Environmental implications of market structure: Shale gas and electricity markets

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Abstract

We examine the environmental implications of market structure using the exogenous variation in the price of natural gas paid by U.S. electric power producers in the aftermath of the shale boom. We find that electric power producers were more responsive to fuel prices in vertically integrated markets than in restructured markets, and we explore the underlying factors driving this heterogeneity in responses. Although differences in the capacity of the most efficient gas power plants between the two market structures are the most important factor, we consider others. The heterogeneity in the response of power plant operators to fuel prices has material implications for carbon dioxide emissions.

JEL codes: L51, L94, Q40, Q51.

Keywords: market structure, environment, coal displacement, emissions, electricity markets, natural gas, utilities.

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1 Introduction

We examine the environmental implications of market structure by comparing the responses to fuel prices of U.S. electric power plants in markets that were restructured in the late 1990s and those that were not. Our primary interest lies in the response of coal and natural gas consumption to the dramatic exogenous drop in the price of natural gas (gas) in the aftermath of the shale boom. On a per unit-of-energy basis ($/MMBtu), the average price of gas was nearly seven times the average price of coal in the beginning of 2006. By the end of 2012, this ratio had decreased to less than two.

We focus on the consumption of coal and gas, as opposed to other fuels, because coal- and gas-fired power plants have accounted for the lion's share (around two thirds) of electricity generation in the country since 1990. Although other factors, such as environmental policy, have contributed to the decline in coal consumption in recent years, the coal-to-gas switching post 2005 has been attributed to a large extent to abundant cheap gas. The environmental implications of coal displacement have also been material and well-documented. Although the use of both coal and gas results in carbon dioxide and other harmful emissions, the coal-to-gas switching is good news for emissions because the carbon dioxide content of gas is 60% less than that for coal per unit of heat input.

However, the changes in fuel-consumption patterns and the resulting emissions need not be homogeneous across markets with different structures. Following the restructuring wave in the late 1990s and the early 2000s, wholesale electricity markets emerged in a large part of the country highlighted by the formation of independent system operators (ISOs) coordinating the function of some type of a "power pool" for buying and selling electricity.[1] In most cases, restructuring emphasized the unbundling of generation from transmission and distribution, which gave rise to merchant generators, known also as independent power producers. Merchant generators focused exclusively on the production of electricity. The utilities continued to be responsible for the transmission and distribution of electricity to retail customers in their franchise areas, often engaging in generation. The parts of the country that did not opt for the creation of a wholesale market maintained the traditional structure of vertically integrated utilities. Utilities and merchant generators, which are the focus of the paper, accounted for more than 90% of all electricity generated in the country during 2003–2012, the period relevant for our analysis. The same entities also accounted for almost the entirety of coal consumption and more than 80% of gas consumption for

[1] See Borenstein and Bushnell (2015) for the status of the U.S. electricity industry after 20 years of restructuring.

electricity generation (EIA (2015)).

Both utilities and merchant generators operate power plants in which they turn heat produced by fuels, such as coal and gas, into electricity. Fuel prices are the largest component of variable costs, about 75%, and electricity generation is best described as a Leontief production function. Hence, non-fuel inputs, such as labor, are not fuel substitutes and fuel consumption may be studied without the concern for any substitution effects with respect to other inputs (Bushnell and Wolfram (2005)). The main objective of our empirical analysis is to estimate plant-level own- and cross-price elasticities of fuel consumption and their implications for carbon dioxide emissions.[2]

Our empirical analysis allows for the response of coal and gas consumption to their prices to be non linear using flexible model specifications (splines) similar to the ones in Cullen and Mansur (2016). Allowing for flexibility in responses is crucial because coal and gas become closer substitutes when the price of coal is high and the price of gas is low because of the technology used in electricity generation. Power plants differ in their ability to transform heat input from coal and gas combustion to electricity. The amount of heat input from coal needed to generate electricity is close to 1.5 times that from gas. Therefore, if the price of gas is sufficiently low, it may be economical for a power plant to switch from coal to gas.

Although the traditional and restructured electricity markets may lead to responses to fuel prices of different magnitude, it is not clear whether the responses in the former should exceed the latter, or vice versa. Our empirical analysis shows that power plants in traditional markets respond more to changes in the prices of coal and gas consistently across a series of regression specifications and robustness checks when using absolute and relative levels of fuel consumption as our dependent variables. We measure the latter using the share of gas in total fuel consumption. While the fuel consumption regressions allow us to use data from all coal- and gas-fired power plants, the share regressions limit the data to dual-fuel plants only (plants that use both coal and gas).

In the case of the fuel-consumption regressions, our estimates show that the elasticity of coal consumption with respect to gas prices is 0.24 for power plants in traditional markets and 0.09 for power plants in restructured markets when the price of gas is \$7/MMBtu. The difference in responses is statistically and practically significant. The elasticity of gas consumption with respect to gas price is -3.5 for power plants in traditional markets and -0.15 for power plants in restructured markets when the price of gas is \$5/MMBtu. Once

[2]Recent related work, albeit with a different focus, on the effects of gas prices in electricity markets following the development of large-scale tight and shale gas extraction includes Cullen and Mansur (2016), Doyle and Fell (2016), Brehm (2016), Fell and Kaffine (2014), and Linn et al. (2014).

again, the difference in responses is statistically and practically significant.

In the case of the gas share regressions, we offer two micro—within-plant—approaches in modeling coal displacement. In the first, we hold the plant's total generation fixed and in the second, we allow generation to change in response to fuel prices. When holding a dual-fuel plant's generation fixed, a \$1 increase in the price of gas leads up to 3 percentage points (ppt) decrease in the share of gas for power plants in traditional markets when the price of gas is \$3–\$6/MMBtu. The same price increase leads to a 1 ppt decrease in the share of gas for power plants in restructured markets. Both are significant effects given that the average share of gas for dual-fuel plants in our sample is around 9% in traditional markets and 6% in restructured markets. When we allow a dual-fuel plant's generation to change, the price effect on the share of gas is up to 4 ppt for the traditional markets and up to 2.5 ppt for the restructured markets when the price of gas is \$4/MMBtu.

We next consider several factors that may explain this difference in responses to fuel prices between traditional and restructured markets noting that such responses are due to "marginal" power plants that move to the left and right of the equilibrium point between the electricity supply and demand curves as fuel prices change. In particular, we examine the role of the following five factors: investment in capacity, plant efficiency, fuel procurement practices, wholesale purchases and retail sales of electricity and, finally, the role of market power.

We show that the differences in gas-fired capacity between states that restructured their wholesale electricity markets and those that did not are consistent with our findings. All else equal, market participants respond more to fuel price signals as long as they face no capacity constraints. One way to relax capacity constraints is through investment, which is usually on technology that is no worse than that in the older vintage of plants. Using a difference-in-difference (DID) approach to compare gas-fired capacity in both markets before and after restructuring, we find lower capacity in the restructured markets post restructuring. We suggest that these differences in capacity explain the fact that power plants in restructured markets are less responsive to fuel prices.

We then suggest that a second explanation for our results is due to differences in the efficiency of gas-fired plants in turning heat from fuel to electricity (heat rate) between traditional and restructured markets. In particular, we use the heat rate as our metric to show that gas-fired generation is a closer competitor to coal-fired generation in traditional markets than in restructured markets.

On the other hand, differences in fuel procurement practices, wholesale purchases and retail sales of electricity seem unlikely to explain differences in responses. The final possible explanation we consider is market power, which is plausible and worth pursuing but entails analysis that would be hard to accommodate within this paper.

Finally, we assess the implications of the difference in responses to fuel prices for plant-level carbon dioxide emissions using two simple back-of-the envelope calculations. Based on the consumption regressions we find that, following a $1 decrease in the price of gas, the decrease in plant-level coal-related emissions is at most 3% for the traditional markets and at most 8% for the restructured markets. The same price decrease leads to an increase in plant-level gas-related emissions of up to 10% for the traditional markets and up to 7% for the restructured markets. In all, the decrease in plant-level coal-related emissions offsets the increase in gas-related emissions leading to an overall decrease in total emissions from the two fuels in both traditional and restructured markets. Based on the share regressions, we see a reduction of up to 1.5% in the emission rate (lbs./MMBtu) for dual-fuel plants in traditional markets and up to 1% for their counterparts in the restructured markets.

The remainder of the paper is organized as follows. We provide a background on gas and coal production, electricity generation technologies, and wholesale electricity markets in Section 2. Section 3 contains a discussion of our data, our baseline results, and robustness checks regarding the heterogeneity in the response of fuel consumption to prices. Section 4 offers explanations for our findings. Section 5 presents the implications of the difference in responses to fuel prices for carbon dioxide emissions using two simple back-of-the envelope exercises. We finally conclude. Tables and figures are attached at the end of the paper. An on-line Appendix with information regarding the data, summary statistics, and some robustness checks, is also provided.

2 Industry background

2.1 Coal and gas in electricity generation

Coal and gas have dominated electricity generation in the U.S. with a combined annual share of 64%–70% between 1990 and 2012.[3] Most of the country's coal-fired plants are owned by utilities located in the Southeast and the Midwest. They supply base load electricity and typically operate throughout the day due to low variable costs and performance penalties in transient operation. Pipes filled with water run through burners and the heat produced by burning coal turns the water to steam, which is then used to rotate a turbine to which an

[3] EIA Monthly Energy Review, October 2016 at http://www.eia.gov/totalenergy/data/monthly/.

electricity generator is attached.

Gas-fired power plants employ three major technologies: steam boilers, combustion turbines, and combined-cycle generators. The steam boiler technology is similar to the one used by coal-fired plants, where gas is the source of heat as opposed to coal. In the case of combustion turbines, compressed air is ignited by burning gas to expand and push the turbine much like steam does in a steam plant. The turbines then turn the electric generators. The combined-cycle technology utilizes a gas turbine generator and a steam turbine that recovers waste heat from the gas turbine. It is the most efficient of the three and it is well-documented that it has revolutionized the industry.

In general, gas-fired generation is more flexible than coal-fired generation when it comes to changes in output and it has historically been the primary option to meet the variable portion of the electricity load and, therefore, typically supplies peak power. However, the availability of abundant cheap gas in the aftermath of the shale boom, coupled with regional and federal environmental policies aiming to reduce the use of coal, often colorfully described as "War on Coal", resulted in more gas-fired generation serving large fractions of base load and displacing coal-fired generation.

The two fuels are different in several dimensions. For example, coal used by different power plants around the country exhibits substantial heterogeneity in its physical characteristics, such as heat and sulfur content—the latter is particularly concerning for environmental reasons. Coal originating in the Power River Basin in Montana and Wyoming has a lower heat and sulfur content than coal originating in the Appalachian region. Coal's physical characteristics, as well as the method of extraction—surface or underground mining—are major determinants of its price. Distance is also important and transportation costs are a major consideration in the choice of coal used as fuel. Coal plants receive more than two thirds of their coal by rail and, while, on average, transportation costs account for approximately 20% of total delivered costs, they can be as high as 60%.[4]

By contrast, gas is a homogeneous product. Since it is delivered by a national network of pipelines, transportation costs are small compared to the ones for coal. However, gas is difficult to store in bulk near power plants, which makes plants dependent on gas pipelines that sometimes have delivery issues. In New England, for example, pipeline capacity has not kept up with the growth in gas demand, which has led to increased volatility and numerous price spikes repeatedly. Importantly, gas is a superior alternative to coal in terms of carbon dioxide, sulfur dioxide, and nitrogen oxide emissions, with many advocating for its use as a

[4]See http://www.eia.gov/coal/transportationrates/.

bridge fuel to a cleaner electric power sector.

2.2 Wholesale electricity markets

Over the years, the U.S. electric industry developed as a loosely connected structure of individual monopoly utility companies, each building and operating power plants and transmission and distribution lines to serve its franchise area. The utilities were overseen by regulators aiming to protect consumers from unfair pricing and other undesirable behavior, such as lack of investment in infrastructure.

In the 1990s, the federal government took a series of steps to restructure wholesale electricity markets with an emphasis on the unbundling of generation from transmission and distribution. Efforts were also put on the promotion of competitive retail markets. For the first time in the history of the industry, retail customers in some states were given the choice to pick their electricity suppliers.

Twenty years later, we have either traditional regulated markets in areas of the country that did not opt for restructuring, and wholesale markets coordinated, initially, by Independent System Operators (ISOs) and, subsequently, by Regional Transmission Organizations (RTOs) in parts of the country that did restructure.[5] California, the Midwest, Texas, the mid-Atlantic states, New York, and New England, were among the parts of the country, where restructured markets emerged. The Western part of the country, excluding the coastal states, and the Southeast maintained the traditional market structure.

Today, electricity generation around the country is either utility- or non-utility owned. Utilities are either investor-owned companies or public agencies. Non-utility electric power plants belong to one of the following groups: merchant generators, also known as independent power producers, commercial, or industrial. The growth of non-utility ownership took off following the restructuring and the divestiture of generation assets by utilities, especially, investor-owned utilities (IOUs) in the late 1990s. Those assets were transferred to another company or to an unregulated subsidiary with its own holding company structure. As a result, around the time of restructuring, the number of IOUs was decreasing, and non-utilities were expanding by buying utility-divested generating assets, increasing their share of generation and new capacity.

In the empirical analysis that follows, we will limit our attention to power plants operated by IOUs (henceforth, utilities) and merchant generators in traditional and restructured markets.

[5] In the remainder of the paper, we use the term ISOs to refer to both ISOs and RTOs.

Entities in the commercial and industrial sectors produce electricity primarily for their own use and are outside the scope of the paper.

3 Empirical analysis

In this section, we examine differences in responses to fuel prices due to market structure and their implication for carbon dioxide emissions. In particular, we examine heterogeneity in responses to fuel prices between traditional and restructured markets employing different types of analysis with plant-level data for utilities and merchant generators between 2003 and 2012.

After providing some preliminary statistics, we discuss the econometric analyses documenting first the heterogeneity in the response of fuel consumption to fuel prices—we analyze coal and gas separately. We next discuss the heterogeneity in the response of gas share in total fuel consumption to fuel prices using data for dual-fuel plants only. Although we report results using fuel consumption (MMBtu), we should note that the conclusions of our analysis are qualitatively the same if we model the response of coal- and gas-fired generation (MWh).[6]

In the last part of our analysis, we document the implications of the heterogeneity in responses to fuel prices for plant-level carbon dioxide (CO_2) emissions and the associated social benefit of a hypothetical decrease in the price of gas. Details regarding the data used in the analyses that follow, along with some robustness checks, are available in the on-line Appendix A.

3.1 Preliminaries

Our sample consists of 393 plants that use coal to generate electricity and 1,259 plants that use gas to generate electricity (Table 1). Once we limit our attention to these two fuels, plants that use coal account for 42% of capacity (MW), 71% of fuel consumption when expressed in units of heat input (MMBtu), and 67% electricity generation (MWh). Their heat rate, which is the consumption-over-generation ratio (MMBtu/MWh), is 10.4, while that for gas plants is 8.5; note that a lower heat rate is a desirable property.

Roughly 180 plants in our sample use both coal and gas to generate electricity and 70% of them are in restructured markets. Almost 47% of the plants that use coal are dual-fuel plants in both traditional and restructured markets (Table 1, panel (b)). Around 12% (16%)

[6]This is also the case when we model the gas share in total (coal- plus gas-fired) generation.

of plants that use gas in traditional (restructured) markets are dual-fuel plants (panel (c)). Dual-fuel plants account for about 37% of coal consumption, generation, and capacity, in both traditional and restructured markets. They also account for 7%–8% (4%–6%) of gas consumption, generation, and capacity in traditional (restructured) markets.

Utilities dominate both fuels in traditional markets, and more so in the case of coal. Their dominance is limited to only coal in restructured markets, where merchant generators dominate gas by far (Table 2). In traditional markets, utilities account for 75% of coal plants (panel (a)). They also account for almost 90% of capacity, consumption, and generation. In restructured markets, they account for half of the plants, and for almost 60% of capacity, consumption, and generation. About half of the gas plants in traditional markets are operated by utilities, which also account for 54% of capacity, and close to 60% of consumption and generation. In restructured markets, utilities account for 27% of all plants, 22% of capacity, and 15% of consumption and generation (panel (b)).

Figure 1 shows that coal prices paid by power plants increased from about \$1.5 to \$2.5 per MMBtu in traditional markets (panel (a)). For the restructured markets, the price of coal increased from about \$1.4 to slightly more than \$2. During the entire period in our sample, coal prices in traditional markets were higher than those in restructured markets, which is consistent with the findings in Cicala (2015) and Chan et al. (2017).[7] These price differences may be attributed to factors such as the physical characteristics of coal and transportation costs that we don't control for, and not necessarily differences in incentives to minimize costs across market structures.

The same figure shows a big drop in the price of gas to around \$2 by the end of our sample after the \$12 spike in the summer of 2008, which is due to the large exogenous supply shock in the market because of fracking that led to gas extraction at unprecedented levels (panel (b)). The other prominent spike is due to hurricane Katrina in the fall of 2005 and the associated large-scale disruptions in the Gulf coast, where many of the country's gas pipelines originate. Power plants pay similar prices in both types of markets. Within traditional markets, utilities pay, on average, higher prices than merchant generators. This price differential is not present in restructured markets.

Finally, a cursory look at coal and gas consumption over time for the traditional and restructured markets (panels (c) and (d)) shows coal-to-gas switching in both cases. Coal

[7] Cicala finds that divested power plants paid 12% less for coal, but this is not the case for gas—divestiture of incumbent integrated utilities' generating assets was a widespread phenomenon following the restructuring of the electricity markets. Chan et al. (2017) find that coal plants in restructured markets paid 6–10% less for coal than coal plants in markets that did not restructure. He et al. (2016) also find that plants in restructured markets negotiate coal prices that are close to 3% lower than those for plants in traditional markets.

consumption decreased over time, while gas consumption increased. The seasonal pattern is more pronounced in gas consumption because gas plants are generally used more than coal plants to serve peak demand. Between 2003 and 2012, the gas share of total (coal plus gas) consumption increased from around 20% to more than 50% in traditional markets in 2012 (panel (e)). In restructured markets, the increase was less pronounced with a peak close to 40%.

In summary, we provide some preliminary evidence that the gas share of fuel consumption has increased over time due to an increase in gas consumption and a decrease in coal consumption between 2003 and 2012. This is true for both the traditional and the restructured markets. During this period, coal prices almost doubled while the 2012 levels of gas prices were at about a sixth of their mid-2008 levels. Although gas prices are very similar in traditional and restructured markets, coal prices are different. The differences in coal prices can be attributed to factors other than market structure, such as physical characteristics and transportation costs.

3.2 Average prices

Before we discuss our econometric results, we should explain how we address the lack of plant-level monthly fuel prices. We address this data availability issue by using monthly regional coal and gas prices. For 95% of our observations, we use average monthly state-level prices calculated using fuel consumption in MMBtu as a weight. For the remaining 5%, we use either monthly prices by North American Electric Reliability (NERC) region, or monthly prices by Environmental Information Administration (EIA) region. NERC regions correspond to geographic areas in the county, which may span several states, under the supervision of entities ensuring the reliability of the electricity grid. The EIA regions correspond to Census divisions.

We use monthly regional prices instead of plant-level prices for several reasons. First, we need coal (gas) prices for plants that only use gas (coal). Second, plants may not make fuel purchases in every month, in which case they don't report fuel prices. This is particularly true for coal because coal can be stored. Third, although we got access to EIA confidential cost data subject to a non-disclosure agreement with the agency, there are still merchant generators for which we are missing fuel prices. Fourth, had we used average regional prices only when price information was missing, we would have introduced measurement error in an asymmetric fashion. Most importantly, we are interested in identifying the effect of gas prices on fuel consumption and time is the primary source of variation in gas prices because of the exogenous supply shock due to shale gas.

Figures 2 and 3 show the distribution and average monthly prices for coal and gas plants by market type. The former is based on the original cost data from EIA including the confidential ones. The latter is based on the average regional prices as discussed above. It is clear that the pattern of time variation in the gas prices, which is of primary interest, is not affected by the use of regional prices. Moreover, we experimented with two alternative calculations of average regional prices and our findings regarding the heterogeneity of response to fuel prices across market structures remain qualitatively the same.[8]

3.3 Heterogeneous response to fuel prices

Our main interest lies in estimating two types of responses to fuel prices. The first is estimating the response of absolute levels of fuel consumption to fuel prices. The second is estimating the response of relative levels of fuel consumption, measured as the share of gas in total fuel consumption, to fuel prices. In the case of coal consumption regressions, we use coal-fired and dual-fuel plants. In the case of gas consumption regressions, we use gas-fired and dual-fuel plants. In the case of the share regressions, we use dual-fuel plants only.

Earlier in the paper, we argued that coal and gas are closer substitutes when coal prices are high and gas prices are low. In order to allow for changes in the degree of responsiveness to prices, we estimate models of the following form for both the consumption and share regressions

$$y_{it} = a_i + \mathbf{x}_{it}'\beta + f(p_{rt}^{coal})'\gamma + g(p_{rt}^{gas})'\delta + u_{it}, \tag{1}$$

where i denotes the plant, t denotes the month in our sample, 2003/01–2012/12, and r denotes the region, which corresponds to a state for the vast majority of the observations. Functions $f(\cdot)$ and $g(\cdot)$ are flexible transformations of the average regional fuel prices (basis splines). We allow these flexible specifications to differ by fuel due to different knots, and to also differ across traditional and restructured markets through an interaction with an appropriate dummy. This is easily implemented because, although the basis splines involve non-linear transformations of fuel prices, the model in (1) is still linear in the parameters.

[8]We point the reader to Figures A.1 and A.2 of the on-line Appendix. In the first figure, we allow the prices to be different for merchant generators and utilities within the geography considered (e.g., different prices for merchant generators and utilities within state). In the second figure, we use power control areas (PCAs) as the finest geography. PCAs are areas in which there is a central dispatch of power plants under a single entity. For the restructured markets, PCAs are mainly ISO areas. For the traditional markets, PCAs are predominantly utility areas. PCAs are also known as balancing authority areas.

Finally, a_i is the plant fixed effect, $\mathbf{x}_{it}$ is a vector of additional controls (including time effects) discussed below, and u_{it} is the error term. The reported standard errors are clustered by state and month of sample.

