American Economic Journal: Economic Policy 2017, 9(3): 106–133
https://doi.org/10.1257/pol.20150388

Inferring Carbon Abatement Costs in Electricity Markets: A Revealed Preference Approach Using the Shale Revolution†

By Joseph A. Cullen and Erin T. Mansur*

This paper examines how carbon pricing would reduce emissions in the electricity sector. Both carbon prices and cheap natural gas reduce the historic cost advantage of coal plants. The shale revolution resulted in unprecedented variation in natural gas prices that we use to estimate the potential near-term effects of carbon prices. Estimates imply that a price of \$20 (\$70) per ton of CO_2 would reduce emissions by 5 (10) percent. Carbon prices are most effective at reducing emissions when natural gas prices are low, but have negligible effects when gas prices are at levels seen prior to the shale revolution. (*JEL* L94, L98, Q35, Q38, Q54, Q58)

Climate change is a global problem with uncertain and potentially costly effects lasting centuries. Regulators are implementing or considering diverse policies to mitigate climate change. Market-based instruments are recognized by economists as cost-effective even though skeptics question their effectiveness. Although debated frequently, a federal price on carbon remains elusive in the United States.

This paper examines how a carbon price is likely to affect emissions from the US electricity sector, which accounts for about one-third of US greenhouse gases (EPA 2013). Firms can respond to carbon prices immediately by altering the mix of power plants used to meet demand: this is known as fuel switching. The proposed Clean Power Plan expects fuel switching ("building block two") to be a key mechanism for compliance.[1] Lafrancois (2012) estimates that switching generation from the currently operating coal plants to the available, underutilized capacity at natural gas plants could reduce carbon dioxide (CO_2) emissions from the electricity industry by 23 to 42 percent. Whether or not this is feasible remains an empirical question.

*Cullen: Olin Business School, Washington University in St. Louis, Campus Box 1133, St. Louis, MO, 63130 (email: jacullen@wustl.edu); Mansur: Tuck School of Business, Dartmouth College, 100 Tuck Hall, Dartmouth College, Hanover, NH 03755 (email: erin.mansur@dartmouth.edu). We thank Luis Gautier, Matthew Kotchen, Nicholas Ryan, Carl Fuchshuber, and seminar participants at Washington University, University of Chicago, Portland Energy Economics Conference, Dartmouth College, University of Colorado, International Industrial Organization Conference, IFN Electricity Markets Conference, the Energy Institute at Haas Conference, Middlebury College, Yale University, the World Bank, the Northeast Environmental Economics Workshop, and the Calgary Renewable Electricity Conference. We thank Wolfram Schlenker for providing weather data.

†Go to https://doi.org/10.1257/pol.20150388 to visit the article page for additional materials and author disclosure statement(s) or to comment in the online discussion forum.

[1] The EPA (2014) reports the expected emissions rate reductions for each building block and state. Building blocks 1, 2, 3, and 4 are dominant in 1, 20, 14, and 14 states, respectively (Vermont is exempt).

This paper measures the expected near-term emissions reductions from a range of carbon prices.

Since we use a revealed preference approach to estimate near-term effects, our results should not be viewed as the ultimate effect of a carbon policy. Carbon pricing is capable of leading to new investment in cleaner technology, the exit of carbon-intensive power plants, changes in demand levels and patterns, long-run fuel supply effects, and innovation in new technologies, which may further reduce emissions over a longer time horizon (Fowlie et al. 2014, Fell and Linn 2013). Simulation approaches would be necessary to predict these additional effects. Therefore, we consider our estimates to be a likely lower bound of the overall effects of a carbon price.

The first contribution of this paper is to show how a carbon price provides similar incentives for fuel switching as does a change in the cost ratio: namely the price of coal (per unit of heat content) over the price of natural gas. Briefly, higher carbon prices make coal-fired power plants less competitive than natural gas-fired power plants. Other power plants (nuclear, hydroelectric, and other renewables) have low marginal costs and remain inframarginal. Similarly, when the cost ratio rises, natural gas plants gain an advantage: some cheap baseload coal plants may be displaced by even cheaper combined-cycle natural gas plants. While broadly this is true of other pollutants, we discuss why the mapping from cost ratios to carbon prices is substantially more precise. This mapping is important since we have no national carbon price that we could use to identify the marginal cost of abating carbon. Even where there are regional policies, there is limited variation in carbon prices.

However, we have recently observed abundant variation in natural gas prices. Technological advances in drilling (i.e., hydrofracturing) have allowed firms to extract natural gas from shale formations. This "shale revolution" resulted in a short run glut of gas: natural gas production increased 26 percent from 2005 to 2012 (Energy Information Administration 2014b). Furthermore, there are limited options to export substantial quantities of natural gas outside of North America. As a result, gas prices have dropped from over $12 per million British thermal units (mmBTU) to less than $2. In 2012, gas in the United States was less than a third of the cost of gas in Europe (see Figure 1).[2]

Using recent variation in fuel prices, we estimate the relationship between CO_2 emissions and the coal-to-gas cost ratio using a flexible functional form. This revealed preference approach measures actual behavior of firms in the market, whatever may be their incentives and information sets as well as the constraints of their power plants and the electricity grid. Our analysis controls for several factors, including electricity load (the quantity consumed), temperature, generation from nonfossil sources, and net imports from Canada. In addition, we use time period fixed effects to proxy for macroeconomic shocks, other policies affecting the electricity sector, and general trends in power plant entry and exits. This paper uses aggregate market-level data and does not control for the set of operating power

[2] The sharp drop in prices in 2008 reflects the recession. Since then, European prices have returned to levels seen before the recession while US prices remain low due to shale gas production (EIA 2012). These data are nominal prices from the World Bank Commodity Price Data (Pink Sheet).

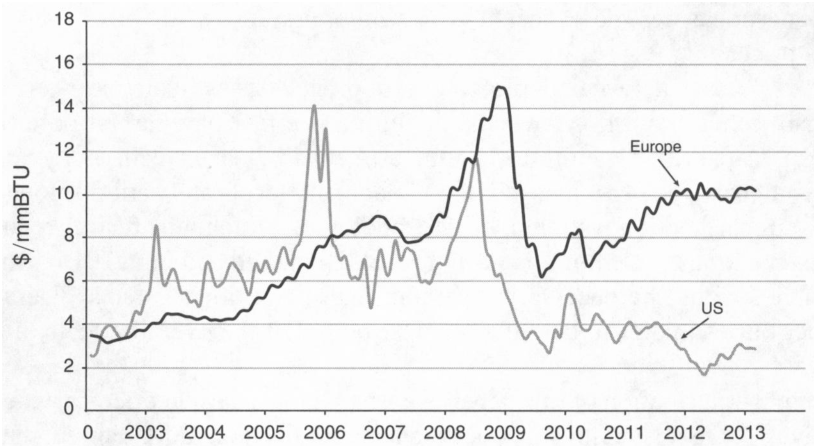

FIGURE 1. US AND EUROPEAN NATURAL GAS PRICES

plants. Therefore, our cost ratio coefficients may also capture any effects of entry or exit, retail pricing, or other factors that are correlated with fuel prices and are not perfectly correlated with the controls. Thus, while our focus is on fuel switching, we recognize that our estimates may capture a broader set of near-term abatement responses.

The first set of results directly examines how fuel prices affect carbon emissions. We find that when gas prices fall from \$6 per mmBTU to \$2, holding coal prices fixed, we predict a 10 percent drop in aggregate CO_2 emissions. Next, we map this response curve into carbon prices. When baseline prices of natural gas are low, carbon prices are effective at reducing emissions. Using expected fuel prices over the next decade from the Energy Information Administration (EIA 2012), we find that even a carbon price of \$10 (\$20) per ton of CO_2 would reduce emissions about 2 (5) percent. A mandate of a 10 percent reduction would be costly: the carbon price would need to be approximately \$70/ton and would cost over \$6 billion a year.

In contrast, when coal holds a sizable cost advantage over natural gas, a marginal change in the cost ratio has no notable effect on emissions. Even a moderate carbon price would have a limited impact on emissions. If gas prices return to historic levels (as they may if environmental regulations either ban or raise the costs of hydrofracking), then even a price of \$20 per ton of CO_2 would reduce emissions by less than 1 percent. Even a \$70/ton price would only reduce emissions by approximately 6 percent.

We decompose the emissions effects by fuel type to test if our findings are consistent with fuel switching. We find that a carbon price increases emissions from gas plants: a \$20 carbon price increases aggregate emissions by less than 1 percent through this mechanism. However, the emissions reductions from coal plants more than offset this effect. The same \$20 price will decrease aggregate emissions by almost 6 percent because of coal plants operating less. Finally, we show how a carbon price can result in co-benefits by reducing local emissions, in aggregate, in an approximately proportional manner. We find spatial heterogeneity in this response, which matters for health effects (Burtraw et al. 1998).

Our research relates to two recent literatures. One simulates counterfactual short-run effects of a carbon tax on emissions using calibrated or structurally estimated models.[3] A second literature examines how the low natural gas prices reduced emissions from the power sector using calibrated models and reduced-form estimates.[4] Many of these papers estimate how a carbon price would reduce emissions from the US electricity industry. However, comparing the findings for a given carbon price is not straightforward. There are differences in the underlying assumptions on baseline fuel prices, demand response, units of analysis, format of the results, region of analysis, and time period of analysis. While such a comparison would be interesting, it is beyond the scope of this paper. Our study complements these papers by using observed market behavior to generate reduced-form estimates of near-term abatement costs. The main advantage of our approach over a least-cost dispatch model is that we are not assuming any behavior of firms in estimating the relationship between emissions and fuel prices. Our paper accounts for the integrated grid across regions, estimates a flexible functional form of the daily cost ratio, and examines a longer time horizon with greater heterogeneity in natural gas prices.

I. Background

Coal-fired power plants produce most of the electricity in the United States (EIA 2014a). On average, these baseload plants have low operating costs, are slow to adjust, and are costly to start up. However, there is substantial heterogeneity in the marginal cost of operating these plants. Some older, less efficient plants operate only during relatively high demand months. Most gas-fired generators fall into two categories: gas turbine peaker plants and combined cycle gas turbines (CCGT). Peaker plants have relatively low capital costs and high marginal costs. They operate during high demand hours, as power is prohibitively expensive to store and demand varies substantially over hours of the day and across seasons. In contrast, baseload CCGT plants are the most efficient fossil plants at turning the fuel's energy into power: i.e., they have low heat rates. As such, some gas-fired power plants may have lower marginal costs than the most efficient coal plants even if coal costs less, per BTU, than natural gas.

