

# Natural Gas Prices, Electric Generation Investment, and Greenhouse Gas Emissions

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## Abstract

Between 2007 and 2013 the natural gas price dramatically declined, in large part due to hydraulic fracturing. These lower natural gas prices induced switching from coal generation to natural gas generation. I find that switching caused 2013 carbon emissions to fall by 14,700 tons/hour. Lower gas prices also incentivized new investment in natural gas capacity. This less carbon-intensive capital stock led to an additional decrease of 2,100 tons/hour in 2013. Using three approaches, I estimate that 65-85% of new capacity was constructed because of lower gas prices. A social cost of carbon of \$35/ton values the estimated total decrease in 2013 emissions at roughly \$5.1 billion.

Keywords: Carbon Emissions, Climate Change, Electricity, Fracking, Capital Investment

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# 1 Introduction

Natural gas prices have fallen by over 65% from their high in 2008. This decline was primarily driven by the large-scale expansion of hydraulic fracturing (fracking) for natural gas, which has transformed the US natural gas sector. Prior to fracking's development in the mid-2000's natural gas production was declining and projected to decline further. With very large reserves of shale gas that can be fracked, production is primarily limited by drilling rig capacity. Consequently, fracking has greatly increased the amount of natural gas produced in the US and the share of total US natural gas production from shale gas. From 2007 to 2013, total US natural gas production increased from 24.7 trillion cubic feet (TCF) to 30.0 TCF and shale gas production more than quintupled from 2 TCF to 11.9 TCF (EIA). Electric utility consumption of natural gas increased by roughly 20 percent. Simultaneously, carbon emissions from electricity generation declined by 11.1% due to several long-term shifts – increased renewable generation, slightly decreased demand, lower gas prices, and increased natural gas generating capacity.

This paper uses a thorough understanding of the electricity sector to value and quantify the total impact of fracking on electricity sector carbon emissions via two primary channels. I first examine how falling natural gas prices cause cheaper and cleaner natural gas to displace coal in the generation merit order, decreasing carbon emissions from electricity generation over the short run. I next consider the effect of falling natural gas prices on carbon emissions through unanticipated generation capacity additions.<sup>1</sup> Construction of gas-fired power plants has greatly exceeded projections made prior to the dramatic decrease in the natural gas price. I argue that many of these new gas-fired power plants would not have been constructed if gas prices had remained high. Because these newly constructed facilities entailed large capital investments, they will likely continue to operate in the future, even if gas prices become relatively more expensive.

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<sup>1</sup>During the previous period of low natural gas prices in the early 2000's there also was a large natural gas-fired capacity expansion.

The paper fits in a broader literature that estimates the effects of natural gas prices on the power sector (Holladay and LaRiviere, 2017; Linn, Muehlenbachs and Wang, 2014). It is also relevant within the literature that estimates greenhouse gas emissions from the electric sector (Kaffine, McBee and Lieskovsky, 2013; Callaway, Fowle and McCormick, 2015; Linn, Mastrangelo and Burtraw, 2014; Cullen, 2013; Novan, 2014). I contribute to this literature by combining novel estimates of the effect of fracking on new investment with estimates of the marginal impact of natural gas prices on emissions to provide a total valuation of emissions reductions due to fracking. These estimates are important for understanding the environmental impact of fracking and the optimal way to abate carbon.

I first empirically estimate the relationship between carbon emissions and natural gas prices using a flexible model that includes electricity demand and a rich set of controls. My specification allows me to separately identify the effects of lower gas prices and increased gas-fired generation capacity – and to examine the interaction of these two effects. While carbon emissions reductions due to low gas prices are only available if prices remain low, reductions due to new capital stock can persist at moderately higher gas prices. This type of effect has been demonstrated before by Davis and Kilian (2011) in the home-heating market.