We considered four different sets of controls in $\mathbf{x}_{it}$ that gave rise to four different specifications: SPEC I–SPEC IV. Table 3 provides the number of observations by market structure for each of the four specifications for both the fuel and the share regressions discussed below. SPEC I uses only plant fixed effects and NERC region-by-month fixed effects. The former control for time-invariant unobservables in plant operations. The latter control for regional seasonality in the use of gas plants. SPEC II uses the same controls as SPEC I plus NERC region-by-year fixed effects controlling for time-varying regional market conditions.

In SPECS III and IV, we control for the plant's capacity and environmental-policy driven substitution between the two fuels. In particular, SPEC III uses plant fixed effects plus the following controls: total (coal plus gas) capacity, SO_2 and seasonal NO_X permit prices in logs, number of electricity generating units (EGUs) with NO_X, SO_2, and particulate matter environmental controls, number of EGUs under various EPA programs, as well as seasonal (month) fixed effects. Finally, SPEC IV uses the same controls as SPEC III plus year fixed effects. We have eliminated the interactions of the year and the seasonal fixed effects with the NERC-region fixed effects in SPEC III and SPEC IV to avoid model overspecification at the risk of not capturing trends and seasonal patterns in market conditions that are specific to NERC regions. In Section A.2 of the on-line Appendix, we test for differences in the various controls that enter SPEC III and SPEC IV. In general, we see statistically significant differences, both positive and negative, in several of these controls, especially those related to the number of EGUs under various EPA programs. This is true for both the consumption and share regressions.[9]

In terms of the specification of the basis splines $f(\cdot)$ and $g(\cdot)$, we considered both single and multiple knots. Our choice of knots was based on the distribution of coal and gas prices. The vast majority of coal (gas) prices are less than \$4 (\$12). The average coal (gas) prices are around \$2 (\$6). Hence, we opted for single knots at \$2 for coal and \$6 for gas. We also considered single knots at \$4 for coal and \$8 for gas. In the case of multiple knots, we considered knots at \$2 and \$4 for coal, and knots at \$6 and \$8 for coal. Furthermore,

[9] A plant may have one or more EGUs on site. Capacity and permit prices in SPEC III and SPEC IV enter in logarithmic form. It is worth mentioning that although the prices of the SO_2 permits were constantly in the range \$100–\$200/ton during the first 10 years of the Acid Rain Program, the situation changed when it became clear that more stringent caps would be put into place following the Clean Air Interstate Rule (CAIR) in 2005. CAIR essentially required some states to reduce the amount of permits by two thirds, which increased substantially the price of the remaining allowances (Schmalensee and Stavins (2012)).

we considered knots at \$1, \$2, \$3, and \$4 for coal, and knots between \$2 and \$12 with increments of \$2, for gas. Although the splines with more than 2 knots for each fuel offer more flexibility in the responses to fuel prices, they proved to be noisy and we discarded them.

Consumption regressions

For the remainder of the paper, we focus on the results implied by the splines with a single knot at \$2 for coal and at \$6 for gas with our primary interest being the effects of the price of gas.[10] The qualitative nature of the results reported below remains the same when we use a single knot at \$4 for coal and at \$8 gas, or when we use knots at \$2 and \$4 for coal and knots at \$6 and \$8 for gas.

Figure 4 shows the change in coal consumption (million MMBtu) due to a \$1 dollar increase in the price of gas when the price of gas is in the range \$2–\$12 for each of the 4 specifications. For example, we show the change in coal consumption due to a \$1 increase when the price of gas is \$2, which is different from a \$1 increase when the price of gas is \$6. Gas prices in the range \$2–\$6 are generally consistent with the ones the industry experienced post 2008. The partial effects shown in each of the four panels are calculated numerically due to the nature of the transformation of the fuel prices in the basis splines. The 95% confidence intervals (dashed lines) are calculated using the delta method, which is straightforward to implement given that the models are linear in the parameters.

The gas cross-price effects are positive in all 4 specifications. In addition, the cross-price effects are smaller when gas prices as higher, which is consistent with the fact that coal and gas become closer substitutes when the price of gas is lower, all else equal. Furthermore, the cross-price effects are larger for the traditional markets for gas prices between \$5 and \$8 in SPEC I and SPEC II. For SPEC III and SPEC IV, although the cross-price effects are larger for the traditional markets for gas prices between \$6 and \$8, their confidence intervals include the cross-price effects for the restructured markets.

In order to assess the economic significance of the cross-price effects, we will use SPEC I noting that SPEC II leads to essentially the same conclusions. When the gas price is \$7, the cross-price effect is about 0.10 (million MMBtu) for the traditional markets, and it is around 0.04 for the restructured markets. These are relatively large effects given that the mean coal consumption is around 2.8 for traditional markets and 3.04 for restructured markets at this price point. An increase by \$1 when the price of gas is \$7 is a 14% increase. The implied

[10] The on-line Appendix figures A.3–A.6 show the effects of \$1 increase in the price of coal.

decrease in coal consumption is 3.3% for the traditional markets and 1.3% for restructured markets when evaluated at the mean level of coal consumption. Therefore, at this price point, the cross elasticities are 0.24 and 0.09, respectively.

We next discuss the own-price effects of gas in Figure 5. Consistent with our expectations, the own-price effects have the expected negative signs and are smaller in magnitude at higher gas prices. In general, there is a statistically significant difference in the own-price effect between traditional and restructured markets for gas prices in the range \$3–\$8. At the lower end of this price range, the response of gas consumption for traditional markets is roughly twice as large as the response for restructured markets. Moreover, we cannot reject the null hypothesis of zero own-price effects for both traditional and restructured markets for gas prices exceeding \$8.[11]

To better understand our findings for the own price effects of gas, we estimated (1) for each of the three main technologies of gas-fired electricity generators: steam boilers, combustion turbines, and combined cycle. Although there are no difference in the own price effects between traditional and restructured markets in the case of the first two technologies, there are differences in the case of the combined-cycle technology, which is the most cost efficient and, hence, the most likely to compete with coal (Figure A.7). Consistent with our findings regarding the own price effects for the combined-cycle technology, in a subsequent section, using a difference-in-difference approach, we find lower combined-cycle capacity in restructured markets post restructuring.

To assess the economic significance of the effects, we look at the implication of a \$1 increase for a gas price at \$5 using SPEC I noting that all the alternative specifications lead to the same conclusions. The decrease in gas consumption is 0.02 (million MMBtu) for traditional markets and 0.01 for restructured markets. At a price of \$5, the mean gas consumption is 0.03 for traditional markets and 0.29 for restructured markets. The 20% increase in the price of gas implies a 70% decrease in gas consumption for traditional markets and a 3% decrease for restructured markets. Hence, the implied own-price elasticities are -3.5 and -0.15, respectively. For gas prices between \$4 and \$10, the average own-price elasticity is -0.20 calculated based on the mean fuel consumption at each price point.

To conclude, a natural question to ask is how our elasticity estimates compare to others in the literature. The short answer to this question is that they are generally comparable

[11] We also considered specifications using the gas-to-coal price ratio, such that we write $y_{it} = a_i + \mathbf{x}_{it}'\beta + f(p_{rt}^{gas}/p_{rt}^{coal})'\gamma + u_{it}$ in (1). Using knots at the 25th, 50th, and 75th percentiles of the gas-to-coal price ratios, gas consumption in the traditional markets responded more than gas consumption in the restructured markets to price ratios of less than 3 that are consistent with the prices the industry experienced after 2008 (panel (e), Figure 9). The results are available from the authors upon request.

to others in the recent literature. Using plant-level data on fuel consumption and average regional prices for 2001–2012, but a less flexible specification for prices (log-log), Linn et al. (2014) report a cross-price elasticity of coal consumption equal to 0.031 with a standard error of 0.013 and an own-price elasticity of gas consumption equal to -0.340 with a standard error of 0.040. Doyle and Fell (2016) examine the response of gas-fired plants to changes in coal and gas prices allowing for the responses to vary by plant technology and market structure. They use annual data and regional (balancing area authority) prices for coal only between 2002 and 2012 and a log-log specification. Although all gas-fired plants respond to gas prices, only the more efficient combined-cycle plants respond to coal prices. The own-price elasticities are -0.77 to -0.64 depending on the technology and market structure, and they are significant at 1%. The cross-price elasticities are 0.057–0.065 for the combined-cycle technology depending on whether they allow for a difference in responses across market structures or not. They are also significant at 1%.[12]

Share regressions

We next examine heterogeneity in responses of the gas share of total (coal plus gas) fuel consumption in the case of dual-fuel plants, which are plants that use both coal and gas to produce electricity. We do so following two different approaches. First, we hold the amount of electricity generated using the two fuels fixed. In this case, gas clearly displaces coal within a plant when the share of gas in fuel consumption increases due to a drop in the price of gas. Second, we allow the amount of electricity generated by dual-fuel plants to change. The share of gas in fuel consumption now may increase because of within-plant coal displacement or because gas-fired generation of one plant displaces coal-fired generation of another plant.

Figure 6 shows the change in the share of gas due to a \$1 increase in the price of gas for each of the four specifications when we hold electricity generation fixed using a third degree polynomial in log total (coal- plus gas-fired) generation in (1). We focus on gas prices between \$2 and \$8, which is the price range for which we already showed coal and gas consumption responding more. In all four specifications, the price effects have the correct signs and they decrease in magnitude as the price of gas increases. In addition, the price effects for the traditional markets are larger than their counterparts for the restructured markets. For

[12] Hausman and Kellogg (2015) report a short-run (long-run) price elasticity for the electric power sector equal to -0.15 (-0.47) using data at the state-by-month level for 2001 onwards. The standard error for the long-run price elasticity is 0.43. Using time-series data for 8 Western European countries between 1978 and 2004. Pettersson et al. (2012) report a cross-price elasticity for coal with respect to the price of gas of 0.108 with a standard error of 0.08. The own-price elasticity for gas is -0.546 with a standard error of 0.13.

example, in SPEC I, the price effects for the traditional markets are three times as large as the price effects for the restructured markets. Moreover, the price effects for the restructured markets are indistinguishable from zero in SPEC II–SPEC IV.

In the case of traditional markets, the price effects for SPEC I exceed those for the remaining specifications. For prices between \$3 and \$6, the price effect is 3 percentage points (ppt), compared to 2 ppt for SPEC II, 1 ppt for SPEC III, and 1.6 ppt for SPEC IV, on average. For the same price range, the price effect for restructured markets in SPEC I is close to 1 ppt. Given that the average gas share in dual-fuel plants is around 9% for traditional markets and 6% for restructured markets, these price effects are economically meaningful, and more so for traditional markets. Note also that the mean total (coal plus gas) fuel consumption for the traditional markets is 3.8 million MMBtu compared to 2.7 for restructured markets.

When we allow the plant's electricity generation to vary, the price effects have the correct signs and exhibit the expected patterns too (Figure 7). Once again, the effects for the traditional markets exceed those for the restructured markets, and are generally larger in magnitude compared to their counterparts when we hold the plant's generation fixed. For SPEC I and SPEC III, we see effects that differ from zero for the restructured markets for gas prices \$2–\$5. At a price of \$4, the price effect is 4 ppt for the traditional markets and 2.5 ppt for the restructured markets using SPEC I.

In summary, using the gas share of fuel consumption as the dependent variable, and holding electricity generation fixed, we see that coal displacement due to a drop in the price of gas for traditional markets is larger than that for restructured markets for two reasons. The first is the magnitude of the price effect. The second is that total fuel consumption is higher, on average, for traditional markets. Moreover, coal displacement due to a drop in the gas price is more pronounced if we allow electricity generation to change in response to the price of the two fuels.

4 Explaining differences in responses

In this section, we explore several factors that could explain the differences in responses to fuel prices between traditional and restructured markets documented above. We use both econometric and descriptive analysis when the former is hindered by data availability. We also provide documentary evidence. In what follows, we examine the role of the following five factors: investment in capacity, plant efficiency, fuel procurement practices, wholesale purchases and retail sales of electricity and, finally, the role of market power.

4.1 Investment in capacity

All else equal, market participants respond more to fuel price signals as long as they face no capacity constraints. One way to relax capacity constraints is through investment, which is usually on technology that is no worse than that in the older vintage of plants. Our findings are then consistent with investment in gas-fired capacity for restructured markets being smaller than its counterpart for traditional markets. To empirically examine whether this is indeed the case, using s to denote the state and t to denote the year, we estimate the following model:

$$Cap_{ng,st} = a + \beta \cdot Rest_{st} \times Post_{st} + \gamma Cons_{st} + \eta_s + \eta_t + \varepsilon_{st}. \tag{2}$$

The dependent variable is gas-fired capacity for 1990–2012. We focus on the most advanced (combined-cycle) gas technology because it is the closest competitor to coal. The most recent gas technologies achieve heat rates—consumption-over-generation ratios (MMBtu/MWh)—as low as 7.5, while the ones for coal-fired generators are close to 10.5. Less efficient types of gas-fired generators, such as steam and combustion turbines, achieve heat rates that are about 10.5 and 11.5, respectively.

We construct the dependent variable using the gas-fired capacities of all entities in a state and not just utilities and merchant generators. In terms of notation, $Rest_{st}$ is a restructuring dummy based on Table 1 in Craig and Savage (2013). The dummy is equal to one if state s adopted an initiative that introduced competition in its wholesale electricity market, and zero, otherwise. In addition, $Post_{st}$ equals one for the restructured states post restructuring and $Cons_{st}$ is the state-level end-use electricity consumption.[13] Finally, η_s and η_t are state and year fixed effects.

The coefficient of interest in the difference-in-difference (DID) regression is β. It captures differences in capacity between states that did not restructure their wholesale electricity markets (traditional) and states that did, post-restructuring. The post-restructuring period largely overlaps with the period in our sample as we discuss below. The DID regression requires the absence of preexisting differences in capacity trends between the two groups of states before restructuring, which is the case here. It can, however, accommodate preexisting differences in capacity levels and any state- or time-specific unobservables. Finally, our DID specification controls for state-level retail electricity consumption.

[13] We use the information in the "Access to wholesale markets/partial competition" column of Table 1 in Craig and Savage to construct $Rest_{st}$. We use the year associated with the access to wholesale markets for each state to construct $Post_{st}$, which is also readily available in Craig and Savage.

Figure 8 shows the main trends in gas capacity for the states that maintained the traditional market structure and the states that restructured their markets with time series plots of capacity by year. Each point on the series is an average of the capacity across multiple states in a given year. The black vertical lines identify the time window during which the restructuring took place, namely between 1997 and 2004. Hence, the post-restructuring period largely overlaps with the time period in our consumption and share regressions (2003–2012). Table 4 provides some basic summary statistics regarding capacity for the two groups of states.

An immediate observation from Figure 8 is the tremendous growth in capacity, especially between the mid-1990s and the mid-2000s, consistent with the well-known phenomenon S-shaped investment Klepper and Miller (1995). However, after 2004, which marks the end of the restructuring wave and the beginning of the shale gas boom, the growth is more notable for states that maintained the traditional market structure—from about 5,500 MW to close to 8,000 MW, on average. During the same period, the average gas-fired capacity increased from about 5,500 MW to around 6,000 MW, on average, in the states with restructured markets. The Southeast and the Southwest drive most of the increase in the states with traditional markets. Texas, California, and the Midwest to a lesser extent, drive most of the increase in the states with restructured markets.

In Table 5, we formalize the comparison between the two groups of states using the DID regression results based on equation (2). We report results for four alternative approaches to address the severe autocorrelation within state. In column (1), we report OLS estimates with clustered standard errors by state. In column (2), we report the results for the Prais-Winsten estimator assuming an AR(1) autocorrelation structure that is common across states. In columns (3) and (4), we report results for a two-step feasible GLS (FGLS) estimator and an iterated FGLS estimator (I-FGLS) with AR(1) autocorrelation structures that also allow for cross-sectional heteroskedasticity. In all 4 cases, we use approximately 670 observations for the contiguous states. Although the reader may be concerned that the right skew in the distribution of the dependent variable drives our results, Figure A.8 of the on-line Appendix shows that this is not the case.[14]

The OLS coefficient estimate of $Rest \times Post$ is quite inefficient. Although OLS produces a larger point estimate than the 3 GLS procedures considered, it also produces a much larger

[14]Furthermore, omitting the observations with "residual" nameplate capacity less than -10,000 that correspond to Texas in Figure A.8, which is among the states with restructured electricity markets gives rise to the following estimates of the $Rest \times Post$ coefficient: -1,115.3 (OLS), -939.6 (PW), -317.2671 (FGLS), -225.5397 (I-FGLS). The PW and I-FGLS estimates are significant at 1%. The FGLS coefficient is significant at 10%.

standard error. As a result, the GLS estimates fall within the 95% confidence interval of the OLS estimator. The GLS estimates are all negative and statistically significant at 5%. The OLS estimate is also negative, but is significant at 10%, noting that our *primary* interest lies in the *qualitative* nature of the results. The negative sign and not the magnitude of the coefficient per se is the major takeaway from this exercise. That is, gas fired-capacity in restructured markets is smaller than its counterpart in traditional markets in the years post restructuring, and this limited the ability of market participants to respond to fuel prices as we documented in the consumption and share regressions.[15] We should also note that the conclusions of our DID regressions remain the same if we divide the state level capacity by the state-level end-use electricity consumption and we eliminate $Cons_{st}$ from the explanatory variables in (2). This is an alternative way to account for differences in the sizes of the states.[16]

Our findings using the DID regressions are consistent with Joskow (2006), who makes the case that restructured wholesale electricity markets do not provide adequate incentives for the proper mix of generating capacity. According to Joskow, a large part of the problem is the failure of wholesale spot markets to produce prices during periods of capacity constraints that are high enough to attract investment in a least-cost mix of generating capacity. The investment disincentives associated with high volatility in wholesale energy prices, limited hedging opportunities, and concerns about regulatory opportunism are also emphasized. Peak-load plants, which tend to be gas plants, in particular, are more exposed to price risk due to their low utilization, which has led to the creation of capacity markets operated by ISOs to attract investment.[17] Furthermore, there is a concern about the strategic use of investment. Large incumbents may choose to postpone investment in generation to drive up

[15]We estimate (2) excluding observations for which the dependent variable equals zero because we estimated the same model using a log specification. Including the observations with zero values leads to coefficient estimates between -1,050 and -250 for $Rest \times Post$. In this case, all coefficient estimates for $Rest \times Post$ are significant at 5% level except for OLS. The logarithmic specification produced a positive coefficient estimate for $Rest \times Post$ that can be explained as follows. Using Y to denote the outcome variable, the logarithmic transformation amplifies the differences between the treated (T) and control (C) states before (B) 1997, $(Y_B^T - Y_B^C)$, and condenses the differences between the treated and control states after (A) 2004 $(Y_A^T - Y_A^C)$. As a result, the difference in differences, $(Y_A^T - Y_A^C) - (Y_B^T - Y_B^C)$, is positive despite the fact that each of the two components is negative. The identifying assumptions in the DID framework are scale dependent; if they hold for the level of Y, they may not hold for monotone transformations of Y. In other words, the way we measure and transform the outcome variable is relevant for the plausibility of the identifying assumptions, even without postulating any parametric model for the relation of confounders and treatment to the outcomes, which has motivated the change-in-change estimator of Athey and Imbens (2006)—see page 155 in Meyer (1995) and page 437 in Athey and Imbens (2006).

[16]We also estimated an AR(1) version of (2) using the Anderson-Hsiao estimator given that the panel is relatively long (Judson and Owen (1999)). The $Rest \times Post$ coefficient is negative and significant at 1%.

[17]The Pennsylvania-New Jersey-Maryland (PJM) capacity market is probably the most-well known example.

prices from existing assets in the presence of barriers to entry that prevent new investment in generating capacity.

Additional support for our findings comes from a report to the U.S. Congress by The Electric Energy Market Competition Task Force (2007) following the Energy Policy Act of 2005. Among other activities, the Task Force solicited comments from industry stakeholders on how competition policy affected the decision making of both buyers and sellers in wholesale electricity markets. In its executive summary, the Task Force concludes that investment in new generation exhibited significant variation across the country since the adoption of open access transmission and the introduction of competition in wholesale electricity markets. In particular, the report emphasized that the lack of long-term contracts for generation and transmission had a dampening effect on investment in generation and transmission highlighting that the availability of long-term contracts was important for non-utility generators to secure capital for new investment. In an effort to provide additional incentives for investment and secure sufficient reserve margins for contingencies, such as supply disruptions or demands spikes, wholesale electricity markets introduced capacity payments.

Moreover, we cannot discount the negative effects of regulatory uncertainty, as discussed by Joskow and also highlighted in the EPACT report. In the aftermath of what became known as the California Crisis, several states that were in the middle of the restructuring process put it on hold introducing uncertainty. In fact, Fabrizio (2012) provides empirical support for such effects. She shows that although the Renewable Portfolio Standards did generate an increase in investment in renewable generating asses, the investment increased significantly less in eight states that had previously passed and repealed legislation to restructure their wholesale markets.

At the same time, more capacity in traditional markets may be the outcome of a well-known consequence of regulation. Averch and Johnson (1962) showed that rate-of-return (RoR) regulation has an unintended consequence. Capital investments by investor-owned utilities exceed the cost-minimizing level in response to the incentives created by the RoR regulation, a finding known in the literature as the "A-J effect". Furthermore, a regulator's disallowance (denial to recover) of some part of the capital costs further exacerbates the A-J effect. Since a portion of capital spending is excluded from the profit calculation, firms will invest more in capital to maintain or increase profits (Douglas et al. (2009)). Using the example of the NO_X Budget Program aiming to limit NO_X emissions in eastern states, Fowlie (2010) shows that the power plants' environmental compliance decisions were influenced by RoR regulation. Deregulated plants recovering capital investment in wholesale electricity markets were less likely to adopt more capital-intensive compliance options compared to regulated plants.[18]

4.2 Plant efficiency and fuel prices on an output basis

The motivation behind the analysis in this section is the fact that gas-fired plants with lower heat rates respond more to gas prices all else equal. Recall also from our earlier discussion that the heat rate is a standard measure of plant's inefficiency because it measures the amount of heat energy from fuel consumption in MMBtu used to generate a MWh of electricity. The higher the heat rate, the less efficient the plant is. In addition, two plants that face the same fuel prices per MMBtu may face different fuel prices per MWh of electricity due to differences in their efficiency.[19] Overall, low heat rates are desirable because they imply fuel costs savings for the power plants and can be achieved in a variety of ways. For example, investment in newer technology leads to lower heat rates. The same is true as the staff of a power plant becomes more familiar with the plant's operations.