[3] Metcalf (2009) uses MIT's Emissions Prediction and Policy Analysis Model to simulate emission outcomes. Newcomer et al. (2008) construct supply functions based on static, least-cost optimization. Least-cost dispatch models assume firms minimize costs, have perfect information, take all input prices as given, do not face start-up costs, ramping constraints, or other unit commitments, and are only subject to the constraints of the grid as modeled by the researcher. In contrast, Cullen (2015) estimates a structural, dynamic model of power plant production decisions in the Texas electricity market to simulate counterfactual outcomes.

[4] Calibrated least-cost dispatch models include Venkatesh et al. (2012). Reduced-form estimates include Holladay and LaRiviere (2015); Linn, Muehlenbachs, and Wang (2014); Knittel, Metaxoglou, and Trindade (2014); Pratson, Haerer, and Patiño-Echeverri (2013); and Lu, Salovaara, and McElroy (2012). Holladay and LaRiviere (2015) use hourly data for each of the eight North American Electric Reliability Corporation (NERC) regions to estimate the marginal emissions from regional fossil-fired gross generation. Linn, Muehlenbachs, and Wang (2014) and Knittel, Metaxoglou, and Trindade (2014) show how plant-level monthly production decisions change with cheap gas. Pratson, Haerer, and Patiño-Echeverri (2013) calculate the average cost of electricity generation for individual fossil plants and relate it to the coal-to-gas cost ratio. Lu, Salovaara, and McElroy (2012) relate the monthly share of coal generation in a census region to the cost difference between natural gas and coal.

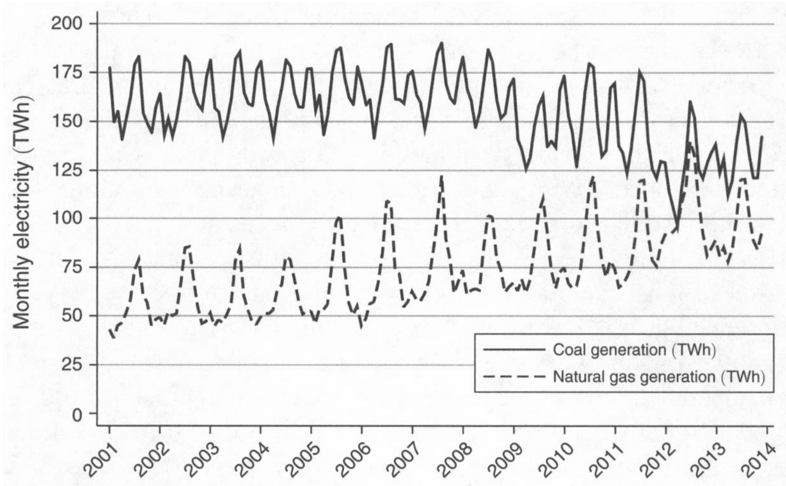

Figure 2. Monthly Generation by Fuel Type

Lower gas prices have been a boon for gas-fired generators in the United States. Efficient gas power plants found themselves in the position to undercut coal-fired power plants. Figure 2 shows the monthly average electricity generation for power plants burning coal or natural gas from 2001 to 2013. While coal-based generation has generally been declining since the start of this century, a notable drop occurred in 2012 when natural gas briefly overtook it as the dominant fuel source. Note that this fuel switching primarily occurs across plants, not within a given plant.

The degree to which production switches from coal to gas generation will depend on several factors. From a static dispatch framework, fuel switching depends on the relative fuel prices, the relative heat rates, the available capacity of gas plants, and the demand for electricity. In addition, intra-day fluctuations in electricity demand may be important as some generators are not well suited for starting and stopping production frequently. Start-up costs, ramping rates, minimum down times, and other intertemporal constraints limit firms' operation decisions (Mansur 2008, Cullen 2015). In addition, coal plants may be limited in the short run by contractual obligations to receive new coal shipments not easily re-sold.

Furthermore, the transmission grid limits how much power plants can produce. As electricity is not stored, power supply and demand must equate at all times. This is subject to the network of transmission lines' capacity constraints, as well as the plants' intertemporal constraints (Mansur and White 2012, Davis and Hausman 2015). Therefore, optimal dispatch from a least-cost static model differs from the dynamic optimization.

Finally, observed production may differ from a static model's prediction for a number of other reasons. Namely, power plants face forced outages whereby they cannot operate when planned. Firms may have imperfect information about trading opportunities (Mansur and White 2012). Firms may exercise market power (Borenstein, Bushnell, and Wolak 2002; Mansur 2007b; Puller 2007; and Bushnell, Mansur, and Saravia 2008). For these reasons, our analysis will use regressions to identify how firms actually respond to relative fuel prices.

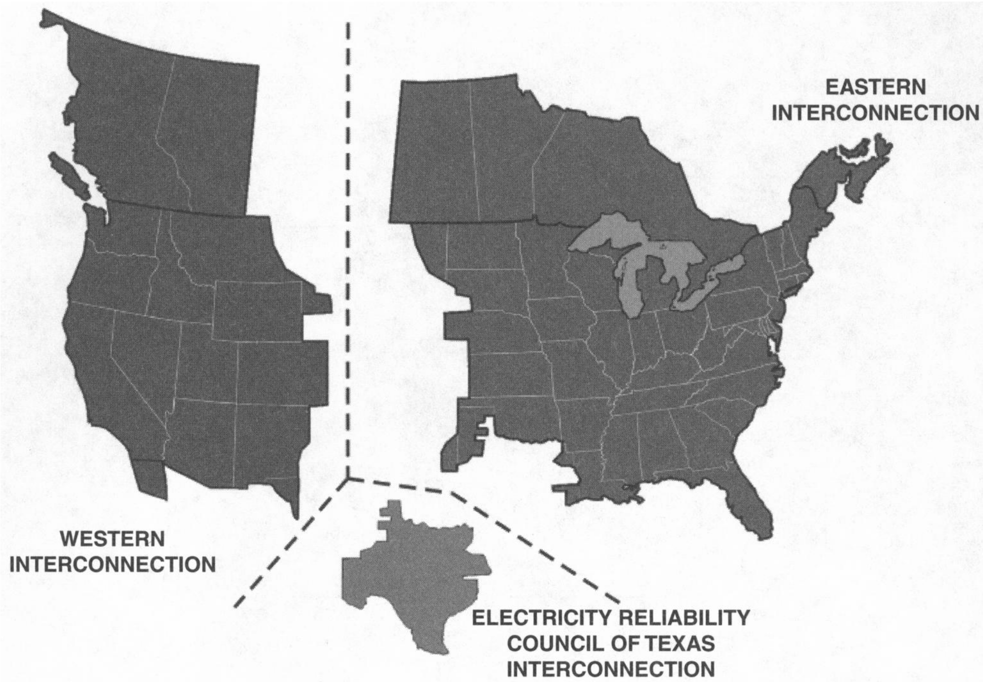

FIGURE 3. ELECTRICITY INTERCONNECTIONS

The US electricity grid consists of three interconnections: East, West, and ERCOT (see Figure 3). Electricity produced in each interconnection is synchronized, allowing electricity to flow freely throughout the interconnection. Relatively little energy is transferred via direct current lines between interconnections due to the costs involved in transferring power between asynchronous grids. Analysis on a finer geographic scale is possible, but presents problems for measuring net emissions reductions in each area due to energy transfers between subregions within an interconnection.

II. Theory

A. *Mapping Carbon Pricing*

Pricing carbon makes natural gas-fired generators more competitive with those burning coal. For a fossil-fired power plant, the marginal cost of producing electricity (MC) is primarily a function of its heat rate (HR), price of fuel (P_{fuel}), fuel carbon content ($CO_{2,fuel}$), and carbon price (P_{co2}):[5]

$$MC = HR \cdot (P_{fuel} + CO_{2,fuel} \cdot P_{co2}) = HR \cdot C_{fuel}. \tag{1}$$

[5] Heat rate is measured in mmBTU/MWh, price of fuel (P_{fuel}) is in \$/mmBTU, fuel-specific carbon content ($CO_{2,fuel}$) is in tons/mmBTU, and the carbon price (P_{co2}) is in \$/ton. Also, we omit from this discussion any variable operating and maintenance ($VO\&M$) costs. These would include expenses for major overhauls, treating water, pumping water for cooling towers, replacing filters, etc., associated with usage of the generator. In addition, firms may have costs associated with pollutants other than CO_2 (e.g., sulfur dioxide permit prices). While these costs were extremely small relative to fuel costs during most of our sample, our analysis controls for them.

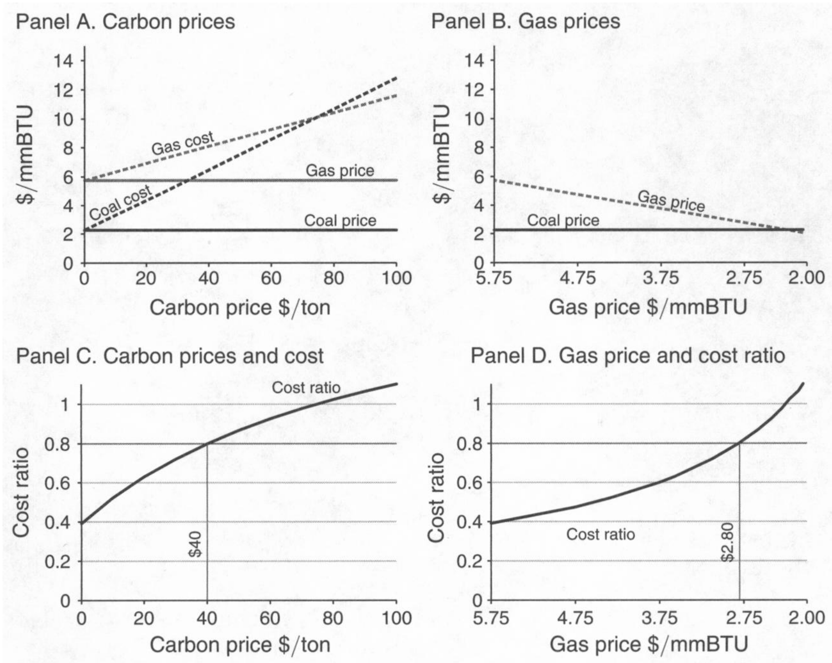

FIGURE 4. RELATIONSHIP BETWEEN GAS PRICES, CARBON PRICES, AND COST RATIOS

We denote the cost of burning fuel, C_{fuel}, as the sum of the price of procuring the fuel plus the CO_2 costs incurred by the firm. Although pricing carbon dioxide emissions increases marginal costs for both gas and coal plants, coal contains approximately twice as much CO_2 per unit of energy as natural gas. Thus, pricing carbon will affect the marginal costs of coal plants more than those of an equivalent gas plant. As previously mentioned, baseload gas plants (CCGT) are more efficient than coal plants. These both lead to marginal costs rising more steeply with carbon prices for coal plants than gas plants. Panel A of Figure 4 illustrates the change in marginal costs for an average coal plant relative to gas-fired technologies (CCGT and peaker) as the price of carbon increases.[6]