I exploit short-term variation in gas prices to identify the effect of gas prices on carbon emissions. There are two primary sources of this variation. The first is weather shocks, which influence gas prices in the short term. For example, unexpectedly cold weather forecasts boost demand for natural gas because many US homes are heated using gas. The second source of variation is production and storage reports. For example, unexpectedly high storage withdrawal, unexpectedly low storage injection, or unexpectedly low production reports will all increase the price of natural gas.<sup>23</sup>

I carefully control for the endogeneity of the price of natural gas. This endogeneity

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<sup>2</sup>Although gas prices have decreased over the long term as fracking has become more prevalent, variation caused by long-run supply changes is difficult to isolate from other trends that change emissions, such as macroeconomic conditions, increasing attention to energy efficiency, and technological improvements. For this reason, I use short-run variation.

<sup>3</sup>Additional details about the sources of gas price variation are available in Online Appendix A.

concern arises due to correlated demand shocks that may directly change both gas prices and electricity demand. For example, unseasonably warm winter weather may decrease both gas prices and electricity demand. Including demand also addresses concerns that as gas prices fall, electricity prices may also fall (increasing the demand for electricity and, therefore, carbon emissions).

Next, I construct a counterfactual of what emissions would have been had natural gas prices remained at their higher levels prior to the large-scale application of fracking. In doing so, I control for renewable production and electricity demand levels. I find that lower gas prices led to fuel switching that caused 2013 carbon emissions to decrease by an additional 14,700 tons/hour. I value 2013's decrease in carbon emissions at \$4.5 billion.

To determine how newly constructed capacity has altered carbon emissions, I rely on the relationship between carbon emissions and electricity demand. In order to construct counterfactual emissions where new gas-fired capacity does not exist, I first determine hour-by-hour electricity generation and carbon emissions from the new capital stock. Then, I use the coefficients on electricity demand to determine what expected marginal emissions would have been if this electricity was instead generated by the existing power plant fleet. The difference between actual emissions and counterfactual emissions reveals 2013 emissions savings of approximately 2,100 tons/hour, valued at \$0.65 billion, caused by the new capital stock. I value 2013's total decline in carbon emissions through these two channels at \$5.1 billion.

I estimate the portion of new capital stock constructed in response to lower gas prices. This is a difficult question that I tackle with three different approaches, concluding that 65-85% of new additions are attributable to falling natural gas prices. First, I compare projections of capital additions from the EIA's Annual Energy Outlook with actual construction. The AEO model makes its forecasts using aggregate data – it is a “macro” model.<sup>4</sup> Second, I regress construction starts on gas prices and electricity demand growth. Finally, I compare

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<sup>4</sup>The Annual Energy Outlook is based, in part, on data from the Form EIA-860. It is combined with other data in order to make projections.

projections of capital additions from the EIA-860 with actual construction. I use the range produced by these three approaches to estimate the amount of new capital stock constructed because of low gas prices. I also consider other potential causes of above-expectation gas-fired capacity construction. I cannot conclusively rule them out, but on balance the evidence points to potential confounders having quantitatively limited impacts.

There are several related studies of the relationship between gas prices and carbon emissions. Lu, Salovaara and McElroy (2012) examine the effect of gas prices on emissions by EPA region using monthly data over a two-year period. They find that between 2008 and 2009, carbon emissions fell by 8.76% in the electric sector, 4.3% of which was due to falling natural gas prices. This paper uses hourly data over a seven-year period to provide more robust and comprehensive estimates and also looks at new gas-fired construction.<sup>5</sup> Cullen and Mansur (2017) estimate the relationship between gas prices and carbon emissions in order to analyze the industry response to a tax on carbon emissions. While their analysis relates emissions to the gas price, they do not specifically address the effect of recent gas price declines on carbon emissions or the effects of new capital stock.<sup>6,7</sup>

The paper proceeds as follows. First, I briefly discuss my data (Section 2). Next, I detail my empirical model and results in Sections 3 and 4. I then analyze how much of new generation capacity was prompted by low gas prices (Section 5). Finally, I discuss and conclude (Sections 6 and 7).<sup>8</sup>

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<sup>5</sup>Hourly data is less reflective of medium-run trends, such as climate policy, than more smoothed monthly data. Even with hourly data, there is still a concern that medium-run trends affect both the gas price and emissions; the added years of data allow for the inclusion of a time trend and monthly fixed effects to help control for this. Using NERC interconnections alleviates concerns about cross-region electricity trading.

<sup>6</sup>Lafrancois (2012) estimates the potential effect of gas-fired power plants constructed before 2006 on carbon emissions.