For the purpose of illustration, assume two gas plants, GH and GL, which are both extra-marginal in the supply curve—located on the right of its intersection with the demand curve—in a world of high gas prices and which are fully described by their heat rates and spare capacity. Although both plants have the same spare capacity, plant GH has a substantially higher heat rate than plant GL. If both plants are exposed to the same decrease in gas prices, there is a higher chance that plant GL will become infra-marginal—move to the left of the intersection point—all else equal.

The top two panels in Figure 9 contain time series plots of the coal and gas heat rates in traditional and restructured markets for 2003–2012. In the case of gas, we see heat rates falling over time, which is generally consistent with investment in combined-cycle (advanced) technology that both types of markets experienced during this time as discussed earlier (panel (a)). The coal heat rates, on the other hand, exhibit an upward trend that is slightly more pronounced in the traditional markets (panel (b)). During this period, there was limited investment and substantial divestment in coal-fired capacity leading to a stock of aging plants. This is a phenomenon that the industry has attributed to falling gas prices and a series of regional and federal regulations aimed to reduce coal use in electricity generation. We also have to keep in mind the slowdown of the economy due to the most recent financial crisis

[18] Lyon and Mayo (2005) find little evidence that cost disallowances were opportunistic (violations of the regulatory contracts) in the case of electric utilities between the 1970s and 1990s. Regulators were largely driven by the desire to punish poorly managed utilities.

[19] To be precise, the heat rate is a feature of EGUs, and a power plant may have multiple EGUs on site. See Fabrizio et al. (2007), and more recently, Chan et al. (2017), among others, for the effect of restructuring on heat rates.

and its effect on investment. Both coal and gas heat rates are generally lower in traditional markets than in restructured markets during 2003–2012, and the difference, around 10%, is more pronounced in the case of gas. Hence, all else equal, gas-fired generation was a closer competitor to coal-fired generation in traditional markets than in restructured markets using the heat rate as our metric, which is consistent with our finding of more responsiveness to fuel prices in traditional markets.

Figure 9 also contains time series plots of coal and gas prices in \$/MWh, as well as a time series plot of their ratio for traditional and restructured markets; panels (c)–(e). These time series plots are constructed using monthly average regional fuel prices in \$/MMBtu and the heat rates in panels (a) and (b). Despite the fact that there is both cross-sectional and time variation in gas prices, time-variation is the dominant one, and this is adequately captured by the time series shown here. Although the gas-over-coal price ratio is generally lower for traditional markets for the period prior to 2008, this is not the case post 2008. Therefore, if differences in fuel prices on a per unit-of-output (MWh) basis were to explain differences in responses to fuel prices on a per unit-of-energy (MMBtu) basis, then these differences should be more relevant for the period prior to 2008, during which gas prices were higher relative to their end-of-sample values. However, coal-to-gas switching was a widespread phenomenon post-2008.[20]

4.3 Fuel procurement practices

Differences in fuel procurement practices may also explain the difference in responses to fuel prices between plants in traditional and restructured markets. One such practice is procurement using long-term contracts for a future delivery date longer than a year. Long-term contracts for purchasing coal have been a common practice in the industry for years. Long-term contracts are also used for gas purchases, albeit to a lesser extent, and more so in recent years. Joskow (1987), and more recently, Jha (2016) and Kozhevnikova and Lange (2009), have all shown that relationship-specific investments often make it desirable for the two parties (utilities and coal suppliers) to enter into long-term contracts.[21]

[20] As an additional check, we used prices in dollars per MWh as opposed to dollars per MMBtu and knots at \$20/MWh for coal and \$60/MWh for gas, respectively. For gas prices in the \$35–\$60/MWh range, which is consistent with the prices the industry experienced post 2008 (panel (c), Figure 9), gas consumption in the restructured markets responded more to gas prices than its counterpart in the traditional markets. The results are available from the authors upon request.

[21] Market participants also hedge their exposure to fuel prices, which may also create frictions in responses to fuel prices. However, it is not clear why hedging should be more prevalent in one of the two market structures. Unfortunately, data availability hinders any form of empirical analysis related to hedging.

Power plants purchasing a larger fraction of their fuel under long-term contracts should respond less to fuel prices due to "lock-in" and the limited ability to shop around (Joskow (1974)). The opposite holds when power plants purchase a larger fraction of their fuel in the spot market. If restructured markets strengthen the utilities' incentives to enter in long-term contracts for fuel procurement, this could explain our findings that utilities respond more to fuel prices in the parts of the country that did not restructure. In what follows, we check for systematic differences in the fraction of coal purchases under long term contracts and gas purchases in spot markets between traditional and restructured markets. We opt for spot purchases in the case of gas since they were the common practice in the industry until recently.

The top panel of Table 6 shows that utility plants in both traditional and restructured markets purchase more than 78% and up to 98% of their coal under long-term contracts. Although the comparison is limited to utilities, the results are essentially identical when we also include independent power producers (IPPs). In column (1) of Table 7, we examine these differences more systematically by regressing the share of annual coal purchases with long-term contracts on year fixed effects, which are also interacted with a restructured-market dummy ($rest$). All interactions of the year fixed effects with the restructured-market dummy fail to be statistically significant at 5%. The interaction of the fixed effect for 2008 has a value of 0.12 and is significant at 10%. Therefore, with the exception of 2008, we don't see statistically and economically significant differences in coal purchases via long-term contracts between traditional and restructured markets. For coal, we repeated the same regression using propensity score and inverse-probability-weighting matching estimators matching on the heat (BTU), sulfur, and ash content of the utilities' annual contract coal purchases to account for any differences in coal characteristics. Once again, the interaction of the year fixed effects with the restructured-market dummy fail to be statistically significant.

Prior to 2008, utility plants in traditional markets were purchasing more than half and up to 72% of their gas in the spot markets. Beginning in 2008, utility plants in the same markets were purchasing 37%–40% of their gas in the spot markets, presumably to lock in low prices in the fear of future price spikes that gas markets are generally prone to. For utility plants in restructured markets, we see a decline from 41% in 2003 to 23% in 2012. We estimate a regression where the dependent variable is the fraction of gas purchased in spot markets. According to the results in column (2) of Table 7, all interactions of year fixed effects with the restructured-market dummy fail to be statistically significant at conventional levels. Hence, it is rather unlikely that differences in spot gas purchases between traditional and restructured markets explain the heterogeneity in responses to fuel prices keeping in mind that our analysis here is limited to utilities only.

4.4 Wholesale purchases and retail sales

Utilities can serve their demand using electricity generated by their own plants, or purchasing electricity from other wholesalers in the markets administered by the ISOs or through bilateral agreements. Utilities purchasing a larger fraction of their electricity may respond less to fuel prices because fuel costs associated with electricity generation are a small fraction of their total expenses for generating electricity.

According to the bottom panel of Table 6, utilities in traditional markets were purchasing between 21% (2007) and 25.5% (2004) of their electricity, while those in restructured markets were purchasing between 36% (2010) and 45% (2005). This difference is consistent with the divestiture of incumbent utilities' plants in restructured markets. However, there were no systematic differences in the fraction of electricity purchased between utilities in traditional and restructured markets in each year between 2003 and 2012 based on the results in column (3) of Table 7.

Regarding retail sales, on one hand, utilities that sell more electricity to retail markets may have weaker incentives for fuel-cost savings because of a full pass through of fuel costs to retail prices due to fuel adjustment clauses (FACs). FACs allow regulators to adjust retail electricity prices following changes in fuel costs during regulatory hearings.[22] On the other hand, lags in rate hearings for retail price adjustments following fuel-cost changes mitigate the incentives created by FACs to not respond to changes in fuel prices (Joskow (1972)). This is the case because regulatory lags allow utilities to enjoy a greater margin—assuming a drop in fuel prices—in their retail sales before an adjustment is made in the next hearing. FACs and regulatory lags are found in both restructured and traditional markets because retail electricity markets are still subject to regulation in many states. In general, it is hard to tell whether FACs and regulatory lags affect utilities in traditional markets more than utilities in restructured markets, or vice versa. Unfortunately, it is also difficult to collect detailed information for FACs over time for the utilities in our sample, as well as information regarding regulatory lags for the various state public utility commissions.[23]

Utilities in both traditional and restructured markets sold roughly 65%–85% of their elec-

[22] FACs can also be automatic in which case there is no need for a regulatory hearing to adjust the retail electricity prices. See Graves et al. (2006) for a very informative discussion of FACs, and Atkinson and Kerkvliet (1989) for an example of the literature for the distortion of utilities' input choice due to FACs.

[23] To the best of our knowledge, Burns et al. (1991) offer the most study of FACs by state. However, their study is dated for the period relevant for our analysis.

tricity (MWh) in retail markets between 2003 and 2012 (Table 6). Using dollars, the retails sales account for 80%–90% of total sales if we exclude the rather unusual 54.7% for the restructured markets in 2005. However, there are no systematic differences between traditional and restructured markets according to the regression results reported in columns (4) and (5) of Table 7, where the dependent variables are the share of retails shales in total sales using MWh and dollars, respectively.

To summarize, differences in utilities' wholesale electricity purchases or retail sales do not appear to explain differences in responses to fuel prices between traditional and restructured markets. Once again, we should keep in mind that we examine such differences for utilities only.

4.5 Strategic market participants

Market power, which has been documented in restructured electricity markets, enhances the response of electricity generation to fuel prices and, hence, the response of fuel consumption to fuel prices. This is easily shown assuming Cournot competition in wholesale electricity markets and a linear demand curve. For the purpose of illustration, consider a Cournot game with N strategic firms facing a cost function of the form $C_i(q_i) = c_i q_i$, which is a reasonable approximation for the electricity industry when not operating under capacity constraints. The oligopolists face the linear inverse demand curve $P = A - BQ$. In equilibrium, firm i produces $q_i^* = (A - Nc_i + C_{-i})/((N+1)B)$, where $C_{-i} \equiv \sum_{j \neq i} c_j$. Hence, output responds more (less) to costs when there is a smaller (larger) number of firms in the market.[24] This result is consistent with the finding in Fabra and Reguant (2014) that pass through rates of CO_2 prices in the Spanish wholesale electricity market were higher during periods of peak demand that are more prone to the exercise of market power.

Therefore, market power is a plausible explanation for differences in responses to fuel prices between restructured and traditional markets. However, the associated analysis is a rather demanding and extensive to fit in this paper since it requires the assessment of market power for the strategic firms in each of the ISO-administered markets, following an approach similar to Bushnell et al. (2008) or Hortacsu and Puller (2008).

[24]For example, assume 3 firms and the marginal cost of all firms decreases by \$1. The implied change in output for firm i is $\Delta q_1(3) = (3-2)/(4B) = 1/(4B)$. In the case of 4 firms, the implied change in output for firm i is $\Delta q_i(4) = (4-3)/(5B) = 1/(5B)$.

5 Implications for emissions

The final piece of our empirical analysis assesses the implications of the difference in responses to fuel prices between traditional and restructured markets for CO_2 emissions using two simple back-of-the envelope (BOE) calculations. We also monetize the benefits from the reduction in emissions using readily available figures from the literature for the social costs of CO_2.

The first BOE calculation is based on the estimates from the fuel-consumption regressions. In particular, we calculate the plant-level increase (decrease) in gas (coal) consumption due to a \$1 dollar decrease in the price of gas for gas prices between \$2/MMBtu and \$8/MMBtu. These own- and cross-price effects are readily available from Figure 4 and Figure 5. We report the implied *total* change in CO_2 emissions in Figure 10 assuming 117 (211) lbs. of CO_2 per MMBtu of gas (coal) consumed as in Cullen and Mansur (2016). The monetized benefits in Figure 11 are based on \$37 per metric ton of CO_2 (IWG (2013)).

Figures 12 and 13 show that the decrease in coal-related emissions offsets the increase in gas-related emissions leading to an overall decrease in total emissions from the two fuels in Figure 10. Using SPEC I in the coal consumption regressions, the decrease in coal-related emissions is larger for plants in restructured markets for gas prices that do not exceed \$4–\$4.5. This is also the case for gas prices up to around \$5–\$6 for SPEC III and SPEC IV. However, we should note that the 95% confidence intervals for plants' emissions in traditional markets overlap with their counterparts in restructured markets. Using SPEC I, the decrease in coal-related emissions is larger for plants in traditional markets for prices exceeding \$5. It is also higher for plants in traditional markets for prices exceeding \$3 in the case of SPEC II. In both cases, the differences are statistically significant at 5%. Overall, the decrease in coal-related emissions is up to 60 million lbs. for plants in restructured markets and up to 20 million lbs. for plants in traditional markets. To assess the practical significance of the results, the reader should keep in mind that the average monthly plant-level CO_2 emissions in traditional (restructured) markets are 702 (724) million lbs. based on the coal consumption regressions for plants facing gas prices \$2–\$6. Therefore, we see a 3% decrease in coal-related CO_2 emissions for plants in traditional markets, and an 8% decrease for plants in restructured markets.

Figure 13 shows that the increase in gas-related CO_2 emissions from a \$1 decrease in the price of gas is higher in traditional markets than in restructured markets across all 4 specifications of the gas-consumption regressions. Depending on the specification, the differences are statistically significant at 5% for gas prices in the range \$4–\$7. Furthermore, the increase in CO_2 emissions from gas is smaller when the gas prices are higher. In particular, the increase in CO_2 is 2–8 million lbs. for traditional markets and no more than 4 million lbs. for the restructured markets. In the case of the gas consumption regressions, the average monthly plant-level CO_2 emissions in traditional (restructured) markets are 84 (61) million lbs. for plants facing gas prices between \$2 and \$6. Hence, we see an increases in gas-related CO_2 emissions of up to 10% for plants in traditional markets and up 7% for plants in restructured markets.

Our second BOE calculation is based on the estimates from the share regressions assuming that a decrease in the price of gas changes the share of gas in total (coal plus gas) fuel consumption but does not affect electricity generation using the two fuels. Recall that fuel consumption translates into heat input (*energy*) that is transformed into electricity generation. This second calculation is also straightforward using the results in Figure 7. In particular, let s_{pre} denote the share of gas prior to the assumed decrease in the price of gas and let s_{post} denote the share of gas after the assumed price decrease. Holding electricity generation constant, the following holds

$$\Delta energy_{gas} = (s_{post} - s_{pre}) \times energy = \Delta s \times energy \tag{3}$$
$$\Delta energy_{coal} = (1 - s_{post} - 1 + s_{pre}) \times energy = -\Delta s \times energy. \tag{4}$$

Figure 14 shows that holding the consumption of the two fuels constant, the reduction in CO_2 emissions due to coal displacement following a drop in the price of gas is larger for the traditional markets than the restructured markets for all 4 specifications considered. The difference in emissions is statistically significant in all 4 specifications for gas prices exceeding \$3. The implied reduction in the CO_2 emission rate is 0.5–3 lbs./MMbtu for the traditional markets and no more than 2 lbs./MMBtu for the restructured markets. To assess the practical significance of the CO_2 emission reductions in the two markets, the average CO_2 emission rate (lbs./MMBtu) for dual-fuel plants in both the traditional and restructured markets is 203 and 207, respectively. That is, we see a reduction of up to 1.5% in the emission rate in traditional markets, but no more than 1% in the restructured markets.

6 Conclusions

In this paper, we examine the environmental implications of market structure using the exogenous variation in the price of natural gas paid by U.S. electric power producers in the aftermath of the shale boom. We find that, compared to plants in markets that were restructured in the late 1990s and early 2000s, power plants traditional vertically integrated markets respond more to changes in the prices of coal and gas. Our results are based on a semi-parametric regression framework that uses absolute and relative levels of fuel consumption as our two dependent variables. We measure the latter using the share of gas in total fuel consumption. In both cases, we employ alternative regression specifications and a series of robustness checks.

According to our estimates, the elasticity of coal consumption with respect to gas prices is 0.24 for power plants in traditional markets and 0.09 for power plants in restructured markets when the price of gas is at its post-summer-2008 levels. The difference in responses is statistically and practically significant. The elasticity of gas consumption with respect to gas price is -3.5 for power plants in traditional markets and -0.15 for power plants in restructured markets when the price of gas is at its 2008 levels. When we hold a dual-fuel plant's generation constant, a $1 increase in the price of gas leads up to a 3 percentage points (ppt) decrease in the share of gas for power plants in the traditional markets when the price of gas is $3–$6/MMBtu, which ensued post 2009. The same price increase leads to a 1 ppt decrease in the share of gas for power plants in restructured markets. Both are significant effects given that the average share of gas for dual-fuel plants in our sample is around 9% in traditional markets and 6% in restructured markets. When we allow a dual-fuel plants' generation to change, the price effect is up to 4 ppt for power plants in traditional markets and up to 2.5 ppt for power plants in restructured markets when the price of gas is $4.

We explore several factors that could explain the differences in responses to fuel prices between traditional and restructured markets by using both econometric and descriptive analysis when the former is hindered by data availability. In particular, we examine the role of the following five factors: investment in capacity, plant efficiency, fuel procurement practices, wholesale purchases and retail sales of electricity and, finally, market power. Differences in gas-fired capacity between states that restructured and states that did not restructure their electricity markets post restructuring offer an explanation consistent with our findings. We provide empirical support for this explanation using a difference-in-difference (DID) regression. A second explanation that is consistent with our findings is given by differences in the efficiency of gas-fired plants turning heat from fuel into electricity (heat rate) across traditional and restructured markets. We provide descriptive analysis that is consistent with this hypothesis, as well as with the DID regressions and the findings in Fabrizio et al. (2007); that is, gas-fired plants in restructured markets had no better heat rates than those in traditional markets. The next two factors we explore, differences in fuel procurement practices, as well as wholesale purchases and retail sales of electricity, seem unlikely to generate differences in responses to fuel prices. Finally, strategic behavior on behalf of market participants is a plausible explanation worth pursuing but entail analysis that would be hard to accommodate within this paper.

In the last part of the paper, we evaluate the implications of the difference in responses to fuel prices for plant-level CO_2 emissions using two simple back-of-the envelope calculations. Based on the consumption regressions, a $1 decrease in the price of gas, implies a decrease of up to 3% in plant-level emissions in traditional markets and up to 8% in restructured markets. The same price decrease leads to an increase in plant-level gas-related emissions of up to 10% for traditional markets and up to 7% for restructured markets. Overall, the decrease in coal-related emissions offsets the increase in gas-related emissions leading to an overall decrease in total emissions from the two fuels in both traditional and restructured markets. The share regressions imply a significant reduction of up to 1.5% in the plant-level emission rate (lbs./MMBtu) for dual-fuel plants in traditional markets and up to 1% for their counterparts in restructured markets.

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Table 1: Preliminary statistics I

	(a) all plants			
Fuel	Count	Capacity	Consumption	Generation
coal	393	2,523	147,123	14,109
gas	1,259	3,521	59,985	7,036
coal %	23.79%	41.75%	71.04%	66.73%
	(b) coal, dual-fuel plants			
Market	Count	Capacity	Consumption	Generation
All	183	974	55,190	5,206
Traditional	53	286	16,166	1,531
Restructured	130	688	39,024	3,675
All	46.56%	38.60%	37.51%	36.90%
Traditional	47.75%	38.37%	37.47%	36.72%
Restructured	46.10%	38.70%	37.53%	36.97%
	(c) gas, dual-fuel plants			
Market	Count	Capacity	Consumption	Generation
All	183	222	3,105	357
Traditional	53	101	1,536	189
Restructured	130	121	1,568	169
All	14.54%	6.31%	5.18%	5.08%
Traditional	12.30%	7.61%	6.54%	6.65%
Restructured	15.70%	5.53%	4.30%	4.02%

Note: Count refers to number of plants. Capacity is measured in thousand MW. Consumption is measured in million MMBtu. Generation is measured in million MWh. We report sums for capacity, consumption, and generation for 2003–2012. Dual-fuel refers to plants that use both coal and gas to generate electricity. The top part of panel (b) shows the coal capacity, consumption, and generation for dual-fuel plants. The bottom part of panel (b) shows the dual-fuel plants' share of total coal capacity, consumption, and generation. The top part of panel (c) shows the gas capacity, consumption, and generation for dual-fuel plants. The bottom part of panel (c) shows the dual-fuel plants' share of total gas capacity, consumption, and generation.

Table 2: Preliminary statistics II

	(a) coal, utilities			
Market	Plants	Capacity	Consumption	Generation
All	222	1,715	99,098	9,587
Traditional	83	663	37,791	3,686
Restructured	139	1,052	61,307	5,902
All	56.49%	67.95%	67.36%	67.95%
Traditional	74.77%	88.97%	87.58%	88.40%
Restructured	49.29%	59.14%	58.96%	59.38%
	(b) gas, utilities			
Market	Plants	Capacity	Consumption	Generation
All	422	1,211	20,131	2,320
Traditional	198	721	14,404	1,707
Restructured	224	490	5,727	613
All	33.52%	34.40%	33.56%	32.98%
Traditional	45.94%	54.31%	61.32%	60.18%
Restructured	27.05%	22.35%	15.69%	14.59%

Note: Capacity is measured in thousand MW. Consumption is measured in million MMBtu. Generation is measured in million MWh. We report sums for capacity, consumption, and generation for 2003–2012. The top part of panel (a) shows the coal capacity, consumption, and generation for utility plants. The bottom part of panel (a) shows the utility plants' share of total coal capacity, consumption, and generation. The top part of panel (b) shows the gas capacity, consumption, and generation for utility plants. The bottom part of panel (b) shows the utility plants' share of total gas capacity, consumption, and generation.

Table 3: Number of observations by specification and market type

Specification	Market	Obs.	# plants
SPEC I	Traditional	11,798	111
	Restructured	30,867	280
SPEC II	Traditional	11,798	111
	Restructured	30,867	280
SPEC III	Traditional	11,452	109
	Restructured	30,161	277
SPEC IV	Traditional	11,452	109
	Restructured	30,161	277

(a) coal consumption regressions

Specification	Market	Obs.	# plants
SPEC I	Traditional	33,298	411
	Restructured	77,599	806
SPEC II	Traditional	33,298	411
	Restructured	77,599	806
SPEC III	Traditional	31,589	375
	Restructured	71,258	719
SPEC IV	Traditional	31,589	375
	Restructured	71,258	719

(b) gas consumption regressions

Specification	Market	Obs.	# plants
SPEC I	Traditional	5,746	53
	Restructured	14,110	129
SPEC II	Traditional	5,746	53
	Restructured	14,110	129
SPEC III	Traditional	5,671	53
	Restructured	13,748	127
SPEC IV	Traditional	5,671	53
	Restructured	13,748	127

(c) gas share regressions

Table 4: Summary statistics: combined-cycle gas capacity

	traditional	restructured		
		both	pre	post
mean	4,213	3,428	616	4,770
std.dev.	5,523	6,181	1,166	7,089
median	2,573	1,377	194	2,697
obs.	178	489	158	331

Note: Capacity in MW. We report summary statistics for states that did not restructure their wholesale electricity markets (traditional), as well as for states that restructured their wholesale electricity markets. The statistics reported in column both are based on data both pre and post restructuring. The statistics reported in column pre (post) are based on data pre (post) restructuring only. For additional details, see Section 4.1.