In our study, we will not observe positive carbon prices, but we do observe substantial variation in coal and gas costs. We define a measure of the relative cost of fuels using the coal-gas cost ratio:

$$CR = \frac{C_{coal}}{C_{gas}} = \frac{P_{coal} + CO_{2,coal} \cdot P_{co2}}{P_{gas} + CO_{2,gas} \cdot P_{co2}}. \tag{2}$$

Since a carbon price increases the cost of burning coal more than burning gas, it will increase the coal-to-gas cost ratio holding fuel prices constant. For example,

[6]To calculate emissions costs, we use the following emissions factors for the carbon content of natural gas (117.0 lbs/mmBTU) and coal (210.86 lbs/mmBTU) based on the rates reported by the EIA (http://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11). We weight bituminous, lignite, and subbituminous rates based on the aggregate annual fuel consumption of coal by power plants in 2011 (EIA form-923).

if coal were priced at \$2.25/mmBTU and gas were priced at \$5.75/mmBTU, this would imply a baseline cost ratio of 0.39. Putting a \$40/ton price on CO_2 would increase the cost of burning coal to \$6.47 and the cost of burning gas to \$8.09, holding fuel prices constant. This, in turn, would imply that the cost ratio would increase from 0.39 to 0.80. This is illustrated in panels A and C of Figure 4. Changing the price of carbon changes the relative costs of coal and gas and their cost ratio. For high enough carbon prices, the cost of burning coal will exceed the cost of burning gas.

Changes in the price of gas or coal will also lead to changes in the cost ratio. Assume the same baseline fuel prices (2.25 and 5.75 for coal and gas, respectively) and cost ratio (0.39). In the absence of a carbon price, if gas prices were to fall from \$5.75 to \$2.81, then the cost ratio would increase from 0.39 to 0.80, holding coal prices constant. This is illustrated in panels B and D of Figure 4. We can see from the figure that for each cost ratio created by changes in gas prices, we can find an identical cost ratio that could be created by a carbon price under fixed fuel prices. Either changes in gas prices or changes in carbon prices could create variation in the relative costs of fossil fuel generators.

Herein lies the intuition for our subsequent results. We use variation in the cost ratios observed in our data to understand how emissions change when gas generators become more competitive with coal plants. Since pricing carbon will change the relative costs of gas and coal generators in an identical manner, we then project our results into the space of carbon pricing to obtain an estimate of the near-term abatement cost curve in the electricity industry. This relationship is clear when we note that we can rearrange equation (2) to express the carbon price as a function of the cost ratio and the baseline fuel prices of gas and coal:

$$P_{co2} = \frac{CR \cdot P_{gas} - P_{coal}}{CO_{2,coal} - CR \cdot CO_{2,gas}}. \tag{3}$$

The assumptions necessary for this mapping to be valid are discussed in the next section.

B. *Identification and Caveats*

Here we examine the similarities and differences between cost ratios and carbon prices. We know that pricing carbon will lead to higher coal/gas cost ratios and *higher* fuel prices. The question is: can we use our experience with high coal/gas cost ratios and *lower* fuel prices to understand carbon pricing? This is equivalent to establishing the conditions under which the cost ratio is a sufficient statistic for emissions from the electricity sector.

Emissions in the electricity sector depend on both the equilibrium quantity of electricity demanded and technological mix of supply. For illustrative purposes, let us compare a high cost and a low cost scenario with the same cost ratio as we did previously ($CR = 0.8$). Figure 5 shows a set of simple supply curves where generators are ordered by their constant marginal costs. For a given realization of demand, it is clear that the production and emissions of each generator are identical in both cases. Thus, fixing the quantity demanded, the cost ratio is a sufficient statistic for emissions

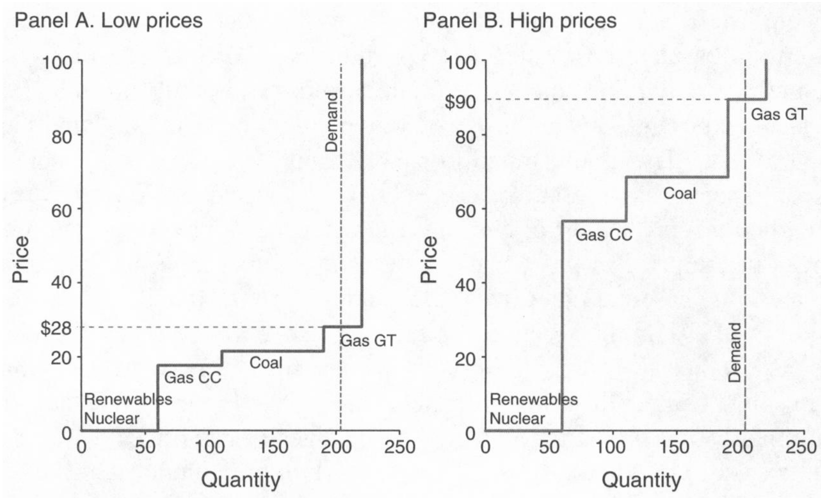

FIGURE 5. HYPOTHETICAL SUPPLY CURVES WITH THE SAME COST RATIO

when marginal costs alone dictate production. For a given cost ratio, the ordering of generators by marginal costs will be identical regardless of the level of fuel costs.

However, even though the cost ratio is identical we would expect the equilibrium price for electricity to be higher in the high fuel cost case. Higher electricity prices will be at least partially passed through to consumers. The demand reduction due to these higher prices will lead to lower carbon emissions for the same cost ratio. Only with a perfectly inelastic demand curve will cost ratios be a sufficient statistic for emissions. Thus, the results will be able to highlight the degree to which technology switching can contribute to emissions reductions under a carbon price absent any demand response. In addition, this scenario is consistent with policies targeting supply-side effects and insulating consumers from price increases by rebating carbon costs back to their electricity bill.[7]

Even conditional on quantity demanded, the cost ratio may fail to be a sufficient statistic for emissions if the supply side of the market changes with the level of fuel costs. In general, the profits of a generator at a fixed cost ratio will change with the level of prices. However, this will affect emissions only if the difference in profits either affects the dispatch order of generators or induces changes in installed capacity.

At first it may not be obvious why profits, and not relative marginal costs, would dictate the production of generators. However, there are short-run and medium-run dynamic considerations in operating a generator. In the short run, generators make operating decisions amid fluctuating intra-day demand. This necessitates that some generators shut down and restart leading them to incur costs of adjustment. Generators will start production only if they expect to cover their start-up costs while operating. Since the profits of generators will be different under the two scenarios

[7] Although this approach is not well suited for estimating the demand response to carbon pricing, we can examine how the technological response would change if demand were at a lower level. In the online Appendix, Figure A.5 shows very similar declines in emissions due to a carbon price at lower levels of demand.

with the same cost ratios, firms may undertake different start-up decisions.[8] The degree to which changes in dynamics affect the outcomes is difficult to judge given our approach. However, structural dynamic estimation of electricity markets indicates that start-up costs are a secondary factor affecting fuel switching under a carbon tax (Cullen 2015). In the medium run, plants must cover their fixed costs of operation. If they cannot cover their fixed costs, they may temporarily exit the market by mothballing their plant. The plants with high fixed costs and high adjustment costs tend to be larger and dirtier facilities such as coal plants. To the extent that the low fuel costs in our data would make it more difficult for these plants to cover these costs, our results would tend to overestimate the reduction of emissions due to carbon pricing. In addition, firms may have greater incentive to exercise market power when fuel prices are high (Mansur 2013). This will also affect the dispatch order and therefore emissions (Mansur 2007a).

Even if identical cost ratios were to imply the same dispatch order, the additional profits in the high cost scenario would provide greater incentive for investment in inframarginal generators. In particular, clean generating technology with little or no carbon emissions would become much more attractive as investments. For this reason, the exact mapping between carbon prices and gas prices only holds when there is no investment in new capacity.

In addition, relative marginal costs must be the primary driver of electricity production and emissions in the short run. It must also be the case that firms treat a shock to marginal costs that is due to fuel prices the same as they would a comparable shock to marginal costs that is due to carbon prices. Fabra and Reguant (2014) find evidence that firms in the Spanish electricity market treat these shocks similarly. Differences in volatility between fuel and carbon prices are unlikely to affect our near-term estimates.[9]

This mapping requires a uniform pollution content for a given fuel type.[10] To summarize, our method will have little to say about the reductions in emissions that will come from longer run adjustments in capacity or demand, but will be able to trace out the near-term abatement cost curve for the electricity sector.

[8] The effect may be lessened if start-up costs scale with the fuel prices. Although fuel costs are a central part of start-up costs, they are not the only component, and thus will not scale perfectly with fuel costs.

[9] Carbon prices can be either taxes or permit prices for cap-and-trade systems. While a tax might exhibit certainty in the near term, the permit price could be quite volatile. Even if natural gas prices are more volatile than carbon prices, it is unclear that uncertainty has a direct effect on the near-term emissions from existing generators. Firms procure natural gas for their generators based on day-ahead or longer term contract prices. Regardless of how the natural gas was purchased, the production decisions are based on the spot prices of natural gas and electricity because natural gas is a liquid commodity: there is an opportunity cost of using the natural gas that is based on the current natural gas price. Therefore, the uncertainty or volatility of input prices (for fuels and pollution allowances) do not change operating decisions when the input markets have liquidity. Furthermore, power plants have limited ability to stockpile natural gas on site. Section VIII discusses the long-term implications of price volatility.

[10] Unlike other pollutants, the carbon content of a given fuel type is relatively homogeneous. Furthermore, there are no economically feasible end-of-pipe abatement technologies. In contrast, the ratio of nitrogen oxides emissions across plants, for example, varies widely because of differences in technologies and operational decisions. Thus, while mapping cost ratios to carbon emissions is reasonable, we do not recommend using this approach for the pricing of other pollutants.