<sup>7</sup>Engineering models such as Venkatesh et al. (2012) have also looked at this topic. They use simplified dispatch models to estimate how the marginal supply curve will change. While this approach has its advantages, it may be less precise for marginal changes. Transmission losses and costs, bottlenecks, ramping costs, market power, and outages may make it so that some power plants are more likely to provide power than their marginal cost would suggest.

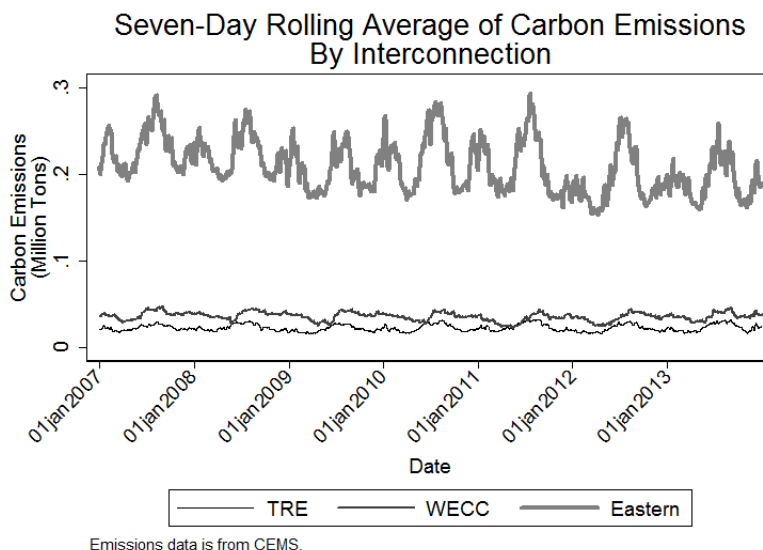
<sup>8</sup>Online Appendix B provides electricity background to unfamiliar readers.

## 2 Data

I aggregate several datasets together to construct a panel data set on the electricity-generation industry over a seven-year period.

Emissions data are collected by the EPA using the Continuous Emissions Monitoring System (CEMS). CEMS collects emissions data from all fossil fuel power plant units that have generation capacity of 25 megawatts or greater. Only very small generators (producing small amounts of pollution) are excluded; CEMS covers the vast majority of pollutant-emitting electricity generation in the US.<sup>9</sup> I use hourly data over the 2007 to 2013 period. Figure 1 summarizes carbon dioxide emissions from these power plants for the Eastern, Western (WECC), and Texas (TRE) interconnections. It illustrates the seasonality of electricity generation and a roughly 10% decline in carbon emissions over the time period.

**Figure 1**



I also use hourly electricity demand data for each planning area from FERC Form 714.<sup>10</sup>

I map planning areas to NERC interconnections and then aggregate the data by intercon-

<sup>9</sup>I use generators labeled “Electric Utility,” “Cogeneration,” “Small Power Producer” or “Institutional.” I consider this the backbone of the electric grid. I exclude a range of industrial plants like “Pulp & Paper Mill” or “Cement Plant” as they frequently do not list electricity generation, but do emit pollutants.

<sup>10</sup>Planning areas are geographic zones that coordinate electricity load to meet demand.

nection, allowing me to control for changing demand.<sup>11</sup>

The EIA requires electricity generators to report monthly information via EIA form 923. I aggregate and use monthly net generation from renewable power plants.<sup>12</sup> Because renewable generation does not emit carbon dioxide or sulfur dioxide, it is not captured by CEMS.

I include daily data from the National Weather Service on heating degree days (HDD) and cooling degree days (CDD).<sup>13</sup> I use population-weighted averages for each interconnection.

Finally, I use daily natural gas spot price data at Henry Hub that are collected by the EIA through Thomson Reuters.

### 3 Empirics

My first empirical analysis essentially estimates a production function for carbon emissions. Using the panel data, I am able to repeatedly view emissions decisions by the electricity-generation industry. Given gas prices, electricity demand, and other control variables, I estimate the causal effect of gas price shocks on carbon emissions. I also estimate the causal effect of newly constructed gas-fired capacity on carbon emissions.

