0013	-0.2008	-0.2787	0.2022
	(0.0889)	(0.1123)	(0.1554)	(0.1139)	(0.1404)	(0.1948)	(0.1407)	(0.1873)	(0.2245)
log NYMEX NG 12m	-0.4220***	-0.2700**	-0.4830***	-0.3348***	-0.1142	-0.3440*	-0.3875**	-0.3354*	-0.2678
	(0.0931)	(0.1114)	(0.1735)	(0.1132)	(0.1351)	(0.2017)	(0.1521)	(0.1764)	(0.2807)
log coal delivery cost lag	-1.0760***	-1.5483***	-1.1791***	0.5042	-0.0922	1.7168***	-2.1387***	-2.5055***	-0.8792
	(0.3565)	(0.5288)	(0.4527)	(0.4939)	(0.6864)	(0.6019)	(0.4795)	(0.7616)	(0.5844)
log NG delivery cost lag	-0.4291***	-0.2202**	-0.6235***	-0.7831***	-0.5482***	-0.7157***	0.0443	0.1488	-0.2311
	(0.0749)	(0.0966)	(0.1083)	(0.1003)	(0.1404)	(0.1135)	(0.1066)	(0.1234)	(0.1742)
log net generation	0.4942***	0.5756***	0.5680	-2.3290***	-2.7047***	0.0242	0.4598***	0.3881***	0.8764
	(0.0459)	(0.0484)	(0.3812)	(0.2672)	(0.3669)	(0.4812)	(0.0535)	(0.0566)	(0.6080)
log net generation (sq.)	-0.1279***	-0.1596***	-0.0896**	0.1738***	0.1883***	-0.0226	-0.0432***	-0.0017	-0.1151*
	(0.0078)	(0.0091)	(0.0429)	(0.0314)	(0.0434)	(0.0540)	(0.0113)	(0.0157)	(0.0687)
log net generation (cb.)	0.0039***	0.0059***	0.0012	-0.0065***	-0.0062***	-0.0014	-0.0013**	-0.0044***	0.0018
	(0.0004)	(0.0005)	(0.0016)	(0.0012)	(0.0016)	(0.0020)	(0.0006)	(0.0010)	(0.0025)
coal plus NG op. capacity	0.0013***	0.0020***	0.0012***	0.0009***	0.0023***	0.0003**	0.0020***	0.0063***	0.0016***
	(0.0001)	(0.0003)	(0.0001)	(0.0001)	(0.0003)	(0.0002)	(0.0004)	(0.0013)	(0.0004)
SO2 permit price	0.2287***	0.3906***	-0.1716	0.2441***	0.4756***	-0.1038	0.0466	0.1496	-0.0202
	(0.0714)	(0.0909)	(0.1159)	(0.0874)	(0.1134)	(0.1329)	(0.1207)	(0.1470)	(0.2034)
SNOX permit price	0.0022	0.0129	0.0491	-0.2017***	-0.1574***	-0.2387***	0.2428***	0.2061***	0.1393
	(0.0352)	(0.0460)	(0.0548)	(0.0426)	(0.0555)	(0.0624)	(0.0575)	(0.0770)	(0.0909)
# of units with SCR	1.4489***	1.0050***	1.6983***	1.5769***	0.7315***	2.5843***	1.5176***	2.5001***	1.1672***
	(0.0554)	(0.0799)	(0.0852)	(0.0655)	(0.0888)	(0.1182)	(0.1182)	(0.2239)	(0.1548)
# of units with SNCR	0.0721*	0.0369	0.1219**	0.1398***	0.1222**	0.1853	-0.0331	-1.6678***	0.0472
	(0.0393)	(0.0603)	(0.0554)	(0.0498)	(0.0593)	(0.1189)	(0.0671)	(0.4254)	(0.0689)
# of units with dry-lime FGD	0.0239	-0.2771***	0.2637**	0.0204	-0.1176	-0.0220	-0.1430	-2.5614***	0.0012
	(0.0682)	(0.1012)	(0.1035)	(0.0819)	(0.1022)	(0.1877)	(0.1286)	(0.4250)	(0.1434)
# of units with wet-lime FGD	-0.1963***	-0.1012	-0.1848***	-0.6794***	-0.2853*	-1.3744***	0.1156		0.1784**
	(0.0548)	(0.1510)	(0.0619)	(0.0864)	(0.1604)	(0.1146)	(0.0746)		(0.0789)
# of units with PM controls	-0.3874***	-0.4335***	-0.3552***	-0.2751***	-0.2162**	-0.2065**	-0.2712***	-0.5936***	0.0208
	(0.0462)	(0.0789)	(0.0683)	(0.0578)	(0.0991)	(0.0959)	(0.0843)	(0.1589)	(0.1049)
# of units in ARP	-0.4118***	-0.4055***	-0.4653***	-0.3156***	-0.3257***	-0.2388***	-1.1608***	-7.0190***	-1.0758***
	(0.0431)	(0.0813)	(0.0564)	(0.0454)	(0.0792)	(0.0600)	(0.1267)	(0.8589)	(0.1320)
# of units in CAIRNOX	0.0045	0.0190	-0.0522	0.0497*	0.0389	0.0289	-0.1260***	0.1027	-0.0606
	(0.0178)	(0.0216)	(0.0335)	(0.0254)	(0.0289)	(0.0592)	(0.0323)	(0.1476)	(0.0486)
# of units in CAIROS	-0.0380**	-0.0218	-0.0728**	-0.0788***	-0.0510*	-0.0945*	0.0037	0.0389	-0.1185**
	(0.0167)	(0.0206)	(0.0304)	(0.0245)	(0.0284)	(0.0548)	(0.0283)	(0.0358)	(0.0468)
# of units in CAIRSO2	-0.0515***	-0.0186	-0.0503**	-0.0687***	-0.0485***	-0.0292	-0.0288	-0.6275***	-0.0344
	(0.0124)	(0.0157)	(0.0222)	(0.0143)	(0.0178)	(0.0279)	(0.0294)	(0.1536)	(0.0408)
# of units in NBP	-0.0223**	0.0050	-0.0278	-0.0624***	-0.0368**	-0.0469**	0.0559**	0.0869***	-0.0310
	(0.0111)	(0.0145)	(0.0180)	(0.0131)	(0.0170)	(0.0214)	(0.0243)	(0.0313)	(0.0403)
# of units in SIPNOX	-0.1677***	-0.1674***	-0.0104	13.1197	13.3907		-0.0838**	-0.0352	0.1100
	(0.0338)	(0.0378)	(0.1138)	(791.2787)	(172.8820)		(0.0423)	(0.0491)	(0.1259)
# of units in TRNOX	0.0371	0.0342	0.0109	0.0753**	0.0784	0.0081	-0.7394**	0.4827*	0.0026
	(0.0347)	(0.0481)	(0.1136)	(0.0345)	(0.0479)	(0.1116)	(0.3197)	(0.2506)	(0.0542)
# of units in TRNOXOS	0.0491**	0.0199	0.0227	0.0258	-0.0001	0.0085	-0.3130	-1.2483***	
	(0.0220)	(0.0384)	(0.0301)	(0.0218)	(0.0379)	(0.0353)	(0.2386)	(0.3337)	
# of units in TRSO2G1	-0.0652**	-0.0230	-0.0298	-0.0640**	-0.0403	0.0522	1.0192***	-0.3661	0.0051
	(0.0281)	(0.0302)	(0.1102)	(0.0277)	(0.0296)	(0.1073)	(0.2142)	(0.5504)	(0.0595)
# of units in TRSO2G2	-0.0157	-0.0057	0.0389	-0.0255	-0.0215	0.1127	1.0218***		
	(0.0309)	(0.0332)	(0.1150)	(0.0306)	(0.0324)	(0.1183)	(0.2190)		
Observations	24,178	14,538	9,640	13,804	8,139	5,665	10,374	6,399	3,975