III. Data

Our data are compiled from several public sources and cover January 2006 to December 2012. The Continuous Emissions Monitoring System (CEMS) of the Environmental Protection Agency (EPA) measures hourly output of CO_2, sulfur dioxide (SO_2), and nitrogen oxides (NO_x) from generators larger than 25 megawatts. We aggregate the hourly generator-level emissions information to construct daily CO_2 emissions. Generators are then aggregated by interconnection to create a measure of daily, regional CO_2 emissions. We aggregate the other pollutants by NERC region.

Second, we use data on electricity consumption (or load) provided by the Federal Energy Regulatory Commission (FERC). FERC Form 714 provides hourly information on electricity load by balancing area. We aggregate load to the daily level and sum across areas to arrive at daily electrical load by interconnection.

Third, we use EIA form 923 data on production of electricity from nonfossil sources and prices paid for coal deliveries by power plants. EIA provides monthly electricity production by NERC region for nuclear and hydro power plants as well as for renewable sources (such as wind, solar, and geothermal). We aggregate these data to the interconnection level for each type of nonfossil monthly electricity production: nuclear, water, and renewables. We also collect data from the National Energy Board of Canada on monthly net imports of power into each interconnection in the United States (National Energy Board 2014). We use monthly data on permit prices for SO_2 from CantorCO2e and the EPA Clean Air Markets progress reports.

Fuel prices are aggregated by interconnection. In practice, there is some spatial heterogeneity in coal prices and, to a lesser degree, in natural gas prices. How much a power plant generates will depend on its own marginal cost as well as those of other plants: all fuel prices affect the order of dispatch. We simplify the vector of all power plants' fuel costs by looking at the average price of each fossil fuel.[11]

The EIA form 923 reports coal prices by transaction (plant, month, contract type, coal type, coal source, etc.). We use this information to create a weighted-average price for each month and interconnection. In particular, we use data from 2001 to 2012 for spot prices only (dropping long-term contracts over 12 months). For each interconnection, we regress coal costs on sulfur, ash, and BTU content, an indicator of surface mining, plant fixed effects, and indicator variables for each month of the sample. We estimate the model using weighted least squares, where we weight using a transaction's volume (in tons). The online Appendix reports the estimates (see Table A.1) and how they are used to construct a monthly coal price index for each region, holding coal composition fixed (see Figure A.1).

[11] Incorporating all power plant fuel costs into the model is important for modeling integrated power markets where electricity frequently trades in large volumes. However, including the full vector of fuel prices in the model is problematic. First, it is unwieldy to interpret and explain the results that would come out of that specification. Second, our dataset would not have enough power to reliably estimate coefficients for hundreds of price variables and their interactions. Thus, some form of aggregation is needed to make progress on this research question. Aggregating to average prices allows us to have a summary statistic for fuel prices that can be estimated and easily interpreted. Averaging also reduces idiosyncratic measurement error in the fuel prices that might occur at the individual price level. However, average prices may not be able to capture the richness of the non-linear relationships between the vector of fuel prices. The effect of aggregation on the results is theoretically unclear.

TABLE 1—SUMMARY STATISTICS

Variable	Units	Eastern	ERCOT	Western
CO_2 emissions	1,000s tons/day	5,005	527	802
		(768)	(89)	(119)
Load	GWh/day	7,456	866	1,835
		(879)	(159)	(168)
Emissions rate	Tons/MWh	0.67	0.61	0.44
		(0.04)	(0.05)	(0.05)
Coal price	$/mmBTU	2.50	2.20	1.84
		(0.42)	(0.34)	(0.24)
Gas price	$/mmBTU	5.49	5.10	5.04
		(2.28)	(2.13)	(1.95)
Cost ratio		0.43	0.41	0.35
		(0.88)	(0.81)	(0.76)

Notes: Our data include 2,557 daily observations covering January 2006 to December 2012. Data are aggregated for three NERC interconnections: eastern, ERCOT, and western. Emissions are from the EPA CEMS. Load consumption data are from FERC form 714. The emissions rate is defined as the ratio of CO_2 emissions to load. We estimate the coal price index for each region as described in the text. Gas prices are from ICE. The cost ratio is the coal price over the gas price.

Finally, we use data from the Intercontinental Exchange (ICE) on the spot prices for natural gas at trading hubs around the country. ICE is an independent open-access electronic exchange for trading wholesale energy and metals commodities. For each gas hub, they report the average trading price for transactions on that day. For each interconnection, we weight the hub prices by the nameplate capacity of surrounding gas generators to arrive at a daily average spot price of natural gas. Although gas generators may have long-term financial contracts for gas, the spot price for natural gas represents the opportunity cost to generators for using the gas to generate electricity versus selling it on the spot market. The general trends in the data are illustrated in Figure 1 using monthly averages.

Table 1 reports the mean and standard deviation for each interconnection. The East is the largest market by far with over four times the load in the West, which in turn is more than double ERCOT. The East is also the most carbon intensive with emissions over six times that in other markets. The table also reports the summary statistics on the fuel prices for each region. All markets show substantial temporal variation in the cost ratio. While some of the variation in fuel prices is across regions, most of it is over time. The coal-to-gas cost ratio is 0.43 on average in the East and slightly smaller in the other markets.

In the next section, we use these data to trace out the emission response of the electricity system to changes in input costs while controlling for important features of the market. However, we first calculate how much of a reduction in carbon emissions is feasible given the current stock of power plants.

As a simple back-of-the-envelope calculation, we examine whether there is sufficient capacity at natural gas facilities to have a substantial effect on carbon emissions. Similar to Lafrancois (2012), we find that the East could reduce 42 percent of its carbon emissions in 2012. ERCOT and the West could fall by 37 and 40 percent, respectively. These results vary over time (see online Appendix A6).

IV. Empirical Model

We aim to create a simple, yet flexible model that can trace out the response of emissions to changes in relative fuel prices that can accommodate the varied technologies on the grid and their complex interactions in electricity markets. The method used is similar to the literature that econometrically estimates the relationship between emissions and either electricity consumption (Holland and Mansur 2008; Graff Zivin, Kotchen, and Mansur 2014), electricity generation (Callaway, Fowlie, and McCormick 2015; Siler-Evans, Azevedo, and Morgan 2012; Holladay and LaRiviere 2015; and Davis and Hausman 2015), or wind production (Cullen 2013; Kaffine, McBee, and Lieskovsky 2013; Novan 2015; and Fell and Kaffine 2014).

The model is a reduced-form regression with daily emissions (CO_{2t}) in an interconnection as the dependent variable. For day t, the estimating equation is:

$$CO_{2t} = s(CR_t | \beta) + s(load_t | \theta) + s(temp_t | \omega) + X_t \psi + D\gamma + \epsilon_t. \tag{4}$$

The variable $load_t$ is the total daily electricity load on the interconnection and $temp_t$ is the average temperature of the day. Since production and its associated emissions may respond in a complex nonlinear fashion to the cost ratio, load, and temperature, we use a flexible, semi-parametric functional form for $s(\cdot)$ to trace out the emissions response of the system. Specifically, we use a cubic spline with six knot points for each of the variables.[12] We control for other factors, X_t, in more traditional parametric ways. We capture the within-day distribution of hourly load using the minimum, maximum, and standard deviation of daily load. We also control for monthly nonfossil electricity production (wind, solar, hydro, nuclear, etc.), net imports of electricity from Canada, and the SO_2 permit prices. Finally, we include a dummy variable (D) for each quarter in the time series to control for trends in generating capacity, macroeconomic shocks, as well as seasonality in generator availability. The importance of these controls is discussed below.

For identification, we rely on exogenous shocks to natural gas prices. When selecting controls, we need to include variables that would directly affect the interconnection emissions and that might also be correlated with the variation in input fuel costs. The quantity of electricity demanded, or load, obviously meets this criteria. The quantity demanded on a given day, although driven by weather and day-specific demand shocks, may be correlated with the spot price for gas. This may be because electricity generators demand more gas when electricity demand is high or simply a correlation in the demand for electricity and the demand of gas outside the electricity sector, such as home heating. For example, lower electricity demand (and emissions) due to a negative macroeconomic shock would be correlated with low prices for natural gas due to the same shock. Failing to account for electricity demand would tend to overestimate the response of emissions to the relative fuel prices. Thus, we include daily electricity demand in the interconnection as a control

[12] Online Appendix A3 tests the robustness of our results to different numbers of knots and find the results to be stable with four or more.

variable. We also include monthly net imports of electricity from Canada to control for demand satisfied by generators outside the US system.[13]

Daily temperature in the interconnection is included as an independent control to appease the laws of thermodynamics. Although weather shocks do affect electricity demand, we are already directly controlling for demand shocks in the model. However, temperature can directly affect the efficiency of fossil fuel generators due to thermodynamic considerations. When the outside temperature is lower, thermal generators can take advantage of the larger temperature differential to produce more electricity with the same amount of fuel. Thus, emissions may be lower during colder time periods even after controlling for electricity demand.

Nonfossil electricity production has low marginal costs and therefore is not likely to change in response to gas or coal prices. However, this production may be correlated with these prices. For example, wind power installations have been growing at the same time as technological innovation has led to more shale gas extraction. Likewise, seasonal variation in the availability of hydroelectric generating capacity may influence the spot prices of natural gas.

We include moments of the distribution of daily demand to account for any within-day dynamics in the production of electricity. For example, a day with high variability in electricity demand may require more flexible, but less efficient generators than a day with the same total electricity demand but lower variability (Holland and Mansur 2008). For this reason, we include the minimum, maximum, and standard deviation of within-day demand as controls. Finally, we include the price SO_2 permits, which directly affect the marginal cost of certain coal generators. In order to account for serial correlation and heteroscedasticity, we use Newey-West standard errors allowing for a seven-day lag structure.

Our choice of the cost ratio as a functional form for fuel costs is advantageous for several reasons. First, as discussed previously is Section II, using the cost ratio implies that the ordering of generators by marginal costs will be identical for a given cost ratio regardless of the level of fuel costs. Second, using the cost ratio serves as a parsimonious function that translates the two dimensions of fuel costs (i.e., coal and natural gas) into a single dimensional object that is simple to interpret. Finally, note that since coal costs are relatively constant over our time period combined with our flexible estimation method implies that using cost ratio produces very similar results when compared with using other functional forms, such as fuel costs differences (see online Appendix A2). Since we are using semi-parametric methods, the values of the coefficients are not easily interpretable. Rather, with the estimated coefficients, we graphically trace out the emissions response of the electricity generating system to changes in the relative costs of coal and gas.[14]

[13] On the one hand, the Eastern interconnection is most affected by international imports. On average, imports supply 1.3 percent of monthly load. The Western interconnection, on the other hand, is a net exporter of electricity, but it only exports 0.4 percent of monthly production on average. ERCOT does not have significant international transfers of electricity.