My identification assumption is that short-run changes in gas prices are uncorrelated with carbon emissions except through dispatch changes. After including appropriate controls, these price changes are orthogonal to other determinants of carbon emissions. Similarly, when estimating the causal effect of newly constructed gas-fired capacity, I assume that the

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<sup>11</sup>For regions where independent system operators (ISOs) report separately from utilities, I only include data from the ISOs. This prevents double counting. For example, this means that the northeast is comprised only of data reported by the NYISO and NEISO, California's data is predominantly from CAISO, etc.

<sup>12</sup>Specifically, I use fuel codes for nuclear, hydroelectric, solar, geothermal, and wind power. This is consistent with Cullen and Mansur (2017). Less than 1% of generation is reported as a "State-Fuel Level Increment" without a NERC region. I assign this data to NERC regions. Results are similar if it is omitted.

<sup>13</sup>The National Weather Service defines HDD and CDD: "A mean daily temperature (average of the daily maximum and minimum temperatures) of 65F is the base for both heating and cooling degree day computations. Heating degree days are summations of negative differences between the mean daily temperature and the 65F base; cooling degree days are summations of positive differences from the same base. For example, cooling degree days for a station with daily mean temperatures during a seven-day period of 67, 65, 70, 74, 78, 65 and 68, are 2, 0, 5, 9, 13, 0, and 3, for a total for the week of 32 cooling degree days." [http://www.cpc.ncep.noaa.gov/products/analysis\\_monitoring/cdus/degree\\_days/ddayexp.shtml](http://www.cpc.ncep.noaa.gov/products/analysis_monitoring/cdus/degree_days/ddayexp.shtml).

electricity demand coefficients represent the marginal emissions from the power plants they are replacing. Gas price and electricity demand changes are exogenously caused and the resulting errors are uncorrelated with carbon emissions.

I run my analysis separately for each hour of the day. As Graff Zivin, Kotchen and Mansur (2014) show, marginal emissions can vary widely from hour to hour. If new gas-fired generators are running overnight they will likely be providing baseload power and replacing coal power plants. This will have a large effect on emissions. However, if the new generators are primarily running during peak hours of demand, they could replace older gas-fired plants, providing minimal emissions savings.

I focus on the NERC interconnection level (Western, Eastern, & Texas) because electricity planning area geography means that electricity demand data cannot be neatly mapped onto NERC subregions. For example, MISO (a planning area) covers parts of MRO, RFC, and SERC. Because of this and because of substantial trading across regions (Appendix B.1), I do not report individual regional estimates for the Eastern interconnection.

### 3.1 Decrease in Emissions from Switching

My primary specification is run at the daily level ( $t$ ) and is estimated separately for each interconnection and hour.<sup>14</sup> It estimates the relationship between total (carbon) emissions ( $TE_t$ ) aggregated across the interconnection and the national price of natural gas ( $P_t^{NG}$ ), controlling for interconnection-level electricity demand ( $Q_t^E$ ), renewable electricity generation ( $Renewables_t$ , including nuclear generation), Heating Degree Days ( $HDD_t$ ), and Cooling Degree Days ( $CDD_t$ ). I also include a flexible time trend ( $Date_t$ ) and month-of-year fixed effects ( $D_m$ ). Finally, I include an interaction term between the gas price and the demand spline. I use a cubic spline,  $s()$ , with six knot points to allow for flexibility in the relationship between emissions and the price of natural gas, electricity demand, renewables, and the time trend. The shape of the spline does not strongly depend on the number of knots. I choose

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<sup>14</sup>That is, each of the three interconnections runs the specification twenty-four times, for a total of seventy-two regressions. Each regression will have approximately (7 years \* 365 days = ) 2,555 observations.



six to be consistent with Cullen & Mansur (2014).<sup>15</sup>

$$\begin{aligned} TotalEmissions(TE_t) = & \alpha_0 + s(P_t^{NG}) + s(Q_t^E) + \mathbb{1}\{P_t^{NG} > med(P_t^{NG})\} * s(Q_t^E) \\ & + s(HDD_t) + s(CDD_t) + s(Renewables_t) + s(Date_t) + \gamma D_m + \epsilon_t \quad (1) \end{aligned}$$

I control for electricity demand for two reasons. Most importantly, including demand will eliminate a major source of possible endogeneity from, e.g., macroeconomic conditions or weather conditions. If the recent economic downturn were correlated with the fall in natural gas prices, the results could be biased. The economic downturn would cause lower emissions through lower gas prices, but also through a decrease in electricity generation. Thus, the analysis could overstate the decrease in emissions caused by the decrease in the natural gas price. Similarly, if warmer summers increased gas prices and electricity consumption, they would cause bias.