Table 14: Operator-level IV Tobit (DV: NG input share)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		ALL			UTILITIES			Non-UTILITIES	
VARIABLES	ALL	NMKT	MKT	ALL	NMKT	MKT	ALL	IC	IPP
log coal delivery cost	0.9669***	1.2536***	0.2363	0.7718***	0.7242**	1.1779***	1.0141***	1.0180***	-0.5508
	(0.2096)	(0.2616)	(0.3423)	(0.2868)	(0.3632)	(0.4565)	(0.2775)	(0.3341)	(0.4671)
log NG delivery cost	-0.6895***	-0.8848***	-0.3108***	-0.3729***	-0.4491***	0.1436	-0.8367***	-0.8333***	-0.4304***
	(0.0594)	(0.0769)	(0.0939)	(0.0851)	(0.1201)	(0.1208)	(0.0798)	(0.0965)	(0.1399)
log net generation	0.6294***	0.6666***	3.1037***	-0.6415***	-0.6780***	2.4898***	0.5064***	0.4727***	3.3964***
	(0.0460)	(0.0479)	(0.4154)	(0.2041)	(0.2395)	(0.6192)	(0.0540)	(0.0585)	(0.6003)
log net generation (sq.)	-0.1659***	-0.2024***	-0.4351***	-0.0453*	-0.0513	-0.3550***	-0.0961***	-0.0999***	-0.4800***
	(0.0080)	(0.0104)	(0.0456)	(0.0247)	(0.0318)	(0.0646)	(0.0117)	(0.0190)	(0.0675)
log net generation (cb.)	0.0064***	0.0097***	0.0149***	0.0023**	0.0030**	0.0117***	0.0031***	0.0042***	0.0170***
	(0.0004)	(0.0006)	(0.0016)	(0.0009)	(0.0014)	(0.0022)	(0.0006)	(0.0013)	(0.0024)
coal plus NG op. capacity	0.0000	0.0005**	0.0000	0.0003***	0.0007***	0.0004***	-0.0000	0.0023**	-0.0000
	(0.0000)	(0.0002)	(0.0000)	(0.0001)	(0.0002)	(0.0001)	(0.0000)	(0.0012)	(0.0000)
SO2 permit price	0.4460***	0.3774***	0.3968***	0.4679***	0.5937***	0.0960	0.3175***	0.0774	0.4821***
	(0.0692)	(0.0889)	(0.1081)	(0.0938)	(0.1246)	(0.1392)	(0.0978)	(0.1174)	(0.1653)
SNOX permit price	0.0554	0.1875***	-0.1529***	-0.0265	0.0979	-0.0982	0.1244**	0.1809***	-0.1490*
	(0.0348)	(0.0444)	(0.0538)	(0.0443)	(0.0599)	(0.0637)	(0.0496)	(0.0586)	(0.0822)
# of units with SCR	0.0954***	0.2032***	0.0934***	0.1259***	-0.1929***	0.1525***	0.0847	2.1452***	-0.0342
	(0.0227)	(0.0589)	(0.0278)	(0.0262)	(0.0587)	(0.0344)	(0.0519)	(0.2139)	(0.0620)
# of units with SNCR	-0.0646***	-0.3764***	-0.0527**	0.0744**	-0.1824	0.0404	-0.1195***	-2.0131***	-0.1376***
	(0.0223)	(0.1306)	(0.0232)	(0.0346)	(0.1333)	(0.0370)	(0.0311)	(0.3844)	(0.0356)
# of units with dry-lime FGD	0.1257**	0.3431	0.0015	-0.1912***	-0.1959	-0.2076***	0.3148***	1.1643***	0.1852*
	(0.0548)	(0.2333)	(0.0600)	(0.0723)	(0.2306)	(0.0776)	(0.0941)	(0.1745)	(0.1036)
# of units with wet-lime FGD	0.0297	0.0291	0.0504	-0.0302	-0.3071	-0.0364	0.0039		0.1037**
	(0.0298)	(0.2445)	(0.0307)	(0.0399)	(0.2328)	(0.0398)	(0.0444)		(0.0482)
# of units with PM controls	-0.1410***	-0.4492***	0.0142	0.0575	-0.2983***	0.2276***	-0.4016***	-0.5406***	-0.2322***
	(0.0346)	(0.0719)	(0.0406)	(0.0394)	(0.0845)	(0.0451)	(0.0605)	(0.1519)	(0.0719)
# of units in ARP	0.0853***	0.1826***	0.0719***	0.1333***	0.3209***	0.0925***	-0.1507***		-0.0770**
	(0.0113)	(0.0361)	(0.0122)	(0.0126)	(0.0327)	(0.0139)	(0.0286)		(0.0330)
# of units in CAIRNOX	0.0049	-0.0222	0.0060	-0.0127	0.0138	-0.0171*	-0.0187*	0.1453	-0.0016
	(0.0060)	(0.0158)	(0.0068)	(0.0079)	(0.0157)	(0.0100)	(0.0102)	(0.1635)	(0.0112)
# of units in CAIROS	-0.0044	0.0634***	-0.0151**	-0.0034	-0.0065	-0.0200**	0.0328***	0.0508	0.0034
	(0.0060)	(0.0155)	(0.0067)	(0.0077)	(0.0170)	(0.0098)	(0.0112)	(0.0311)	(0.0126)
# of units in CAIRSO2	-0.0277***	-0.0245*	-0.0296***	-0.0361***	-0.0007	-0.0350***	-0.0037	-0.2267	-0.0118
	(0.0045)	(0.0147)	(0.0050)	(0.0051)	(0.0147)	(0.0055)	(0.0092)	(0.1953)	(0.0103)
# of units in NBP	-0.0254***	0.0389**	-0.0319***	-0.0365***	-0.0472***	-0.0400***	0.0146	0.0867***	-0.0065
	(0.0045)	(0.0153)	(0.0049)	(0.0049)	(0.0179)	(0.0050)	(0.0102)	(0.0279)	(0.0115)
# of units in SIPNOX	-0.0421**	0.0227	0.1409*				0.0014	0.0756**	0.1794*
	(0.0197)	(0.0242)	(0.0817)				(0.0232)	(0.0334)	(0.1072)
# of units in TRNOX	-0.0429	-0.0007	-0.0169	0.0011	0.0111	-0.0134	0.1882	0.6062***	-2.0363***
	(0.0595)	(0.0175)	(0.0602)	(0.0526)	(0.0159)	(0.0523)	(0.2050)	(0.2351)	(0.5862)
# of units in TRNOXOS	-0.0129**	-0.0850***	-0.0056	-0.0241***	-0.0716***	-0.0031	-0.2076	-1.2838**	2.0335***
	(0.0064)	(0.0190)	(0.0069)	(0.0067)	(0.0171)	(0.0074)	(0.2053)	(0.5274)	(0.5867)
# of units in TRSO2G1	0.0667	0.0999***	0.0400	0.0274	0.1057***	0.0293	0.0317**		0.0744***
	(0.0592)	(0.0186)	(0.0597)	(0.0523)	(0.0170)	(0.0517)	(0.0143)		(0.0181)
# of units in TRSO2G2	0.0570		0.0482	0.0165		0.0534			
	(0.0595)		(0.0600)	(0.0525)		(0.0522)			
Observations	15,134	8,456	6,678	7,228	3,750	3,478	7,906	4,706	3,200