Table 5: State-level difference-in-differences regressions:
combined-cycle gas capacity

	(1)	(2)	(3)	(4)
VARIABLES	OLS	PW	FGLS	I-FGLS
$Rest \times Post$	-1,576.9470*	-909.3138***	-335.0440**	-229.1362***
	(865.4763)	(273.8900)	(162.8444)	(80.2367)
Obs.	667	667	667	667
States	38	38	38	38
States Rest.	28	28	28	28
Consumption	✓	✓	✓	✓
State FE	✓	✓	✓	✓
Year FE	✓	✓	✓	✓

Note: The column headers PW, FGLS, and IFGLS denote the Prais-Winsten, feasible GLS, and iterated feasible GLS estimators we employed. In the case of OLS, the standard errors are clustered by state. The asterisks denote statistical significance at 1%(***), 5%(**), and 10%(*), respectively. The row “States” indicates the total number of states used in our analysis. The row “States Rest.” indicates the number of states that restructured their wholesale electricity markets. In all cases, we control for state-level retail electricity consumption, state fixed effects, and year fixed effects. For additional details, see Section 4.1.

Table 6: Utilities comparisons I

	coal contract		gas spot	
Year	trad.	rest.	trad.	rest.
2003	83.7%	78.4%	61.6%	40.6%
2004	84.1%	80.4%	68.6%	34.3%
2005	88.7%	83%	70.7%	28.9%
2006	89.8%	82.7%	71.7%	26.5%
2007	93.9%	84.9%	67.5%	32.5%
2008	90.2%	89.2%	46.7%	26.6%
2009	96.3%	93.2%	41.9%	26.5%
2010	95.3%	92.5%	39.5%	30.3%
2011	95.6%	92.8%	39%	27.8%
2012	98.1%	94.1%	37.4%	22.6%

(a) Fuel purchases (contract and spot)

	whole purch. %		retail % MWh		retail % USD	
Year	trad.	rest.	trad.	rest.	trad.	rest.
2003	25.1%	40.4%	78.7%	67.5%	85.6%	79.7%
2004	25.5%	44.4%	79.2%	63.8%	86.2%	77.2%
2005	24.3%	45.2%	79.5%	64.2%	83.7%	54.7%
2006	23.3%	41.1%	80.4%	72.1%	85.2%	78.7%
2007	20.6%	37.4%	82.7%	77.3%	85.8%	81.6%
2008	23.1%	37.5%	82.3%	78.5%	84.3%	81.4%
2009	23.1%	37.3%	83.9%	77.6%	87.8%	84.1%
2010	22.2%	36.1%	84.9%	77.3%	86.9%	83.1%
2011	22.6%	36.6%	85.7%	77.6%	88.2%	82.5%
2012	23%	38.2%	86%	77%	89.1%	82%

(b) Wholesale purchases and retail sales

Note: In panel (a), we first show the percentage of coal purchased using long term contracts in traditional and restructured markets. We then show the percentage of gas purchased via spot transactions in traditional and restructured markets. In panel (b), we first show the percentage of electricity purchased via wholesale transactions in traditional and restructured markets noting that utilities may opt to buy electricity as opposed to generate electricity for subsequent resale. We then show the percentage of total MWh, as well as dollars, that retail sales of electricity account for noting that utilities sell some of their electricity in wholesale markets. See Section 4.3 and Section 4.4 for additional details.

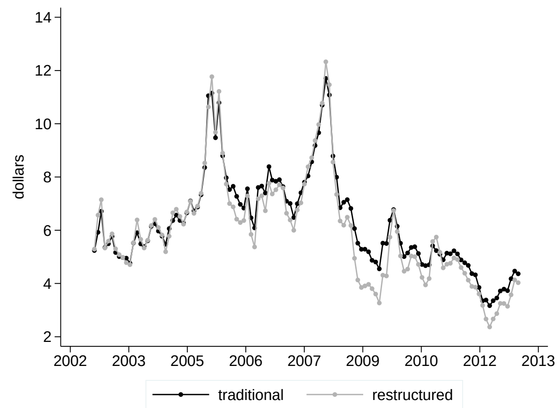
Table 7: Utilities comparisons II

VARIABLES	(1) coal contract %	(2) gas spot %	(3) % purchased	(4) % retail MWh	(5) % retail USD
year2003	0.8467***	0.5818***	0.2912***	0.7424***	0.7984***
	(0.0409)	(0.1007)	(0.0395)	(0.0374)	(0.0361)
year2004	0.7913***	0.5749***	0.2994***	0.7381***	0.7960***
	(0.0457)	(0.0945)	(0.0420)	(0.0401)	(0.0344)
year2005	0.8117***	0.5529***	0.3262***	0.7464***	0.7802***
	(0.0603)	(0.0959)	(0.0469)	(0.0388)	(0.0347)
year2006	0.8470***	0.5332***	0.3184***	0.7456***	0.7858***
	(0.0545)	(0.0925)	(0.0476)	(0.0388)	(0.0352)
year2007	0.8705***	0.5307***	0.2887***	0.7719***	0.7988***
	(0.0501)	(0.0925)	(0.0429)	(0.0365)	(0.0343)
year2008	0.7971***	0.6428***	0.3301***	0.7633***	0.7833***
	(0.0667)	(0.0703)	(0.0439)	(0.0332)	(0.0316)
year2009	0.9310***	0.7220***	0.3271***	0.7841***	0.8220***
	(0.0255)	(0.0696)	(0.0466)	(0.0340)	(0.0321)
year2010	0.9302***	0.7591***	0.3125***	0.7837***	0.8206***
	(0.0226)	(0.0667)	(0.0466)	(0.0337)	(0.0316)
year2011	0.9129***	0.7761***	0.3142***	0.7874***	0.8270***
	(0.0309)	(0.0669)	(0.0466)	(0.0332)	(0.0315)
year2012	0.9546***	0.7927***	0.3095***	0.7944***	0.8422***
	(0.0255)	(0.0655)	(0.0456)	(0.0339)	(0.0323)
restXyear2003	-0.0988	-0.2126	0.0667	0.0089	0.0033
	(0.0655)	(0.1361)	(0.0534)	(0.0464)	(0.0421)
restXyear2004	-0.0198	-0.1951	0.0716	0.0114	0.0037
	(0.0672)	(0.1279)	(0.0582)	(0.0504)	(0.0425)
restXyear2005	-0.0233	-0.1216	0.0633	0.0222	-0.0020
	(0.0787)	(0.1326)	(0.0614)	(0.0472)	(0.0441)
restXyear2006	-0.0348	-0.0478	0.0821	0.0235	0.0099
	(0.0711)	(0.1251)	(0.0621)	(0.0468)	(0.0412)
restXyear2007	-0.0467	-0.1021	0.0969*	0.0047	0.0009
	(0.0671)	(0.1257)	(0.0566)	(0.0432)	(0.0385)
restXyear2008	0.1180*	0.0908	0.0658	0.0284	0.0218
	(0.0695)	(0.0950)	(0.0586)	(0.0400)	(0.0357)
restXyear2009	0.0206	0.0294	0.0592	-0.0203	-0.0188
	(0.0282)	(0.0948)	(0.0592)	(0.0430)	(0.0402)
restXyear2010	0.0106	-0.0051	0.0488	-0.0236	-0.0213
	(0.0274)	(0.0926)	(0.0584)	(0.0439)	(0.0398)
restXyear2011	0.0302	0.0009	0.0631	-0.0206	-0.0278
	(0.0332)	(0.0912)	(0.0596)	(0.0448)	(0.0409)
restXyear2012	-0.0178	-0.0287	0.0771	-0.0349	-0.0509
	(0.0335)	(0.0931)	(0.0574)	(0.0461)	(0.0424)
Observations	579	655	777	777	777
R-squared	0.9442	0.6905	0.6679	0.9423	0.9579

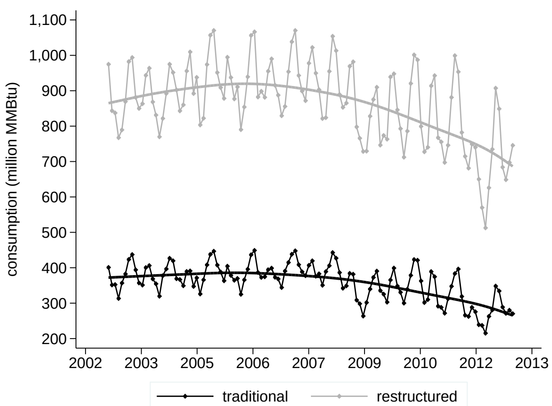
Column (1) refers to the percentage of coal purchases measured in MMBtu via long-term contracts. Column (2) refers to the percentage of gas purchases measured in MMBtu in spot markets. Column (3) refers to the fraction of electricity purchased, as opposed to generated, by utilities. Columns (4) and (5) refer to the fraction of electricity sold in retail markets (MWh and USD), as opposed to wholesale markets, by utilities. Heteroskedasticity-robust standard errors are reported in parentheses. The asterisks denote statistical significance at 1%(***), 5%(**), and 10%(*), respectively. See Section 4.3 and Section 4.4 for additional details.

Figure 1: Fuel prices and consumption

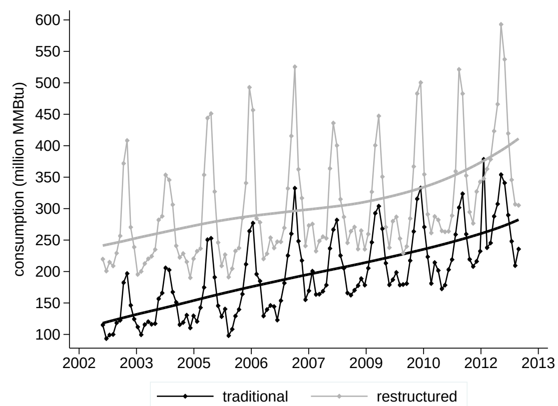
(a) coal price



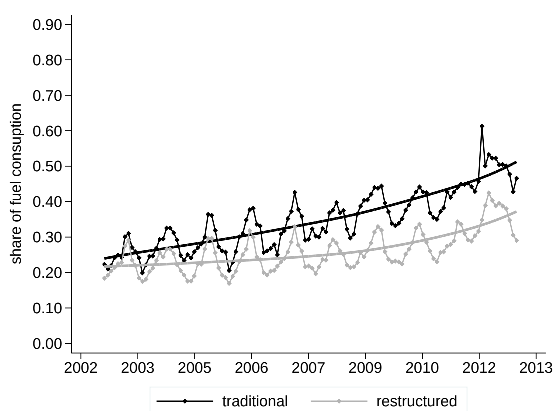
(b) gas price



(c) coal consumption



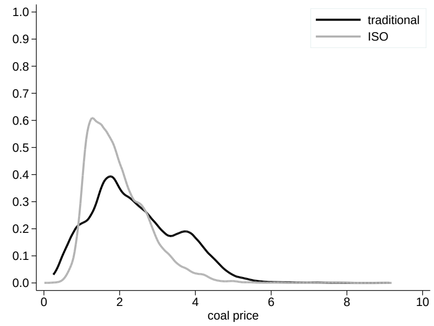
(d) gas consumption



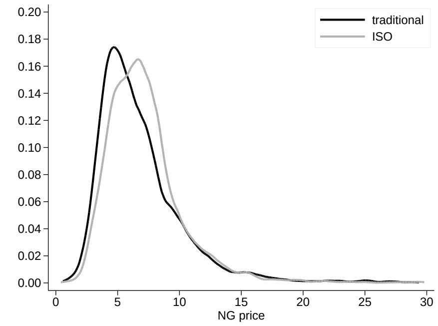
(e) gas share of consumption

Note: Panels (a) and (b) show the average monthly price of coal and gas ($/MMbtu) for utilities and merchant generators weighted using fuel consumption (MMBtu). Panels (c) and (d) shows total monthly coal and gas consumption in million MMBtu. Panel (e) shows the share of gas in total (coal plus gas) consumption, with the consumption measured in million MMBtu. The lines indicating the trends in panels (c)–(e) are based on LOWESS regression.

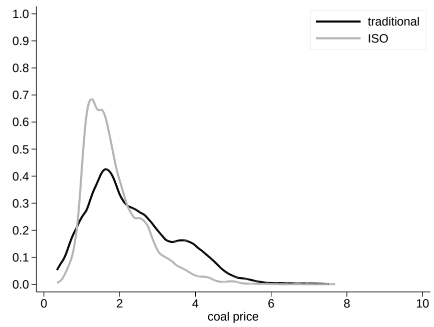
Figure 2: Distribution of plant-level monthly fuel prices by plant type



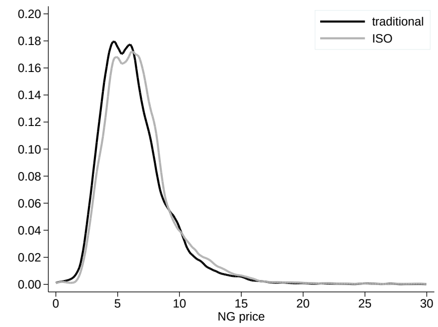
(a) coal-fired, coal price



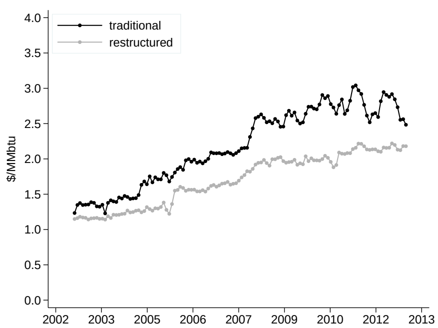
(b) coal-fired, gas price



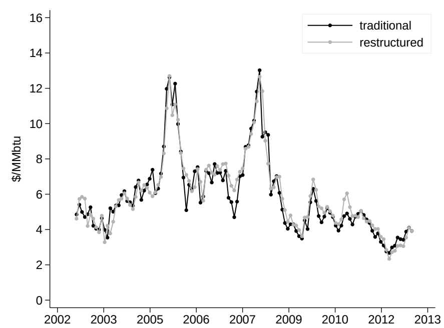
(c) gas-fired, coal price



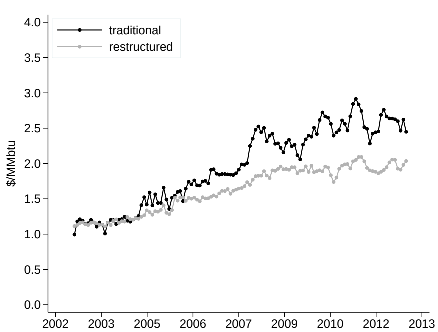
(d) gas-fired, gas price



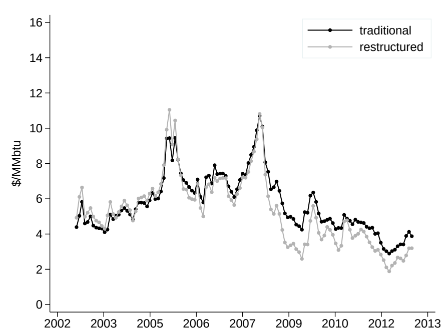
(e) coal-fired, coal price



(f) coal-fired, gas price



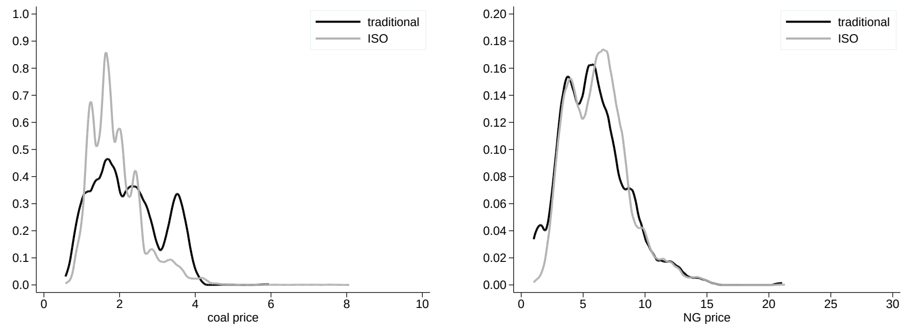
(g) gas-fired, coal price



(h) gas-fired, gas price

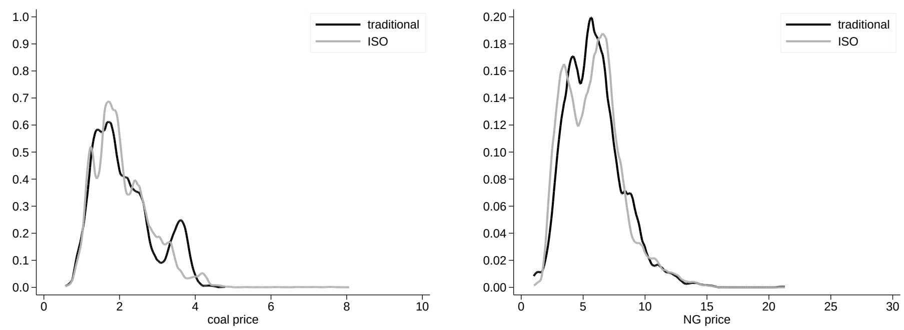
Note: We use coal-fired to refer to plants with coal-fired electricity generators. Similarly, we use gas-fired to refer to plants with gas-fired electricity generators. Coal and gas prices are measured in $/MMBtu. See Section 3.2 for additional details.

Figure 3: Distribution of average regional monthly fuel prices by plant type



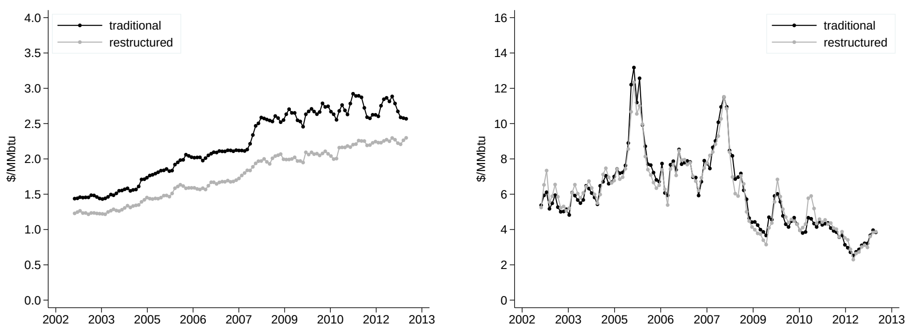
(a) coal-fired, coal price

(b) coal-fired, gas price



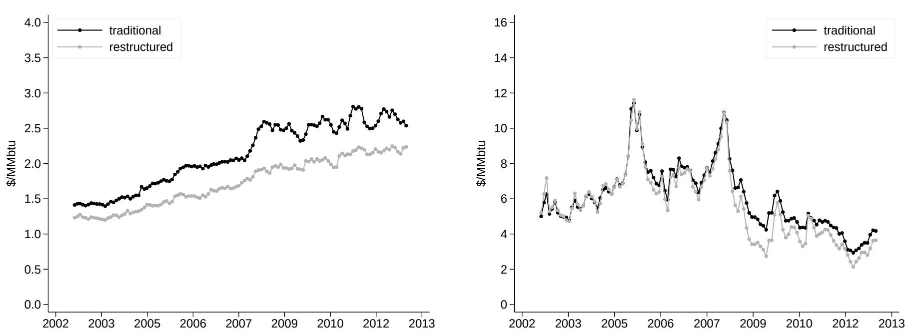
(c) gas-fired, coal price

(d) gas-fired, gas price



(e) coal-fired, coal price

(f) coal-fired, gas price

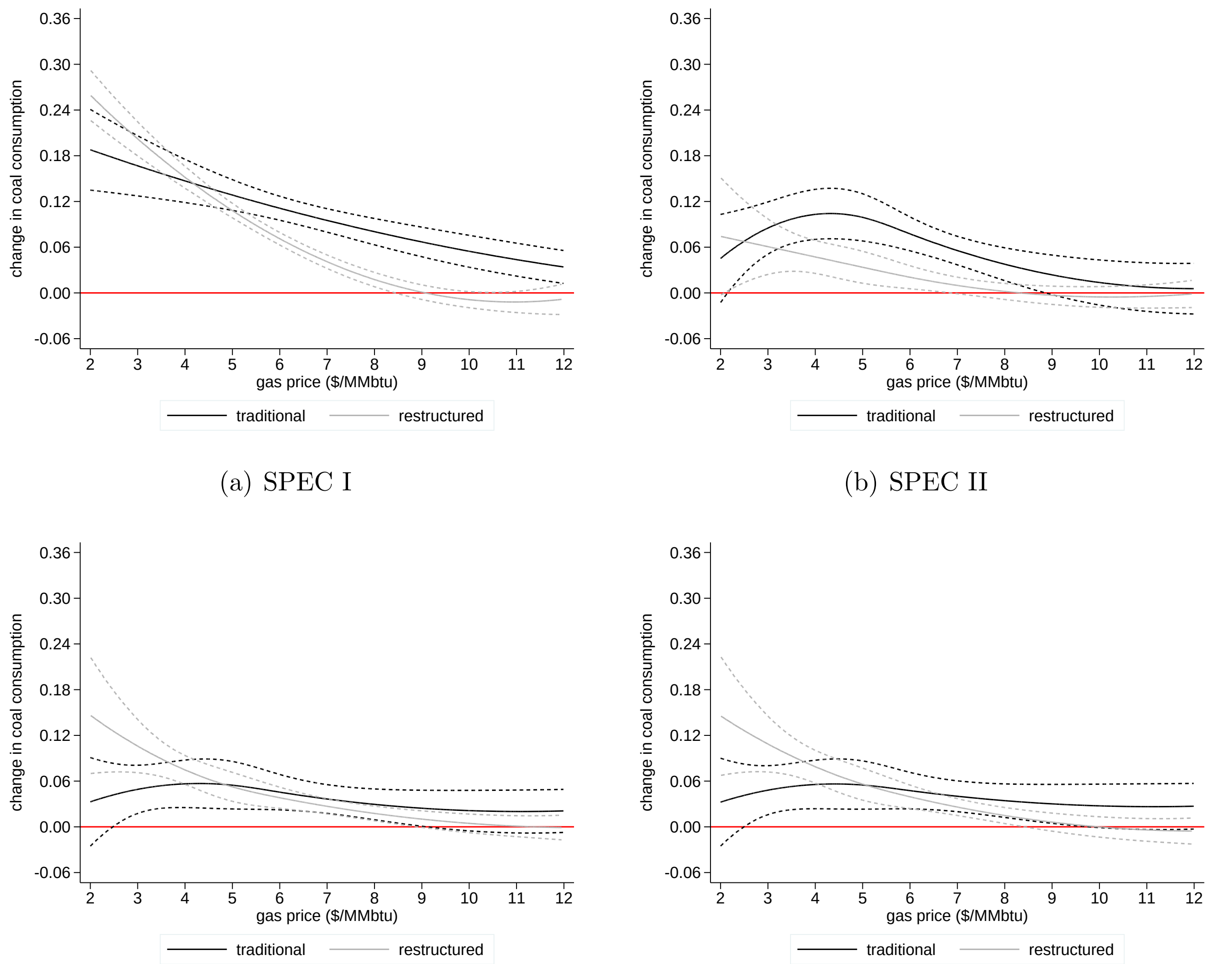


(g) gas-fired, coal price

(h) gas-fired, gas price

Note: We use coal-fired to refer to plants with coal-fired electricity generators. Similarly, we use gas-fired to refer to plants with gas-fired electricity generators. Coal and gas prices are measured in $/MMBtu. See Section 3.2 for additional details.