I also include electricity demand because lower gas prices, over the medium-to-long run, may cause lower electricity prices and increase the quantity demanded of electricity. To the extent that medium run effects exist, including demand as a control allows me to isolate the first-order effect of gas prices on carbon emissions. While including demand directly in the model is unconventional, it is likely appropriate in the electricity sector. I assume that, in the short-run, demand is determined exogenously outside the model. This is reasonable because prices are generally not available in real time, thus fixing the quantity of electricity demand over short periods of time.

I control for the level of renewable generation because renewable generation directly replaces conventional generation. Renewable generation increases during the time period. Additionally, wind and solar patterns are seasonal, causing seasonable generation patterns. For instance, in the Western interconnection, winds (and generation) are strongest around April and are generally much weaker in October. Gas prices are also seasonal. Failing to

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<sup>15</sup>For the spline on HDD and CDD I use three knots. The ambient temperature ranges are too small to allow for six knots.

control for the variation inherent in renewable electricity production would cause bias.

While electricity demand and carbon emissions data are hourly and gas prices are daily, renewable electricity generation is only available at the monthly level. Nuclear power and renewable generation from wind and solar has very low marginal costs. As a result, it should always come before gas and coal in the dispatch order. On a day-to-day level, it is not very correlated with gas prices. Thus, the lack of granularity in the data will only cause very limited bias in my results.<sup>16,17</sup>

It is possible that failing to control for generator efficiency changes caused by changes in ambient temperature causes my results to be overstated. This could be the case, e.g., because hot days increase both carbon emissions and electricity demand or the gas price. Hotter days may cause generators to operate less efficiently, directly increasing gas usage and carbon emissions. They could also increase electricity demand (air conditioning) or the gas price (more demand for electricity). Controlling for ambient temperature will prevent this type of bias.

HDD and CDD are better suited to analyze temperature's effect on generator efficiency than raw temperature. A raw temperature average could disguise important temperature heterogeneity. For example, if the Western interconnection had a temperature of 65 F in all areas, this would result in a raw average temperature of 65 F, HDD of 0, and CDD of 0. However, it could also be the case that California is hot and the rest of the west is cold. Here, the average temperature would still be 65 F, but HDD and CDD would both be 10. Using HDD and CDD allows me to more accurately capture the effect of ambient temperature on carbon emissions through generator efficiency.

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<sup>16</sup>Online Appendix E.1 checks the robustness of this assumption using hourly wind data that are available only in the Texas interconnection. In all sample years, wind, wood, and hydroelectric power are by far the largest sources of renewable power. For more, please see the EIA's Electric Power Monthly, Table 1.1.A.

<sup>17</sup>It is possible, however, that hydroelectric generation is correlated with gas prices. This could happen because operators are able to produce electricity when gas prices are relatively high within the same month. This is unlikely because it requires that operators know whether near future prices will be higher or lower than current prices. Predicting future gas prices is very difficult. To the extent that this hydroelectric generation is correlated with gas prices, this would work against finding results in this paper. Because operators would be providing more renewable power when gas prices are high, the gas price spline would be flatter.

I include month-of-year dummies to control for residual seasonal variation. This might arise because of seasonal generator maintenance. The flexible time trend is used to control for trends through time. In particular, the generation mix and international demand for coal are changing slowly over time. The time trend is likely sufficient to control for new capacity additions. While they are important, they are only  $\sim 6\%$  of the existing generation stock.<sup>18</sup> Note that controlling for the effect the changing generation mix has on the gas price spline does not preclude me from estimating its effects on carbon emissions.