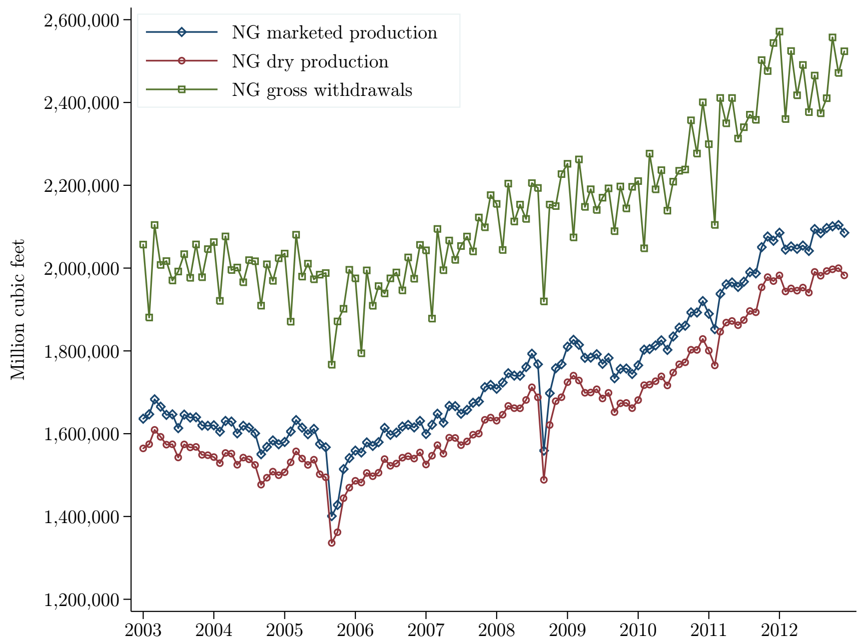
Figure 1: Shale plays and coal fields

Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI.
Updated: May 9, 2011

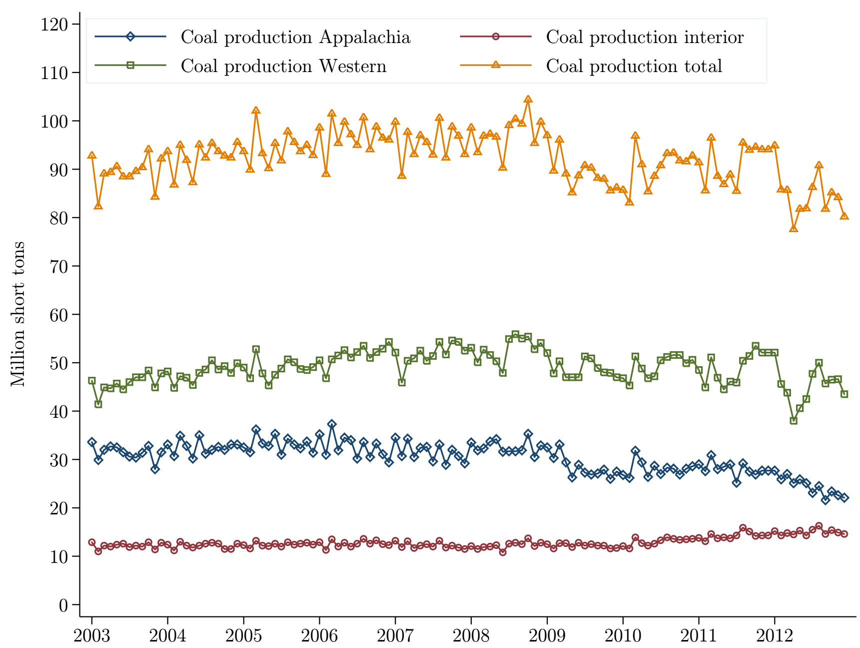
(a) Natural gas shale plays

(b) Coal fields

Figure 2: Natural gas and coal production

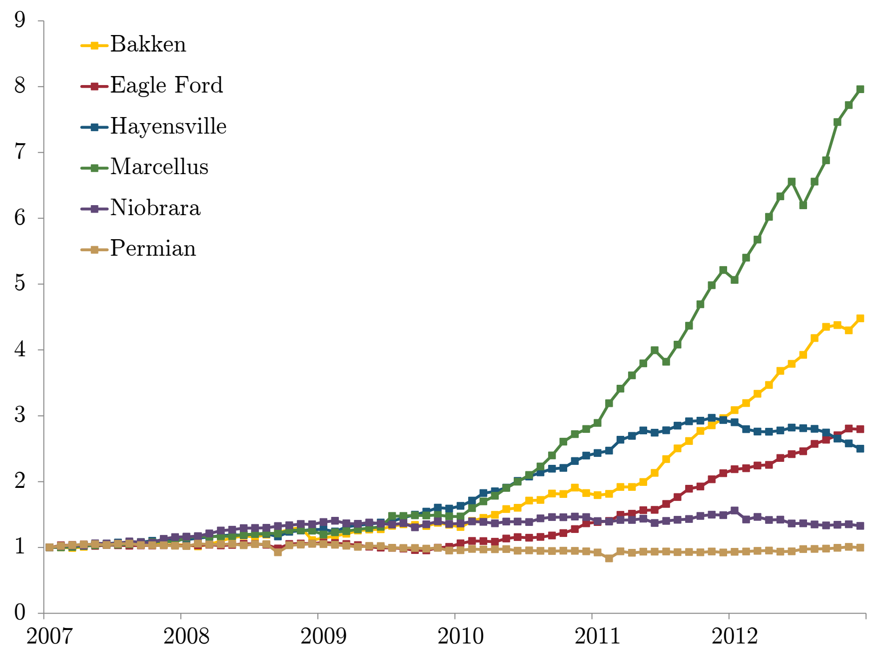


(a) Natural Gas

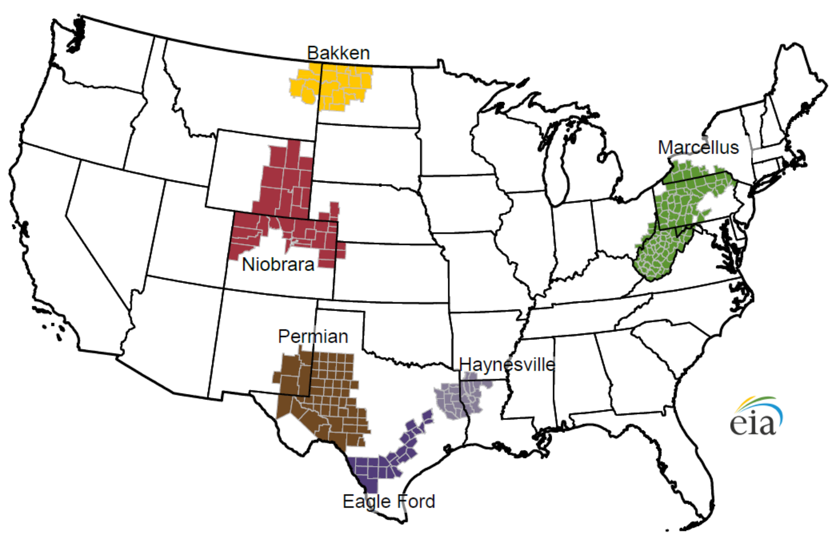


(b) Coal

