DISCUSSION PAPER

July 2014 ■ RFF DP 14-19

How Do Natural Gas Prices Affect Electricity Consumers and the Environment?

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RESOURCES FOR THE FUTURE

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July 18, 2014

Abstract

Between 2008 and 2012, the delivered price of natural gas to the U.S. power sector fell 60 percent. This paper addresses, in theory and in practice, the effects of this negative price shock on electricity consumers and the environment. We demonstrate with a simple model that the larger the effects of gas prices on consumer welfare, the smaller the effects on pollution emissions and the smaller the increase in profits of existing natural gas–fired generators. Using detailed data on electricity prices, fuel consumption, and fuel prices from 2001 to 2012, we confirm this hypothesis. Regions that experience greater reductions in pollution emissions experience smaller reductions in electricity prices and consumer welfare.

JEL Classification Numbers: Q41, Q53

Key Words: Electricity Demand, Natural Gas, Coal, Shale Gas, Pollution

*We thank Theodore Kury, Erin Mansur, Karen Palmer, Anthony Paul, and Lilei Xu for comments and suggestions and the Heising-Simons foundation for funding. Linn: Resources for the Future, Washington, DC, *linn@rff.org*. Muehlenbachs: University of Calgary and Resources for the Future, Washington, DC, *muehlenbachs@rff.org*. Wang: Resources for the Future, Washington, DC, *ywang@rff.org*.

1 Introduction

In recent years the United States has experienced a dramatic increase in natural gas production from shale formations. The phrase "game-changing" abounds in the popular press when discussing shale gas.[1] Coinciding with a three-fold increase in the estimated technically recoverable shale gas reserves between 2008 and 2012, and a twenty-fold increase in the share of U.S. gas production from shale formations, the delivered natural gas price at U.S. power plants has decreased by 60 percent.

Although natural gas suppliers surely benefit from technological progress associated with shale gas development, the broad effects of shale gas on welfare and the environment has created considerable controversy and opposition among certain groups. Owners of coal-fired electricity generators, already facing increasingly stringent air pollution regulations by the Environmental Protection Agency, are suddenly much less competitive than they used to be. On the other hand, recent proposals to expand natural gas exports from the U.S. have drawn strong opposition from consumer groups opposed to the higher retail natural gas prices that would result. Furthermore, because gas-fired generators have lower rates of emissions per megawatt hour (MWh) of generation for carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrogen oxides (NO_x), fuel switching would cause pollution emissions to decrease.[2] This paper focuses on the interrelated impacts on power plant operators, electricity consumers and the environment from a natural gas price shock.[3]

The effects of energy prices on economic activity and welfare have generated considerable interest among economists, but the literature provides only limited insights for the particular case of shale gas. The literature has documented a strong statistical—and, many argue, causal—connection between energy prices and economic activity (see, for example, Hamilton, 2005, and Kilian, 2008, for reviews). These large effects are perhaps surprising given that energy accounts for a small share of overall business costs and consumer expenditures. A subset of the literature has tested theories seeking to explain the large effects, such as the inability to adjust the energy needs of the existing capital stock (e.g., Wei, 2003). This literature typically focuses on aggregate energy use and economic activity, but the effects of shale gas on the electric power

[1] For examples of the popular press, "The 'Game-Changing' Effect of Shale Gas," February 1, 2012, *Washington Post*; "Shale Gas Revolution," November 3, 2011, *New York Times*.

[2] In this paper we focus on the emissions upon combustion at individual power plants, but there is a growing, unsettled literature on the net climate benefits when accounting for the lifecycle greenhouse gas emissions including fugitive methane before delivery at the power plant (e.g., Burnham et al., 2011; Venkatesh et al., 2012; Alvarez et al., 2012; Allen et al., 2013; Miller et al., 2013).

[3] There is also a growing body of research documenting shale gas development's impacts on other aspects such as water quality (Osborn et al., 2011; Olmstead et al., 2013), local air pollution emissions (McKenzie et al., 2012; Kemball-Cook et al., 2010), public health (Hill, 2012; Adgate et al., 2014), and property values (Muehlenbachs et al., 2014).

sector are more nuanced. Several factors distinguish this sector: a) energy comprises a large share of total production costs; b) the capital stock is extremely long-lived; c) capital installed at existing plants differs considerably in the extent to which it uses natural gas. More specifically, energy accounts for roughly one-third of total costs in the power sector, as compared to an economy-wide average of 5 percent. The large energy cost share implies that natural gas price shocks could have commensurately large effects on the sector. Furthermore, capital accounts for most of the remaining costs and plants typically operate for many decades. The three characteristics imply that a natural gas price shock could have large and persistent effects on the relative costs and utilization of individual generators (Atkeson and Kehoe, 1999). Because of the importance of the electric power sector in providing services (about \$370 billion in sales in 2013) and pollution emissions (40 percent of U.S. CO_2 emissions, 70 percent of U.S. SO_2 emissions, and 15 percent of U.S. NO_x emissions), natural gas price fluctuations can have extremely high economic and environmental consequences.

In this paper we theoretically and empirically characterize the effects of lower natural gas prices, due largely to shale gas development and production, on the electric power sector and the environment. We begin by documenting the dramatic decrease in natural gas prices from 2008 to 2012 as well as the extensive variation across U.S. regions in relative fuel prices and the mix of coal and gas generators. In the context of an aggregate natural gas price shock and regional variation in fuel prices and generator mix, we show theoretically that the negative price shock should cause a shift from coal to gas-fired generation, as well as decreases in pollution emissions and electricity prices. We also demonstrate that the greater the shift from coal to gas-fired generation, the larger the decrease in pollution emissions but the smaller the decrease in electricity prices. Thus, regions that experience greater environmental benefits from the lower natural gas prices experience smaller benefits to electricity consumers in the form of lower electricity prices (assuming wholesale market price changes are passed to retail prices). Using recent changes in natural gas prices, we find strong evidence that natural gas prices have affected fuel consumption, pollution emissions, and electricity prices across the U.S. Moreover, the regional effects of natural gas prices differ considerably, and the regions experiencing greater changes in coal and gas-fired generation experience a greater emissions reduction but a smaller decrease in wholesale electricity prices.

Using a simple model in which coal- and natural gas–fired generators compete to supply electricity we show the interrelated relationship between the magnitude of fuel switching, emissions, and consumer benefits that arises from a drop in natural gas price. In the model, marginal generation costs vary both within and across fuel types. We first consider an equilibrium in which natural gas prices are sufficiently high that the marginal costs of gas generators exceed the marginal costs of coal generators; the situation corresponds to the pre-shale period. The coal generators operate at full capacity and the gas generators account for the difference between electricity consumption and coal-fired generation. The price of electricity equals the cost of producing electricity at natural gas generators. We compare this case with two possible equilibria when natural gas prices are lower (i.e., the post-shale period). The first possibility is that the marginal costs of the gas-fired generators remain higher than the marginal costs of the coal-fired generators. In that case, there is no change in generation but the electricity price falls in proportion with the natural gas price decrease. The second possibility is that the lower natural gas prices cause the marginal costs of some natural gas generators to fall below the marginal costs of some coal generators. In that case, the coal generators no longer operate at full capacity, and generation from the natural gas generators increases (i.e., fuel switching). When fuel switching occurs, the equilibrium electricity price now depends on the marginal costs of the coal generators and the decrease in the equilibrium electricity price is smaller in magnitude than the decrease that occurred when there was no fuel switching. The simple model thus yields three predictions: a) a decrease in natural gas prices reduces electricity prices and may cause fuel switching; b) the more fuel switching that occurs, the greater the decrease in emissions; and c) the more fuel switching, the smaller the decrease in electricity prices.

We use extensive data on fuel prices, power plant operation, emissions, and electricity prices to test these predictions. We implement a straightforward differences-in-differences strategy that takes advantage of the dramatic temporal and regional variation in delivered natural gas prices from 2001 to 2012. Lower natural gas prices indeed reduce coal-fired generation and increase natural gas–fired generation. In the primary empirical specification, the elasticity of coal-fired generation to the price of natural gas is 0.04 and the elasticity of natural gas–fired generation to the price of natural gas is -0.37, both of which are statistically significant at the 1 percent level. Because coal-fired generators are typically much larger than gas-fired generators, the estimates imply roughly a 1:1 switch from coal to natural gas generation due to a hypothetical natural gas price decrease. A decrease in natural gas prices significantly reduces carbon dioxide emissions, and the estimated elasticities are very similar to the fuel consumption elasticities. Natural gas prices also have large effects on wholesale electricity prices, with an average elasticity of 0.94 (off-peak) to 0.96 (peak). The Appendix includes a large set of additional statistical tests that confirm the main findings.

These results represent U.S.-wide averages, but we also find substantial regional variation that is consistent with the simple model's second and third predictions. In certain regions—Texas and Florida, in particular—natural gas prices have large effects on electricity prices but much smaller effects on fuel consumption and emissions. In contrast, in other regions, such as the Southeast and Northeast, natural gas price decreases cause substantial fuel switching and emissions reductions, but much smaller reductions in electricity prices.

Finally, we use the empirical estimates to quantitatively test the simple model's predictions. Simulating a 10 percent decrease in the natural gas price, we observe extensive fuel switching in some regions but very little in others. Across regions, there is a direct relationship among fuel switching, electricity prices, and emissions; the more fuel switching that occurs, the greater the reduction in pollution emissions, and the smaller the decrease in electricity prices.

This paper makes several contributions to the literature. It is the first to demonstrate the theoretical connection between the effects of natural gas prices on electricity prices and the environment. Numerous studies have used computational models of the electricity sector (or the entire economy) under different scenarios of natural gas supply (e.g., Brown and Krupnick, 2010; Burtraw et al., 2012; Macedonia et al., 2011; Fine et al., 2011; Venkatesh et al., 2012). These studies conclude that lower natural gas prices result in lower emissions of greenhouse gases, SO_2, and NO_x; lower coal-fired generation and electricity prices; and higher natural gas–fired generation. However, these studies do not discuss the theoretical links between these outcomes, and the computational models rely on assumptions regarding market structure, firm behavior, and technology costs. The second contribution is that, despite the recent natural gas price variation, ours is the first paper to estimate the effects of natural gas prices using observed market outcomes; a couple other recent empirical papers focus on emissions (Holladay and LaRiviere, 2013, and Cullen and Mansur, 2013). There is a large body of research on electricity markets showing that power plant operators behave inefficiently in regulated markets.[4] Here we focus on the post-restructured period and show that the relative marginal costs of and gas-fired generation play a fundamental role in the environmental outcomes and consumer welfare associated with natural gas price shocks. Furthermore, demonstrating the relationship between natural gas prices, fuel switching and electricity prices reiterates the importance of understanding these relationships when estimating cost pass-through.[5]

[4]For instance, Joskow, 1997, Borenstein et al., 2002 or Fabrizio et al., 2007 or newer studies such as Malik et al., 2011, Cicala (forthcoming), or Chan et al., 2013.

[5]See Fabra and Reguant (forthcoming) for an in-depth discussion of the difficulties of estimating the pass-through rate of emissions costs.

2 Data

We construct our main data set using data from the Energy Information Administration (EIA), the Environmental Protection Agency (EPA), and Platts. From the EIA we have both public and restricted-use data on fuel prices, fuel consumption, and generation by plant, month, and fuel type; from the EPA we have public data on emissions by plant, month, and fuel type; and from Platts we have their proprietary data on wholesale electricity prices by trading location and month.

2.1 Plant-level fuel consumption and net generation

We obtain information on plant-level fuel consumption and net generation from the EIA's Form EIA-923, "Power Plant Operations Report" (which prior to 2008 was Form EIA-906/920).[6] These forms provide information on each power plant in the United States for the years 2001-2012.[7] All electric power and combined heat and power plants that are connected to the grid and have a nameplate capacity of at least one megawatt (MW) must report data to the EIA. Large plants must report monthly data and smaller plants annual data. Of the approximately 6,000 reporting in the year 2012, about 1,900 report monthly data. We restrict our sample to include only plants reporting monthly, which account for 96 percent of total coal generation and 88 percent of total gas generation (see Table 1). Plant age and nameplate capacity were obtained from Form EIA-860, "Annual Electric Generator Report."

2.2 Geographic regions

Ideally, we would define electricity markets in such a way that electricity demand in a month exactly equals supply, so that net exports from a market are zero. In practice, because power flows from electricity generators to consumers along a transmission grid, we use the geography of the transmission system to define electricity markets. We distinguish three levels of geographic boundaries: power control areas (PCAs), North American Electric Reliability Corporation (NERC) regions, and interconnections. A PCA includes an integrated power grid in which all generators are operated by a single dispatcher (EPA, 2012). Transmission lines connect PCAs to one another, and

[6]Fuel consumption is listed as "total fuel consumption", which includes consumption for electricity and process steam production as well as "fuel consumption for electricity generation." Throughout the analysis, we use total fuel consumption because the methodology the EIA used to estimate fuel consumption for electricity generation changed during the sample period.