Marginal emissions, which new gas-fired plants are displacing, could vary with the gas price because the dispatch order of power plants adjusts as gas prices change. The interaction term,  $\mathbb{1}\{P_t^{NG} > med(P_t^{NG})\} * s(Q_t^E)$ , allows me to examine how high gas prices interact with the demand spline. The term is a “high gas price demand spline.” It is constructed by finding the median gas price over my time period and creating a dummy if the gas price is above the median. I then multiply this dummy by a demand spline to allow for marginal emissions from demand to vary when the gas price moves above the median.<sup>19</sup>

Previous literature sometimes uses the ratio of the natural gas to the coal price as an independent variable. I omit the coal price because the coal price is in part determined by the natural gas price.<sup>20</sup> If natural gas were more expensive, demand for coal would be substantially higher. I aim to capture the total effect of increased natural gas supplies on carbon emissions through gas and coal prices - not only through the price of natural gas itself. I consider specifications with a coal price in Online Appendix E.4; results are similar to those using only gas prices.

The Durbin-Watson statistic suggests that autocorrelation may be an issue. I use Newey-

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<sup>18</sup>If I use year-of-sample dummies instead of a time trend, the resulting price spline is qualitatively similar, but somewhat flatter. Gas prices are consistently high in the first two years, and consistently low in the last four years. The inclusion of year-of-sample dummies causes the estimation to struggle with the transition between the (pre-fracking) high gas price regime and the (post-fracking) low gas price regime.

<sup>19</sup>The median gas price in my sample is about \$4/MMBtu. I also run the analysis using \$6/MMBtu as the break point. Results are similar.

<sup>20</sup>While fracking likely causes the coal price to exogenously change, the coal price is also driven by trends like changing international demand. My specification controls for trends over time, but directly including the coal price would not allow me to control for these trends.

West standard errors with seven lags. I choose seven lags for two reasons. First, it is a full week. It is possible that a firm’s decision today (e.g., Tuesday) is correlated with Monday’s decision, as well as the decision that they took on the previous Tuesday. Second, Greene (2012) recommends using the fourth root of the number of observations, which in this case is just under seven.

Aggregate calculations which combine results from several regressions use bootstrapped standard errors. I use seven-day block bootstrapping with 1,000 replications to mimic the possible autocorrelation in the data. Where possible, I have compared analytic standard errors with bootstrapped standard errors for accuracy. They are similar.

### 3.2 Decrease in Emissions from New Natural Gas Capacity

The key relationship when estimating the decrease in emissions from new natural gas capacity is between emissions and the electricity demand spline. The CEMS database allows me to directly calculate how much electricity was generated by newly constructed power plants, as well as the carbon that was emitted when generating the electricity. This power would otherwise have been produced by the old generation stock. Using the actual conditions at the time of power generation, I generate counterfactual emissions by increasing electricity demand and moving up along the demand spline by the amount of power that new plants are generating. A simple comparison between actual emissions from the newly constructed plants and marginal emissions from the counterfactual reveals the decrease in carbon emissions caused by these new facilities.<sup>21,22</sup>

Figure 2 demonstrates that generation from gas-fired plants constructed between 2010 and 2013 has played an increasingly large role in US power generation. New plants are most important in the Eastern interconnection. By the end of 2013, over 10 GW of generation

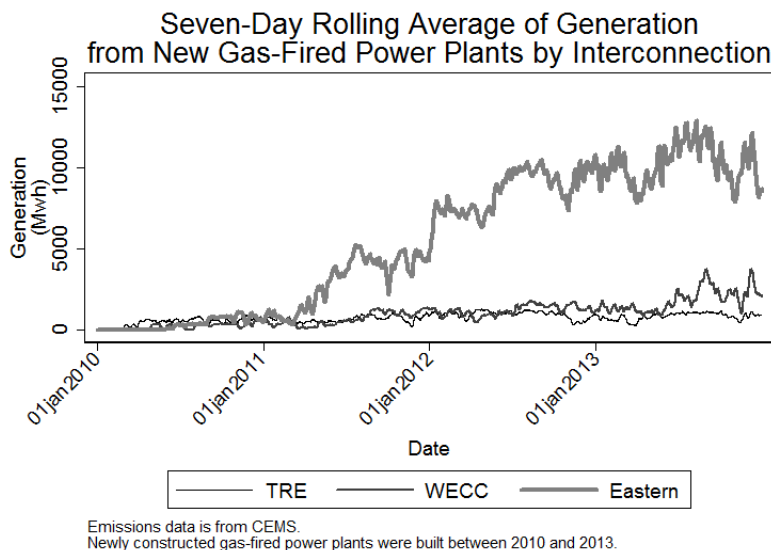
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<sup>21</sup>This approach is similar to the one taken by Davis and Hausman (2014).