[14] For completeness and replicability, we include the full set of estimated parameters with their associated standard errors in Table A.4.

V. Results

A. *Main Results*

The estimated effects of relative fuel prices on emissions in each interconnection are shown in Figure 6. For ease of interpretation, we plot results against a decreasing natural gas price, which is a monotonic transformation of the cost ratio for a fixed coal price.[15] Dashed lines show the 95 percent confidence interval for the estimates using Newey-West corrected standard errors.

The results show statistically insignificant changes in emissions for high gas prices. That is, when gas prices are above \$6 (per mmBTU), changes in gas prices do not result in switching between high polluting plants and cleaner facilities. Not until the gas prices approach \$4–\$5 do emissions begin to fall. For the Eastern interconnection, emissions fall by about 10 percent when the gas price falls to \$2. At this gas price, carbon emissions fall by about 10 and 13 percent in ERCOT and the Western interconnection, respectively. The rate of decline is also steeper in both ERCOT and the West than in the East. This may be due to the fact that the East is a much larger grid with more heterogeneity in the generating capacity. Keep in mind that \$2 reflects *historically* low gas prices and brings much of the gas-fired fleet on par with coal-fired generators. Though the reduction in emissions is significant, it does not begin to approach the 40 percent estimates predicted by the back-of-the-envelope calculation in Section III. This suggests that dynamics, transmission constraints, or other factors excluded from simpler models greatly reduce the emissions reductions possible from fuel switching.

B. *Effect of Carbon Price on Carbon Emissions*

We use the electricity industry's experience with low gas prices to explore how the industry may respond to a carbon price. As a first step, we need to choose a baseline level for fuel prices from which to compare the effect of various carbon prices. We assume that these prices are exogenously determined, with prices returning to the long-run average costs of extracting and processing the fuels. The EIA (2012) forecasts that average delivered coal prices will be \$2.25/mmBTU and gas prices will be \$5.75/mmBTU in 2025. This implies a baseline cost ratio of 0.39, which will serve as our benchmark.[16]

Next, we map the emissions response curves from Figure 6 into carbon prices using equation (3). For each region, Figure 7 shows the estimated emissions reductions that would come from a carbon price (in \$/ton of CO_2) under these assumptions. The figures focus on the cost ratios that correspond to positive carbon prices under the baseline fuel costs. They show that emissions fall steeply at lower levels

[15] For these graphs, we fix the coal price using predictions for future coal prices in EIA (2012). In particular, we set the coal price at \$2.25/mmBTU. Control variables, such as demand and nonfossil electricity production, are held at their average levels in the sample.

[16] In this section, we do not account for the impact that an increasing carbon price may have on the equilibrium price of fuels. Section VII examines how a carbon price that leads to increased demand for natural gas could increase the price of gas.

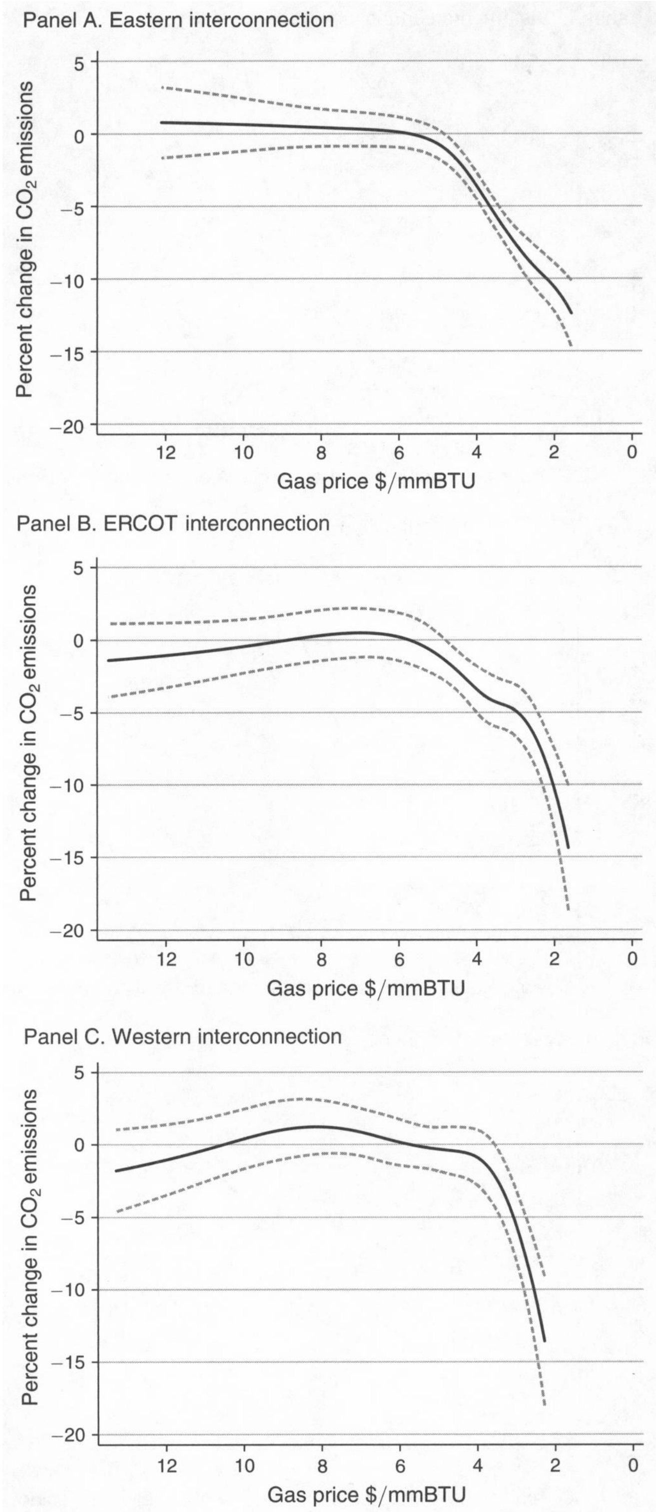

FIGURE 6. ESTIMATED CO_2 RESPONSE TO FUEL PRICES

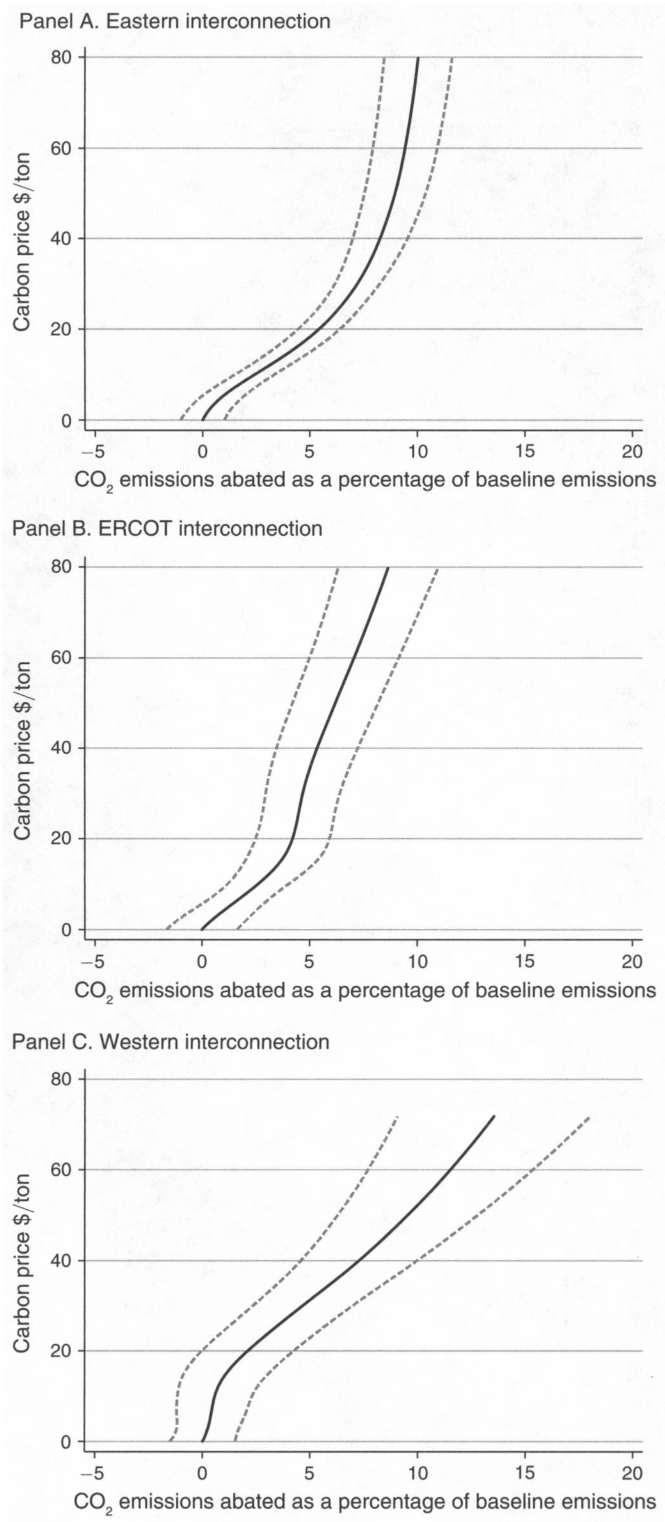

Figure 7. Imputed CO_2 Response to Carbon Prices

TABLE 2—PREDICTED EMISSIONS (*and percentage abatement*)

Tax	East		ERCOT		West		All	
0	51.7	(0.0%)	5.7	(0.0%)	8.7	(0.0%)	66.2	(0.0%)
10	50.5	(2.4%)	5.6	(2.6%)	8.7	(0.6%)	64.8	(2.2%)
20	49.0	(5.4%)	5.5	(4.2%)	8.5	(2.1%)	63.0	(4.9%)
30	48.0	(7.2%)	5.5	(4.7%)	8.3	(4.7%)	61.8	(6.7%)
40	47.5	(8.3%)	5.4	(5.3%)	8.1	(7.2%)	61.0	(7.9%)
50	47.1	(8.9%)	5.4	(6.2%)	7.9	(9.5%)	60.4	(8.8%)
60	46.9	(9.4%)	5.3	(7.1%)	7.7	(11.5%)	59.9	(9.5%)
70	46.7	(9.8%)	5.3	(7.9%)	7.6	(13.1%)	59.5	(10.0%)
80	46.6	(10.0%)	5.2	(8.6%)	7.5	(13.6%)	59.3	(10.4%)

Note: Prediction emissions are in 100,000 tons/day.

of a carbon price, but the rate of change decreases for higher levels of a carbon price. These results indicate that much of the emissions reduction from technology switching can be captured with a relatively modest price on carbon. High prices on carbon do result in some further reduction in carbon dioxide emissions, but it seems that the large impact from a high carbon price is likely to come from retooling the generating infrastructure.