Figure 3: Production (mcf/day) by major play, Jan-2007:1



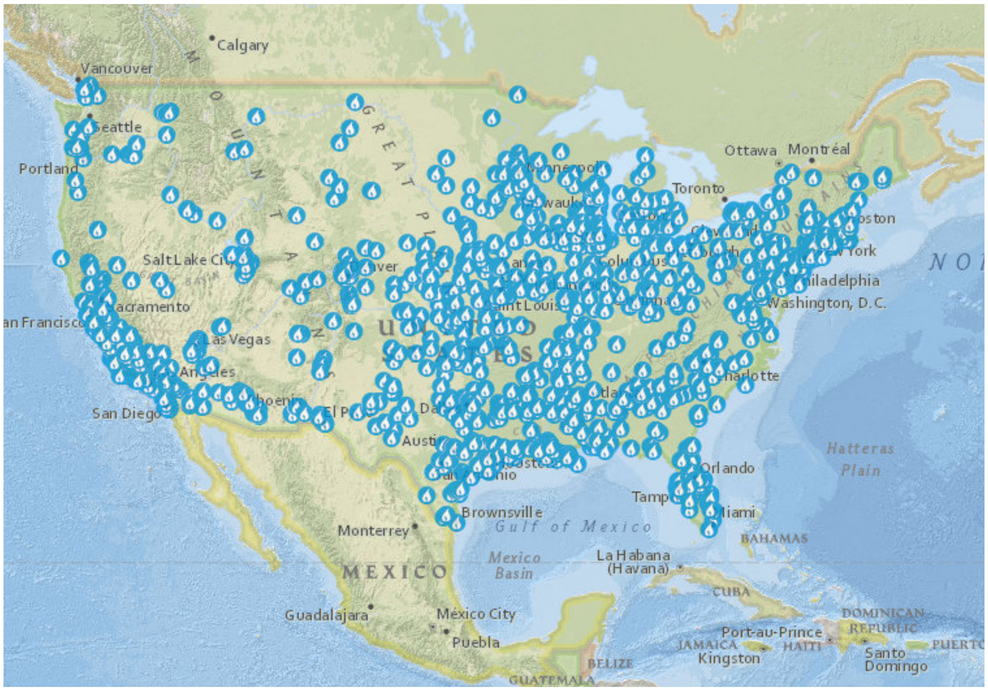
(a) Production



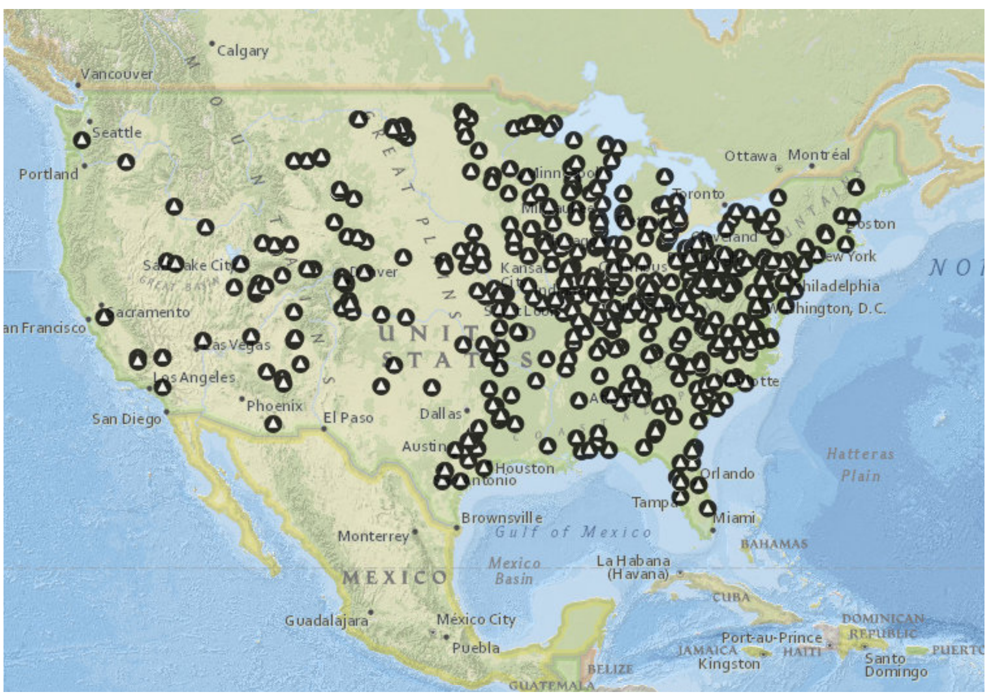
(b) Shale plays

Source: EIA Drilling Productivity Report

Figure 4: Power plants



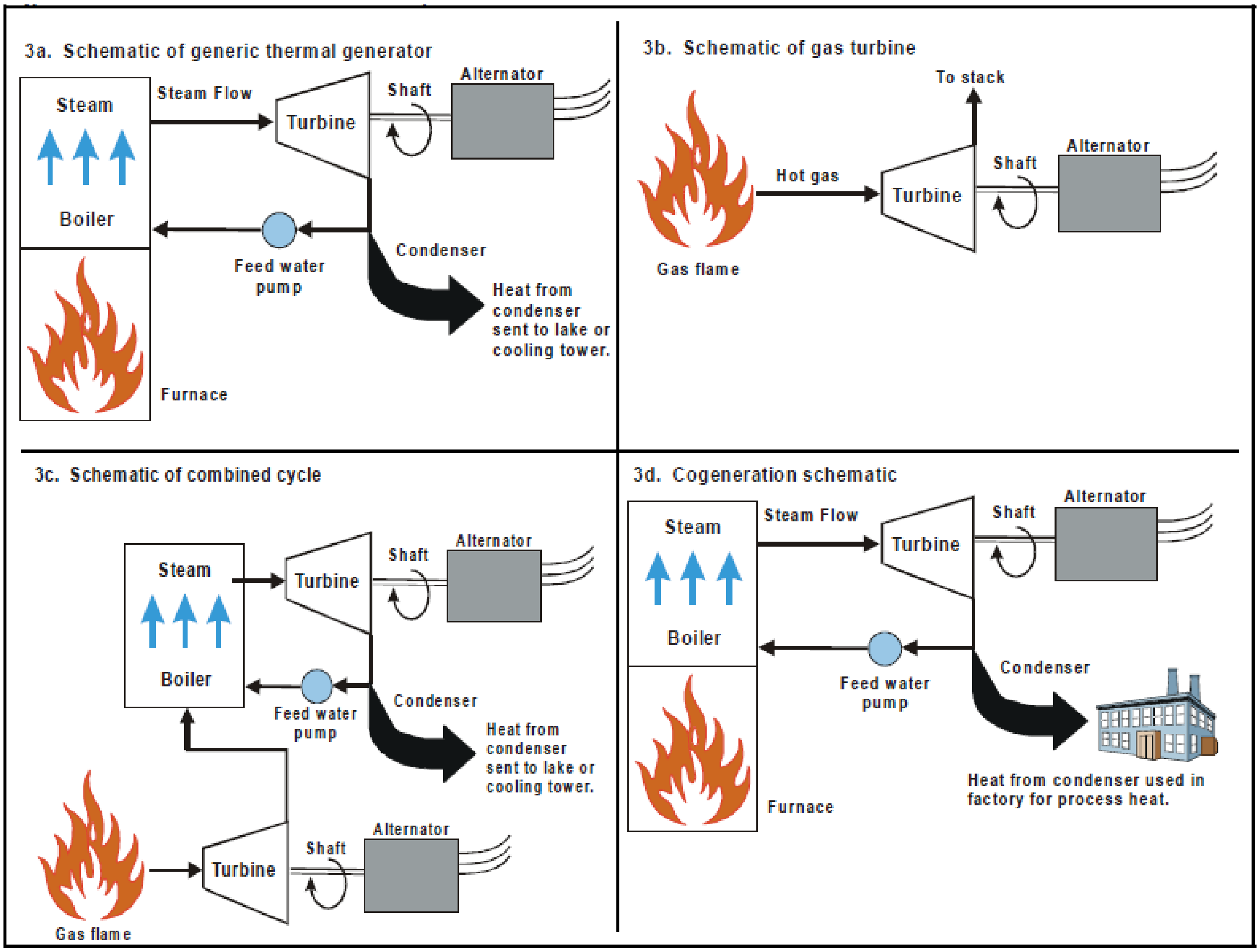
(a) Natural gas



(b) Coal

Source: EIA US energy mapping system

Figure 5: Simple schematic of power plant operations



Source: EIA (2000)