<sup>22</sup>My analysis does not consider the effect of delayed gas retirements or accelerated coal retirements due to low gas prices. These changes also yielded benefits to the extent that they shifted generation away from coal-fired sources. One important difference between adjusted retirement dates and new construction is that new construction will have a lifespan of several decades, while retirement adjustments only affect the marginal years surrounding retirement.

is supplied at any one time by these plants. On average, this is about 3% of total US generation.

**Figure 2**



At this point the reader may be concerned that I do not control for new capacity additions, which could alter the shape of the gas price or demand splines. This is not likely to be a problem because the capacity additions are small relative to the existing capacity stock.<sup>23</sup> The time trend controls for much of these changes. Residual bias would work against finding results in this paper because new gas-fired capacity allows for lower emissions levels and will flatten the gas price and demand splines.<sup>24</sup> A flatter gas price spline would cause emissions savings from lower gas prices to be (marginally) underestimated and my estimate of emissions savings from new plants to also be lower.

For emissions reductions estimates, I only look at new capacity added between 2010 and 2013 (25.9 GW). Of this, I estimate roughly 65-85% was induced because of fracking (see Section 5).

<sup>23</sup>Between 2007 and 2013, about 50 GW of natural gas capacity was added, relative to the existing generation stock of about 1,000 GW.

<sup>24</sup>New capacity is more efficient than older capacity and is profitable to run at higher gas prices than older plants. When gas prices drop to the point where switching between coal and gas becomes profitable, the new plants will be the first to be called upon.

Online Appendix E checks the robustness of my primary specification to including daily wind generation, using additional Newey-West lags, using alternative gas prices, and using a gas/coal price ratio.

## 4 Results

### 4.1 Decrease in Emissions from Switching

Figure 3 shows the relationship between the gas prices and carbon emissions in the Eastern, Western, and Texas interconnections as estimated using equation 1. It shows results for two representative (“Peak” and “Off-Peak”) hours. The vertical lines represent the knot points in the splines.<sup>25</sup>

In all three interconnections, the gas price spline is strongly significant. The increase in carbon emissions from raising the natural gas price by \$1 is highest when natural gas prices are low because coal and natural gas have similar marginal costs when gas is relatively inexpensive. Marginal changes at higher gas prices have weaker (or non-existent) effects – coal is cheaper than \$7/MMBtu gas and it is also cheaper than \$12/MMBtu gas. Note that the figures only include the effect of the gas price – fixed effects and other covariates (e.g., electricity demand) have been stripped out.

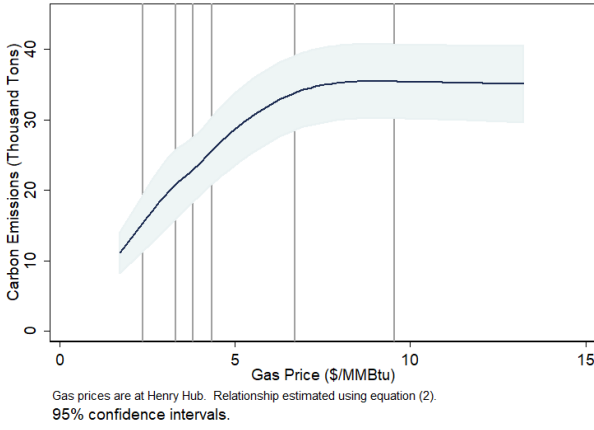
The Eastern interconnection has higher levels of emissions because it is much larger than the other two interconnections (see Figure 1). The slope is steeper at low gas prices because there is more coal-fired generation to displace in the Eastern interconnection. In contrast, the Western and Texas interconnections have less coal-fired generation (and less overall generation).