[7]Our sample period begins in 2001 because we found discrepancies between EIA-906/920 data and the state-level numbers published by the EIA (specifically, in the case of non-utility generation in the years 1999 and 2000). After conversations with individuals at the EIA, who also were not able to explain the discrepancies, we decided to begin our analysis in 2001.

there is substantial power flow between PCAs. Consequently, a PCA is not a suitable definition of the geographic extent of a market.

NERC is a non-profit corporation established by the utility industry to ensure the reliability of the North American bulk power system. The NERC regions used in this paper correspond to the eight regional reliability entities that NERC oversees. And finally, the United States contains three interconnections, the Eastern, Western, and Texas. Although the interconnections are connected electrically to one another, very little power flows between the three interconnections. In most of the analysis we treat each NERC region as a distinct market, although because there is some power flow between NERC regions we also perform some analysis using interconnections as markets.

Although the PCAs are not used to define a market, they are used to construct the fuel prices (see Section 2.3). We assign each plant to a PCA using the EPA's Emissions & Generation Resource Integrated Database (eGrid) data. The eGrid data provide a plant's PCA for the years 1996-2000, 2006, 2007, 2010, and 2012. During the period 1996-2012, the number of PCAs in the United States varies from 112 to 144. In the years with missing PCA data we impute each plant's PCA. Appendix subsection A.1 describes the steps taken to impute the PCA when data are not available, but we summarize the approach here. If a plant's PCA does not change between two non-consecutive eGrid years, we assume that the PCA does not change during the intervening years. If the PCA does change between two non-consecutive eGrid years, we infer the year in which the PCA change occurred using information obtained online about the system operator or plant owner. In cases when information is not available, we impute the year in which the change occurred based on the available data for nearby plants. Figure 1 shows the PCA regions in 2012 based on plants in the EIA data set. The figure shows that PCAs vary considerably in size, ranging from small municipalities to large power pools.

The EIA-923 provides each plant's NERC region. The NERC boundaries have changed somewhat over time, and to obtain static market definitions we use the NERC region most recently reported in the EIA data. Because the NERC region is missing for some plants in our data, we impute the NERC region using the NERC region of the nearest plant (which is determined in GIS using the plants' latitudes and longitudes, obtained from eGRID). We impute the NERC region for 0.45 percent of the sample.

We adjust the NERC boundaries so that each PCA lies in exactly one NERC region. These adjustments are fairly minor, and affect just 0.14 percent of the sample. Figure 2 shows a map of the final NERC regions, which correspond very closely to the standard regional boundaries. The plant's interconnection depends on the NERC region; the Western Interconnection includes the Western Electricity Coordinating

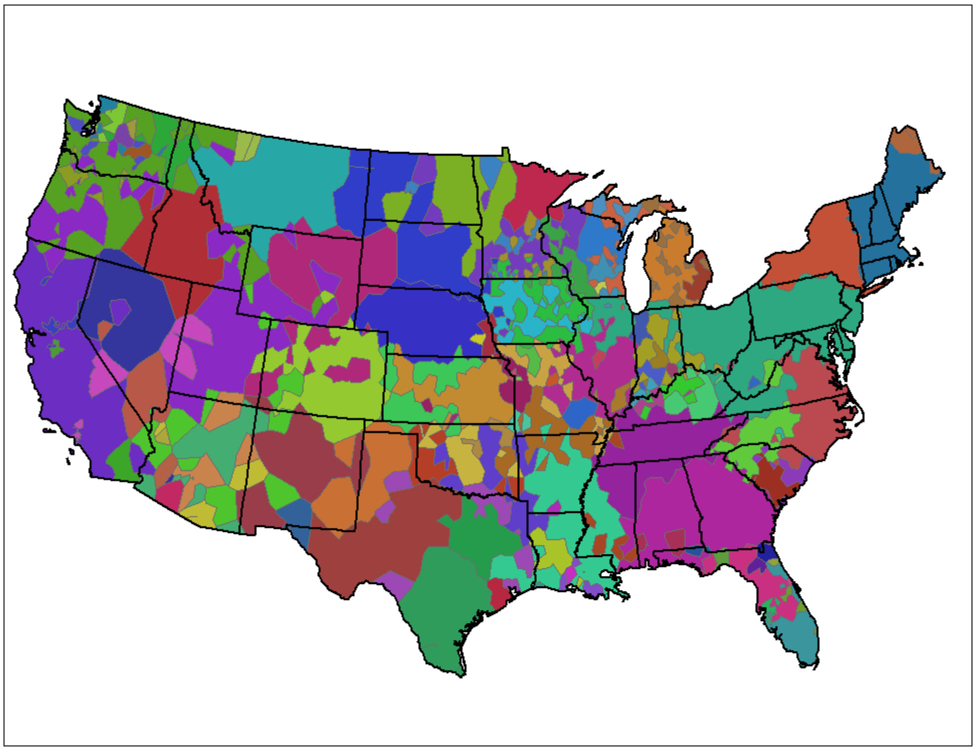


Figure 1: Power Control Areas (2012)

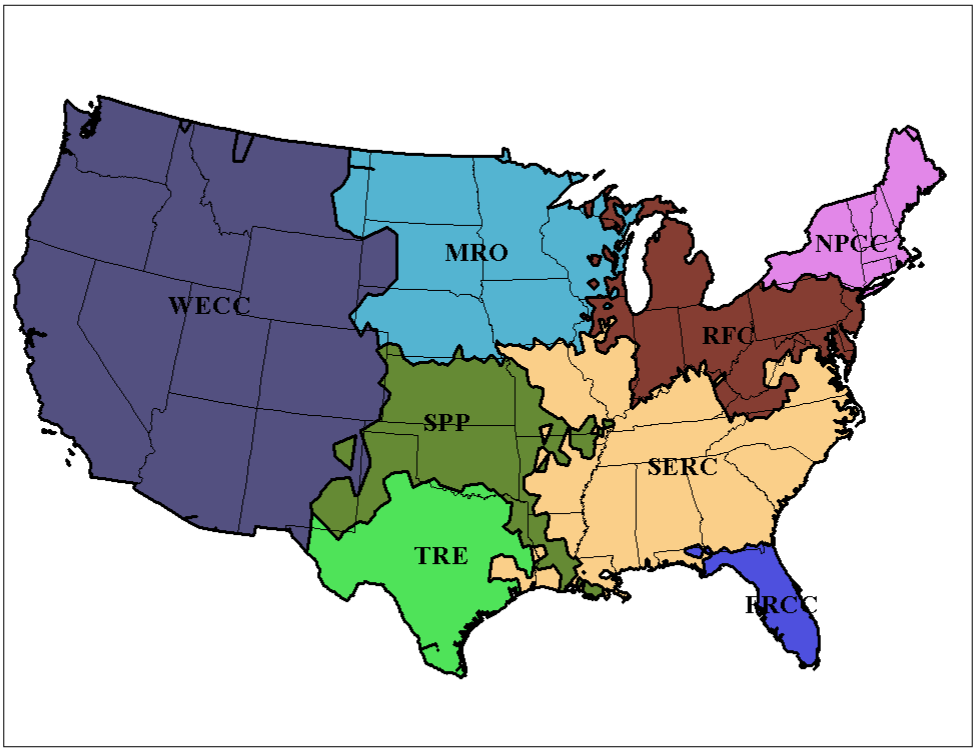


Figure 2: NERC Regions

Council (WECC), the Texas Interconnection includes the Texas Reliability Entity (TRE), and the Eastern Interconnection includes all other NERC regions.

We also drop observations missing fuel prices, fuel consumption, generation, or geographic identifiers. We show in Section 2.4that the resulting sample accounts for a high fraction of U.S. fuel consumption for electricity generation.

2.3 Coal and natural gas prices

We obtain plant-level fuel costs from the EIA Forms 423 and 923 ("Monthly Report of Cost and Quality of Fuels for Electric Plants" and "Power Plant Operations Report"). The data are reported similarly to the EIA fuel consumption and generation data, but for a smaller set of plants. More specifically, the data include the delivered costs of fuels by plant, month, and fuel type, in nominal dollars. The data also include the quantity of fuels delivered, in physical units, and the heat content of the fuel. Because the public EIA data only include fuel cost data for regulated plants, we have obtained confidential data from the EIA that include fuel cost data for non-regulated plants. From these data we compute the plant's average cost of delivered fuels by fuel type and month, in dollars per million British thermal units (mmBtu). In the regression analysis we use the PCA-average fuel costs, which equal the heat input-weighted average of the plant-level fuel costs in the PCA.

2.4 CEMS Emissions data

For the years 2001-2012, we obtain monthly fuel consumption and emissions of CO_2, SO_2, and NO_x by plant and fuel type from the EPA's Continuous Emissions Monitoring System (CEMS).[8] The number of plants covered in CEMS increases over time coinciding with changes in NO_x regulations. The data include all plants regulated under the U.S. Acid Rain Program and sources with NO_x emissions regulated by the EPA (EPA, 2009c).[9]With the expansion of the NO_x trading program over time, the coverage of gas-fired generation in the CEMS data increased.[10] The percentage of national heat input reported in CEMS also found in EIA-923 increased from 70 percent in 2001 to 93 percent in 2012. The percentages of fuel consumption covered by the CEMS data vary regionally, however, because of the geographic scope of NO_x regulation.

Table 1 shows the national coverage of the EIA and CEMS data sets. The table reports the percentage of fuel consumption found in the sample as a factor of fuel consumption in the raw EIA data, for 2001, 2006, and 2012. The final EIA data set covers 95 to 98 percent of coal fuel consumption reported in the raw data in most cases, although coverage of natural gas plants is somewhat lower because many natural gas plants report annually. Because of the greater coverage, we use the EIA data in most of the regression analysis.

[8]The CEMS sample is somewhat different from the EIA sample because of differences in the EIA and EPA reporting requirements. Furthermore, the CEMS data report gross generation as opposed to net generation in the EIA (net generation is equal to gross generation minus electricity used to power the plant's equipment).

[9]These include all units with greater than 25 megawatts of capacity and new units with less than 25 megawatts of capacity that use fuel with a sulfur content greater than 0.05 percent by weight (EPA, 2009a).

[10]The NO_x trading program was first implemented through the Ozone Transport Commission (OTC) from 1999 to 2002 and included Maine, New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island, New York, New Jersey, Pennsylvania, Maryland, Delaware, the northern counties of Virginia, and the District of Columbia (EPA, 2009c). These states transitioned to the trading program "NO_x SIP Call" in May 2003 (EPA, 2009c). Alabama, Illinois, Indiana, Kentucky, Michigan, North Carolina, Ohio, South Carolina, Tennessee, Virginia, and West Virginia joined the program in May 2004, and Missouri in May 2007 (EPA, 2009b). In 2009, the program was replaced by the Clean Air Interstate Rule (CAIR) NO_x ozone season program (EPA, 2009b). The CAIR covers 28 eastern states and the District of Columbia, of which Arkansas, Florida, Iowa, Louisiana, Minnesota, Mississippi, Texas, and Wisconsin were not regulated by previous programs.

Table 1: Fraction Fuel Consumption Included in Final Monthly Datasets

	EIA		CEMS	
	Natural Gas	Coal	Natural Gas	Coal
2001	0.91	0.98	0.90	0.99
2006	0.88	0.96	0.96	0.97
2012	0.87	0.95	0.95	0.97

Notes: For the final monthly EIA and CEMS data sets, total fuel consumption by fuel type is computed for the indicated years. The table reports the share of fuel consumption in the sample and year in total fuel consumption.

2.5 Electricity price data

We construct a separate data set that contains fuel prices and wholesale electricity prices by trading location and month. We purchased market-level electricity prices from Platts. The raw data report daily peak and off-peak wholesale electricity price indexes or assessments for 33 trading locations across the United States.[11] Because the fuel price, generation, and emissions data are monthly, we compute monthly peak and off-peak electricity prices as the arithmetic average of daily peak and off-peak prices. In some cases, daily data are missing because of insufficient trading; we drop location-months when more than 20 percent of the days have missing data, which account for 11

We match fuel prices in the first data set to electricity prices in the second data set. Specifically, each plant in the first data set is assigned to the closest trading location in the same NERC region. The location fuel prices are heat input-weighted averages across the matched plants. For 11 out of 32 of the locations, the data cover the years 2001-2012; for the remaining locations, the first year of the sample occurs between 2002 and 2007.