Figure 4: Change in coal consumption due to a change in gas prices



(a) SPEC I

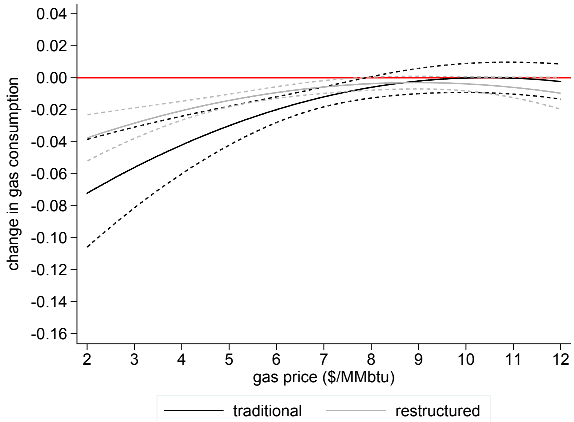
(b) SPEC II

(c) SPEC III

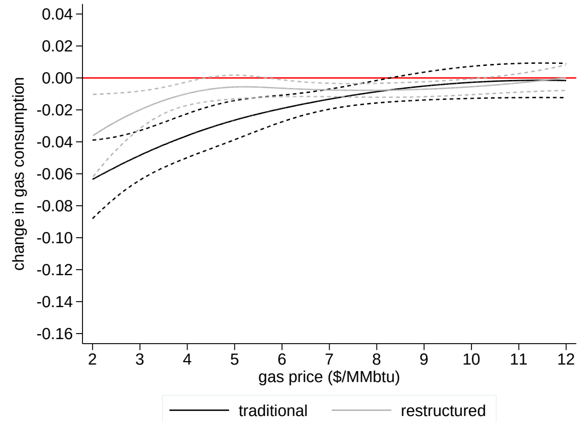
(d) SPEC IV

Note: The figure shows the change in coal consumption measured in million MMBtu due to a $1 increase in the price of gas for gas prices between $2 and $12 per MMBtu using basis splines with knots at $2 per MMBtu for coal, and $6/MMBtu for gas. The dashed lines show 95% confidence intervals. SPEC I: plant fixed effects and NERC region-by-month fixed effects. SPEC II: as in SPEC I plus NERC region-by-year fixed effects. SPEC III: plant fixed effects, logarithm of coal- plus gas-fired capacity, logarithm of SO_2 and seasonal NO_X permit prices, number of electricity generating units (EGUs) with NO_X, SO_2, and particulate matter environmental controls, number of EGUs under various EPA programs, and month fixed effects. SPEC IV: as in SPEC III plus year fixed effects. For additional details regarding the data, see Section A.1 in the on-line Appendix. For additional details regarding the regression specifications, see Section 3.3.

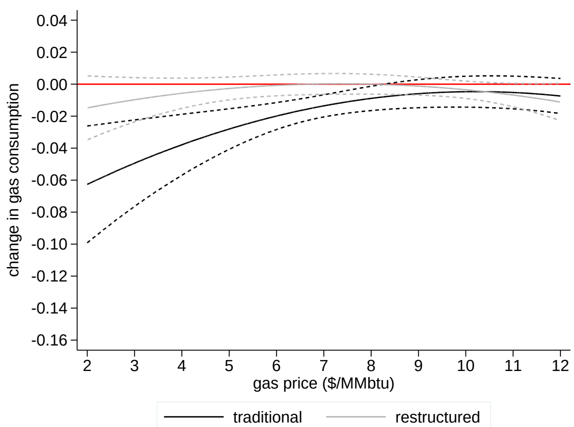
Figure 5: Change in gas consumption due to a change in gas prices



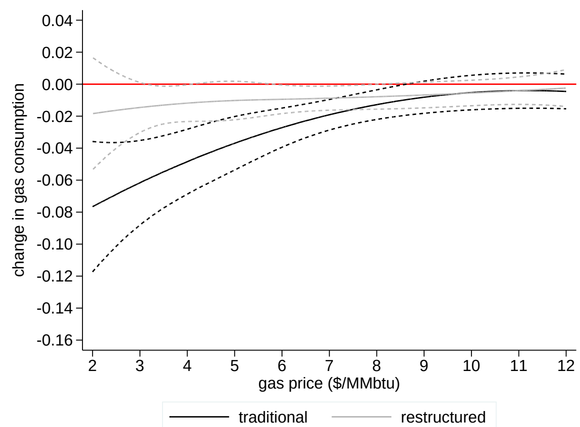
(a) SPEC I



(b) SPEC II



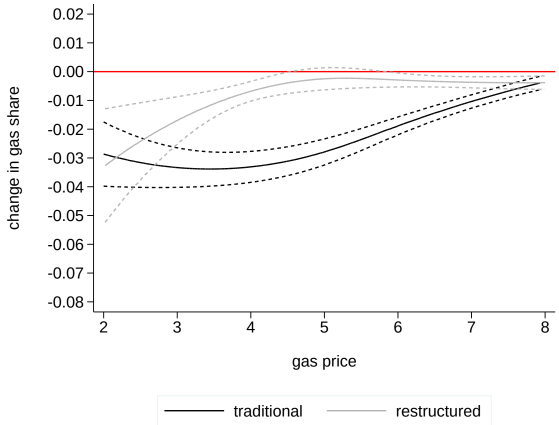
(c) SPEC III



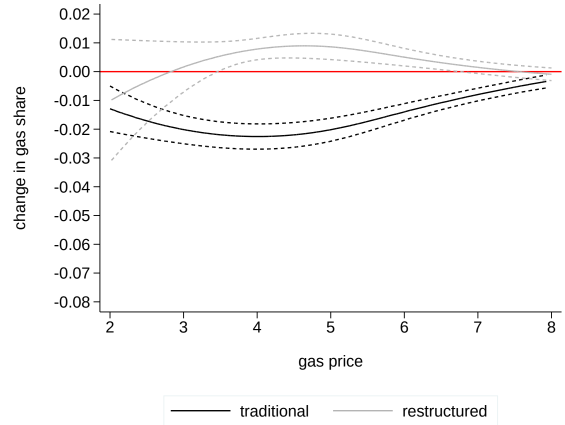
(d) SPEC IV

Note: The figure shows the change in gas consumption measured in million MMBtu due to a $1 increase in the price of gas for gas prices between $2 and $12 per MMBtu using basis splines with knots at $2 per MMBtu for coal, and $6/MMBtu for gas. The dashed lines show 95% confidence intervals. SPEC I: plant fixed effects and NERC region-by-month fixed effects. SPEC II: as in SPEC I plus NERC region-by-year fixed effects. SPEC III: plant fixed effects, logarithm of coal- plus gas-fired capacity, logarithm of SO_2 and seasonal NO_X permit prices, number of electricity generating units (EGUs) with NO_X, SO_2, and particulate matter environmental controls, number of EGUs under various EPA programs, and month fixed effects. SPEC IV: as in SPEC III plus year fixed effects. For additional details regarding the data, see Section A.1 in the on-line Appendix. For additional details regarding the regression specifications, see Section 3.3.

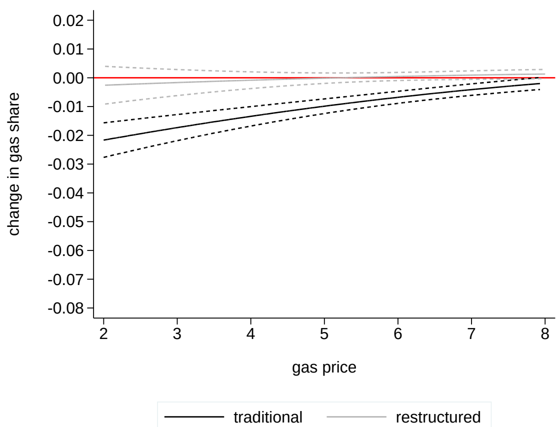
Figure 6: Change in the gas share of fuel consumption due to a change in gas prices: controlling for the plant's generation



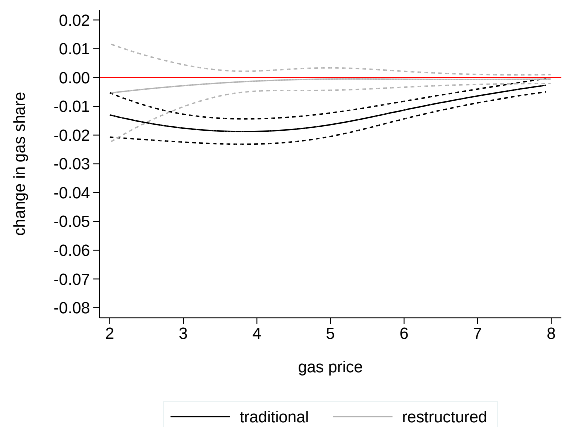
(a) SPEC I



(b) SPEC II



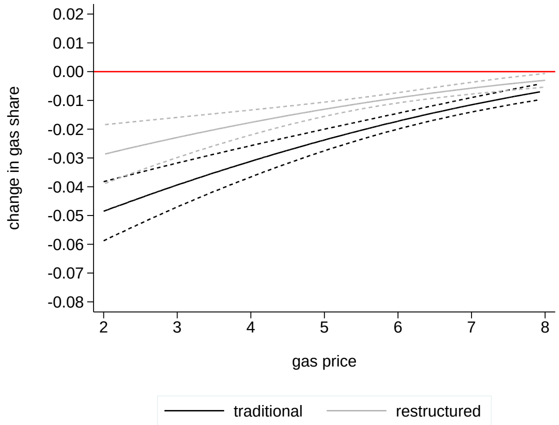
(c) SPEC III



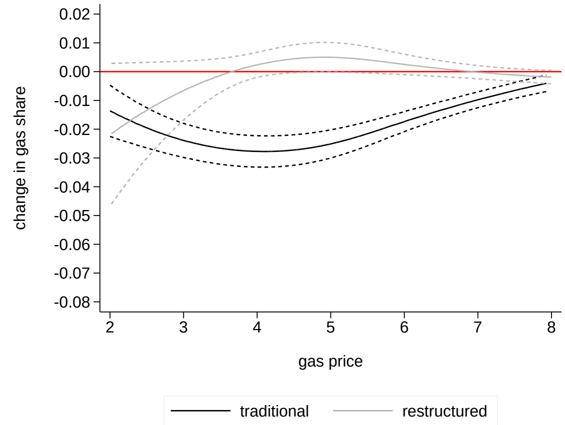
(d) SPEC IV

Note: The figure shows the change in the gas share of fuel consumption for plants using both coal and gas due to a \$1 increase in the price of gas for gas prices between \$2 and \$12 per MMBtu using basis splines with knots at \$2 per MMBtu for coal, and \$6/MMBtu for gas. The dashed lines show 95% confidence intervals. SPEC I: plant fixed effects and NERC region-by-month fixed effects. SPEC II: as in SPEC I plus NERC region-by-year fixed effects. SPEC III: plant fixed effects, logarithm of coal- plus gas-fired capacity, logarithm of SO_2 and seasonal NO_X permit prices, number of electricity generating units (EGUs) with NO_X, SO_2, and particulate matter environmental controls, number of EGUs under various EPA programs, and month fixed effects. SPEC IV: as in SPEC III plus year fixed effects. For additional details regarding the data, see Section A.1 in the on-line Appendix. For additional details regarding the regression specifications, see Section 3.3.

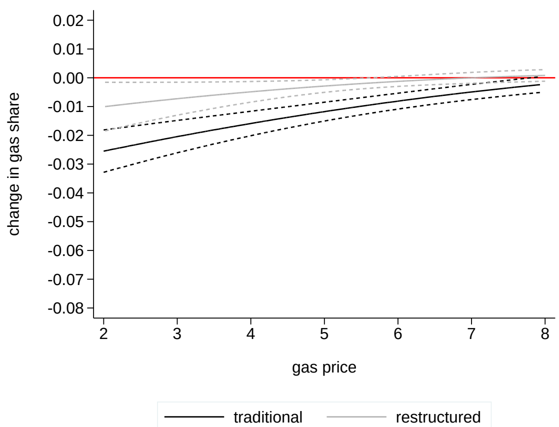
Figure 7: Change in the gas share of fuel consumption due to a change in gas prices: without controlling for the plant's generation



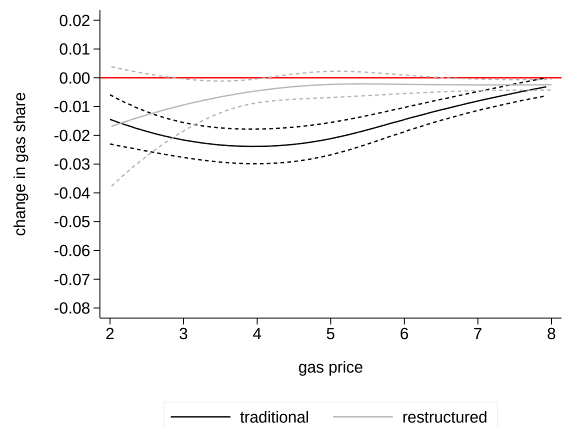
(a) SPEC I



(b) SPEC II



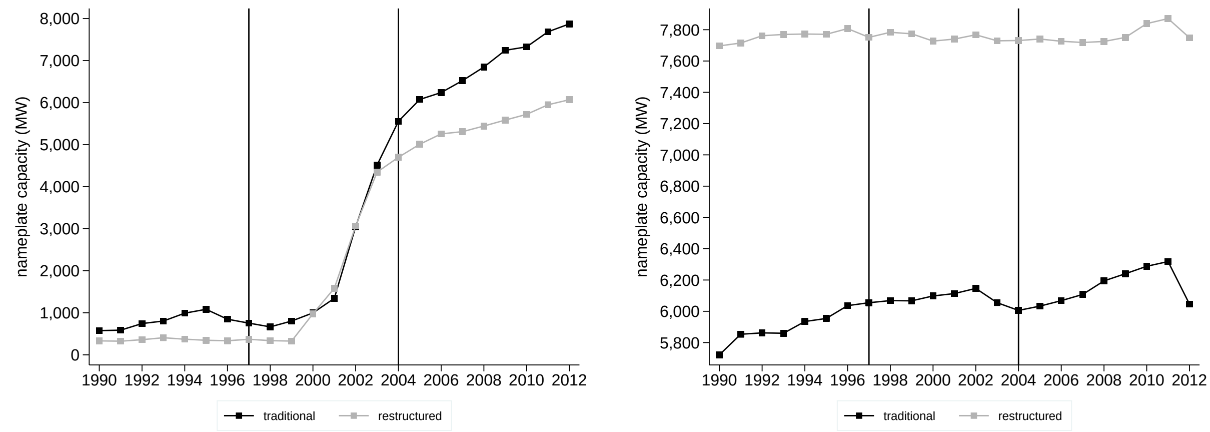
(c) SPEC III



(d) SPEC IV

Note: The figure shows the change in the gas share of fuel consumption for plants using both coal and gas due to a \$1 increase in the price of gas for gas prices between \$2 and \$12 per MMBtu using basis splines with knots at \$2 per MMBtu for coal, and \$6/MMBtu for gas. The dashed lines show 95% confidence intervals. SPEC I: plant fixed effects and NERC region-by-month fixed effects. SPEC II: as in SPEC I plus NERC region-by-year fixed effects. SPEC III: plant fixed effects, coal- plus gas-fired capacity, logarithm of SO_2 and seasonal NO_X permit prices, number of electricity generating units (EGUs) with NO_X, SO_2, and particulate matter environmental controls, number of EGUs under various EPA programs, and month fixed effects. SPEC IV: as in SPEC III plus year fixed effects. For additional details regarding data, see Section A.1 in the on-line Appendix. For additional details regarding the regression specifications, see Section 3.3.

Figure 8: State-level capacity

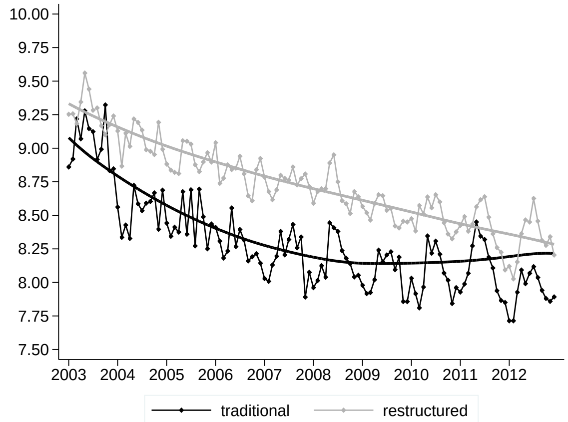


(a) gas, combined-cycle technology

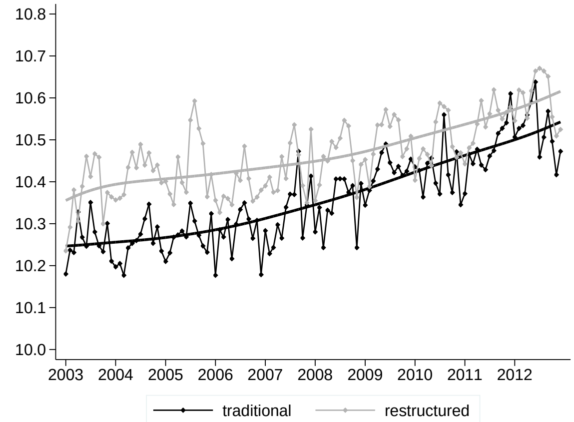
(b) coal

Note: The figure shows the average annual state-level gas- and coal-fired capacity for states with traditional and restructured markets in panels (a) and (b), respectively. In the case of gas, we focus on the most cost-efficient (combined cycle) technology only. The black vertical lines identify the beginning and end of the restructuring period as described in Craig and Savage (2013). For additional details, see Section 4.1.

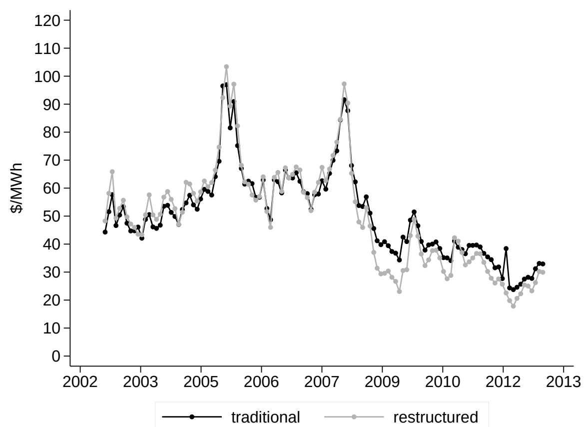
Figure 9: Fuel efficiency and prices



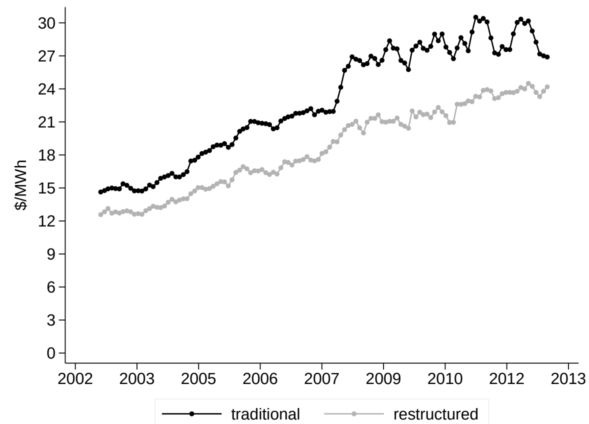
(a) gas heat rates



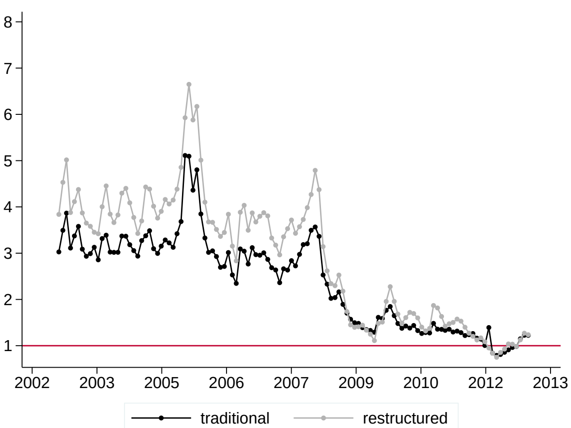
(b) coal heat rates



(c) gas price ($/MWh)



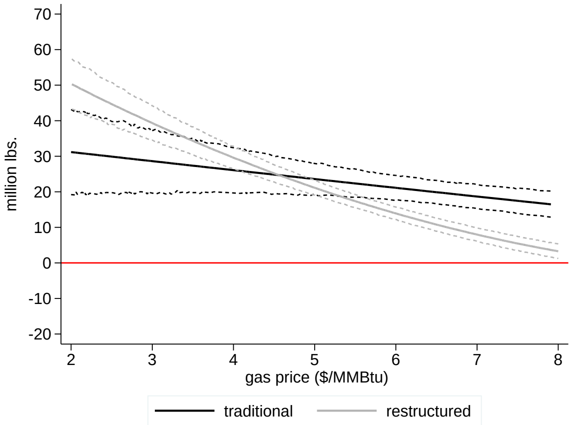
(d) coal price ($/MWh)



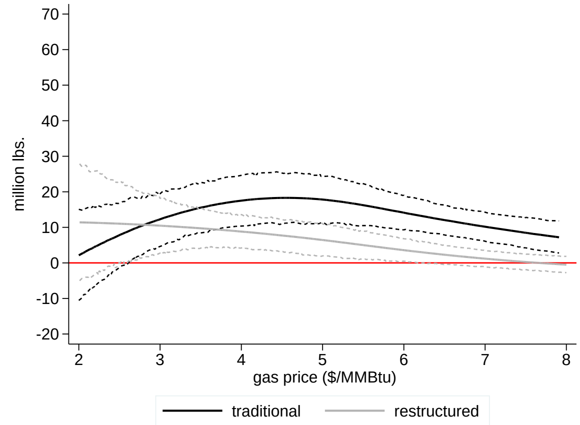
(e) gas/coal price ratio

Note: Fuel consumption in MMBtu. Electricity generation in MWh. Heat rate is the consumption-over-generation ratio. The higher the heat rate, the more heat input in MMBtu is needed to generate 1 MWh of electricity. The lines indicating the trends in panels (a) and (b) are generated using a LOWESS regression.