A national supply curve for abatement can be constructed by horizontally summing these three markets after multiplying the percent changes in emissions by their respective baseline emissions levels as shown in the last column of Table 2. We can see that a carbon price of \$20/ton would reduce daily emissions by over 320,000 tons or 4.9 percent of total electricity sector CO_2 emissions. However, to achieve a 10 percent reduction, the carbon price would need to be closer to \$70/ton and would cost over \$6 billion per year.[17]

C. *Effect on Carbon Emissions by Fuel Type*

The previous sections have examined aggregate emissions from all sources collectively. In this section, we decompose the emissions changes by fuel type in order to test if the behavior of certain types of power plants is consistent with fuel switching. In particular, fuel switching would imply that coal generators decrease emissions, while gas generators increase their production and associated emissions. We test this insight with our data.

To decompose emissions, we identify a plant's primary type (where type is by fuel and prime mover) using the fuel consumption data from EIA form 923. To determine the plant's type, we calculate the total quantity of fuel burned (mmBTU) by each generator type at the plant from 2003 through 2012. Most facilities use multiple fuels either because start-up fuel is required or because a facility has multiple generator types at its location. For example, a facility might house one large coal generator and several smaller gas generators. However, as this section tests whether (dominant) coal plants decrease emissions in response to a carbon price and conversely for (dominant) gas plants, we do not attempt to model the fuel mix of some

[17] For each day in our dataset, we integrate under the imputed emissions response curves from Figure 8 in order to calculate the total cost of abatement.

TABLE 3—CO_2 EMISSIONS ABATED AT $20/TON BY FUEL TYPE[a]

	East	ERCOT	West
Coal	−5.97	−6.16	−3.29
	(0.45)	(1.09)	(1.02)
Gas	0.40	2.33	1.21
	(0.25)	(0.61)	(0.58)
Other	0.18	−0.37	–
	(0.06)	(0.08)	–
Total	−5.39	−4.21	−2.08

[a]Percentage of baseline emissions.

plants. Our plant classification reflects the binary nature (all coal versus all gas) of most plants in the CEMS data.[18]

The results confirm that fuel switching is driving our results. Table 3 shows that reductions in emissions from coal facilities are larger than aggregate reductions in each of the three regions. Gas facilities, on the other hand, increase their emissions, but by a much smaller amount than decreased emissions from coal facilities. The results at other carbon prices show the same qualitative relationship. As carbon prices increase, emissions decrease steeply at coal plants and increase more modestly at gas plants.

Since a mix of generators may exist at a facility of a given fuel type, our results should not be strictly interpreted as the reduction in emissions from burning a particular fuel, but rather as the reduction in emissions from facilities which consume mostly that fuel type. The fact that gas generators may be collocated at coal facilities means that the reduction in emissions from burning coal will be biased toward zero. For example, emissions at a facility dominated by coal may have a larger decrease in emissions from coal generators that is attenuated by increased production from gas generators at the same facility. Likewise, if coal generators are located at facilities dominated by gas generation, the increase in emissions from gas facilities will be biased toward zero.

D. *Robustness*

Given the complexity of electricity markets, it is quite likely that the response of emissions to coal and gas prices is highly nonlinear. To be sure that our specification is not constraining our results, we examine the robustness of the results to our functional form assumptions of coal and gas prices and specification of the cubic spline. We find that the results do not change significantly when using different functions of fuel prices (see Figure A.2 in the online Appendix). Likewise the results are stable over a range of possible knot points for the cubic spline (see Figure A.3 in the online Appendix).

[18]For the plants that we denoted as coal plants, we measure the percentage of BTUs that were consumed that came from coal. For the median "coal" plant, 99.6 percent of the BTUs were from coal, with an interquartile range of 97.4 to 99.8 percent. Of the plants that we denote as gas plants, the median plant consumed natural gas for 99.9 percent of its BTUs (with an interquartile range of 96.4 to 100 percent).

We also examine the distribution of the fuel and carbon price data. Figures A.8–A10 in the online Appendix show the density over the relevant domain. The relatively uniform density of data suggests that we are not relying on only a few observations plus functional form to identify the response of the system to relevant carbon prices. Thus, we have some confidence that our results are not being driven by functional form.

We examine the sensitivity of the results to dropping our controls and to differing time fixed effects. The controls are very important for correctly estimating the effect of gas prices on emissions. For example, failing to control for load leads to much larger estimated reductions from low gas prices. The specification of time fixed effects is less dramatic, but still important. Notably, one specification includes month-of-sample fixed effects that control for all variation in our estimated coal prices. Even within a month, we observe modest fuel switching due to variation in daily natural gas prices. Online Appendix Section A10 reports the full results of the sensitivity analyses.

Our main results reflect multiple near-term effects from low natural gas prices, including fuel switching and possible entry and exit. In order to separate these effects, we focus on the aggregate emissions from a balanced sample of power plants. Specifically, we remove any plants that may have entered or exited at some point during the sample. A plant is considered stable if it produced in each year from 2006 to 2012. By examining a stable set of plants, we exclude, for example, a coal plant that exited due to low electricity prices driven by cheap gas. Using the stable set plants, we apply the same methodology as in our main specification. We find that the results using the stable plants are very similar and statistically indistinguishable over the relevant range of carbon prices (see online Appendix Figure A.13). This suggests that while the methodology can account for several near-term effects, our findings are primarily the result of fuel switching.

We have considered concerns of potential endogeneity. We rely on exogenous variation in natural gas prices for identification. While we control for the effect that electricity demand and temperature might have on fuel prices, a random shock to daily emissions, *conditional* on electricity demand, could shift the market demand for fuels. For example, suppose a large coal fired-power plant is forced to shut down for a few days. All else equal, this increases demand for natural gas, while at the same time emissions fall. In theory, this could increase the price of natural gas and introduce bias into our coefficient estimates. This would imply that our estimates are an underestimate of the true effect. However, we argue that these biases are likely to be small. First, we have included most of the factors that affect fuel choice like production from nonfossil power plants, net imports, etc. Second, the storage of electricity and fuels are dramatically different: while power is prohibitively expensive to store, fuels are storable commodities. Today's natural gas price reflects both current weather conditions and electricity load, but also expectations about future demand. Thus, one day's demand shock may have a limited effect on prices.

VI. Extensions

In this section, we extend our analysis to examine other counterfactual situations. First, we highlight that the effectiveness of a carbon price depends crucially on the market price for gas and coal. Then, we use our methodology to examine the co-benefits of pricing carbon. Specifically, we estimate the extent to which regulating carbon may reduce other harmful pollutants, like sulfur dioxide and nitrogen oxides, which are typically emitted alongside of carbon dioxide.

A. *Carbon Pricing under High Gas Prices*

The results of the paper thus far are based on a counterfactual situation where future market prices for fuels reflect EIA's predicted fuel prices for 2025. However, it is possible that gas prices will be much higher than expected. We can use our estimates to examine how effective carbon prices would be at reducing emissions in a high-natural-gas-price world. We do so by assuming that US fuel prices also returned to the levels seen in the spring of 2008. Figure 8 shows the effect of carbon pricing under that assumption side by side with our main results, which have lower natural gas prices. The figure shows that, when natural gas prices are high, carbon prices are much less effective at reducing carbon emissions. For example, a \$20/ton carbon price reduces carbon emissions in the East by about 6 percent in the base case (see Figure 7, panel A), but by less than 1 percent when gas prices are high. In other words, in order to achieve a carbon emission target, a much higher carbon permit price would be required if gas prices were high. The intuition for this is quite straightforward. Since dirty coal generators enjoy a much larger marginal cost advantage when gas prices are high, a price on carbon is much less effective at inducing generation from cleaner generators.

B. *Co-benefits of Carbon Price*

By changing the dispatch of power plants, carbon prices are likely to reduce other pollutants like SO_2 and NO_x that have local and regional health effects (Schmalensee and Stavins 2013). For each interconnection, we replicate the estimation and simulation methods of Sections IV and VB, where we replace the dependent variable in equation (4) with the daily emissions of either SO_2 or NO_x within a given interconnection. We estimate how these emissions depend on the coal-to-gas cost ratio, which we then convert into a carbon price as above.

Figure 9 shows the aggregate response of SO_2 emissions to carbon prices. We see that a \$20/ton carbon price results in about a 6 percent drop in emissions in each region. However, the functions differ at other prices. For example, a 10 percent drop in SO_2 emissions would require a carbon price of \$40 in the East or the West, but almost double that in ERCOT. Figure 10 shows the response curves for NO_x emissions by region. Here, a large reduction in NO_x emissions would occur from a much larger carbon price in the East than in the other regions.[19]

[19] Note that these figures mask important spatial variation. Unlike CO_2 emissions, the location of these local emissions matters for estimating the marginal damages. While a precise estimate of these marginal damages is beyond the scope of this paper, we do examine the spatial distribution of these emissions. In particular, we modify equation (4) by defining the dependent variable as the daily emissions (SO_2 or NO_x) within a given subregion of an interconnection. Online Appendix Figure A.11 shows the regional variation in responses. Online Appendix Figure A.12 maps these subregions as defined in the EPA's eGrid database.