3 Background

3.1 Background on the U.S. Natural Gas Industry

Geologists have been aware of natural gas in shale formations since the early 1900s, but only with advances in hydraulic fracturing, horizontal drilling, and three-dimensional seismic imaging over the last two decades has extraction of the trapped natural gas become economical. Between 2008 and 2012, production from shale formations increased

[11] The indexes include fixed-price physical deals for next-day delivery. When the volume-weighted average price (the midpoint index) is not available, we take the average of maximum and minimum prices. For trading locations with very limited liquidity, Platts publishes an assessment rather than the index. The assessments are made based on “transactions, differentials to other locations, physical bid/ask spreads, derivatives trading and other information” (Platts, 2012, p. 5).

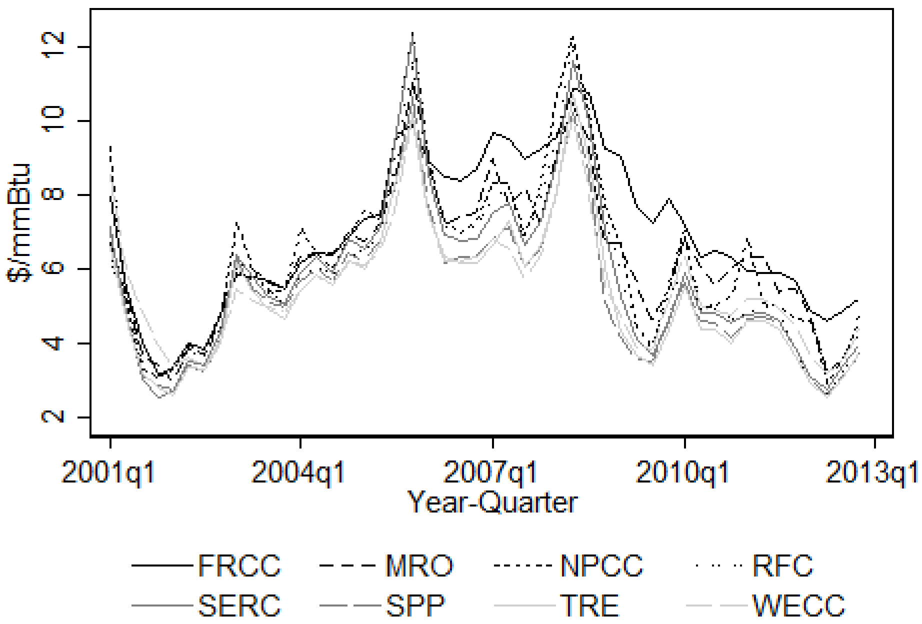
from 11 to 35 percent of total U.S. production.[12]

Coinciding with the increase in shale gas production there has been a dramatic decrease in natural gas prices. As Figure 3a indicates, on average, gas prices in 2012 were less than half of average gas prices in 2008. The figure also shows that the extent of the price decrease varied across NERC regions. Before 2006, the prices across regions tracked each other very closely, with the greatest spread occurring in winter months, and particularly in the Northeast Power Coordinating Council (NPCC) region. After 2006, regional variation has increased—particularly for the Florida Reliability Coordinating Council (FRCC) region, but for other regions as well. By comparison with natural gas prices, coal prices are much less volatile (see Figure 3b)

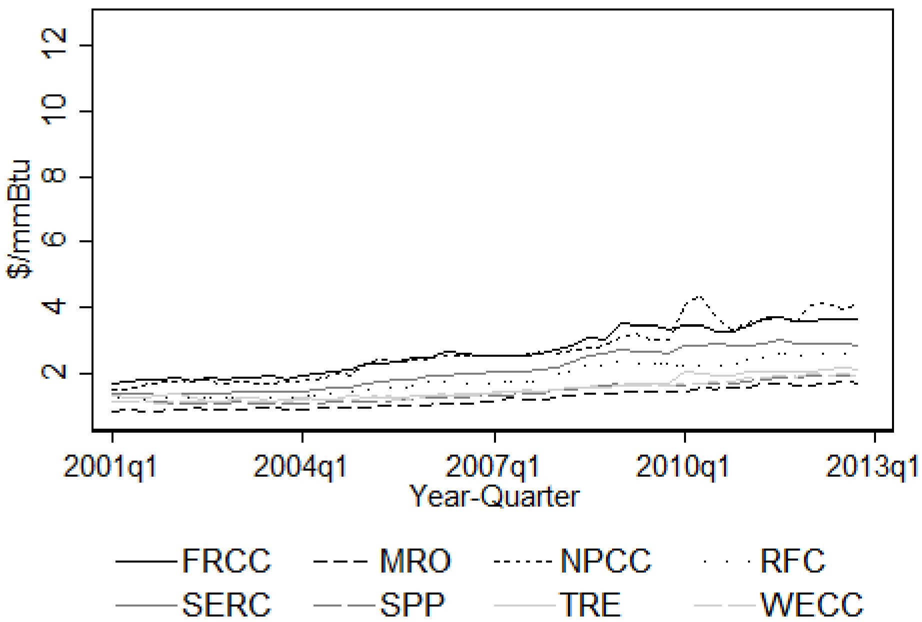
There are several, interrelated, reasons why natural gas production could affect prices differentially across NERC regions. First, pipeline congestion prevents delivered natural gas prices from being equal across locations at a particular time. These constraints are driven by differences in the locations of the supply of natural gas and the demand for natural gas. Besides the electricity sector, the major sectors consuming gas include residential and commercial heating, and manufacturers of steel, glass, brick, fertilizers, chemicals, clothing, and medicine. In 2013, the electric power sector accounted for about 34 percent of natural gas consumption, with the residential and commercial (34 percent) and industrial (31 percent) sectors accounting for most of the rest. These consumption shares vary dramatically across regions, which, combined with the temporal variation in demand from each of these sectors, contributes to some of the temporal and geographic price variation in Figure 3a. Also, within a region, natural gas–fired electricity plants that are located more closely to major pipelines would benefit from lower delivered prices. Every year there are additions to pipeline capacity; the largest addition to capacity during our study period occurred in 2008, coinciding with the increasing shale gas production and falling natural gas prices.[13] Geographic price variation can also be driven by variation in the availability of storage capacity. Well-placed storage could reduce geographic price variation caused by pipeline transmission congestion. Gas may be stored in salt caverns, depleted reservoirs, aquifers, above-ground tanks, and even pipelines. Storage is particularly useful in moderating seasonal price fluctuations, but regions have varying amounts of storage capacity. This section has focused on the sources of regional gas price variation, which is used in the empirical analysis. The next section characterizies how the *(*effects) of gas prices on the power sector may vary across regions.

[12]Using EIA data on U.S. natural gas gross withdrawals.

[13]Specifically, in 2008, almost 45 billion cubic feet per day capacity was added, compared to the next largest addition in 2009 of just over 21 billion cubic feet per day (EIA, 2013).



(a) Average Natural Gas Price at Plants

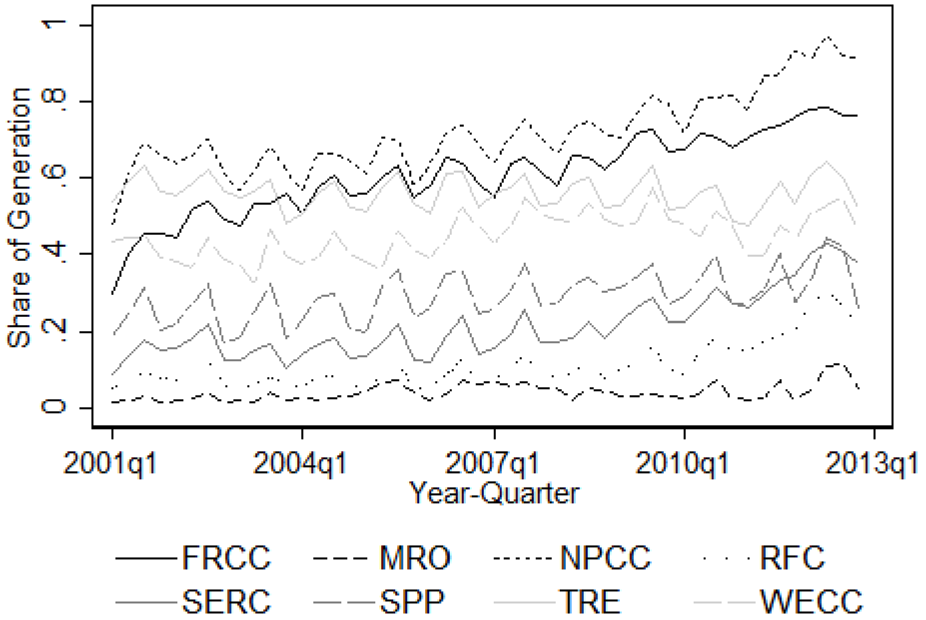


(b) Average Coal Price at Plants

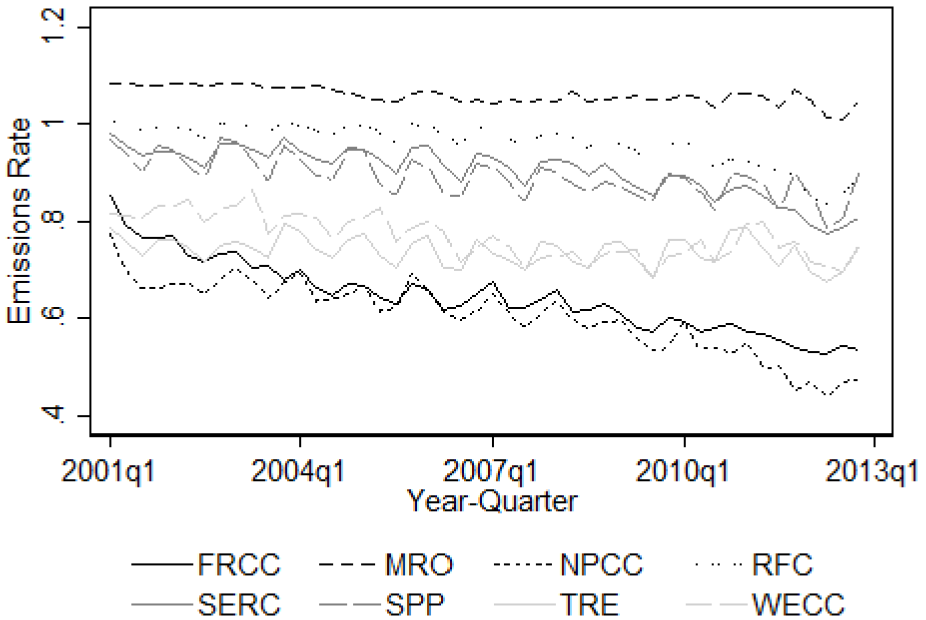
Figure 3: Average Natural Gas Price and Coal Price by NERC Region

3.2 Regional Variation in Fuel Prices and Generator Stock

During the sample period, Figure 4a demonstrates that gas-fired generation, as a fraction of coal and gas generation, slightly increased over time, with a steeper increase after 2008. At the same time, most regions experienced a gradual decrease in the CO_2 emissions rate (Figure 4b).



(a) Share of Generation from Natural Gas



(b) CO_2 Emissions per Generation

Figure 4: Share of Generation from Natural Gas and CO_2 Emissions Rate by NERC Region

Further discussed at the end of Section 4, there are factors other than fuel input costs that might influence the degree of fuel switching, including the availability of excess gas-fired capacity. Without unused capacity, a decrease in natural gas prices would not be able to cause short-run fuel switching. Table 2 shows the total generation capacity as well as the average capacity factor across all plants by region and fuel type in 2012. A capacity factor much less than one suggests that some capacity may be available, although perhaps not at peak demand times. Excess natural gas–fired capacity does vary across regions, with MRO having the most spare natural gas capacity and FRCC having the least.

Table 2 also shows that the average age of plants varies across regions, with coal plants being older than gas plants in all regions. However, in some regions the difference is very small (i.e., FRCC, SPP and TRE). Because the fuel efficiency of new gas plants has improved over time, the age differences of the gas generators suggest that the relative costs of operating a natural gas plant and a coal plant might vary significantly across regions.