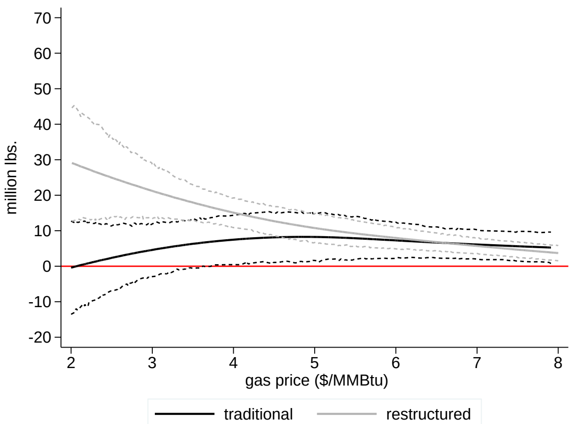
Figure 10: Decrease in total CO_2 emissions due to a change in gas prices: based on consumption regressions



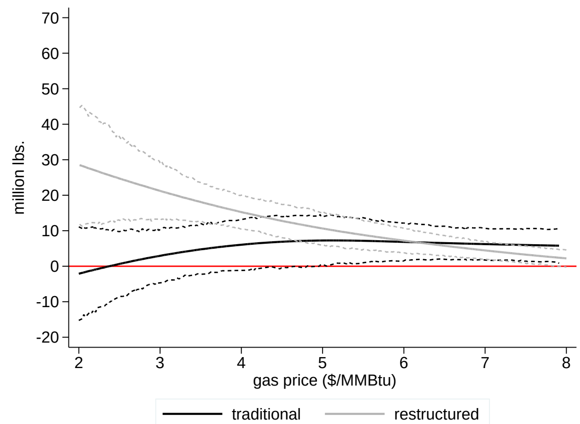
(a) SPEC I



(b) SPEC II



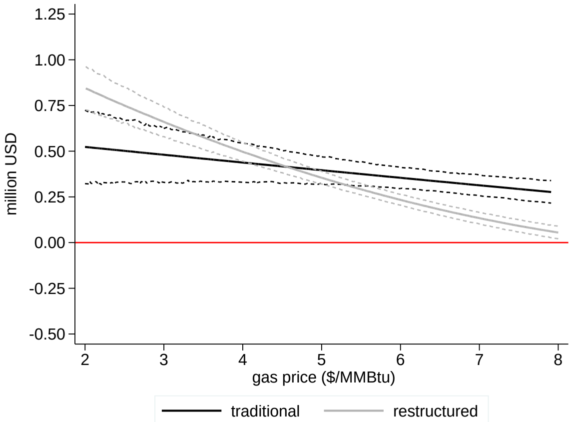
(c) SPEC III



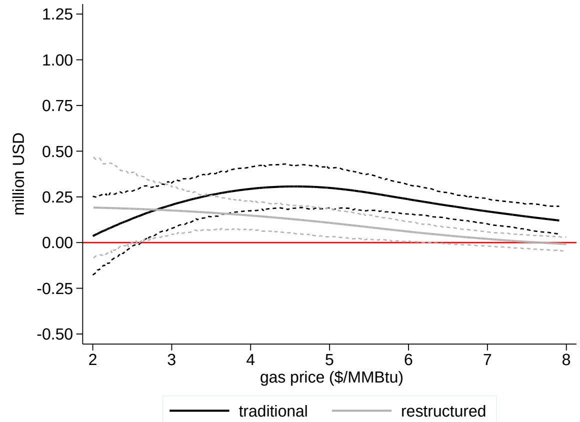
(d) SPEC IV

Note: The figure shows the decrease in total plant-level CO_2 emissions due to a decrease in the price of gas by \$1/MMBtu based on the response of coal and gas consumption in traditional and restructured markets for each of the four specifications in Figure 4 and Figure 5. The calculations are based on 117 (211) lbs. of CO_2 per MMBtu of gas (coal). The dashed lines show 95% confidence intervals.

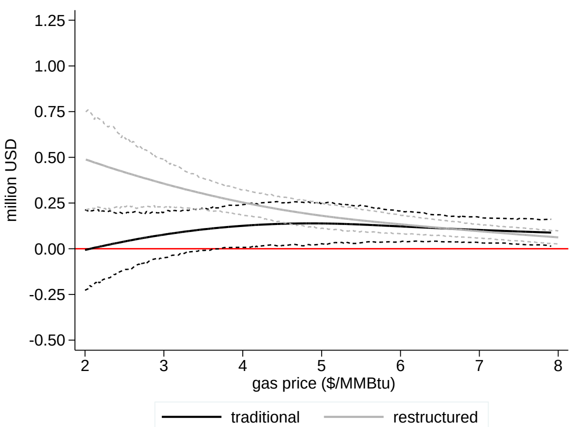
Figure 11: Benefits from the decrease in total CO_2 emissions due to a change in gas prices: based on consumption regressions



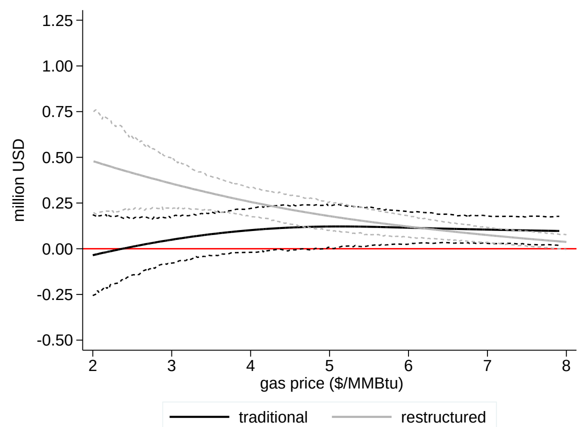
(a) SPEC I



(b) SPEC II



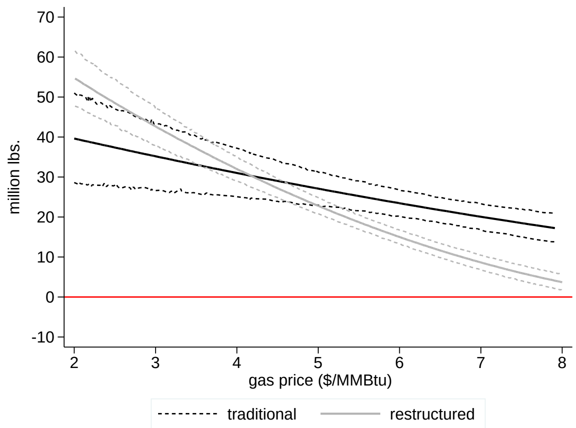
(c) SPEC III



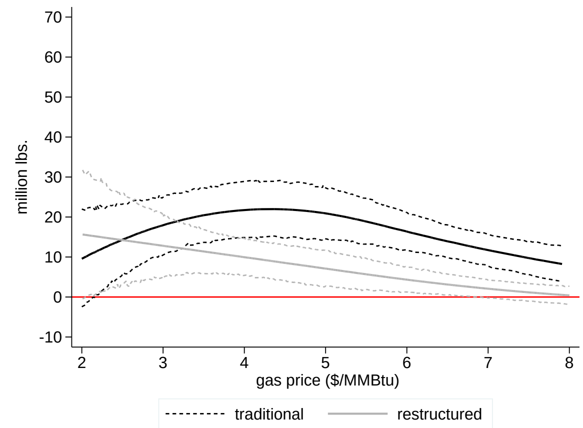
(d) SPEC IV

Note: The figure shows the benefit from a decrease in total plant-level CO_2 emissions due to a decrease in the price of gas by $1/MMBtu based on the response of coal and gas consumption in traditional and restructured markets for each of the four specifications in Figure 4 and Figure 5. The calculations are based on 117 (211) lbs. of CO_2 per MMBtu of gas (coal). We also assume a social cost of CO_2 equal to $37 per metric ton. The dashed lines show 95% confidence intervals.

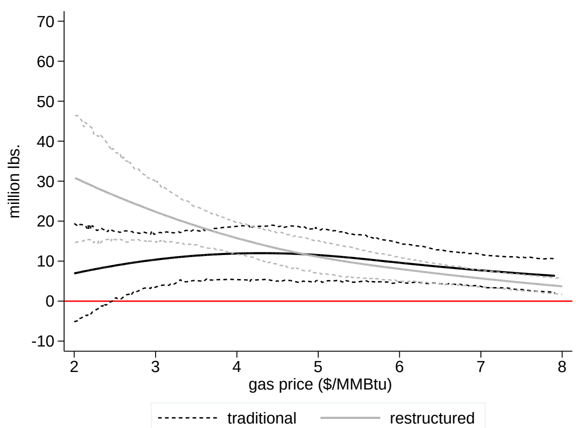
Figure 12: Decrease in coal-related CO_2 emissions due to a change in gas prices: based on consumption regressions



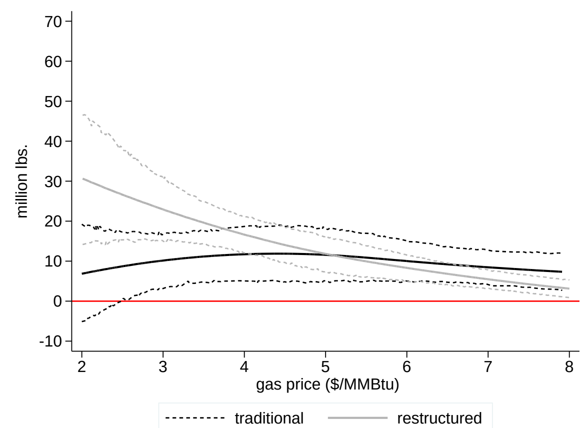
(a) SPEC I



(b) SPEC II



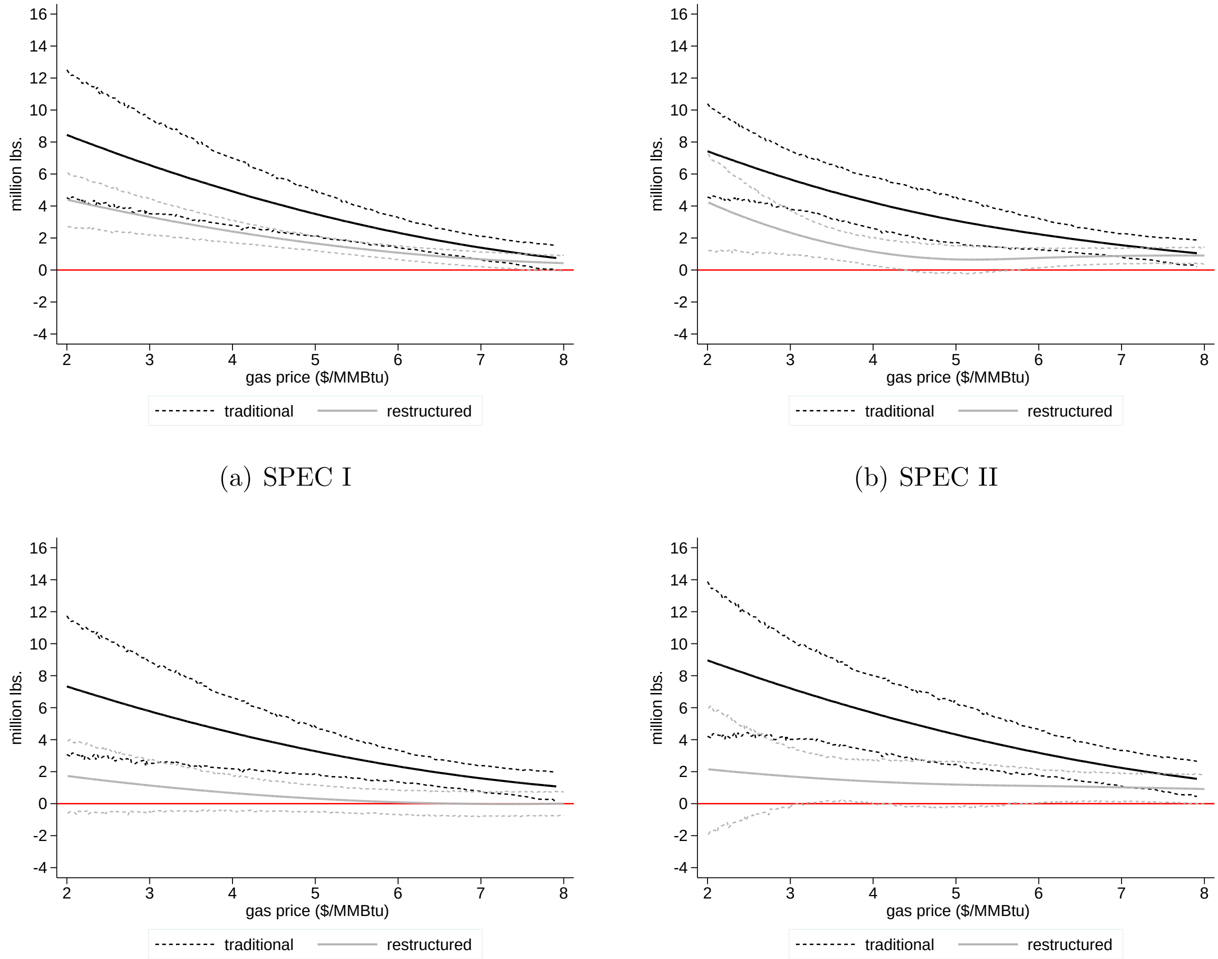
(c) SPEC III



(d) SPEC IV

Note: The figure shows the decrease in plant-level coal-related CO_2 emissions due to a decrease in the price of gas by $1/MMBtu based on the response of coal consumption in traditional and restructured markets for each of the four specifications in Figure 4. The calculations are based on 211 lbs. of CO_2 per MMBtu of coal. The dashed lines show 95% confidence intervals.

Figure 13: Increase in gas-related CO_2 emissions due to a change in gas prices: based on consumption regressions



(a) SPEC I

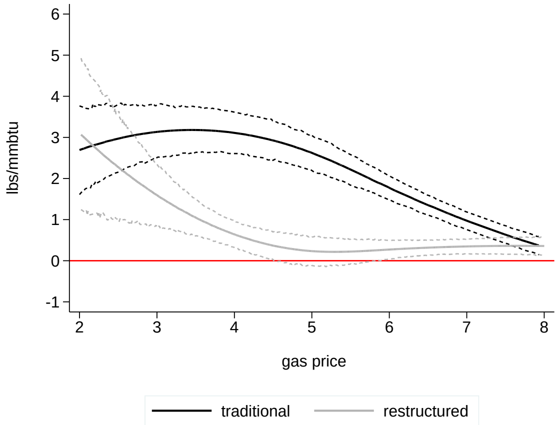
(b) SPEC II

(c) SPEC III

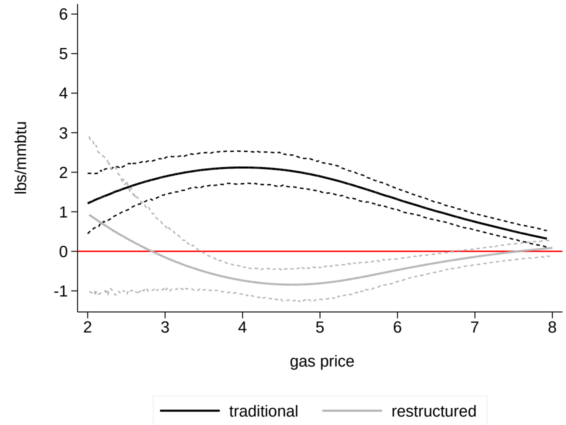
(d) SPEC IV

Note: The figure shows the increase in plant-level gas-related CO_2 emissions due to a decrease in the price of gas by $1/MMBtu based on the response of gas consumption in traditional and restructured markets for each of the four specifications in Figure 5. The calculations are based on 117 lbs. of CO_2 per MMBtu of gas. The dashed lines show 95% confidence intervals.

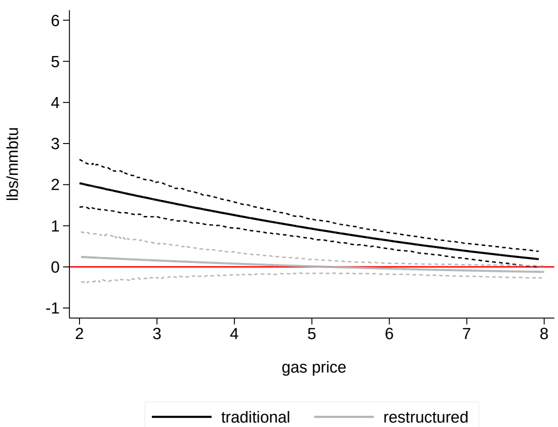
Figure 14: Decrease in total CO_2 emissions due to a change in gas prices: based on share regressions and holding electricity generation fixed



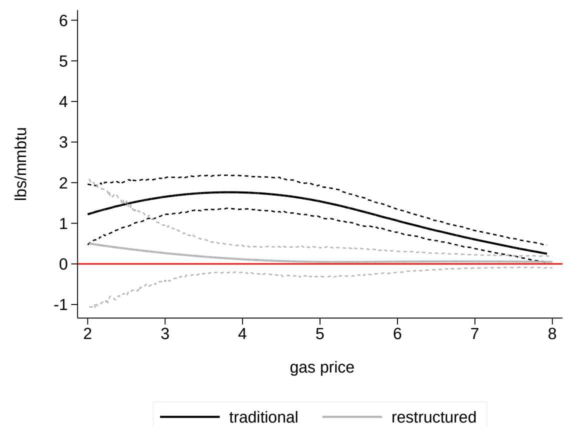
(a) SPEC I



(b) SPEC II



(c) SPEC III



(d) SPEC IV

Note: The figure shows the decrease in total plant-level CO_2 emissions due to a decrease in the price of gas by \$1/MMBtu based on the response of gas share of of fuel consumption in traditional and restructured markets for each of the four specifications in Figure 6, while holding fuel consumption constant. The calculations are based on 117 (211) lbs. of CO_2 per MMBtu of gas (coal). The dashed lines show 95% confidence intervals.

A Online Appendix

A.1 Data

The vast majority of the data used in our analyses are publicly available from the U.S. Energy Information Administration (EIA) and the U.S. Environmental Protection Agency (EPA). We aggregate monthly data for net generation (MWh) from the EIA-906, EIA-920, and EIA-923 forms, at the plant level. Monthly data for total fuel consumption (electricity plus thermal output) in physical units and associated heat content (Btu) by fuel are available from the same forms. We also aggregate fuel consumption at the plant level.[25]

Monthly plant-level fuel receipts in physical units and delivery costs ($/MMBtu) are publicly available from the FERC-423 and EIA-923 forms. The same forms contain information regarding the quality of fuel receipts (e.g., heat content). Although data on fuel receipts and associated heat content for merchant generators (Independent Power Producers) are publicly available from the EIA-423 and EIA-923 forms, the associated delivery costs are not. For this reason, we obtained access to EIA confidential data.

The FERC-423 form was filed by plants with a total steam turbine electric generating capacity and/or combined-cycle generating capacity of 50 or more megawatts. Only fuel delivered for use in steam-turbine and combined-cycle EGUs was reported. Fuel received for use in gas-turbine or internal-combustion EGUs that was not associated with a combined-cycle operation was not reported. In the case of EIA-923, fuel receipts and costs are collected for plants with a nameplate capacity of 50MW or more and burn fossil fuels. The Form EIA 423 collected the cost and quality of fossil fuels to non-utility plants— merchant generators, and commercial and industrial combined heat and power producers with a nameplate capacity of 50MW or more.[26]

Annual data for nameplate capacity (MW) are available at the generator level from EIA-860. The form reports up to six energy sources for each generator. We use the primary energy source to construct a measure of nameplate capacity fired by coal and natural gas. For example, for a generator with operating nameplate capacity of 50MW for which the primary energy source is coal and the secondary source is natural gas, the coal-fired name-

[25] The Appendix in EIA (2013) provides a very informative and concise summary of the EIA and FERC forms used in our analysis.

[26] Using the databases described, we calculated annual generation, fuel consumption for electricity only in physical units, and fuel receipts in physical units, for coal and natural gas for the period 2001–2012. We then compared these annual figures with the corresponding ones in Tables Tables 3.1.a, 5.1.a, 5.4.a, and 7.2 in EIA (2013). The maximum percentage difference is around 5% and is associated with natural gas fuel receipts for years between 2008 and 2012.

plate operating capacity is 50MW, while the natural gas-fired nameplate operating capacity is zero.