Figure 6: Entities involved in the supply of electricity

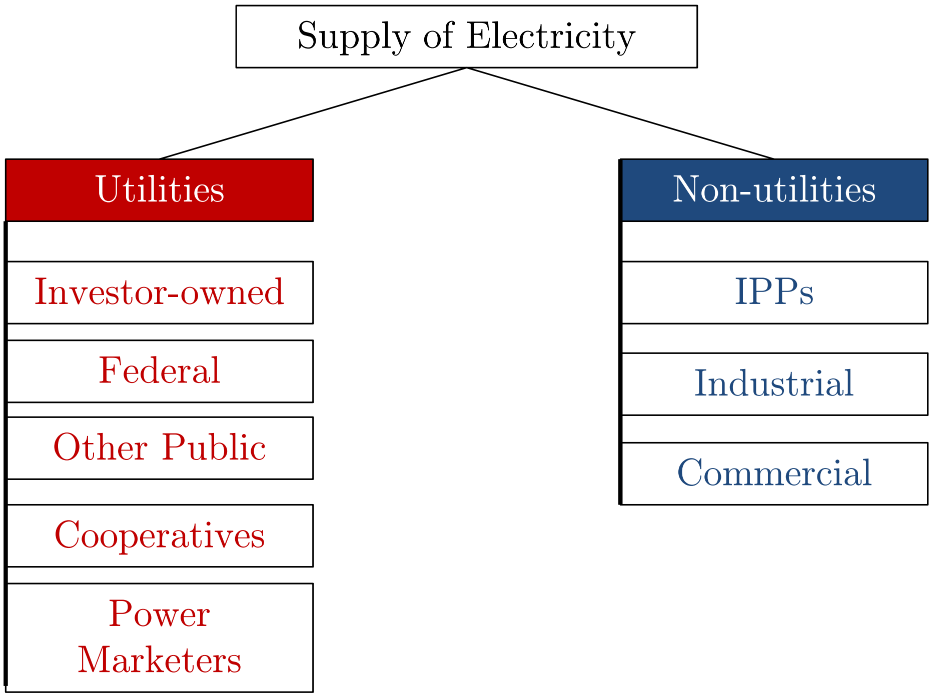
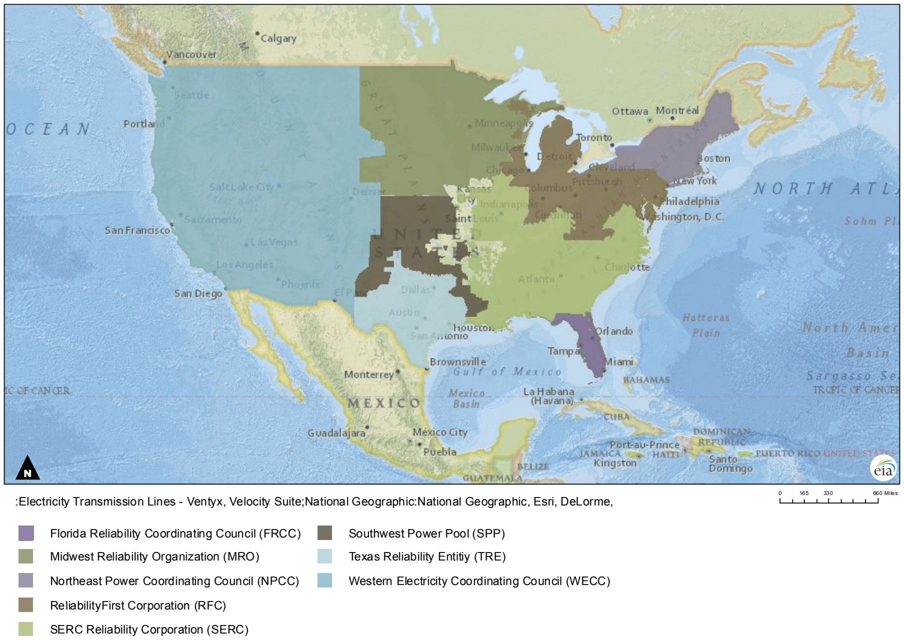
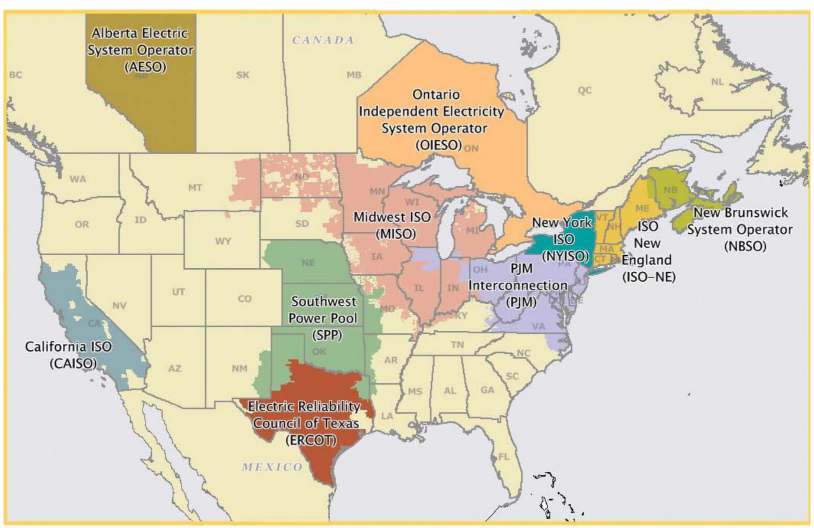


Figure 7: North American Electric Reliability Corporation Regions



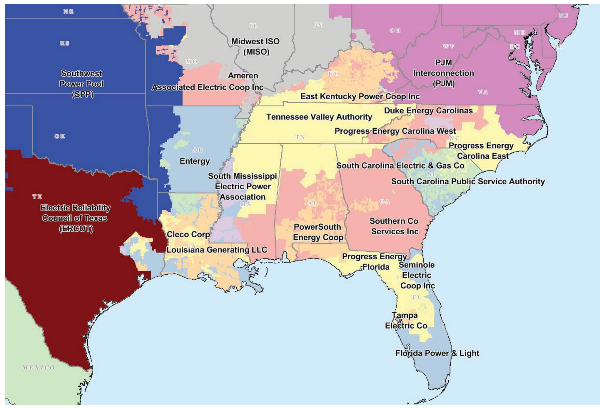
Source: EIA US energy mapping system

Figure 8: U.S. Regional Transmission Organizations, October 2011

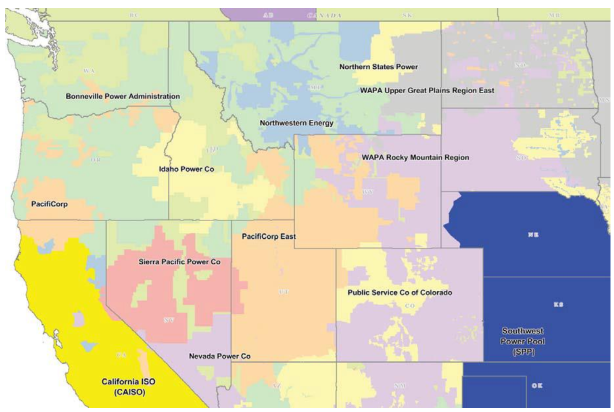


Source: FERC (2012)