Table 2: Total Capacity and Plant Characteristics by Region

	All	FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC
Total Capacity (TW, Coal)	322.87	9.58	23.39	5.04	105.45	104.29	22.52	21.07	31.54
Total Capacity (TW, Gas)	419.06	36.25	12.22	30.79	65.34	111.85	32.58	55.68	74.36
Avg. Capacity Factor (Coal)	0.51	0.48	0.62	0.18	0.47	0.47	0.59	0.6	0.64
Avg. Capacity Factor (Gas)	0.31	0.44	0.12	0.38	0.27	0.29	0.27	0.33	0.29
Avg. Age (Coal)	44.65	30.39	47.65	55.94	48.22	45.73	38.35	28.95	40.34
Avg. Age (Gas)	28.4	30.03	37.09	29.87	24.76	28.29	37.36	25.33	25.37

Notes: To avoid double counting, all plants were designated as coal or gas, depending on majority share of nameplate capacity. Plant average capacity factor and age are calculated for 2012.

Figure 5 demonstrates the very strong relationship between the U.S. average peak electricity price and the average natural gas price. The electricity price is typically set at the marginal cost of the highest-cost generator in operation, implying that natural gas–fired generators are typically the highest-cost generators.

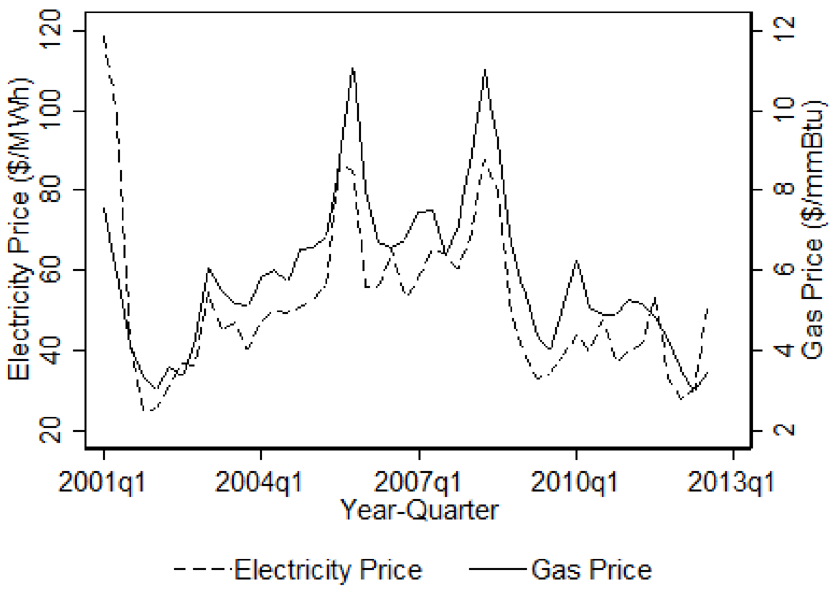


Figure 5: Natural Gas Price and Peak Electricity

4 Simple Power Sector Model

The previous section documented the temporal and geographic natural gas price variation. In this section, we use a simple model to show the theoretical effects of fuel prices on fuel switching, emissions, and consumer welfare. The central result is that the more a gas price shock causes fuel switching, the greater the change in emissions and the smaller the change in electricity prices and consumer welfare.

Consider a one-period electricity market. Electricity demand is fixed at Q, which is independent of the equilibrium price, p.

On the supply side, there is a set of coal-fired electricity generators and a set of gas-fired electricity generators. An independent firm owns each generator and each firm takes the electricity price as exogenous. To focus on the short-run effects of gas prices we assume that fixed costs for each generator equal zero and variable costs consist entirely of fuel costs.

Each coal generator has an infinitesimally small maximum generating capacity, and the sum of capacity across coal generators in the market is $\bar{q}_c < Q$. Each coal generator is identical and its marginal costs equal its heat rate (which is the heat input per MWh of electricity generated, i.e., the inverse of fuel efficiency) multiplied by the price of coal, p_c. We normalize the heat rate of the coal generators to 1 and the marginal costs of each coal generator equal to the price of coal: $m_c = p_c$.[14] Let q_c equal total

[14]In reality there is a lot of variation in the efficiency of coal plants due to age and other factors (Linn et al., 2014). We make the simplification that marginal costs are equal to the price of coal for

equilibrium coal-fired generation.

The rate of emissions per unit of coal heat input is e_c. Because the heat rate is 1, the emissions per unit of generation equal e_c.

Like coal generators, each natural gas generator is infinitesimally small and has zero fixed costs. Unlike coal generators, natural gas generators have both fuel and non-fuel variable costs. Fuel costs are the same for all natural gas generators and equal a constant multiplied by the price of natural gas fuel; as with the coal generators, we normalize the heat rates of the natural gas generators to equal 1. The non-fuel costs vary across natural gas generators and we order the natural gas generators by increasing non-fuel costs. This ordering yields an upward sloping supply curve for the natural gas generators: $m_g = p_g + bq_g$ where b is a positive constant, q_g is aggregate generation from gas generators, and p_g is the price of natural gas. Note that we could relax the assumption that natural gas generators have identical heat rates to one another; doing so would complicate the equilibrium expressions below but would not affect the qualitative conclusions.[15]

Emissions from gas generators per unit of generation equal the heat rate multiplied by the emissions per unit of heat input, e_g. Emissions per unit of generation are e_g.

In equilibrium each coal generator operates if the equilibrium electricity price exceeds its marginal costs, and likewise for each natural gas generator. Equilibrium consists of an electricity price, p^*, total coal capacity in operation, q_c, and total natural gas capacity in operation, q_g. In equilibrium, total generation equals total demand.

To characterize the short-run implications of a natural gas price decrease, we compare equilibriums across three cases in which fuel prices differ. *Case 1:* Suppose, first, that the coal price is lower than the natural gas price so that $m_{c1} < p_{g1}$ (the subscript 1 indicates the case number being considered). Generation from each of the (identical) coal generators has lower marginal costs than generation from any of the natural gas generators. Therefore, in equilibrium coal generators operate at full capacity and $q_{c1} = \bar{q}_c$. Natural gas generators supply the remaining electricity and $q_{g1} = Q - \bar{q}_c$. Solving for equilibrium electricity price: $p_1^* = p_{g1} + b(Q - \bar{q}_c)$. Emissions equal $\bar{q}_c e_c + (Q - \bar{q}_c)e_g$.

Figure 6 shows the equilibrium. Generation is plotted along the horizontal axis. Coal generation increases from left to right beginning at the left vertical axis and gas generation increases from right to left beginning at the right vertical axis. The solid lines represent the coal and gas supply curves and the supply curves intersect at the equilibrium electricity price. *Case 2:*

exposition; relaxing this assumption would not change the main implications of our model.

[15]For example, we could recognize differences between combined cycle gas turbines (CCGTs) and open-cycle plants, which are more expensive to operate.

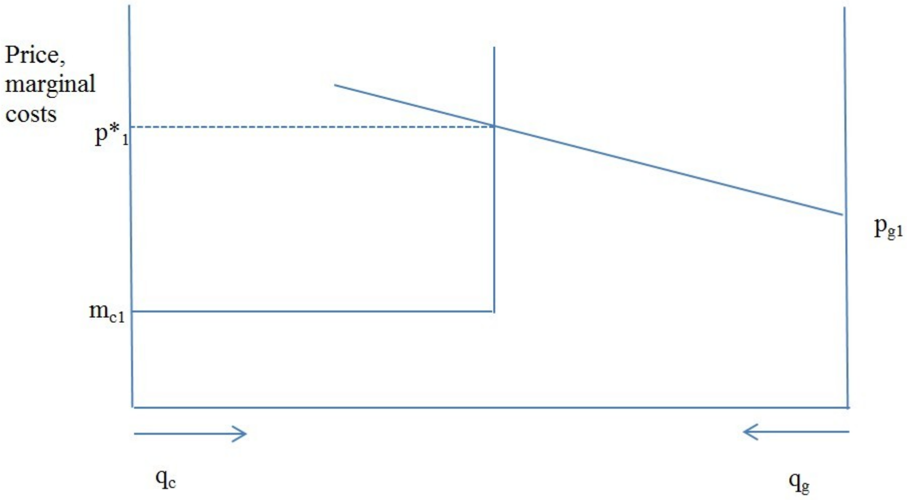


Figure 6: Equilibrium for Case 1

Notes: The figure shows the equilibrium for case 1. The horizontal axis plots generation and the vertical axes plot the electricity price and marginal costs. Coal generation increases from left to right starting at the left vertical axis and gas generation increases from right to left starting from the right vertical axis. The two curves represent the coal and gas supply curves and the intersection indicates the equilibrium electricity prices and quantities.

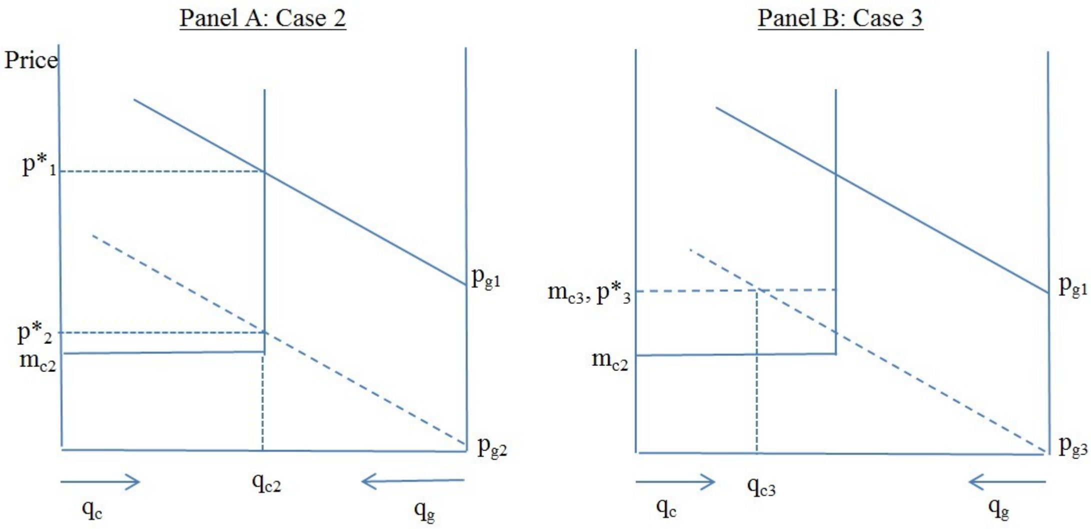


Figure 7: Equilibrium for Cases 2 and 3

Notes: The figure shows the equilibriums for case 2 (Panel A) and case 3 (Panel B). The figures are constructed similarly to Figure 6. In Panel A the dashed diagonal curve represents the gas supply curve with the lower price of gas compared to case 1. In Panel B the gas supply curve is the same as in Panel A and the coal supply curve is shifted up from the coal supply curve in Panel A. The coal generation quantity is q_{c2} in Panel A and q_{c3} in Panel B, where $q_{c3} < q_{c2}$.

Suppose, instead, that the natural gas price is lower than in the previous equilibrium, and is equal to p_{g2}. However, coal prices are sufficiently low that even at the lower gas price (compared to case 1), the marginal costs of the coal generators are still lower than the marginal costs of the highest-cost gas generators that are operating. No fuel switching occurs, meaning that coal and natural gas generation are the same as in case 1. Because there is no change in generation, emissions are also unchanged from case 1. The equilibrium electricity price falls to $p_2^* = p_{g2} + b(Q - \bar{q}_c)$.

Panel A of Figure 7 shows the equilibrium for case 2. The downward shift of the natural gas supply curve causes the equilibrium price to fall below the level in case 1. The equilibrium quantity of coal-fired generation is unchanged from case 1.

Case 3:

In case 3 the natural gas price is the same as in case 2 but the coal price is higher than in cases 1 and 2; $p_{c3} > p_{c1}$. The coal price is sufficiently high that if all coal generators operate at full capacity, the marginal costs of some gas generators that are not operating are lower than the marginal costs of the coal generators: $m_{c3} > p_{g3} + b(Q - \bar{q}_c)$. This cannot be true in equilibrium and, compared to cases 1 and 2, coal-fired generation decreases and natural gas–fired generation increases. Natural gas generation is $q_{g3} = (m_{c3} - p_{g3})/b > Q - \bar{q}_c$. Coal generation is $q_{c3} = Q - q_{g3} < \bar{q}_c$.

The decrease in coal generation implies that some coal generators are not operating, because of which the equilibrium electricity price equals the marginal costs of the coal generators: $p_3^* = m_{c3}$ (we assume that natural gas prices are sufficiently high that there is at least some coal generation in equilibrium). Because $m_{c3} > p_2^*$, the equilibrium price falls by less in case 3 than in case 2.

Emissions are lower in case 3 than in case 2 because of the switch from coal to gas generation. The change in emissions is $(e_g - e_c)(\bar{q}_c - q_{c3})$, which is equal to the difference between the coal and gas emissions rates multiplied by the amount of fuel switching.