Using information from EIA-860, the EPA E-GRID 2012 database, and the proprietary SNL Financial Power Plant Database, we were able to check which plants in our sample fall within the footprint of the various ISOs. As an additional—albeit imperfect—check, we compared monthly total net generation and loads for 2007–2012 across six ISOs (CAISO, ERCOT, ISO-NE, MISO, NYISO, PJM). The absolute value of their percentage difference never exceeded 5%.[27]

Annual information for environmental controls at the generator level are available from the EPA Air Markets Program Data (AMPD) database for facility attributes. We collected information for the following environmental controls: Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), Wet Lime Flue Gas Desulfurization (wet lime FGD), Dry Lime Flue Gas Desulfurization (dry lime FGD), Particulate Matter fabric filters (PM).

The AMPD data contain also information on annual and ozone season (May–September) programs at the generator level. The *annual* programs include the Acid Rain program (ARP), the Transport Rule NO_x Annual program (TRNOX), the Transport Rule SO_2 Annual Group 1 program (TRSO2G1), the Transport Rule SO_2 Annual Group 2 program (TRSO2G2), the CAIR SO2 (CAIRSO2), the CAIR NO_x Annual program (CAIRNOX), and the Regional Greenhouse Gas Initiative (RGGI). The ozone season programs include the Transport Rule Ozone Season NO_x program (TRNOXOS), the CAIR Ozone Season NO_x program (CAIROS), the State-Implementation-Plan NO_x program (SIPNOX), and the NO_x Budget Program (NBP).

Monthly plant-level fuel purchases via spot transactions and long-term contracts are available from the EIA-423 and FERC-423 forms. Annual wholesale electricity purchases, wholesale electricity sales, and retail electricity sales for utilities are available from the EIA-861 form (Schedules 2 and 4).

Finally, The daily settlement SO_2 and seasonal NO_x (SNO_x) permit prices are from Evolution Markets, an allowance broker we identified through EPA's website.[28]

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

[28] See http://www.epa.gov/airmarkets/trading/buying.html. Additional information about Evolu-

A.2 Summary statistics

In Tables A.1–A.3, we provide detailed summary statistics for the explanatory variables that enter two of the specifications, SPEC III and SPEC IV, of the consumption and share regressions discussed in Section 3.3 of the main text. We also test formally for differences in these variables between plants in traditional and restructured markets. We exclude the SO_2 and NO_X permit prices, which exhibit only time variation.

In the case of coal consumption regressions, we see statistically significant differences with mixed signs in the case of fuel prices, as well as for the number of a plant's electric generating units (EGUs) covered by the NBP, TRNOXOS, TRSO2G1, and TRSO2G2 EPA programs (Table A.1). For the gas consumption regressions, we see statistically significant differences, also with mixed signs, in the case of total (coal plus gas) capacity, as well as for the number of plant EGUs covered by the following EPA programs: ARP, NBP, SIPNOX, TRNOXOS, TRSO2G1, and TRSO2G2 (Table A.2). Finally, for the share regressions. we see statistically significant differences for the price of coal, as well for the number of a plant's EGUs covered by the following EPA programs: TRNOXOS, TRSO2G1, and TRSO2G2 (Table A.3). Once again, the differences have mixed signs.

tion Markets is available at http://www.evomarkets.com/environment/emissions/_markets.

Table A.1: SPEC III and SPEC IV covariates table: coal consumption regressions

Variable	Traditional markets			Restructured markets			Difference	
	mean	s.d	c.v	mean	s.d.	c.v	size	p-value
Gas price	5.887	2.700	0.459	6.193	2.426	0.392	0.306	0.044
Coal price	2.190	0.885	0.404	1.899	0.695	0.366	-0.291	0.000
Coal plus gas capacity	0.882	0.846	0.960	0.751	0.710	0.946	-0.130	0.170
# of units with SCR	0.580	1.285	2.214	0.415	0.845	2.034	-0.165	0.223
# of units with SNCR	0.222	0.817	3.688	0.294	0.792	2.693	0.073	0.369
# of units with dry-lime FGD	0.176	0.540	3.062	0.186	0.787	4.226	0.010	0.885
# of units with wet-lime FGD	0.288	0.869	3.013	0.155	0.674	4.351	-0.133	0.114
# of units with PM controls	0.503	1.010	2.009	0.565	1.172	2.073	0.062	0.590
# of units in ARP	3.005	2.332	0.776	2.536	1.797	0.708	-0.468	0.065
# of units in CAIRNOX	1.371	2.481	1.810	1.232	1.896	1.539	-0.139	0.372
# of units in CAIROS	1.092	2.244	2.055	1.246	1.928	1.547	0.154	0.306
# of units in CAIRSO2	1.078	2.272	2.109	0.958	1.749	1.825	-0.119	0.336
# of units in NBP	0.982	2.180	2.219	1.341	2.023	1.509	0.358	0.039
# of units in SIPNOX	0.000	0.000		0.007	0.109	15.223	0.007	0.049
# of units in TRNOX	0.236	1.121	4.753	0.229	0.923	4.027	-0.007	0.821
# of units in TRNOXOS	0.236	1.121	4.753	0.163	0.803	4.927	-0.073	0.017
# of units in TRSO2G1	0.066	0.567	8.539	0.197	0.875	4.435	0.131	0.000
# of units in TRSO2G2	0.116	0.845	7.308	0.028	0.296	10.642	-0.088	0.001
obs.		11282			29827			
# plants		109			277			

Note: Fuel prices in \$/MMBtu and capacity in thousand MW. We report the mean, standard deviation, and coefficient of variation. We use # of units to refer to the number of electricity generating units in a power plants. SCR, SNCR, FGD, and PM refer to air pollution control technologies. **SCR**: Selective Catalytic Reduction, **SNCR**: Selective Non-Catalytic Reduction; **FGD**: Flue Gas Desulfurization ("scrubbing", wet or dry using lime as reagent); **PM**: Particulate Matter fabric filters (also known as baghouses). ARP–TROSO2G2 refer to U.S. Environmental Protection Agency (EPA) program aiming to curb emissions: **ARP**: Acid Rain program; **CAIRNOX**: Clean Air Interstate Annual NO_x program; **CAIRSO2**: Clean Air Interstate Rule SO_2 program; **NBP**: NO_x Budget Program; **SIPNOX:** State-Implementation-Plan NO_x program; **TRNOX**: Transport Rule NO_x Annual program; **TRNOXOS:** Transport Rule Ozone Season NO_x program; **TRSO2G1**: Transport Rule SO_2 Annual Group 1 program; **TRSO2G2**: Transport Rule SO_2 Annual Group 2 program. The p-value of the difference reported in the rightmost column of the table is based on standard errors clustered at the plant level.

Table A.2: SPEC III and SPEC IV covariates table: gas consumption regressions

Variable	Traditional markets			Restructured markets			Difference	
	mean	s.d	c.v	mean	s.d.	c.v	size	p-value
Gas price	5.872	2.255	0.384	5.810	2.317	0.399	-0.062	0.311
Coal price	2.104	0.793	0.377	2.055	0.760	0.370	-0.049	0.233
Coal plus gas capacity	0.569	0.610	1.072	0.458	0.499	1.089	-0.110	0.006
# of units with SCR	0.845	1.632	1.931	0.701	1.279	1.823	-0.144	0.168
# of units with SNCR	0.037	0.336	9.013	0.046	0.298	6.526	0.008	0.669
# of units with dry-lime FGD	0.039	0.247	6.356	0.013	0.146	10.930	-0.025	0.081
# of units with wet-lime FGD	0.032	0.289	9.046	0.029	0.302	10.549	-0.003	0.873
# of units with PM controls	0.087	0.422	4.856	0.104	0.495	4.746	0.018	0.577
# of units in ARP	2.541	2.611	1.027	2.138	2.103	0.984	-0.404	0.015
# of units in CAIRNOX	1.136	2.850	2.509	1.016	2.174	2.139	-0.120	0.339
# of units in CAIROS	1.007	2.781	2.763	0.934	2.405	2.576	-0.073	0.569
# of units in CAIRSO2	0.915	2.604	2.845	0.804	1.983	2.468	-0.112	0.269
# of units in NBP	0.361	1.510	4.187	0.967	2.580	2.667	0.607	0.000
# of units in SIPNOX	0.000	0.000		0.019	0.226	11.657	0.019	0.001
# of units in TRNOX	0.239	1.374	5.761	0.209	1.066	5.110	-0.030	0.243
# of units in TRNOXOS	0.239	1.374	5.761	0.157	0.941	5.977	-0.081	0.001
# of units in TRSO2G1	0.029	0.485	16.614	0.157	0.964	6.154	0.127	0.000
# of units in TRSO2G2	0.080	0.676	8.448	0.049	0.461	9.494	-0.032	0.020
obs.		30526			69542			
# plants		375			719			

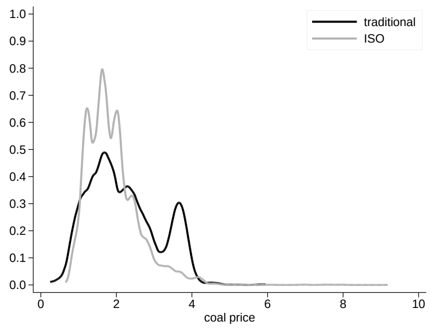
Note: Fuel prices in $/MMBtu and capacity in thousand MW. We report the mean, standard deviation, and coefficient of variation. We use # of units to refer to the number of electricity generating units in a power plants. SCR, SNCR, FGD, and PM refer to air pollution control technologies. **SCR**: Selective Catalytic Reduction, **SNCR**: Selective Non-Catalytic Reduction; **FGD**: Flue Gas Desulfurization ("scrubbing", wet or dry using lime as reagent); **PM**: Particulate Matter fabric filters (also known as baghouses). ARP–TROSO2G2 refer to U.S. Environmental Protection Agency (EPA) program aiming to curb emissions: **ARP**: Acid Rain program; **CAIRNOX**: Clean Air Interstate Annual NO_x program; **CAIRSO2**: Clean Air Interstate Rule SO_2 program; **NBP**: NO_x Budget Program; **SIPNOX:** State-Implementation-Plan NO_x program; **TRNOX**: Transport Rule NO_x Annual program; **TRNOXOS:** Transport Rule Ozone Season NO_x program; **TRSO2G1**: Transport Rule SO_2 Annual Group 1 program; **TRSO2G2**: Transport Rule SO_2 Annual Group 2 program. The p-value of the difference reported in the rightmost column of the table is based on standard errors clustered at the plant level.

Table A.3: SPEC III and SPEC IV covariates table: gas share regressions

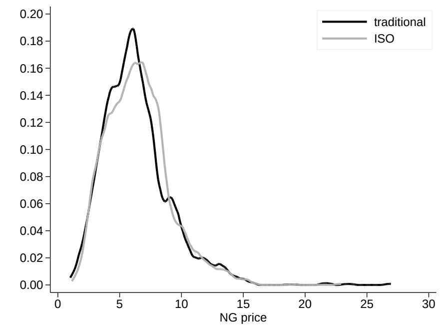
	Traditional markets			Restructured markets			Difference	
Variable	mean	s.d	c.v	mean	s.d.	c.v	size	p-value
Gas price	5.818	2.562	0.440	6.114	2.324	0.380	0.297	0.119
Coal price	2.109	0.860	0.408	1.808	0.657	0.364	-0.301	0.004
Coal plus gas generation	0.302	0.343	1.137	0.279	0.308	1.106	-0.023	0.667
Coal plus gas capacity	0.805	0.689	0.855	0.689	0.644	0.934	-0.115	0.309
# of units with SCR	0.515	1.186	2.302	0.409	0.852	2.081	-0.106	0.556
# of units with SNCR	0.196	0.743	3.796	0.230	0.640	2.788	0.034	0.730
# of units with dry-lime FGD	0.215	0.548	2.551	0.066	0.319	4.828	-0.148	0.051
# of units with wet-lime FGD	0.178	0.662	3.724	0.147	0.674	4.570	-0.030	0.782
# of units with PM controls	0.482	0.894	1.856	0.537	1.017	1.895	0.055	0.719
# of units in ARP	3.447	2.565	0.744	2.856	1.908	0.668	-0.592	0.141
# of units in CAIRNOX	1.509	2.706	1.793	1.283	2.050	1.598	-0.226	0.350
# of units in CAIROS	1.256	2.498	1.988	1.244	2.056	1.652	-0.012	0.961
# of units in CAIRSO2	1.191	2.478	2.081	0.994	1.881	1.892	-0.196	0.306
# of units in NBP	0.959	2.318	2.417	1.330	2.152	1.619	0.370	0.178
# of units in SIPNOX	0.000	0.000		0.012	0.150	12.342	0.012	0.090
# of units in TRNOX	0.280	1.317	4.696	0.236	0.967	4.092	-0.044	0.367
# of units in TRNOXOS	0.280	1.317	4.696	0.148	0.795	5.374	-0.132	0.007
# of units in TRSO2G1	0.057	0.586	10.328	0.194	0.897	4.629	0.137	0.000
# of units in TRSO2G2	0.141	1.003	7.136	0.038	0.364	9.536	-0.102	0.015
obs.		5671			13748			
# plants		53			127			

Note: Fuel prices in \$/MMBtu. Generation in million MWh. Capacity in thousand MW. We report the mean, standard deviation, and coefficient of variation. We use # of units to refer to the number of electricity generating units in a power plants. SCR, SNCR, FGD, and PM refer to air pollution control technologies. **SCR**: Selective Catalytic Reduction, **SNCR**: Selective Non-Catalytic Reduction; **FGD**: Flue Gas Desulfurization ("scrubbing", wet or dry using lime as reagent); **PM**: Particulate Matter fabric filters (also known as baghouses). ARP–TROSO2G2 refer to U.S. Environmental Protection Agency (EPA) program aiming to curb emissions: **ARP**: Acid Rain program; **CAIRNOX**: Clean Air Interstate Annual NO_x program; **CAIRSO2**: Clean Air Interstate Rule SO_2 program; **NBP**: NO_x Budget Program; **SIPNOX:** State-Implementation-Plan NO_x program; **TRNOX**: Transport Rule NO_x Annual program; **TRNOXOS:** Transport Rule Ozone Season NO_x program; **TRSO2G1**: Transport Rule SO_2 Annual Group 1 program; **TRSO2G2**: Transport Rule SO_2 Annual Group 2 program. The p-value of the difference reported in the rightmost column of the table is based on standard errors clustered at the plant level.

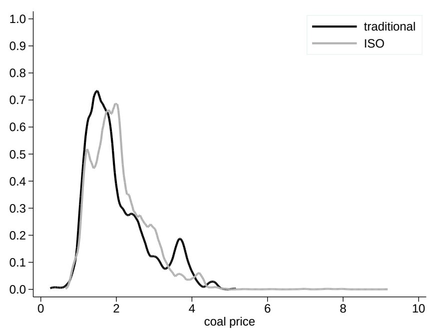
Figure A.1: Distribution of fuel prices by plant type, regional sector



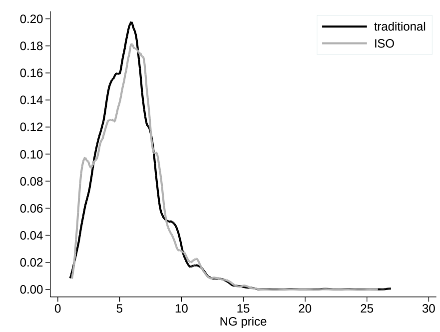
(a) coal-fired, coal price



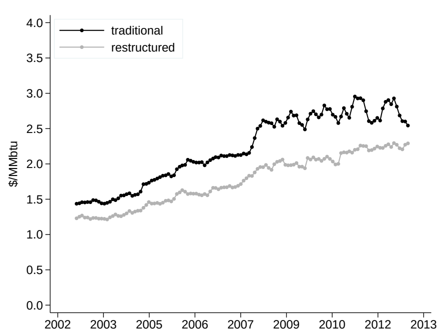
(b) coal-fired, gas price



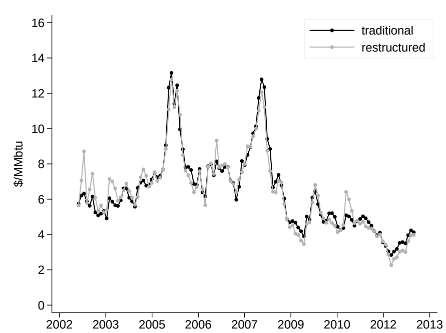
(c) gas-fired, coal price



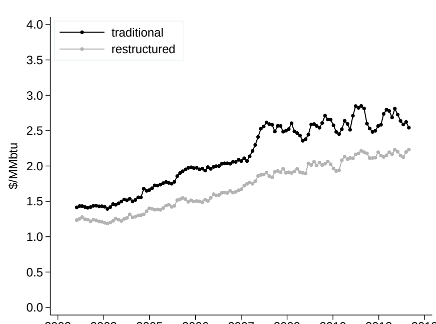
(d) gas-fired, gas price



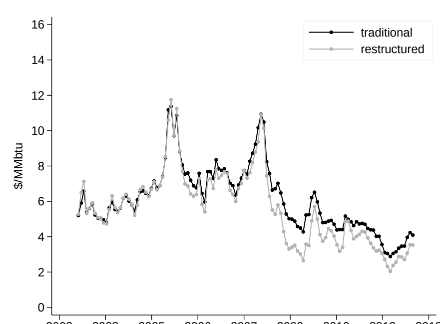
(e) coal-fired, coal price



(f) coal-fired, gas price



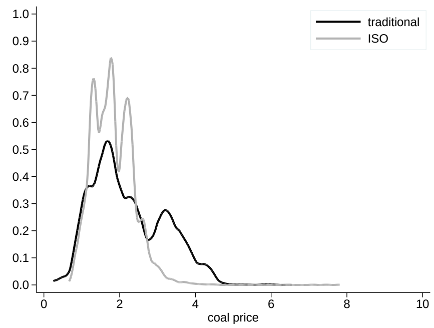
(g) gas-fired, coal price



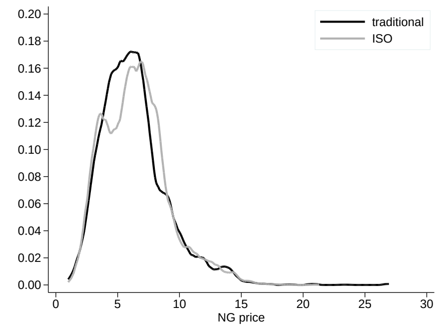
(h) gas-fired, gas price

Note: We use coal-fired to refer to plants with coal-fired electricity generators. Similarly, we use gas-fired to refer to plants with gas-fired electricity generators. Coal and gas prices are measured in $/MMBtu. See Section 3.2 for additional details.

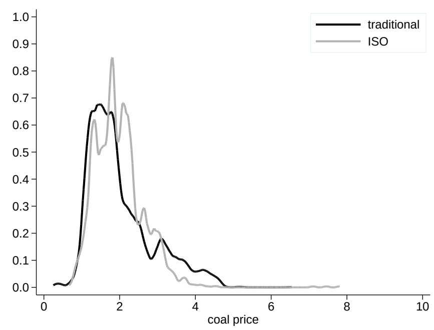
Figure A.2: Distribution of fuel prices by plant type, PCA sector



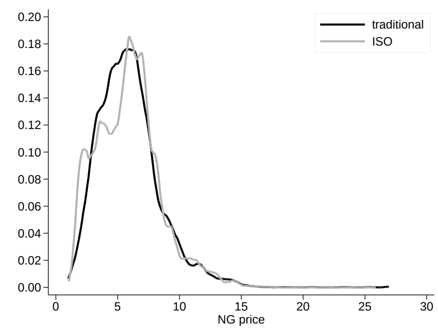
(a) coal-fired, coal price



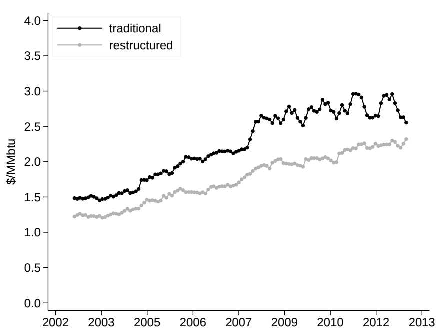
(b) coal-fired, gas price



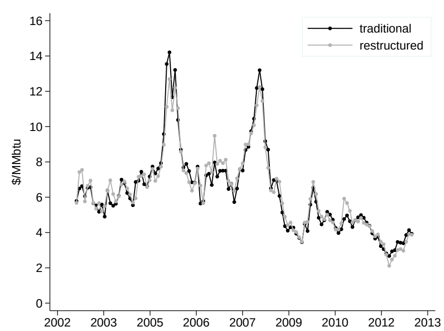
(c) gas-fired, coal price



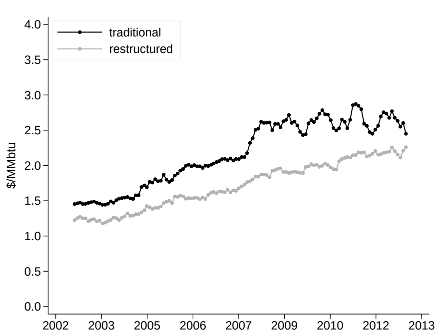
(d) gas-fired, gas price



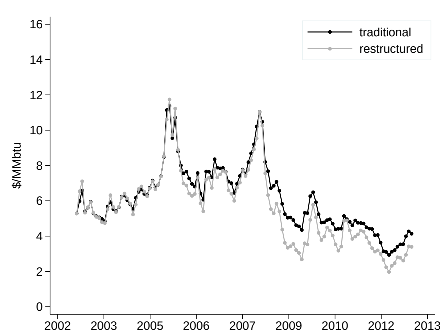
(e) coal-fired, coal price



(f) coal-fired, gas price



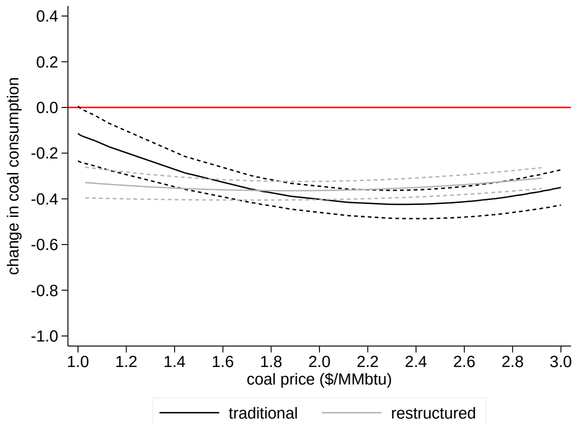
(g) gas-fired, coal price



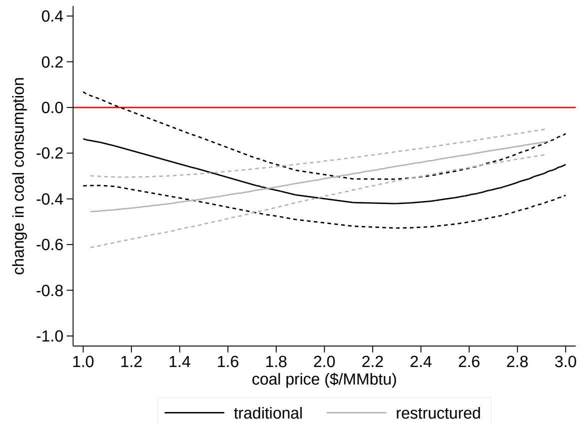
(h) gas-fired, gas price

Note: We use coal-fired to refer to plants with coal-fired electricity generators. Similarly, we use gas-fired to refer to plants with gas-fired electricity generators. Coal and gas prices are measured in $/MMBtu. See Section 3.2 for additional details.