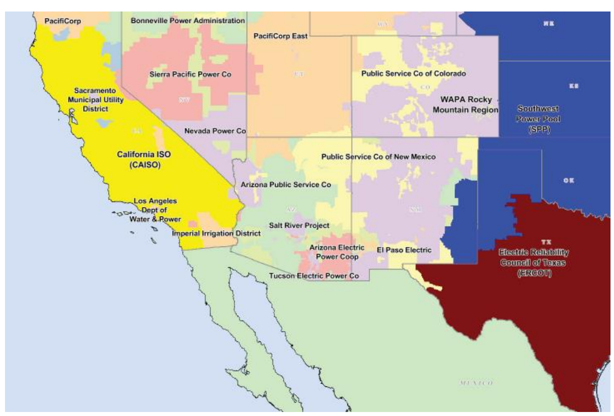
Figure 9: Traditional regional wholesale electricity markets



(a) Southeast



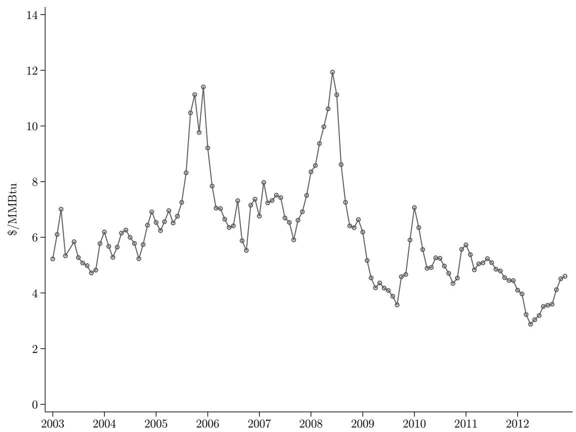
(b) Nortwest



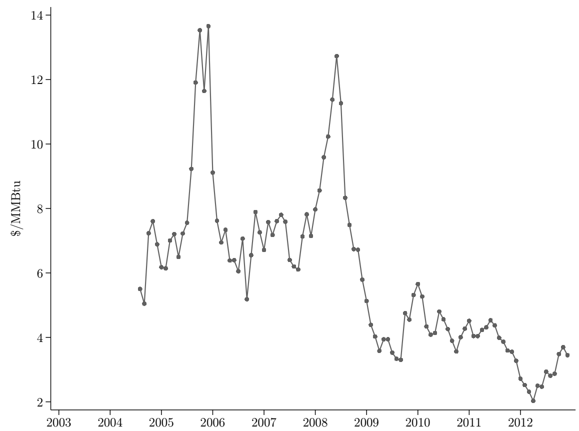
(c) Southwest

Source: FERC (2012)

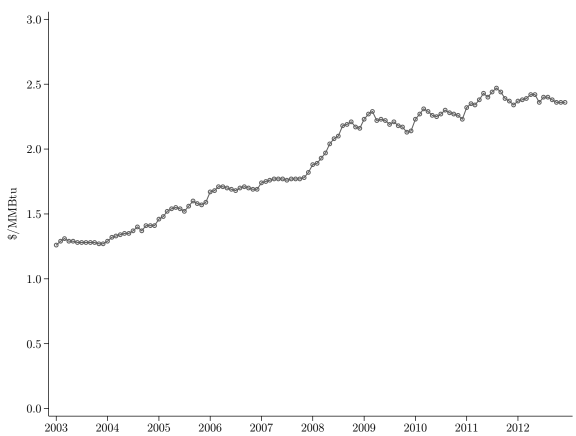
Figure 10: Fuel and allowance related costs



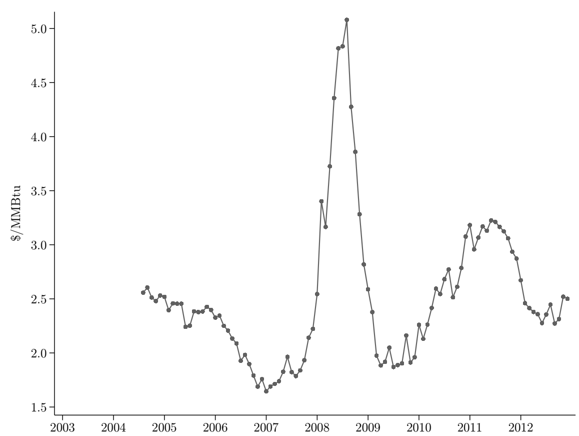
(a) Electric power sector price for natural gas



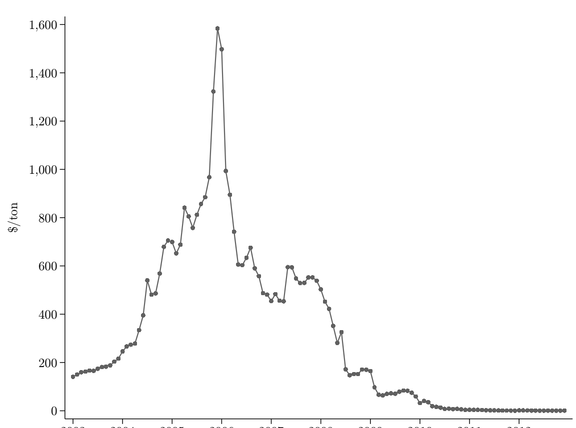
(b) NYMEX Henry Hub prompt month



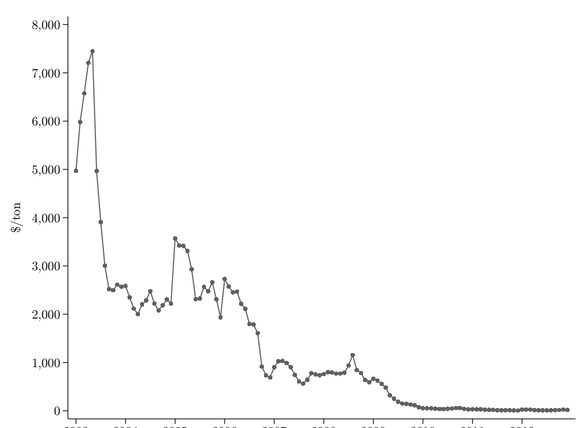
(c) Electric power sector price for coal