Panel B of Figure 7 shows the equilibrium for case 3 to compare with the equilibrium for case 2. In the two panels, the natural gas supply curve shifts down by the same amount, but the coal supply curve is higher for case 3 than for case 2. As a result, the equilibrium electricity price is higher and coal generation is lower for case 3 than for case 2.

Comparing cases 2 and 3, the emissions reduction is inversely related to the amount of fuel switching; the more switching from gas to coal generation, the greater the decrease in emissions. We can derive a simple numerical relationship between the amount of fuel switching and the emissions reduction. If we assume that the coal emissions rate is twice that of gas, which is approximately true for existing coal and gas generators in the United States, the fractional change in emissions is $\Delta E = (q_{c3} - \bar{q}_c)/(Q + \bar{q}_c)$. By comparison, the ratio of the change in coal generation to total generation—a measure of the amount of fuel switching —is $(q_{c3} - \bar{q}_c)/Q$. This quantity is larger than the fractional change in emissions. How much larger depends on the shares of coal and gas in total generation. Prior to the decrease in natural gas prices in 2008, coal accounted for about half of total generation. In that case, the fractional change in emissions is about two-thirds the fractional change in generation.

Comparing the three cases shows that the amount of fuel switching, the change in emissions, and the change in electricity prices depend on the initial conditions. The model demonstrates the importance of relative fuel prices: the higher the price of coal is initially, the more fuel switching, the greater the reduction in emissions, and the smaller the decrease in electricity prices. Other factors, not modeled explicitly, may also affect these outcomes, such as non-fuel costs and the share of coal and gas generators in the system. Similar results would apply if, instead of comparing cases with different non-fuel costs of coal generators, we considered different magnitudes of the natural gas price decrease. Despite the simplicity of the model, however, three conclusions apply more broadly:

1. *Electricity prices:* Comparing case 1 with cases 2 and 3, lower natural gas prices cause lower electricity prices and may cause fuel switching because in case 1 the electricity price is proportional to the price of natural gas.

2. *Fuel switching and the environment:* Comparing cases 2 and 3, the more fuel switching that occurs, the greater the reduction in emissions.

3. *Fuel switching and electricity prices:* Comparing cases 2 and 3, the more fuel switching that occurs, the smaller the reduction in electricity prices.

The model contains several additional simplifications. First, transmission congestion could reduce the amount of fuel switching in case 3.[16] Second, natural gas and coal are often purchased under long-term contract, which could delay the effects of changes in gas production on delivered gas prices. In our data, 89 percent of coal fuel consumption is purchased via a long-term contract, as compared to 59 percent of gas consumption.[17] When gas is not purchased through long-term contracts, it is often purchased a day ahead, placing power plants at lower priority to receive natural gas than companies serving heating customers (ISO New England, 2014), which

[16]Kaplan, 2010 examines the unused capacity at CCGTs within 10 km of coal plants, and calculates that at most natural gas could displace 30 percent of coal. More switching could require sufficient transmission capacity to allow for fuel switching from gas generators located more than 10 km from coal plants.

[17]Calculated using an indicator for whether transactions occur on the spot market in the EIA-423 data set.

could also limit switching should there be natural gas pipeline capacity constraints. Third, many coal contracts include "take-or-pay" clauses (Macmillan, Antonyuk, and Schwind, Macmillan et al.), which would discourage fuel switching. Fourth, when electricity prices are determined at rate hearings in regulated regions there are disincentives for a firm to produce efficiently. Unlike periods of "regulatory lag," when prices are fixed and the firm is the residual claimant to any cost minimization (Joskow, 1974), during rate cases firms do not have this incentive and have indeed been shown to produce less efficiently (Abito, 2014).[18] Although these factors reduce the extent of fuel switching caused by a natural gas price decrease, allowing for these factors may attenuate the effects of a natural gas price shock but would not affect the three conclusions listed above.

5 Estimation Strategy and Summary Statistics

5.1 Estimation strategy

The empirical objective is to estimate the effect of natural gas prices on three outcomes: a) fuel consumption from coal and natural gas–fired power plants; b) generation from coal and gas plants; and c) equilibrium electricity prices. We first discuss our strategy for estimating the effect of natural gas prices on fuel consumption and then turn to the other two outcomes.

Natural gas prices may have different effects on fuel consumption in the short and long run. As Section 4 shows, in the short run, gas prices affect the utilization of generators that are already in operation, taking the existing plant stock and transmission system as given. In the long run, gas prices can also affect investment in and retirements of existing plants, as well as investments in the gas pipeline and electricity transmission systems. Because the model's conclusions pertain to the short run, we focus empirically on the short-run effects of natural gas prices.

We aim to estimate own and cross-price elasticities of a plant's fuel consumption to fuel prices. We begin with a simple linear equation in which the dependent variable is the ratio of the plant's fuel consumption to total fuel consumption in the market, and the independent variables include fuel prices and plant-year interactions:

$$\ln(f_{it}^{j}/F_{Mt}) = \beta^{g}\ln p_{at}^{g} + \beta^{c}\ln p_{at}^{c} + \eta_{iy} + \varepsilon_{it} \tag{1}$$

The variable f_{it}^{j} is the consumption of fuel j (coal or natural gas) by plant i in year-

[18]In our estimation sample, all observations are from years following electricity restructuring. We control for differences between regulated and unregulated plants by including plant-year fixed effects in the regressions.

month t. The ratio f_{it}^{j}/F_{Mt} is the share of total fossil fuel consumption for plant i and fuel type j in market M. We normalize by market-level fuel consumption because, as Section 4 showed, fuel prices affect the share of each generator's fuel consumption in total fuel consumption. Implicitly, we assume that monthly fuel prices do not affect short-run electricity demand in the same month, which is supported by the fact that real-time pricing is rare in the United States and retail price schedules are usually predetermined.

The two price variables, p_{at}^{g} and p_{at}^{c}, are the average price of natural gas and coal in the plant's PCA in year-month t. We use the average PCA prices, rather than plant-level prices, for three reasons. First, because most plants in the data use only coal or natural gas and not both, for most plants the data include the price of one fuel or the other. Therefore, we would need to impute the other price for such plants, in which case the two fuel prices would not be consistent—one would be the plant's reported price and the other would be imputed based on prices of other plants. Using the PCA average maintains consistency for the two fuel price variables. Second, the plant's prices may be correlated with firm-specific and potentially time-varying unobserved variables such as managerial quality or bargaining power in fuel markets. Using average prices avoids the bias that would result. Third, the overall objective is to derive empirical estimates that can be the basis of the simulations of the effects of shale gas on emissions and consumer welfare. If we use plant-level prices the elasticities would be estimated partly on aggregate price shocks and partly on idiosyncratic (i.e., plant-level) price shocks. Because shale gas is primarily an aggregate shock—as Section 3 showed—we seek empirical estimates based entirely on aggregate price shocks.[19]

We estimate a separate regression for coal and gas plants. The model predicts that a decrease in gas prices should decrease coal consumption at coal-fired plants and increase natural gas consumption at gas-fired plants. Analogous predictions hold for a coal price increase.

The plant-year interactions, η_{iy}, play an important role in the interpretation of the coefficients on the log fuel prices. Because of the fixed effects, the price elasticities are identified by within-plant and year variation in fuel prices and fuel consumption. Consequently, the elasticities represent short-run elasticities because they do not include the effects of plant entry and exit on fossil fuel consumption.

Two immediate concerns arise regarding the use of equation (1) to estimate the own and cross-price elasticities for fuel consumption. First, the denominator in the dependent variable includes fuel consumption at all plants, including those for which fuel consumption cannot be measured (particularly, nuclear, hydroelectric, and wind-

[19]We could aggregate fuel prices further, for example, to the NERC region. The Appendix shows that the results are similar when using more aggregated fuel prices.

powered). If we include in the denominator the fuel consumption at fossil fuel–fired plants, which we can measure, equation (1) would yield unbiased results if fuel consumption from fossil and non-fossil plants were uncorrelated with one another. Second, fuel prices could be correlated with electricity demand in market m. For example, an increase in industrial activity could raise demand for both electricity and natural gas because many industrial facilities use both electricity and natural gas. This would bias coefficient estimates in equation (1) because the fuel prices would be correlated with unobserved demand shocks.

We address both concerns by defining a market as a NERC region and adding year-month-NERC interactions to equation (1) to obtain our estimating equation:

$$\ln(f_{it}^j) = \beta^g \ln p_{at}^g + \beta^c \ln p_{at}^c + \eta_{iy} + \tau_{nt} + \varepsilon_{it} \tag{2}$$

The year-month-NERC interactions, τ_{nt}, control flexibly for demand (or supply) shocks at the NERC level, such as changes in industrial activity.[20] In equation (2) a market corresponds to a NERC region. This eliminates the need to normalize the dependent variable by total market fuel consumption (i.e., we would obtain the same coefficients estimating this equation and estimating an equation in which the dependent variable is normalized by total fuel consumption). Turning to the correlation between fuel prices and natural gas demand, ideally, the market would be defined such that there is no transmission congestion within a market, and there is no transmission capacity connecting markets. In that case, the NERC region-time interactions in equation (2) would control for market-level demand shocks. As we discussed in Section 2, defining a market at a lower level of geography, such as a PCA, would not be appropriate because of the substantial transmission capacity connecting PCAs. Likewise, defining a market as an interconnection would not be appropriate if there is significant transmission congestion across NERC regions within the same interconnection.

We discuss three remaining potential concerns with equation (2): sub-NERC demand or supply shocks correlated with fuel prices; correlation between unobserved variables, entry and exit; and the log-log functional form. Although the inclusion of the NERC-time interactions controls for demand or supply shocks at the NERC region level, because we use PCA-average fuel prices, sub-NERC level shocks could be correlated with the fuel prices. The Appendix shows that the results are robust to three approaches to address this concern: controlling for PCA-level total generation (as a proxy for demand); controlling for electricity price; and instrumenting for fuel prices.

The second concern with equation (2) is that the sample is an unbalanced panel

[20] Since WECC is the largest NERC region, spanning most of 11 states, we divide it into four subregions as defined by the EIA. We include year-month-subregion interactions in the case of WECC.

because of entry and exit of generators at plants and because of entry and exit of entire plants. In panel data settings, such entry and exit could cause coefficient estimates in equation (2) to be biased (Pakes and Olley, 1995). However, because of sunk entry and exit costs, entry and exit decisions are based on persistent shocks to (unobserved) productivity. The plant-year interactions control for such shocks, reducing concerns that fuel prices are correlated with omitted profitability shocks.

Finally, the log-log assumption in equation (2) may be violated in practice if large gas price changes have disproportional effects on fuel consumption. The empirical analysis relies on equation (2) as an approximation to the "true" relationship, but in practice if we add higher-order polynomials in fuel prices the coefficients on the additional terms are small and the main predictions are unchanged (not shown). Related to this point, the effects of fuel prices on fuel consumption may vary across plants, whereas equation (2) imposes the assumption that the effect is proportional for all plants; the Appendix reports results that relax this assumption.

The effects of fuel prices on generation are estimated similarly to the effects of fuel prices on fuel consumption. The dependent variable is the log of net generation, as computed from the EIA data, instead of the log of fuel consumption.

Finally, we use the Platts data for wholesale electricity prices to estimate a variant of equation (2). We estimate a linear equation:

$$P_{jt} = \beta^g p^g_{jt} + \beta^c p^c_{jt} + \upsilon_j + \varphi_y + \phi_m + \phi_m * (t)_+ \phi_m * (t^2)_+ \varepsilon_{jt} \tag{3}$$

The dependent variable is the price of electricity in location j and month t. For two reasons, we do not estimate the equation in logs. First, wholesale electricity prices are expected to equal the marginal cost of the highest-cost generator in operation, in which case wholesale electricity prices should be proportional to gas prices. Second, the electricity price can take on negative values and taking logs would cause these observations to be omitted. The independent variables include average fuel prices in location j and month t, location υ_j, year φ_y, and month fixed effects ϕ_m. To allow for month-specific trends, we also include the month dummies interacted with a linear time trend, $\phi_m * (t)$, and a quadratic time trend, $\phi_m * (t^2)$. Separate regressions are estimated for each NERC region and for peak and off-peak hours, where off-peak hours include 11PM through 8AM (. As with equation (2), the location-year interactions cause us to interpret the coefficients in (3) as the short-run effects of fuel prices on wholesale electricity prices.

6 Estimation Results

We first report the estimated effects of fuel prices on fuel consumption and generation using the full national sample. Subsequently, the estimates by NERC region are compared to the national results. Finally, we report estimated effects of fuel prices on wholesale electricity prices nationally and by NERC region. The Appendix contains an extended set of additional results that address potential concerns about inference and identification.