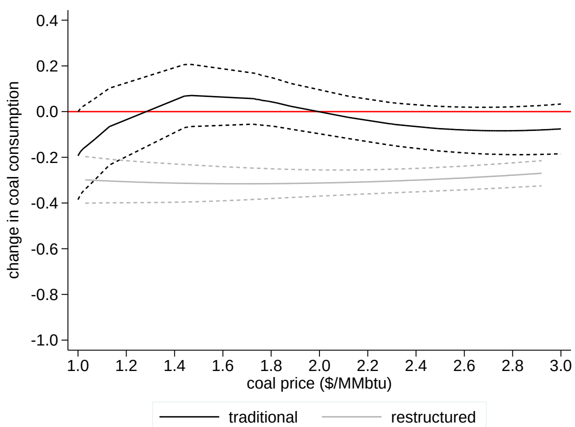
Figure A.3: Change in coal consumption due to a change in coal prices



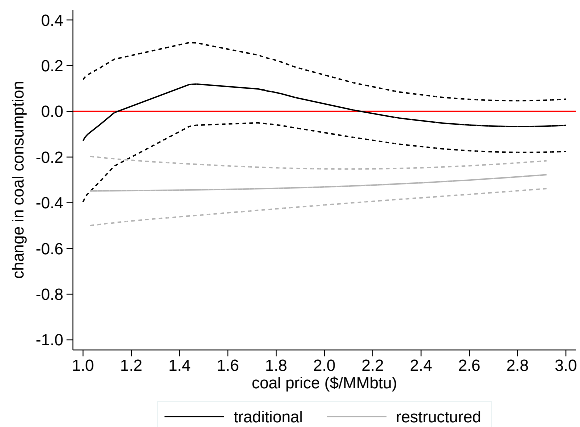
(a) SPEC I



(b) SPEC II



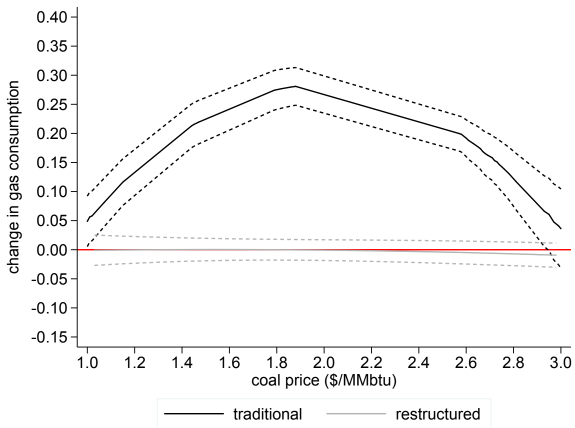
(c) SPEC III



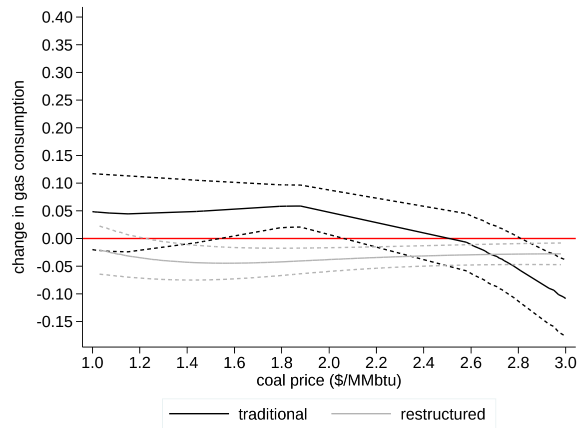
(d) SPEC IV

Note: The figure shows the change in coal consumption measured in million MMBtu due to a $1 increase in the price of coal for coal prices between $1 and $3 per MMBtu using basis splines with knots at $2 per MMBtu for coal, and $6/MMBtu for gas. The dashed lines show 95% confidence intervals. SPEC I: plant fixed effects and NERC region-by-month fixed effects. SPEC II: as in SPEC I plus NERC region-by-year fixed effects. SPEC III: plant fixed effects, logarithm of coal- plus gas-fired capacity, logarithm of SO_2 and seasonal NO_X permit prices, number of electricity generating units (EGUs) with NO_X, SO_2, and particulate matter environmental controls, number of EGUs under various EPA programs, and month fixed effects. SPEC IV: as in SPEC III plus year fixed effects. For additional details regarding the data, see Section A.1 in the on-line Appendix. For additional details, regarding the regression specifications, see Section 3.3.

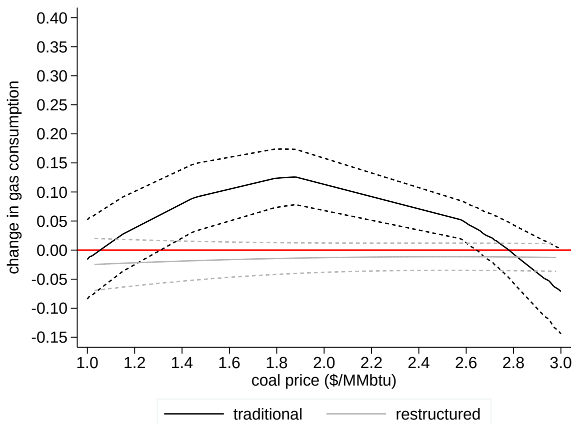
Figure A.4: Change in gas consumption due to a change in coal prices



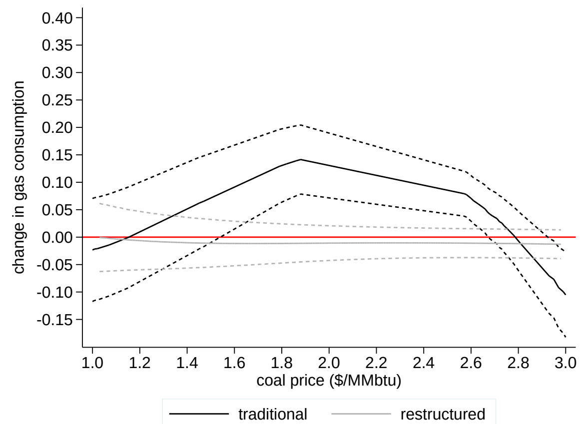
(a) SPEC I



(b) SPEC II



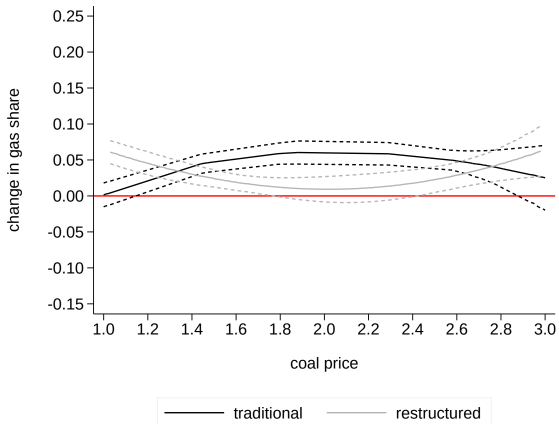
(c) SPEC III



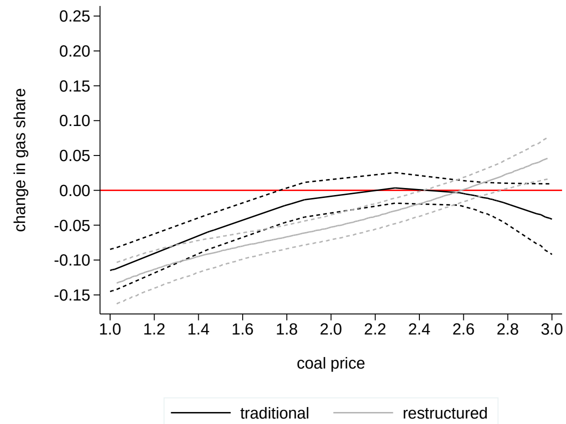
(d) SPEC IV

Note: The figure shows the change in gas consumption measured in million MMBtu due to a $1 increase in the price of coal for coal prices between $1 and $3 per MMBtu using basis splines with knots at $2 per MMBtu for coal, and $6/MMBtu for gas. The dashed lines show 95% confidence intervals. SPEC I: plant fixed effects and NERC region-by-month fixed effects. SPEC II: as in SPEC I plus NERC region-by-year fixed effects. SPEC III: plant fixed effects, logarithm of coal-plus gas-fired capacity, logarithm of SO_2 and seasonal NO_X permit prices, number of electricity generating units (EGUs) with NO_X, SO_2, and particulate matter environmental controls, number of EGUs under various EPA programs, and month fixed effects. SPEC IV: as in SPEC III plus year fixed effects. For additional details regarding the data, see Section A.1 in the on-line Appendix. For additional details, regarding the regression specifications, see Section 3.3.

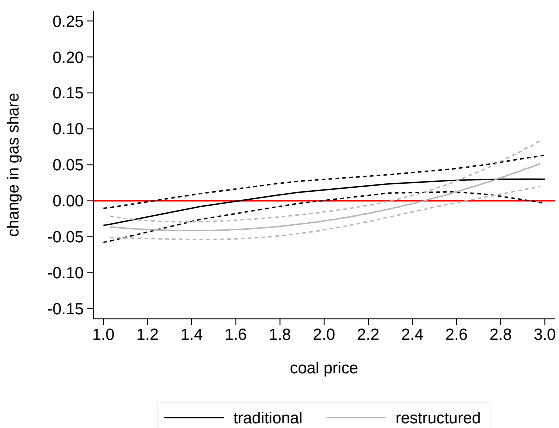
Figure A.5: Change in the gas share of fuel consumption due to a change in coal prices: controlling for the plant's generation



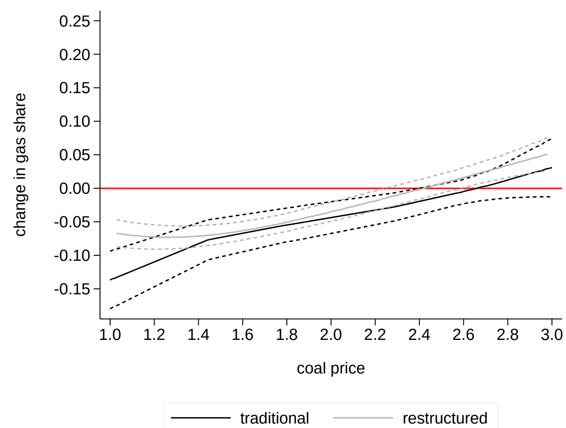
(a) SPEC I



(b) SPEC II



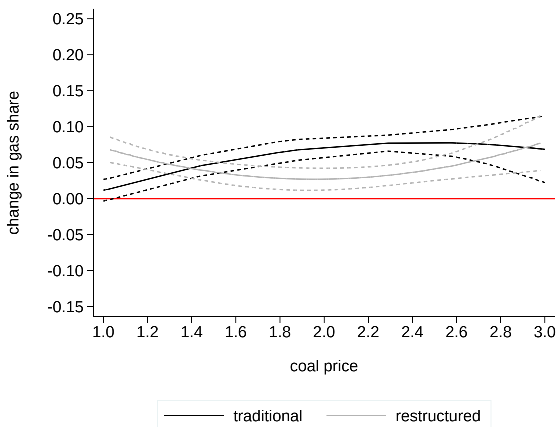
(c) SPEC III



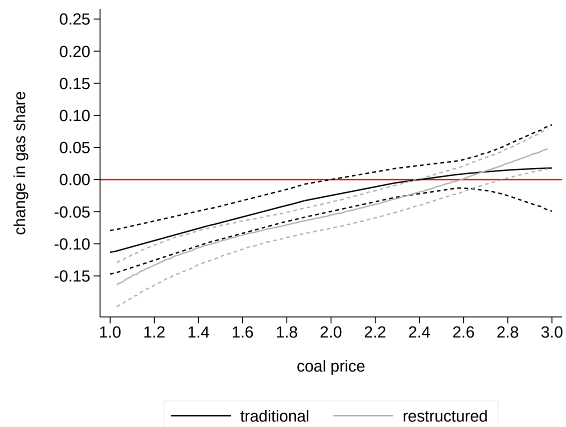
(d) SPEC IV

Note: The figure shows the change in the gas share of fuel consumption for plants using both coal and gas due to a \$1 increase in the price of coal for coal prices between \$1 and \$3 per MMBtu using basis splines with knots at \$2 per MMBtu for coal, and \$6/MMBtu for gas. The dashed lines show 95% confidence intervals. SPEC I: plant fixed effects and NERC region-by-month fixed effects. SPEC II: as in SPEC I plus NERC region-by-year fixed effects. SPEC III: plant fixed effects, logarithm of coal- plus gas-fired capacity, logarithm of SO_2 and seasonal NO_X permit prices, number of electricity generating units (EGUs) with NO_X, SO_2, and particulate matter environmental controls, number of EGUs under various EPA programs, and month fixed effects. SPEC IV: as in SPEC III plus year fixed effects. For additional details regarding the data, see Section A.1 in the on-line Appendix. For additional details, regarding the regression specifications, see Section 3.3.

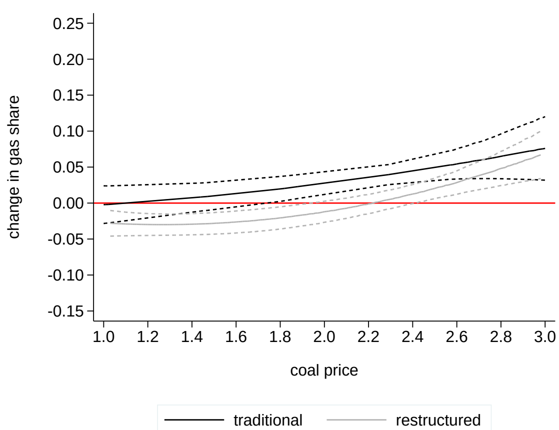
Figure A.6: Change in the gas share of fuel consumption due to a change in coal prices: without controlling for the plant's generation



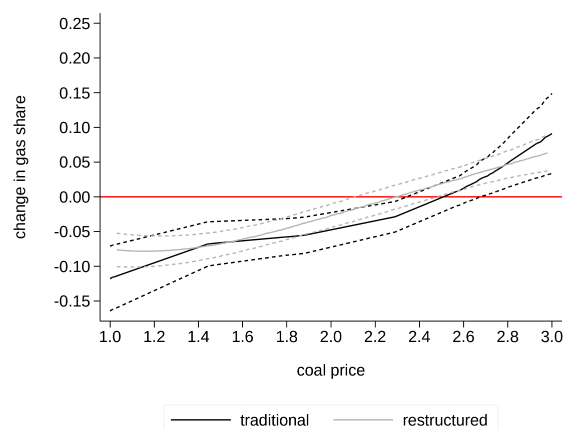
(a) SPEC I



(b) SPEC II



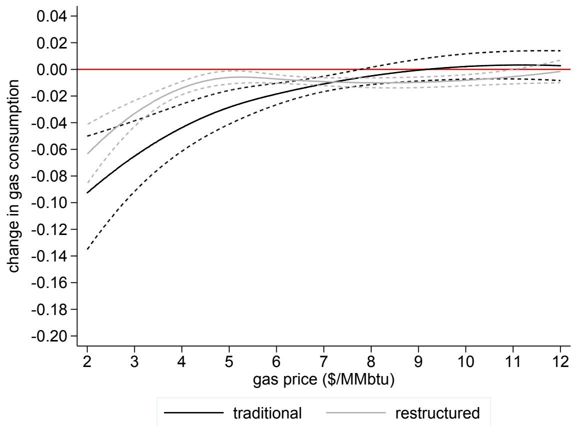
(c) SPEC III



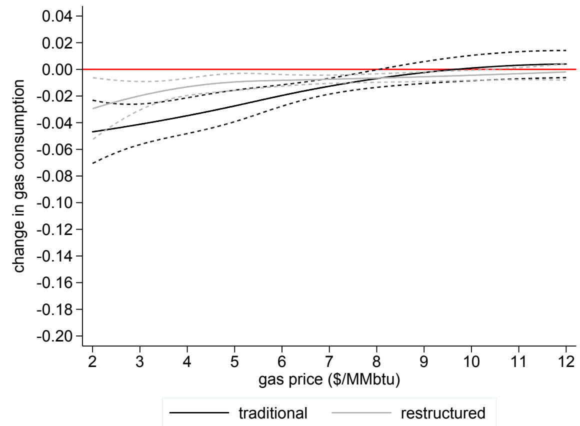
(d) SPEC IV

Note: The figure shows the change in the gas share of fuel consumption for plants using both coal and gas due to a $1 increase in the price of coal for coal prices between $1 and $3 per MMBtu using basis splines with knots at $2 per MMBtu for coal, and $6/MMBtu for gas. The dashed lines show 95% confidence intervals. SPEC I: plant fixed effects and NERC region-by-month fixed effects. SPEC II: as in SPEC I plus NERC region-by-year fixed effects. SPEC III: plant fixed effects, logarithm of coal- plus gas-fired capacity, logarithm of SO_2 and seasonal NO_X permit prices, number of electricity generating units (EGUs) with NO_X, SO_2, and particulate matter environmental controls, number of EGUs under various EPA programs, and month fixed effects. SPEC IV: as in SPEC III plus year fixed effects. For additional details regarding data, see Section A.1 in the on-line Appendix. For additional details, regarding the regression specifications, see Section 3.3.

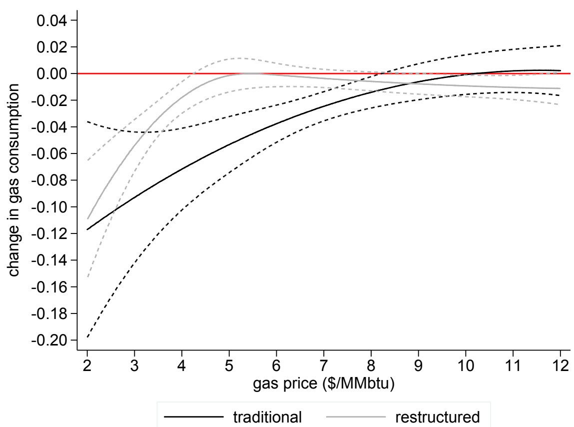
Figure A.7: Change in gas consumption due to a change in gas prices: combined-cycle only



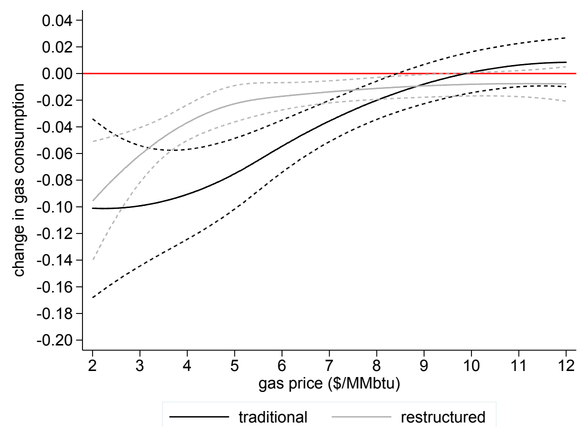
(a) SPEC I



(b) SPEC II



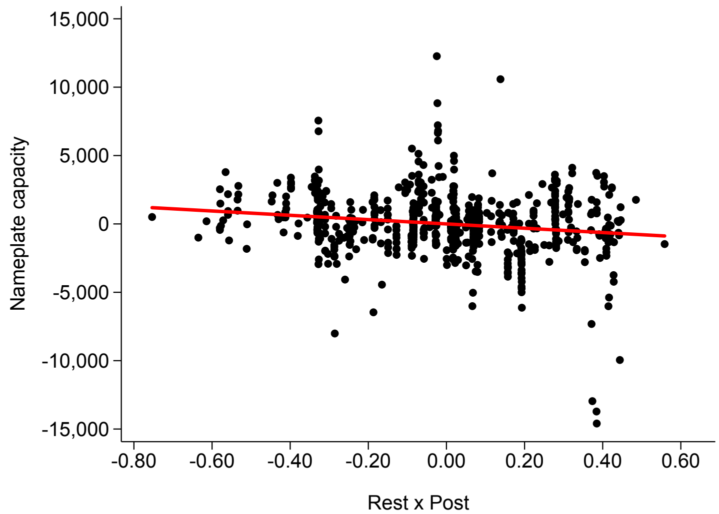
(c) SPEC III



(d) SPEC IV

Note: The figure shows the change in gas consumption for the combined-cycle technology only measured in million MMBtu due to a \$1 increase in the price of gas for gas prices between \$2 and \$12 per MMBtu using basis splines with knots at \$2 per MMBtu for coal, and \$6/MMBtu for gas. The dashed lines show 95% confidence intervals. SPEC I: plant fixed effects and NERC region-by-month fixed effects. SPEC II: as in SPEC I plus NERC region-by-year fixed effects. SPEC III: plant fixed effects, logarithm of coal- plus gas-fired capacity, logarithm of SO_2 and seasonal NO_X permit prices, number of electricity generating units (EGUs) with NO_X, SO_2, and particulate matter environmental controls, number of EGUs under various EPA programs, and month fixed effects. SPEC IV: as in SPEC III plus year fixed effects. For additional details regarding the data, see Section A.1 in the on-line Appendix. For additional details regarding the regression specifications, see Section 3.3.

Figure A.8: State-level capacity, partial response



Note: This is a scatterplot of the dependent variable in (2) against the variable of interest, $Rest \times Post$, with the effect of the remaining regressors partialled out. The slope of the red (partial response) line equals the OLS estimate of β reported in column (1) of Table 5.