(d) NYMEX CAPP prompt month

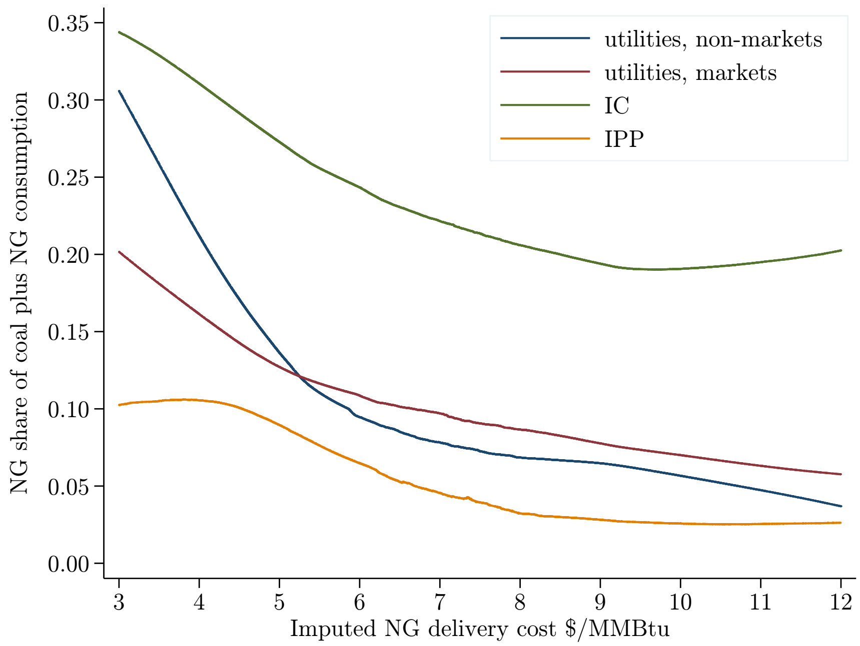


(e) SO_2 permit prices current vintage

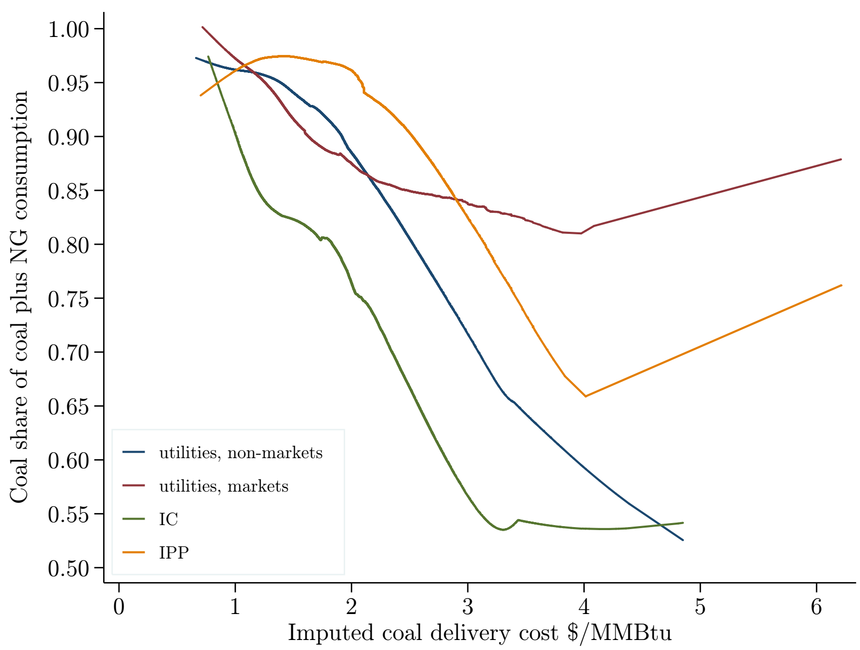


(f) Seasonal NO_x permit prices current vintage

Figure 11: Demand curves



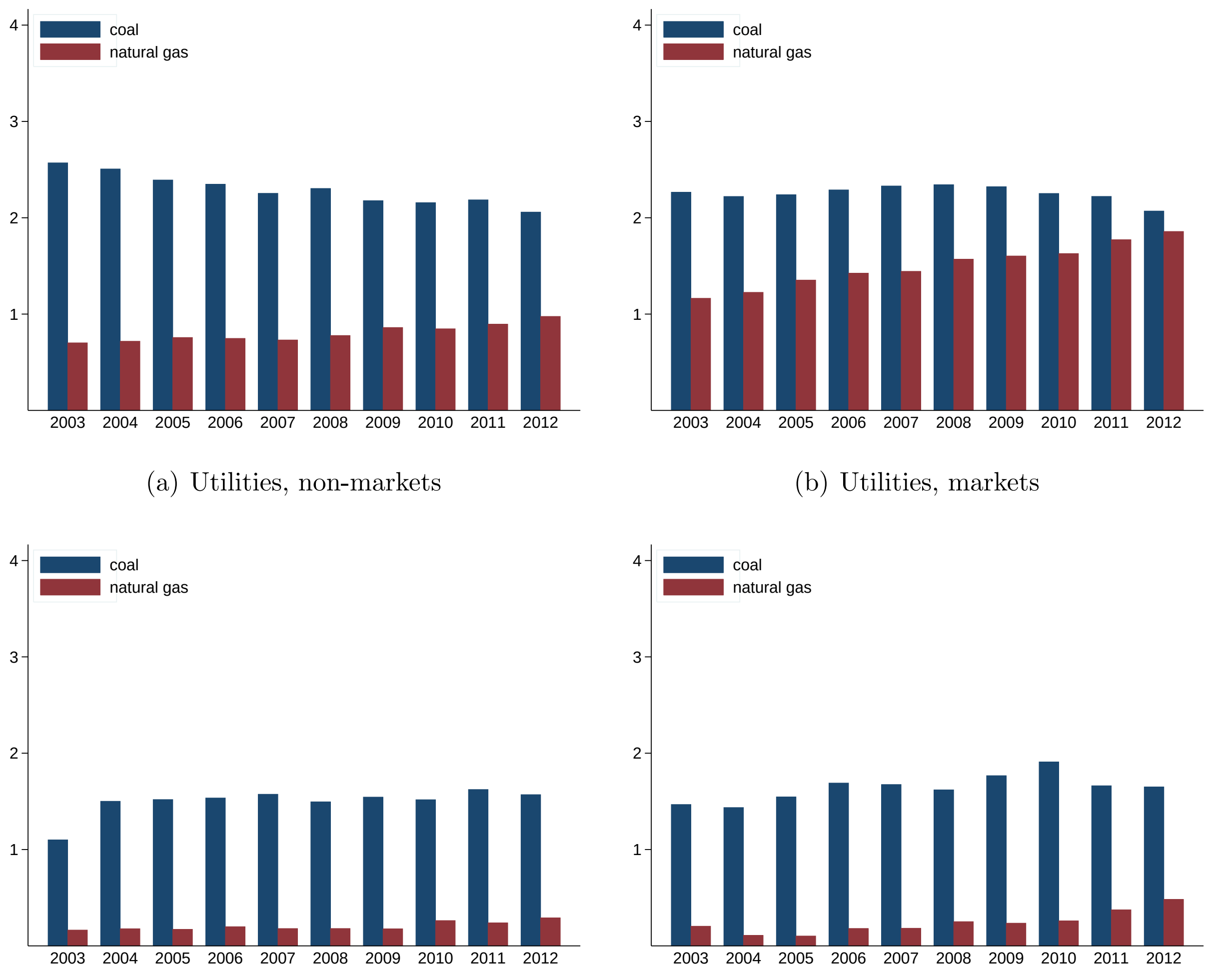
(a) Natural gas



(b) Coal

Note: We produce the graphs excluding delivery cost below the 5th and above the 95th percentiles.