6.1 Fuel consumption and generation

6.1.1 National sample

Table 3 shows the results with the full national samples of natural gas and coal plants. Panel A (columns 1-3) reports results for coal plants and Panel B (columns 4-6) reports results for natural gas plants. In all regressions, observations are by plant, year, and month. Besides including the logs of coal and natural gas prices, all regressions include plant-year fixed effects and year-month-NERC region interactions. Within each panel, the columns differ by the data source (EIA or CEMS) and the dependent variable as indicated at the top of the table. The table reports the coefficients on the two fuel price variables with standard errors clustered by year-month-PCA.[21]

Table 3: Effects of Fuel Prices on Fuel Consumption, Generation, and CO_2 Emissions

	Panel A: Coal			Panel B: Gas		
	(1)	(2)	(3)	(4)	(5)	(6)
	EIA	EIA	CEMS	EIA	EIA	CEMS
	ln(Input)	ln(Gen.)	ln(CO_2)	ln(Input)	ln(Gen.)	ln(CO_2)
Log coal price	-.090***	-.109***	-.139***	.110*	.129**	.136**
	(.031)	(.032)	(.044)	(.064)	(.066)	(.060)
Log gas price	.031**	.042***	.037**	-.340***	-.371***	-.310***
	(.013)	(.015)	(.018)	(.040)	(.043)	(.044)
n	63,941	63,941	57,508	121,507	121,507	84,844
R^2	.93	.94	.87	.87	.88	.85

Notes: Standard errors in parentheses clustered by year-month-PCA. Observations are by plant-year and month. Panel A reports results for plants that use coal and Panel B reports results for plants that use natural gas. The column headings indicate the data source and the dependent variables. The table reports the coefficients on the log coal price and log gas price, where prices are the average prices for the plant's PCA (see text for details). All regressions include plant-year fixed effects and year-month-NERC region interactions (or subregion in the case of WECC). Statistically significant at the *** 1% level; ** 5% level; * 10% level.

[21] We cluster standard errors by year-month-PCA to match the variation in fuel prices. The error term could be correlated within PCAs over time, however, because of persistence of fuel prices or other factors. In a regression not shown, we also cluster standard errors by PCA. The standard errors are substantially larger than in Table 3 but most coefficient estimates remain significant at the 1 percent level.

In columns 1 and 4 the dependent variable is the log of coal and natural gas fuel consumption. The own-price elasticities have the expected signs and are statistically significant at the 1 percent level. Because the dependent variables and fuel prices are in logs, the magnitudes imply that a 1 percent increase in the price of natural gas increases coal consumption by about 0.03 percent and lowers natural gas consumption by about 0.3 percent. The magnitudes are similar in columns 2 and 5, in which the dependent variables are the logs of net generation rather than fuel consumption. The coefficients thus imply that an increase in gas prices causes an increase in coal consumption and coal-fired generation, and a decrease in gas consumption and gas-fired generation. Thus, the increase in gas prices causes fuel switching away from natural gas and toward coal; a natural gas price decrease has the opposite effect. The coal plants typically have about five times higher fuel consumption and generation than the gas plants in our sample. Therefore, the coefficient estimates imply that the increase in generation from one fuel type is roughly offset by the decrease in generation of the other fuel type—in other words, that the fuel prices do not affect total generation from coal and gas plants.

The coal price coefficients in the first row are less precisely estimated than the gas price coefficients because there is much less coal price variation than gas price variation in the sample (see Section 3). However, the coal price coefficients, like the gas price coefficients, suggest that fuel price changes cause fuel switching.

As noted in Section 2, the EIA data have more complete coverage than the CEMS data. For that reason, we use the EIA data in the main regression analysis. Nonetheless, for comparison with these results we also report results using the CEMS emissions data.[22] The quantity of CO_2 emitted is typically a fixed proportion of the fuel input. We expect fuel prices to have the same effect on emissions as on fuel consumption. In columns 3 and 6 we show that, as expected, using the CO_2 emissions reported in the CEMS data as the dependent variable we obtain percentage changes that are not statistically different from the changes obtained using the EIA heat input and generation data.[23]

6.1.2 Results by NERC region

The model in Section 4 suggests that the effects of a given gas price decrease could vary across markets. Motivated by electricity transmission infrastructure (see Section

[22]Another reason for not using the CEMS data is provided by ?, who argues that CO_2 emissions estimated from the EIA records of fuel consumption are more accurate than the CEMS records of emissions.

[23]Because both EIA and CEMS include fuel consumption data, we are also able to compare the fuel consumption results across data sets. Also as expected, we find that the regression coefficients on natural gas and coal prices are not statistically different across the data sets (not shown).

2), we define each NERC region as representing a unique market. Table 4 reports estimates of equation (2) by NERC region; each panel shows results for a separate NERC region, with regions ordered alphabetically. The regressions reported in columns (1) through (4) in Table 4 correspond to columns (1-2) and (4-5) in Table 3 except that we replace year-month-NERC interactions with year-month fixed effects. The largest NERC region, Western Electricity Coordinating Council (WECC) (see Figure 2), is substantially larger than the rest, and we therefore include year-month-subregion fixed effects in the specification for WECC.

Table 4: Fuel Consumption and Generation Results by NERC Region

	Panel A: Coal		Panel B: Gas	
	(1)	(2)	(3)	(4)
Dependent Variable	ln(Input)	ln(Generation)	ln(Input)	ln(Generation)
	Florida Reliability Coordinating Council (FRCC)			
Log coal price	.044	.006	.020	-.109
	(.178)	(.196)	(.212)	(.241)
Log gas price	.092	.065	-.028	-.078
	(.088)	(.098)	(.122)	(.129)
n	1,722	1,722	6,977	6,977
R^2	.85	.87	.89	.90
	Midwest Reliability Organization (MRO)			
Log coal price	-.102	-.116*	-.256	-.283
	(.066)	(.070)	(.254)	(.261)
Log gas price	-.047**	-.049*	-.423***	-.474***
	(.023)	(.025)	(.102)	(.111)
n	7,558	7,558	8,255	8,255
R^2	.95	.96	.79	.79
	Northeast Power Coordinating Council (NPCC)			
Log coal price	.103	.238	.141	.032
	(.193)	(.183)	(.269)	(.271)
Log gas price	.095	.108	-.044	-.050
	(.270)	(.288)	(.205)	(.213)
n	2,691	2,691	10,930	10,930
R^2	.92	.93	.86	.88
	ReliabilityFirst Corporation (RFC)			
Log coal price	.012	-.032	-.006	.052
	(.058)	(.064)	(.194)	(.211)
Log gas price	.061**	.077***	-.477***	-.502***
	(.024)	(.027)	(.095)	(.102)
n	19,409	19,409	21,954	21,954
R^2	.91	.92	.84	.84
	SERC Reliability Corporation (SERC)			
Log coal price	-.083	-.097	.307**	.338**
	(.057)	(.060)	(.144)	(.151)
Log gas price	.033	.048*	-.467***	-.506***
	(.025)	(.029)	(.100)	(.104)
n	19,536	19,536	26,030	26,030
R^2	.94	.95	.85	.86
	Southwest Power Pool (SPP)			
Log coal price	-.355***	-.386***	.171	.190
	(.136)	(.141)	(.181)	(.193)
Log gas price	.061	.075	-.577***	-.623***
	(.068)	(.070)	(.171)	(.179)
n	4,540	4,540	9,934	9,934
R^2	.89	.90	.85	.85
	Texas Reliability Entity (TRE)			
Log coal price	.451*	.487*	-.026	-.025
	(.260)	(.272)	(.110)	(.126)
Log gas price	-.141	-.095	.153	.087
	(.262)	(.263)	(.254)	(.305)
n	2,140	2,140	13,052	13,052
R^2	.83	.83	.86	.85
	Western Electricity Coordinating Council (WECC)			
Log coal price	-.212***	-.236***	-.011	.033
	(.052)	(.053)	(.103)	(.103)
Log gas price	.075***	.078***	-.132**	-.137**
	(.028)	(.028)	(.064)	(.069)
n	6,345	6,345	24,375	24,375
R^2	.95	.96	.89	.89

Notes: Standard errors in parentheses clustered by year-month-PCA. Observations are by plant-year and month. All regressions are the same as in Table 3 except that the samples include the NERC regions indicated in the table headings. All regressions include plant-year fixed effects and year-month interactions (or year-month-subregion in the case of WECC). Statistically significant at the *** 1% level; ** 5% level; * 10% level.

Focusing on the gas price coefficients, the results vary substantially across regions. An increase in natural gas prices causes a statistically significant reduction in gas consumption and gas-fired generation in five of the eight NERC regions: Midwest Reliability Organization (MRO), ReliabilityFirst Corporation (RFC), SERC Reliability Corporation (SERC), Southwest Power Pool (SPP), and the Western Electricity Coordinating Council (WECC). For all of these regions, a gas price increase causes a corresponding increase in coal consumption and generation, but in some cases the estimates are not statistically significant. Within this set of regions, however, the magnitudes vary somewhat; a gas price increase causes a much smaller decrease in gas generation in WECC than in MRO, RFC, SERC, and SPP. In the remaining three NERC regions, on the other hand, gas prices do not have a statistically significant effect on coal or gas consumption and generation. For these regions, which include the Florida Reliability Coordinating Council (FRCC), the Northeast Power Coordinating Council (NPCC), and the Texas Reliability Entity (TRE), the point estimates are smaller in magnitude than the point estimates for the first set of regions. Having documented regional variation in the responsiveness of fuel consumption and generation to gas prices, we quantify the economic importance of these estimates in the next section.

6.2 Electricity prices

The model in Section 4 showed that a decrease in natural gas prices decreases equilibrium wholesale electricity prices, but the model also implied that the magnitude of this effect depends on relative fuel prices and other factors. Furthermore, for the following reason we expect the effects of natural gas prices to differ between peak and off-peak hours, particularly when natural gas prices are initially relatively high. Electricity demand tends to be higher during peak than off-peak hours. In most U.S. electricity markets, when natural gas prices are relatively high (for example, just before 2008), natural gas generators tend to vary electricity production with demand. Other generators, such as nuclear and coal, operate nearly continuously. In competitive wholesale markets, like the market modeled in Section 4, the price of electricity at a particular time typically equals the marginal costs of the highest-cost generator in operation at that time. Consequently, during peak hours natural gas generators often determine the electricity price, whereas during off-peak hours the price may be set by coal or even hydroelectric (in this context, peak hours refer to hours in which some available generation capacity is unused; otherwise the electricity price may exceed the cost of gas-fired generation). In such a case, a small decrease in natural gas prices (where small is defined so as not to cause any fuel switching) would cause a proportional reduction in electricity prices during peak hours but would not have any effect on electricity prices during off-peak hours. Of course, the distinction between peak and off-peak hours is not always so stark, as natural gas generators sometimes determine wholesale prices during off-peak hours as well. However, for purposes of our empirical analysis, natural gas generators are more likely to determine electricity prices during peak hours than during off-peak hours, and we expect natural gas prices to have a larger effect on electricity prices during peak than during off-peak hours.

Table 5 reports estimates of equation (3), with the first column using the full national sample and the remaining columns using samples from the indicated NERC regions. The dependent variable in the top panel is the peak electricity price and the dependent variable in the bottom panel is the off-peak electricity price. Besides the reported variables, all regressions include dummies for year, month, and trading hub, as well as month interacted with a linear time trend and month interacted with a quadratic time trend.

Table 5: Effects of Fuel Prices on On- and Off-Peak Electricity Price

	(1) National	(2) FRCC	(3) MRO	(4) NPCC	(5) RFC	(6) SERC	(7) SPP	(8) TRE	(9) WECC
	Dependent Variable: On-Peak Electricity Price ($/MWh)								
Coal Price ($/mmBtu)	-.37	-13.96*	-10.95	1.38	2.71	.37	25.59	-2.14	.32
	(.89)	(7.18)	(10.90)	(1.25)	(2.24)	(.97)	(19.52)	(4.12)	(2.15)
Gas Price ($/mmBtu)	5.99***	13.75***	2.65***	7.14***	3.54***	5.46***	6.10***	11.13***	9.60***
	(.20)	(1.01)	(.50)	(.36)	(.21)	(.19)	(.47)	(.65)	(.54)
n	3,482	127	210	389	677	593	126	453	907
R^2	.67	.92	.83	.87	.84	.90	.94	.78	.72
	Dependent Variable: Off-Peak Electricity Price ($/MWh)								
Coal Price ($/mmBtu)	1.33*	-1.04	-16.87**	1.49	2.08	.59	-.68	-3.04**	.98
	(.69)	(5.80)	(7.02)	(1.16)	(1.42)	(.70)	(15.64)	(1.29)	(1.66)
Gas Price ($/mmBtu)	3.06***	4.26***	.44	4.80***	1.18***	1.89***	2.16***	6.84***	6.99***
	(.15)	(.81)	(.32)	(.34)	(.13)	(.13)	(.38)	(.20)	(.42)
n	3,309	124	209	231	670	591	125	452	907
R^2	.61	.79	.75	.87	.81	.83	.87	.91	.66

Notes: Observations are by electricity trading hub, year, and month. Regressions include fixed effects for year, month, and trading hub, and month fixed effects interacted with a linear time trend as well as with a quadratic time trend. Statistically significant at the *** 1% level; ** 5% level; * 10% level.