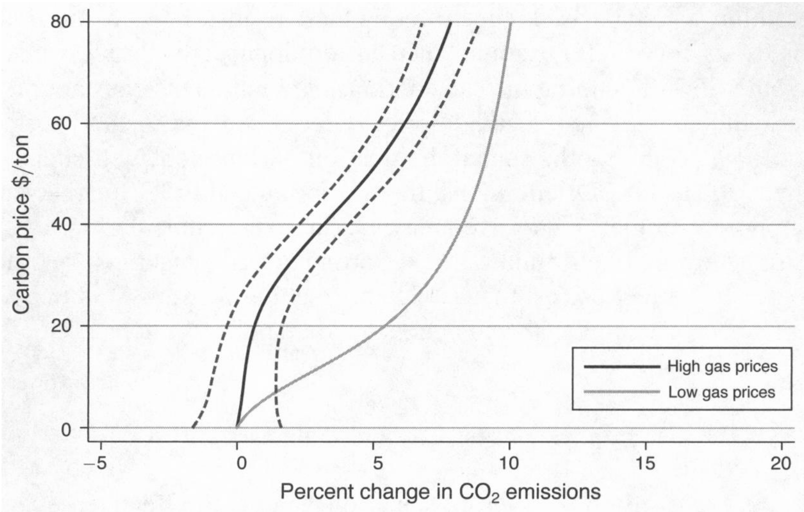

FIGURE 8. EMISSION RESPONSE LIMITED IN A HIGH GAS PRICE SCENARIO

Notes: Response is for the Eastern Interconnection. The base case is on the left, and the high gas prices case is on the right.

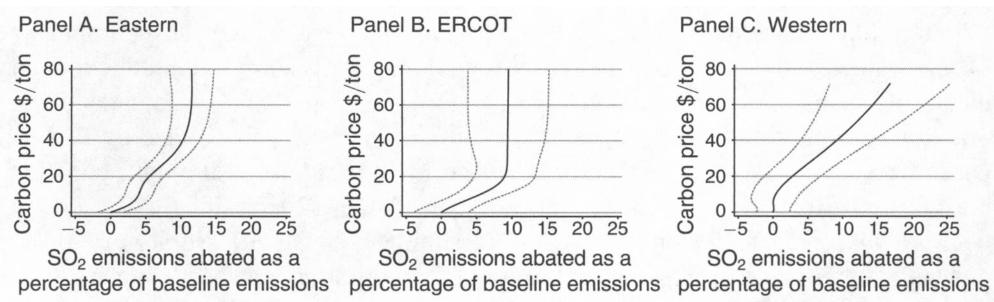

FIGURE 9. SO_2 RESPONSE TO CARBON PRICE BY INTERCONNECTION

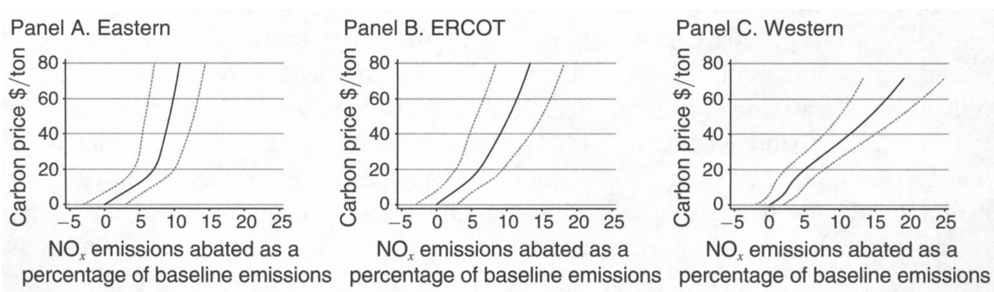

FIGURE 10. NO_x RESPONSE TO CARBON PRICE BY INTERCONNECTION

Some caution should be used in interpreting these results. If a cap-and-trade market already exists, for SO_2 for example, then an additional carbon price cannot affect aggregate emissions (assuming the cap continues to bind). This does not mean that the market will be unaffected: a carbon price reduces demand for SO_2 permits, the permit prices will fall, and the spatial distribution of emissions will change. Even for the direct effects on CO_2 emissions, the California and RGGI markets are now capping emissions in their respective areas. During our sample period, RGGI permits were quite low and California was just starting to trade, making it very unlikely that these policies affect our estimates. However, going forward, it is important to keep in mind how state, regional, and national carbon policies interact (Goulder and Stavins 2011).

VII. Implications for Carbon Abatement Policies

Our results are likely to be a lower bound of the overall effectiveness of a carbon price. While most long-run effects reduce carbon emissions, others will cause emissions to increase. On the one hand, carbon pricing is capable of leading to new investment in cleaner technology, the exit of carbon-intensive power plants, changes in demand levels and patterns, and innovation which would further reduce emissions over a longer time horizon. For example, Cullen and Renolds (2016) develop an equilibrium model of generator investment and find that a carbon price as low as \$20/ton may induce the exit of most coal facilities and encourage substantial entry of renewables. Other work using structural modeling finds substantial reductions in electricity demand due to pricing carbon. Newcomer et al. (2008) calculates that a \$50/ton carbon price would reduce the quantity of electricity demanded by 10 percent offpeak and by 4 percent on peak in the MISO region (assuming a constant elasticity of -0.1). For a similar carbon price, Cullen (2015) finds a 19 percent decrease in aggregate demand in ERCOT (assuming a constant elasticity of -0.7).

On the other hand, if long-run fuel supply functions are not perfectly elastic, then a carbon price will cause prices to rise for low-carbon fuels, like natural gas, and will cause prices to fall for high-carbon fuels, like coal. To gauge the impact of this effect, we exploit our main results to develop a back-of-envelope calculation for the likely increase in gas prices under carbon pricing due to increased demand for natural gas in the electricity sector. Section V estimates the reduction in aggregate emissions from pricing carbon, holding fixed the expected future fuel prices, the generating capital, and electricity demand. Under these assumptions, the predicted reduction in emissions observed must come from increased electricity production from natural gas and decreased electricity production from coal. Since the increased demand for natural gas may lead to higher than expected future natural prices, our estimates of carbon emission reductions may be overstated. Here, we use our model estimates and assumptions on generator characteristics to gauge the extent to which natural gas prices might increase due to carbon pricing.

Table 4 first aggregates the model results across regions to produce the national reduction in CO_2. We see that at a \$20 carbon price, the model predicts a decrease in carbon emissions by 321,000 tons per day on average. This represents a 5 percent reduction in overall emissions. Similarly, a \$70 price leads to 655,000 fewer

TABLE 4

	Carbon price	
	\$20	\$70
National CO_2 emissions reduction		
Thousands of tons daily	−321	−665
Percentage	−5%	−10%
Electricity production (GWh)		
Δ Coal	−518	−1,072
Δ Gas	518	1,072
Fuel consumption (Btu × 10^{12})		
Δ Coal	−5.2	−10.8
Δ Gas	3.9	8.2
Percentage change in gas consumption		
Electricity sector	15%	32%
All sectors	5%	11%
Percentage change in gas prices		
Supply elasticity 0.81	4%	9%

tons of carbon dioxide or 10 percent of baseline emissions. Holding the quantity of electricity demanded constant, a one ton reduction in emissions implies that the electricity sector burns more natural gas and less coal. How much more gas will be burned depends on the relative efficiencies of the relevant natural gas and coal burning power plants. We use data to calibrate the relative efficiencies of representative power plants (see online Appendix Section A11).

We combine the plant efficiencies with information on the carbon content of coal and natural gas in order to calculate the CO_2 emissions by unit of production for natural gas combined cycle and coal plants.[20] The generator heat rates multiplied by the carbon content of the fuel burned gives the CO_2 emissions per unit of electricity as shown in the last column of online Appendix Table A.7. From these figures, one can see that switching one MWh of production from an average coal plant (emission rate of 1.07) to an average gas plant (emission rate 0.45) would lead to a −0.62 ton decrease in CO_2 emissions. Dividing the predicted changes in emissions from Table 4 by this number gives the implied production switching necessary to produce those emission reductions. For example, the 321,000 ton reduction in emissions implies that 581 GWhs of production switched from coal generators to gas generators. This 581 GWhs of production would necessitate burning an additional 3.9 trillion BTUs of natural gas. This represents a 15 percent increase in natural gas consumption in the electricity sector. Bear in mind that this is a generous estimate of the additional gas burn necessary to achieve the CO_2 reduction since the numbers in online Appendix Section A11 are conservative estimates of the relative efficiency of gas and coal plants engaged in switching.

Next, we want to understand how a 15 percent increase in natural gas consumption in the electricity sector might affect the price for natural gas. First, we need to

[20]Note that characteristics of combined cycle gas plants are used for the calculations since these are the most likely switchers. They are the most efficient and most plentiful type of gas fired power plants.

understand what effect this will have on the overall demand for natural gas. Using data from the EIA of monthly natural gas consumption across all sectors, the 15 percent increase in demand from the electricity sector implies only a 5 percent change in overall gas consumption.

Using estimates of the supply elasticity for natural gas, we can calculate the expected change in natural gas prices due to increased demand for natural gas under a carbon price. Recent work estimates the supply elasticity of gas to be in the neighborhood of 0.81 (Hausman and Kellogg 2015). This would imply a 4 (9) percent change in the price of natural gas due to a \$20 (\$70) carbon price. While not insignificant, this indicates that the equilibrium fuel price response is not likely to seriously reduce either the near-term or the longer term emission reductions of carbon pricing in the electricity sector.

VIII. Conclusion

This paper provides estimates, based on observed behavior rather than simulations, of the impact of carbon pricing on electricity-sector emissions. We show how lower gas prices and a carbon price can affect the relative costs of generators in similar ways. This paper exploits significant variation in natural gas prices that resulted from a rare combination of factors: a large recession, the start of the shale revolution, and limited capacity to export gas. In the near future, the federal government projects an end to these low prices as exports rise and the economy recovers (EIA 2012). In this paper, we use the recent price variation to estimate how the electricity sector's carbon emissions respond to fuel cost shocks, and examine conditions under which this response to relative fuel prices can inform us about how a price on carbon dioxide will change emissions in the near term.

Our results indicate that carbon prices will result in a modest effect on emissions: even a price of \$70 per ton of carbon dioxide will reduce emissions by only 10 percent. However, much of the reduction in carbon dioxide emissions can be captured with a relatively modest carbon price: a price of \$20 reduces emissions by 6 percent. Furthermore, carbon prices are much more effective at reducing emissions when natural gas prices are low. In contrast, modest carbon prices have negligible effects when gas prices are at levels seen prior to the shale revolution. Finally, we show how a carbon price can result in co-benefits by reducing local emissions, in aggregate, in an approximately proportional manner.

Since we use a revealed-preference approach to estimate near-term effects, our results should not be viewed as the ultimate effect of a carbon policy. Carbon pricing is capable of leading to new investment in cleaner technology, the exit of carbon-intensive power plants, changes in demand levels and patterns, long-run fuel supply effects, and innovation in new technologies which may further reduce emissions over a longer time horizon. We acknowledge that a simulation approach would be necessary to understand the role of these additional effects. Therefore, we consider our estimates to be a likely lower bound of the overall effects of a carbon price.