Figure 12: Average number of generating units



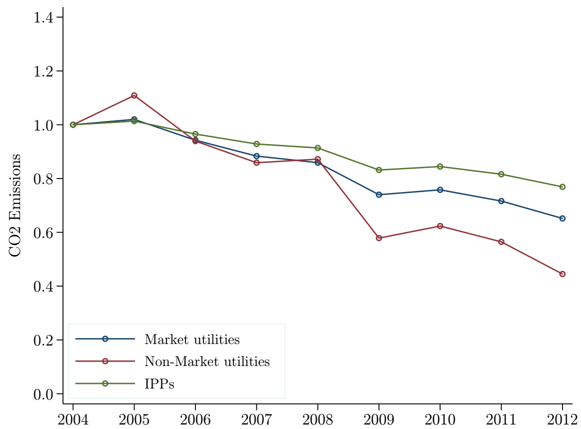
(a) Utilities, non-markets

(b) Utilities, markets

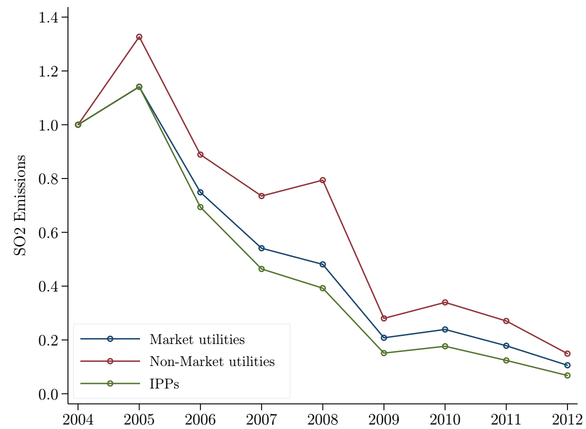
(c) IC

(d) IPP

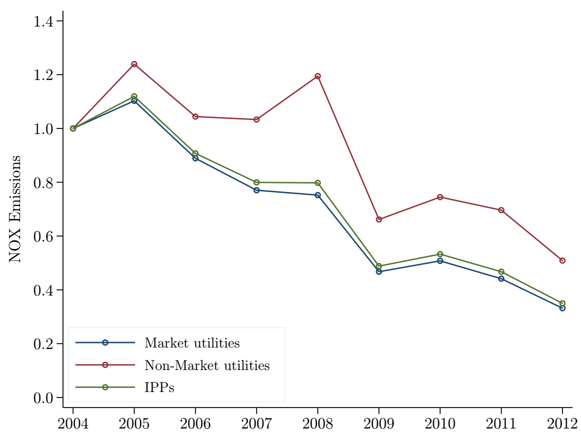
Figure 13: Back-of-the-Envelope Emissions



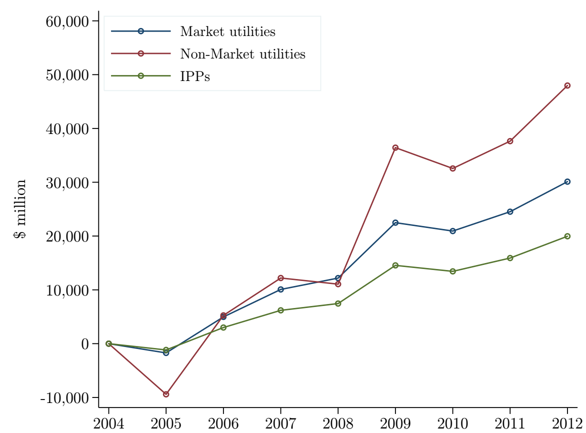
(a) CO_2 emissions



(b) SO_2 emissions



(c) NO_x emissions



(d) Gains from CO_2 emission reductions

Appendix

Overview of EPA programs

The overall goal of the Acid Rain Program (ARP) was the reductions in emissions of sulfur dioxide and nitrogen oxides, the primary causes of acid rain. Title IV of the Clean Air Act set a goal of reducing annual SO_2 emissions by 10 million tons below 1980 levels. To achieve these reductions, the law required a two-phase tightening of the restrictions placed on fossil fuel-fired power plants. Phase I began in 1995 and affected 263 units at 110 mostly coal-burning electric utility plants located in 21 eastern and Midwestern states. An additional 182 units joined Phase I of the program as substitution or compensating units, bringing the total of Phase I affected units to 445. Phase II, which began in the year 2000, tightened the annual emissions limits imposed on these large, higher emitting plants and also set restrictions on smaller, cleaner plants fired by coal, oil, and gas, encompassing over 2,000 units in all. The program affects existing utility units serving generators with an output capacity of greater than 25 megawatts and all new utility units. The Act also called for a 2 million ton reduction in NO_x emissions by 2000.[67]

In the 1970s, EPA established the National Ambient Air Quality Standard (NAAQS) for ozone initially at 0.08 parts per million (ppm)/hour (1971), revised to 0.12ppm/hour in 1979. In 1997, a new, more stringent 8-hour ozone standard of 0.08 ppm was promulgated. EPA responded by developing programs to reduce NO_x emissions, including the NO_x State Implementation Plan (SIP) Call rule in 1998. The NO_x Budget Trading Program (NBP), a central component of the SIP, was a cap-and-trade program created to reduce the regional transport of NO_x emissions from power plants and other large combustion sources that contribute to ozone non attainment in the eastern US. All 20 states covered by the NO_x SIP Call were in the NBP. In March 2008, EPA again strengthened the 8-hour ozone standard to 0.075 ppm. In 2009, CAIR's NO_x ozone season program began, effectively replacing the NBP in the affected states and requiring further NO_x reductions from the power sector.[68]

On March 10, 2005, EPA issued the Clean Air Interstate Rule (CAIR), which provides states with a solution to the problem of power plant pollution drifting from one state to another. CAIR covers 27 eastern states and the District of Columbia. The rule uses a cap and trade system to reduce the target pollutants—SO_2 and NO_x—by 70 percent. States must achieve the required emission reductions using one of two compliance options: (1) meet

[67] http://www.epa.gov/airmarkets/progsregs/arp/.

[68] http://www.epa.gov/airmarkets/progsregs/NO_x/sipbasic.html. Additional information is available at http://www.epa.gov/airmarkets/progsregs/NO_x/docs/NBPbasicinfo.pdf.

the states emission budget by requiring power plants to participate in an EPA-administered interstate cap and trade system that caps emissions in two stages, or meet an individual state emissions budget through measures of the states choosing. [69]

In July 2011, EPA finalized the Cross-State Air Pollution Rule (CSAPR), also known as the "Clean Air Transport Rule," requiring states to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine-particle pollution in other states ("good neighbor" provisions). More specifically, CSAPR requires a total of 28 states to reduce annual SO_2 emissions, annual and/or ozone season NO_X emissions to assist in attaining the 1997 ozone and fine-particle and 2006 fine-particle NAAQS.[70] CSAPR was intended to replace CAIR. The 1st phase of compliance was to begin January 1, 2012, for SO_2 and annual NO_X reductions and May 1, 2012, for ozone season NO_X reductions. The second phase of CSAPR begins January 1, 2014 and increases the stringency of SO_2 reductions in several states. However, CAIR remains in place until the end of a long legal battle among the stakeholders, which has reached the Supreme Court, regarding the details of the CSAPR implementation.[71]

[69]See http://www.epa.gov/cleanairinterstaterule/.

[70]http://www.epa.gov/airtransport/CSAPR/basic.html

[71]A December 2008 court decision kept the requirements of CAIR in place temporarily but directed EPA to issue a new rule to implement CAA requirements concerning the transport of air pollution across state boundaries. Subsequently, EPA made adjustments to CSCAPR to implement these CAA requirements and respond to the court's concerns in July 2011. On December 30, 2011, the DC Circuit Court ordered a stay of CASPR and ordered that CAIR be implemented until judicial review of CASPR was complete. On August 21, 2012, the same court ultimately vacated CSAPR and ordered that CAIR be continued to be implemented until the rule is rewritten. The Administration requested a rehearing of this ruling on October 5, 2012, but the U.S. Court of Appeals for DC denied the request. The administration petition the Supreme Court to review the Courts ruling. On June 24, 2013, the Supreme Court announced they would review the lower courts ruling. The Supreme Court heard oral arguments on December 10, 2013 but has not ruled yet. Meanwhile, CAIR remains in place until a replacement rule that satisfies the Courts is adopted.