Consistent with our expectations, natural gas prices have a larger effect on peak prices than off-peak prices—both when using the full national sample and when restricting the samples by NERC region. In all cases except off-peak MRO prices, natural gas prices have a positive and statistically significant effect on wholesale electricity prices. Coal prices, on the other hand, generally do not have a statistically significant effect on electricity prices (in some cases, the coefficient is even negative), which suggests that coal generators seldom determine equilibrium electricity prices during the time period and in the markets included in this analysis. However, the coal price standard errors are often large because of the limited coal price variation in the data.

Comparing the results across regions, natural gas prices have much larger effects on electricity prices in some regions than in others. For both peak and off-peak hours, the largest effects are for FRCC, NPCC, TRE, and WECC. These are precisely the four regions for which gas prices have the smallest effects on natural gas fuel consumption and generation. The electricity price results are thus consistent with our model's predictions, and in the next section we quantify the regional differences in the effects of natural gas prices on electricity prices, generation, and pollution emissions.

7 Effects of a Natural Gas Price Decrease on Electricity Prices, Generation, and Emissions

The previous section documented variation across markets in the effects of natural gas prices on fuel consumption, generation, and electricity prices. In this section, we use the coefficient estimates for two purposes. First, we wish to quantify the economic meaning of the coefficient estimates. Second, we wish to test the second and third predictions of the model in Section 4, that the more fuel switching occurs, the more emissions fall and the less electricity prices fall.

Starting from observed levels of fuel consumption and generation in 2008, we simulate the effects of a 10 percent decrease in natural gas prices on electricity prices, generation, and emissions. Table 6 reports percent changes in outcome variables along with bootstrapped standard errors in parentheses. To estimate emissions, we multiply the change in generation by the plant's average rate of emissions per unit of generation. The CO_2 emissions rate is calculated by multiplying a fuel-specific rate of emissions per mmBtu of heat input by the reported ratio of generation to heat input for the corresponding year. We assume an emissions rate per mmBtu of heat input of 0.05 for natural gas generators and 0.1 for coal generators. The predicted emissions rate is equal to the total predicted emissions divided by total predicted generation, across all plants in the sample. For NO_x and SO_2 we use CEMS data to calculate each plant's average rate of emissions per heat input.

The electricity price changes are estimated using the coefficients reported in Table 5. Table 6 reports separate results for peak and off-peak prices. Consistent with the results in Table 5, the natural gas price decrease has a greater effect on peak than off-peak electricity prices, and the effects are largest in FRCC, NPCC, TRE, and WECC. For some regions the price changes are quite large, implying that the elasticity of wholesale prices to natural gas prices is close to one. The differences are economically meaningful; at the extremes, the peak price in TRE falls twice as much as in RFC (in percent terms).

Table 6: Simulated 10 Percent Decrease in Natural Gas Price

	All	FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC
% Δ Peak Price	-7.67	-18.64	-3.72	-8.02	-5.01	-7.92	-7.53	-11.17	-9.74
	(0.30)	(2.17)	(0.76)	(0.60)	(0.32)	(0.36)	(0.83)	(0.61)	(0.59)
% Δ Off-Peak Price	-6.72	-10.54	-1.31	-7.59	-3.07	-5.08	-5.38	-11.76	-9.85
	(0.42)	(2.83)	(1.18)	(0.85)	(0.37)	(0.42)	(1.31)	(0.43)	(0.80)
% Δ Generation Share	1.42	0.50	4.10	0.46	5.31	4.54	4.82	-0.80	1.08
	(0.42)	(0.55)	(1.48)	(1.86)	(0.82)	(0.95)	(1.93)	(1.99)	(0.51)
% Δ Generation	2.41	0.51	0.14	0.35	0.43	0.90	1.87	-0.49	0.68
	(0.42)	(0.55)	(1.48)	(1.86)	(0.82)	(0.95)	(1.93)	(1.99)	(0.51)
% Δ CO_2	-0.93	-0.33	-0.08	-0.34	-0.26	-0.48	-0.98	0.37	-0.47
	(0.19)	(0.87)	(0.07)	(2.80)	(0.14)	(0.27)	(1.02)	(1.95)	(0.50)
% Δ NO_x	-1.67	-0.92	-0.11	-0.67	-0.25	-0.52	-1.01	0.71	-0.90
	(0.09)	(0.33)	(0.04)	(1.27)	(0.08)	(0.13)	(0.51)	(0.94)	(0.23)
% Δ SO_2	-1.83	-0.97	-0.13	-0.91	-0.30	-0.70	-1.65	1.23	-1.00
	(0.16)	(0.63)	(0.07)	(2.53)	(0.15)	(0.21)	(0.57)	(1.57)	(0.48)

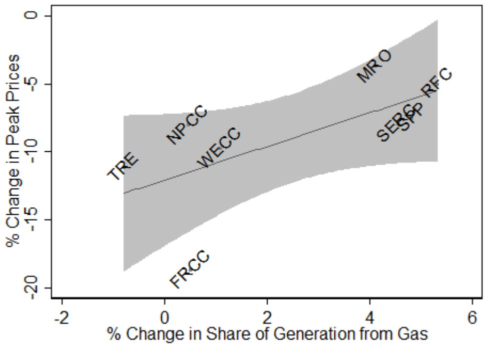
Notes: Simulated percent change in outcome variables from their 2008 levels from a 10% decrease in natural gas price. Generation share is the share of gas-fired generation. Percent change in generation is expressed as a fraction of total generation. Emissions rates are emissions per generation. Bootstrapped standard errors in parentheses.

We use the coefficient estimates from Table 4 to predict each plant's generation from natural gas and coal. Table 6 reports the percent change in the natural gas generation share. For all regions and nationally the natural gas generation share increases because of a switch from coal-fired generation to gas-fired generation (TRE is an exception, where the gas generation share decreases by a relatively small amount, and the change is not statistically significant). Fuel switching is quantified using two alternative definitions: the percent change in the share of generation from gas as well as the percent change in generation from gas (as a fraction of total generation). Switching represented as a fraction of total generation is more comparable to the change in emissions rate than when represented as a change in the share of generation (that is, when comparing with emissions rate, we use switching that is a factor of total generation).

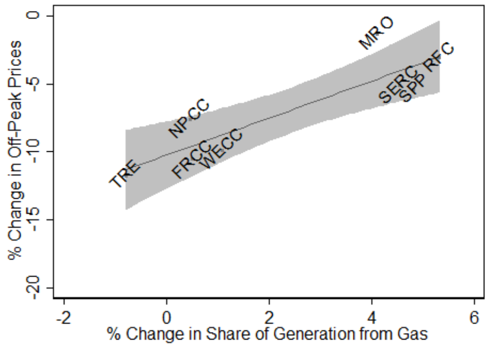
Comparing the generation share results with the wholesale electricity price results, the estimates are consistent with the model's main prediction; the regions that experience smaller increases in gas-fired generation experience larger decreases in electricity prices. See Figure 8, which plots the point estimates as well as the linear fit through these points; the shaded region is the 95 percent confidence interval.

Because coal-fired generators have higher emissions rates of CO_2, NO_x, and SO_2, we expect the regions with the largest increases in gas generation to experience the largest reductions in pollution emissions.

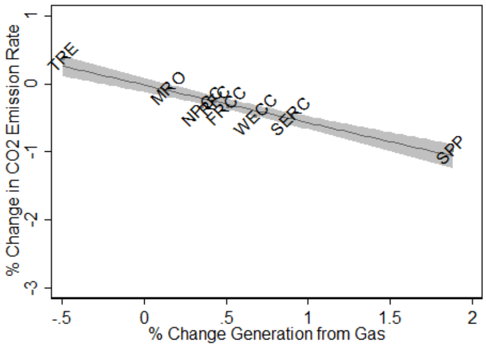
The resulting percent changes in CO_2 emissions rates are small, ranging from statistically insignificantly different from zero to -0.98 percent. The changes in emissions rates of the other pollutants are somewhat larger, and the changes for all three pollu-



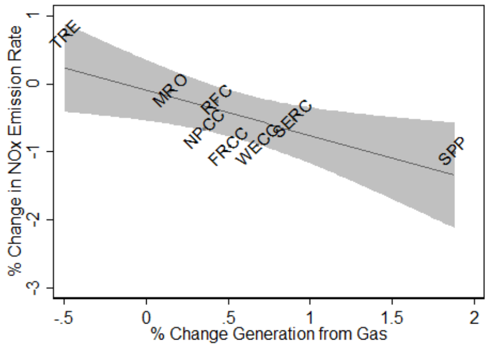
(a) Peak Price



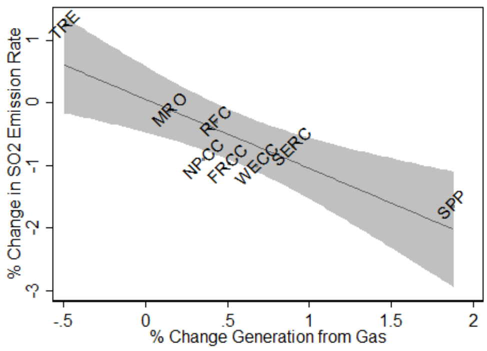
(b) Off-Peak Price



(c) CO_2



(d) NO_x



(e) SO_2

Figure 8: Linear Fit across NERC Regions of Simulated Percent Changes from 10 Percentage Decrease in Natural Gas Price.

tants vary across regions. Figure 8 shows that the regions with the most fuel switching experience the greatest decrease in emissions rates, which is consistent with the model's prediction.

8 Conclusions

We provide estimates of the short-run response from power plants to changes in fuel input prices using detailed monthly data covering nearly all coal and natural gas generation in the United States. We find that low natural gas prices cause a significant degree of switching away from coal-fired generation and toward natural gas–fired generation. Importantly, our fuel price elasticities are estimated using monthly variation in fuel prices within the same plant in the same year while controlling for regional shifts in fuel prices or other factors over time. This approach implies that our estimates are driven by short-run natural gas price changes and not by new EPA regulations, long-run changes in the generation stock, or other factors.[24] We show that lower gas prices induce fuel switching and reduce emissions. We also find that natural gas prices have a significant effect on electricity prices, with an elasticity of close to 1 for peak electricity prices in some regions.

These are national results and we demonstrate theoretically that the degree to which low natural gas prices affect emissions and electricity prices depends on the degree of fuel switching that occurs; the more fuel switching, the greater the emissions reduction but the smaller the decrease in electricity prices. Indeed, the empirical results are consistent with these predictions. Comparing results across NERC regions, when there is more fuel switching, the environment benefits are greater, but the reduction in electricity prices is smaller.

These cross-region differences are large in magnitude, and suggest that shale gas has had varying effects on pollution emissions from power plants and on electricity consumer welfare. We have not attempted to explain this regional variation, but a few hypotheses are plausible. First, there could be regional differences in the non-fuel costs of coal or gas generators. The model showed that this could cause the effects of natural gas prices to vary across regions. Second, Figure 3a showed that natural gas prices decreased by different amounts across regions; a straightforward extension of the simple model would show that this could cause regional variation in the effects of lower gas prices, but the correlation between fuel switching and electricity price changes would be the same as in this paper. Third, there may be regional differences in the available natural gas–fired generation capacity, which could affect the short-run ability of natural gas generation to increase following a gas price decrease. Because there are eight NERC regions it is not possible to distinguish these hypotheses statistically, and we leave for future work a rigorous evaluation of their merits.

This analysis focuses on the short-run effects of natural gas prices, in which the

[24] Using a simulation of the U.S. electricity market, Burtraw et al. (2012) also find that recent decreases in forecast natural gas prices have a larger expected effect on generation than the upcoming Cross State Air Pollution Rule (CSAPR) or the Mercury and Air Toxics Standards (MATS).

generation stock is fixed. The studies based on computational models cited above analyze the long run, i.e., 20 years or more. The advantages of the short-run approach are that we derive sharp theoretical predictions and we can estimate the effects of natural gas prices and test the predictions using observed market outcomes, rather than relying on assumptions embedded in long-run computational models. On the other hand, computational models enable analysis of future policies and other shocks that cannot be considered using our approach. Nonetheless, the short-run effects on profitability also lend insight into the long-run effects of natural gas prices, which would include effects on investment.