While the overarching objective of climate policy is to reduce aggregate cumulative emissions of greenhouse gases, much of the focus to date has been on the short-run impacts. First, carbon policies like California's Cap-and-Trade (CAT) or the Regional Greenhouse Gas Initiative (RGGI) are designed to protect consumers from rate increase; this limits the effect of a carbon price on demand. Second, power plants are long lived so some of the other options may take a long time. In contrast, some policies seek short-term performance. Many emissions trading policies including the EU ETS, RGGI, and RECLAIM have been criticized for their effectiveness in reducing emissions in the short run.[21] Criticisms like these may arise from unreasonable expectations about the likely near-term impact of policies. We have provided evidence that the immediate effect of carbon pricing is likely to be small. However, this does not imply that carbon pricing is an ineffective policy. Rather, it highlights that, in complex markets, sufficient time is necessary to realize the full impact of a policy.

REFERENCES

Borenstein, Severin, James B. Bushnell, and Frank A. Wolak. 2002. "Measuring Market Inefficiencies in California's Restructured Wholesale Electricity Market." *American Economic Review* 92 (5): 1376–1405.

Burtraw, Dallas, Alan Krupnick, Erin Mansur, David Austin, and Deirdre Farrell. 1998. "Cost and Benefits of Reducing Air Pollutants Related to Acid Rain." *Contemporary Economic Policy* 16 (4): 379–400.

Bushnell, James B., Erin T. Mansur, and Celeste Saravia. 2008. "Vertical Arrangements, Market Structure, and Competition: An Analysis of Restructured US Electricity Markets." *American Economic Review* 98 (1): 237–66.

Callaway, Duncan, Meredith Fowlie, and Gavin McCormick. 2015. "Location, location, location: The variable value of renewable energy and demand-side efficiency resources." Energy Institute at Haas Working Paper 264.

Cullen, Joseph. 2013. "Measuring the Environmental Benefits of Wind-Generated Electricity." *American Economic Journal: Economic Policy* 5 (4): 107–33.

Cullen, Joseph A. 2015. "Dynamic Response to Environmental Regulation in the Electricity Industry." http://www.josephcullen.com/resources/dynamicresponse.pdf.

Cullen, Joseph A., and Erin T. Mansur. 2017. "Inferring Carbon Abatement Costs in Electricity Markets: A Revealed Preference Approach Using the Shale Revolution: Dataset." *American Economic Journal: Economic Policy.* https://doi.org/10.1257/pol.20150388.

Cullen, Joseph A., and Stanley S. Renolds. 2016. "The Long Run Impact of Environmental Policies on Wholesale Electricity Markets: A Dynamic Competitive Analysis." https://editorialexpress.com/cgi-bin/conference/download.cgi?db_name=IIOC2016&paper_id=173.

Davis, Lucas, and Catherine Hausman. 2015. "Market Impacts of a Nuclear Power Plant Closure." Energy Institute at Haas Working Paper 248R.

Ellerman, A. Denny, and Barbara K. Buchner. 2007. "The European Union Emissions Trading Scheme: Origins, Allocation, and Early Results." *Review of Environmental Economics and Policy* 1 (1): 66–87.

Energy Information Administration (EIA). 2012. *Annual Energy Outlook 2012 with Projections to 2035.* US Energy Information Administration. Washington, DC, June.

Energy Information Administration (EIA). 2014a. *Electric Power Monthly with Data for December 2013.* US Energy Information Administration. Washington, DC, February.

Energy Information Administration (EIA). 2014b. "Natural Gas Gross Withdrawals and Production." https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGW_mmcf_m.htm (accessed August 7, 2014).

Environmental Protection Agency (EPA). 2013. "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2011." US Environmental Protection Agency Report EPA-430-R-13-001.

[21] The EU ETS was criticized for over-allocating permits making the policy ineffective in its first few years (Ellerman and Buchner 2007). Similarly, RGGI has had extremely low prices, which has led regulators to tighten the cap in 2013. Tvinnereim (2014) discusses several reasons why many cap-and-trade policies have had lower permit prices than expected. Concerns over RECLAIM were due to high prices, noncompliance, and environmental justice. See Fowlie, Holland, and Mansur (2012) for an analysis of these concerns.

Environmental Protection Agency (EPA). 2014. "Goal Computation Technical Support Document." US Environmental Protection Agency Technical Support Document EPA-HQ-OAR-2013-0602.

Fabra, Natalia, and Mar Reguant. 2014. "Pass-Through of Emissions Costs in Electricity Markets." *American Economic Review* 104 (9): 2872–99.

Fell, Harrison, and Daniel T. Kaffine. 2014. "A one-two punch: Joint effects of natural gas abundance and renewables on coal-fired power plants." Colorado School of Mines Division of Economics and Business Working Paper 2014-10.

Fell, Harrison, and Joshua Linn. 2013. "Renewable electricity policies, heterogeneity, and cost effectiveness." *Journal of Environmental Economics and Management* 66 (3): 688–707.

Fowlie, Meredith, Lawrence Goulder, Matthew Kotchen, Severin Borenstein, James Bushnell, Lucas Davis, Michael Greenstone, et al. 2014. "An economic perspective on the EPA's clean power plan." *Science (Policy Forum)* 346 (6211): 815–16.

Fowlie, Meredith, Stephen P. Holland, and Erin T. Mansur. 2012. "What Do Emissions Markets Deliver and to Whom? Evidence from Southern California's NO_X Trading Program." *American Economic Review* 102 (2): 965–93.

Goulder, Lawrence H., and Robert N. Stavins. 2011. "Challenges from State-Federal Interactions in US Climate Change Policy." *American Economic Review* 101 (3): 253–57.

Graff Zivin, Joshua S., Matthew J. Kotchen, and Erin T. Mansur. 2014. "Spatial and temporal heterogeneity of marginal emissions: Implications for electric cars and other electricity-shifting policies." *Journal of Economic Behavior and Organization* 107 (Part A): 248–68.

Hausman, Catherine, and Ryan Kellogg. 2015. "Welfare and Distributional Implications of Shale Gas." *Brookings Papers on Economic Activity* 45 (1): 71–139.

Holladay, J. Scott, and Jacob LaRiviere. 2015. "The Impact of Cheap Natural Gas on Marginal Emissions from Electricity Generation and Implications for Energy Policy." University of Tennessee Haslam College of Business Department of Economics Working Paper 2015-07.

Holland, Stephen P., and Erin T. Mansur. 2008. "Is Real-Time Pricing Green? The Environmental Impacts of Electricity Demand Variance." *Review of Economics and Statistics* 90 (3): 550–61.

Kaffine, Daniel T., Brannin J. McBee, and Jozef Lieskovsky. 2013. "Emissions Savings from Wind Power Generation in Texas." *Energy Journal* 34 (1): 155–75.

Knittel, Christopher R., Konstantinos Metaxoglou, and Andre Trindade. 2014. "Dash for Gas: The Sequel." Unpublished.

Lafrancois, Becky A. 2012. "A lot left over: Reducing CO_2 emissions in the United States' electric power sector through the use of natural gas." *Energy Policy* 50: 428–35.

Linn, Joshua, Lucija Muehlenbachs, and Yushuang Wang. 2014. "How Do Natural Gas Prices Affect Electricity Consumers and the Environment?" Resources for the Future Discussion Paper 14-19.

Lu, Xi, Jackson Salovaara, and Michael B. McElroy. 2012. "Implications of the Recent Reductions in Natural Gas Prices for Emissions of CO_2 from the US Power Sector." *Environmental Science and Technology* 46 (5): 3014–21.

Mansur, Erin T. 2007a. "Do Oligopolists Pollute Less? Evidence from a Restructured Electricity Market." *Journal of Industrial Economics* 55 (4): 661–89.

Mansur, Erin T. 2007b. "Upstream Competition and Vertical Integration in Electricity Markets." *Journal of Law and Economics* 50 (1): 125–56.

Mansur, Erin T. 2008. "Measuring Welfare in Restructured Electricity Markets." *Review of Economics and Statistics* 90 (2): 369–86.

Mansur, Erin T. 2013. "Prices versus quantities: Environmental regulation and imperfect competition." *Journal of Regulatory Economics* 44 (1): 80–102.

Mansur, Erin T., and Matthew W. White. 2012. "Market Organization and Efficiency in Electricity Markets." http://www.dartmouth.edu/~mansur/papers/mansur_white_pjmaep.pdf.

Metcalf, Gilbert E. 2009. "Designing a Carbon Tax to Reduce U.S. Greenhouse Gas Emissions." *Review of Environmental Economics and Policy* 3 (1): 63–83.

National Energy Board. 2014. "Monthly Net Imports of Power." https://apps.neb-one.gc.ca/CommodityStatistics/Statistics.aspx?language=english (accessed June 5, 2017).

Newcomer, Adam, Seth A. Blumsack, Jay Apt, Lester B. Lave, and M. Granger Morgan. 2008. "Short Run Effects of a Price on Carbon Dioxide Emissions from US Electric Generators." *Environmental Science and Technology* 42 (9): 3139–44.

Novan, Kevin. 2015. "Valuing the Wind: Renewable Energy Policies and Air Pollution Avoided." *American Economic Journal: Economic Policy* 7 (3): 291–326.

Pratson, Lincoln F., Drew Haerer, and Dalia Patiño-Echeverri. 2013. "Fuel Prices, Emission Standards, and Generation Costs for Coal vs. Natural Gas Power Plants." *Environmental Science and Technology* 47 (9): 4926–33.

Puller, Steven L. 2007. "Pricing and Firm Conduct in California's Deregulated Electricity Market." *Review of Economics and Statistics* 89 (1): 75–87.

Schmalensee, Richard, and Robert N. Stavins. 2013. "The SO_2 Allowance Trading System: The Ironic History of a Grand Policy Experiment." *Journal of Economic Perspectives* 27 (1): 103–21.

Siler-Evans, Kyle, Inês Lima Azevedo, and M. Granger Morgan. 2012. "Marginal Emissions Factors for the US Electricity System." *Environmental Science and Technology* 46 (9): 4742–48.

Tvinnereim, Endre. 2014. "The bears are right: Why cap-and-trade yields greater emission reductions than expected, and what that means for climate policy." *Climatic Change* 127 (3): 447–61.

Venkatesh, Aranya, Paulina Jaramillo, W. Michael Griffin, and H. Scott Matthews. 2012. "Implications of changing natural gas prices in the United States electricity sector for SO_2, NO_X and life cycle GHG emissions." *Environmental Research Letters* 7 (3): 1–9.