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A Appendix

A.1 Imputing missing PCAs

The following steps were used to impute each plant's PCA in the missing e-GRID years:

1. If the reported PCA is the same for adjacent eGRID years (e.g., 2000 and 2006), impute the same PCA for all intervening years.

2. If the PCA is not the same for adjacent eGRID years, we found online documentation on the year in which the PCA changed. For example, American Electric Power joined PJM in 2004, so we assign the corresponding plants to American Electric Power for the years 2001-2003 and to PJM for 2004 and 2005. A data appendix, available upon request, provides details of the imputation based on online resources.

3. For all subsequent years, use the PCA from the last year in which eGRID provides the plant's PCA.

4. For all earlier years, use the PCA from the first year in which eGRID provides the plant's PCA.

5. If still missing, use the PCA from the nearest plant with available PCA information for the same year. We determine the nearest plant using latitude and longitude in eGRID. Then repeat steps (1) to (4) after completing step (5).

6. Missing values remain for non-eGRID years such that the plant's PCA in the previous eGRID year differs from the PCA for the next eGRID year. For these cases we impute the year in which the PCA changed based on the most common year of change for which online information was available pertaining to the same PCAs.

After completing steps (1) to (7), the only missing PCAs are for plants not contained in eGRID. These plants are dropped from the final data set. Table A1 shows, for each step in the imputation procedure, the share of net generation accounted for by plants whose PCAs were imputed using the corresponding step. For example, the eGRID provides the PCA for 30 percent of EIA net generation, and we were able to impute the PCA for an additional 48 percent in step 2. We also break ERCOT into four PCAs (ERCOT West, ERCOT South, ERCOT North, and ERCOT Houston) according to the regions defined by Platts for its electricity price data (Platts, 2012).

Table A1: Fraction of Generation by Imputation Step

	EIA	CEMS
PCA non-missing in eGRID years	0.30	0.30
Interpolating between eGRID years, no PCA change (step 1)	0.48	0.45
Year of PCA change determined from public information (step 2)	0.08	0.09
PCA filled forward from eGRID year (step 3)	0.00	0.00
PCA filled backward from eGRID year (step 4)	0.02	0.03
PCA imputed using nearest plant (step 5)	0.02	0.02
Year of PCA change determined by most common year of change (step 6)	0.02	0.02

Notes: The table reports the share in total generation of the generation for which the PCA is determined by the indicated step. The first column reports percentages for the monthly EIA sample and the second column reports percentages for the monthly CEMS sample. An eGRID year refers to a year in which the eGRID is available: 1996-2000, 2006, 2007, 2010, and 2012. The first row shows the percentage of generation for which the PCA is available in eGRID years. The remaining rows show the percentage of generation for each of the indicated steps (see text for details).

A.2 Robustness

The paper noted several potential concerns with identification and inference for the main estimating equations. Here we report a number of additional variants of equation (2). In Section 5 we discussed several possible reasons why the assumed exogeneity may not hold in practice. We take several approaches to show that these factors are probably not important in practice. We noted that the year-month-NERC interactions control for NERC-level demand or supply shocks that may be correlated with PCA-level fuel prices, such as seasonal variation in electricity demand, population growth, or changes in business activity. If sub-NERC region shocks are correlated with coal or gas prices the estimated elasticities in Table 3 would be biased.

Table A2: Controlling for Sub-NERC Demand or Supply Shocks

	Panel A: Coal		Panel B: Gas	
	(1)	(2)	(3)	(4)
Dependent Variable	ln(Input)	ln(Generation)	ln(Input)	ln(Generation)
	Control for log PCA generation			
Log coal price	-.014	-.025	.146**	.170**
	(.028)	(.029)	(.064)	(.066)
Log gas price	.029**	.040***	-.331***	-.361***
	(.012)	(.014)	(.040)	(.042)
n	63,941	63,941	121,504	121,504
R^2	.93	.95	.87	.88
	Control for electricity price bins			
Log coal price	-.095**	-.117***	.066	.086
	(.044)	(.046)	(.071)	(.072)
Log gas price	.040**	.053***	-.479***	-.509***
	(.017)	(.020)	(.050)	(.054)
n	48,643	48,643	97,778	97,778
R^2	.93	.94	.87	.88
	Instrument for log gas price			
Log coal price	-.080***	-.102***	.111**	.129**
	(.030)	(.033)	(.048)	(.052)
Log gas price	.031	.037	-.349***	-.337***
	(.041)	(.045)	(.108)	(.115)
n	59,547	59,547	111,874	111,874
First stage F-stat	12.32	12.32	16.68	16.68

Notes: Standard errors in parentheses clustered by year-month-PCA except as indicated. All regressions are the same as in Table 3 except as indicated in the table. In the top panel, the regression includes log PCA generation as a regressor. In the middle panel, the count of days in 10 peak-electricity price bins are included. In the lower panel, log natural gas price is instrumented for using PCA dummies interacted with monthly-state natural gas production. Statistically significant at the *** 1% level; ** 5% level; * 10% level.

In the top section of Table A2 we show a regression similar to our main specification with year-month-NERC interactions but in addition includes the log of total monthly PCA generation to proxy for demand shocks. The results are very similar to Table 3, with the exception that the price of coal at coal-fired plants becomes statistically insignificant. As we discuss in the paper, there is very little variation in the price of coal over the time period.

We also check to see if our coefficients are robust to including electricity price in the regression—this would capture any residual demand that our year-month-NERC interactions are not capturing. Specifically, we include a flexible measure of electricity by including counts of the number of days in a month that fall within 10 electricity price bins (similar to Deschênes and Greenstone, 2011). The middle section in Table A2 shows that our coefficients are robust to including these additional regressors, with the exception that the coefficients on the price of coal at gas-fired plants become statistically insignificant.

We take another approach to account for the possibility of sub-NERC demand shocks. Under the concern that the macroeconomic conditions affecting the demand for both natural gas and electricity might also be persistent, we employ a different specification to filter out shocks that would affect both natural gas price and electricity demand. Under the assumption that natural gas production at the state level is exogenous to demand shocks at the PCA level, we instrument for PCA-natural gas price using state-level production interacted with PCA indicators. Specifically, we use production from the top five shale gas producing states, Texas, Louisiana, Arkansas, Oklahoma, and Pennsylvania.[25] The point estimates found in the bottom section of Table A2 are very similar to our main specification; however, the standard errors are larger in the case of coal plants. The combined results in Table A2

[25] According to the EIA's production estimates for 2010, 95 percent of production came from these five states.

show that sub-NERC demand or supply shocks are unlikely to create substantial bias to the estimates in our main specification.

The year-month-NERC interactions control for NERC-level demand or supply shocks, but in fact, because there are transmission connections between many NERC regions within the same interconnection, it may be more appropriate to control for interconnection-level demand and supply shocks using year-month-interconnection interactions. The top section of Table A3 reports the results, which, for the most part, are quite similar to the results in Table 3, with the exception of coal price at natural gas plants.

Table A3: Controlling for Interconnection and PCA Demand Shocks

	Panel A: Coal		Panel B: Gas	
	(1)	(2)	(3)	(4)
Dependent Variable	ln(Input)	ln(Generation)	ln(Input)	ln(Generation)
Replace year-month-NERC with year-month-interconnection interactions				
Log coal price	-.114***	-.142***	-.062	-.041
	(.033)	(.035)	(.064)	(.063)
Log gas price	.068***	.079***	-.345***	-.369***
	(.013)	(.015)	(.038)	(.040)
n	63,941	63,941	121,507	121,507
R^2	.93	.94	.87	.87
Replace PCA prices with NERC prices				
Log coal price	.080	.023	.178	.146
	(.142)	(.153)	(.205)	(.212)
Log gas price	.152***	.165***	-.305***	-.321***
	(.041)	(.046)	(.096)	(.102)
n	63,915	63,915	121,355	121,355
R^2	.93	.94	.87	.87

Notes: Standard errors in parentheses clustered by year-month-PCA except as indicated. All regressions are the same as in Table 3 except as indicated in the table. The regressions in the second section replace the PCA fuel prices with NERC fuel prices, replace year-month-NERC interactions with year-month-interconnection interactions, and also include NERC-month interactions. Statistically significant at the *** 1% level; ** 5% level; * 10% level.

The previous analysis focused on seasonality or other demand-side reasons why fuel prices could be correlated with the error term. Another possibility is that firms have market power in input supply markets, resulting in correlation between the error term and fuel prices. In our main regressions, to mitigate this concern we aggregated prices to the PCA level. Nonetheless, some PCAs are geographically small (see Figure 1), and prices may still be correlated with unobserved plant-level market power. In the lower section of Table A3 we present estimates from aggregating prices to the NERC-region level. We replace the year-month-NERC interactions with year-month-interconnection interactions and add NERC-month interactions to control for seasonality. The results are quite similar to the results in Table 3, except that the elasticities of gas consumption to gas prices are larger using the NERC prices instead of the PCA prices. We also lose statistical significance on coal prices.

Table A4: Sub-samples, First-Differences, and PCA Aggregation

	Panel A: Coal		Panel B: Gas	
	(1)	(2)	(3)	(4)
Dependent Variable	ln(Input)	ln(Generation)	ln(Input)	ln(Generation)
	Include small and old coal plants and large and new gas plants			
Log coal price	-.065	-.056	.246*	.284**
	(.078)	(.085)	(.126)	(.137)
Log gas price	.013	.034	-.596***	-.644***
	(.031)	(.035)	(.082)	(.089)
n	13,164	13,164	37,200	37,200
R^2	.83	.87	.83	.83
	First-difference model			
Log coal price	-.029	-.041	.030	.062
	(.035)	(.037)	(.048)	(.050)
Log gas price	.033***	.039***	-.215***	-.238***
	(.012)	(.013)	(.039)	(.042)
n	57,829	57,829	104,684	104,684
R^2	.11	.11	.10	.10
	PCA aggregation with PCA-year fixed effects			
Log coal price	-.133***	-.164***	.102	.114
	(.036)	(.039)	(.098)	(.110)
Log gas price	.019	.020	-.388***	-.426***
	(.018)	(.019)	(.048)	(.054)
n	12,856	12,856	14,308	14,308
R^2	.97	.97	.93	.92

Notes: Standard errors in parentheses clustered by year-month-PCA except as indicated. All regressions are the same as in Table 3 except as indicated in the table. The first two columns of the first section only include small, old coal plants. The second two columns of the first section only include large, new gas plants. In the second section, observations are of the first difference across months of plant-year observations. In the third section, observations are aggregated to the PCA, and PCA-year fixed effects are included instead of plant-year fixed effects. Statistically significant at the *** 1% level; ** 5% level; * 10% level.

So far, we have estimated average elasticities across all plants of a given fuel type. The model in Section 4 suggests that elasticities are likely to vary across plants. In particular, fuel switching occurs between inefficient coal plants and efficient gas plants. Therefore, inefficient coal plants should be more sensitive to fuel prices than efficient coal plants. On the other hand, efficient gas plants should be more sensitive to fuel prices than inefficient gas plants.

Ideally, we would stratify plants by marginal costs and restrict the samples to high-cost gas and coal plants. We cannot observe costs directly, but we can proxy for marginal costs by restricting the samples by age and size, which are likely to be correlated with costs. We expect fuel prices to have larger effects on old and small coal plants than on young and large coal plants because old and small coal plants are likely to be less efficient. Likewise, we expect fuel prices to have larger effects on large and young gas plants than on small and old gas plants. Columns 1-2 in the top section of Table A4 include only small and old coal plants and columns 3-4 include only large and young gas plants. We expect the magnitudes for these sub-samples to be larger than the magnitudes for the samples in Table 3. Small and old coal plants are not more sensitive than the average plant, but large and young gas plants are about twice as sensitive as the average gas plant. To the extent that plant size is indicative of firm size, differences in these coefficients could be driven by the bidding strategies for electricity supply being different for small and large firms (Hortaçsu and Puller, 2008). In the middle section of Table A4 we present results from a first differences specification in which we take the first difference across months in the plant-year observations. Again we lose significance on the coefficients on coal price. Finally, instead of examining within-plant switching to natural gas we turn to within-PCA switching to natural gas in the bottom panel of Table A4. In this case we find that consumption of and generation by a particular fuel is only sensitive to that fuel's price.