In Figure 4, I plot seven-day average (rolling) emissions reductions if gas prices were at 2008 levels. Counterfactual emissions are constructed by taking each day’s control variables as given, except the gas price is replaced by the gas price from the corresponding date in 2008.

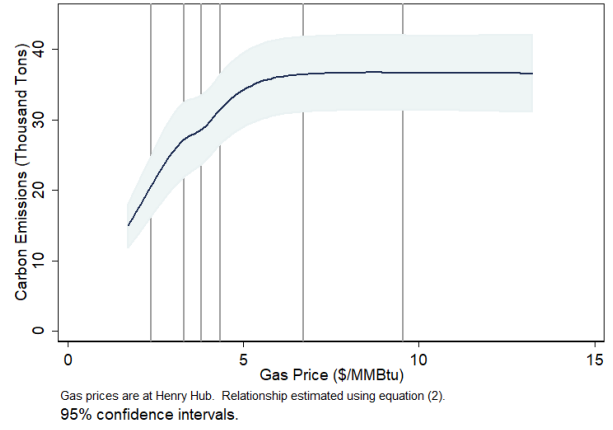
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<sup>25</sup>My primary specification does a very good job of predicting emissions, see Online Appendix D for details.

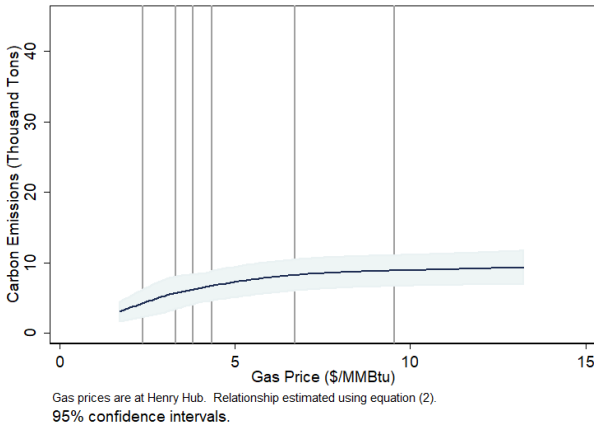
**Figure 3: Hourly Relationship between Gas Prices and Carbon Emissions**



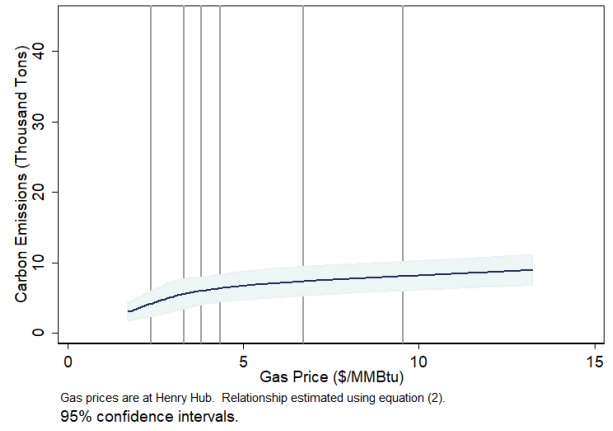
**(a) Eastern: 2:00 AM (Off-Peak)**



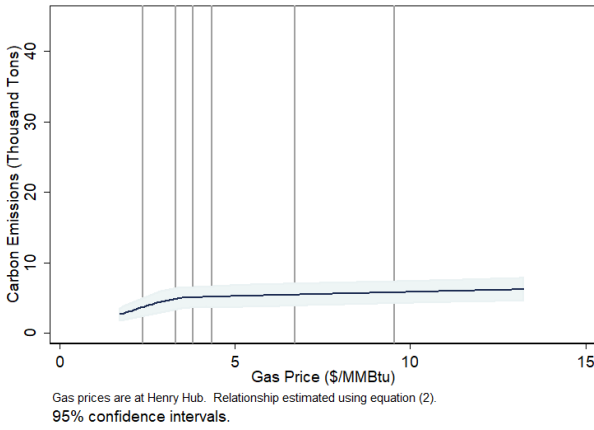
**(b) Eastern: 6:00 PM (Peak)**



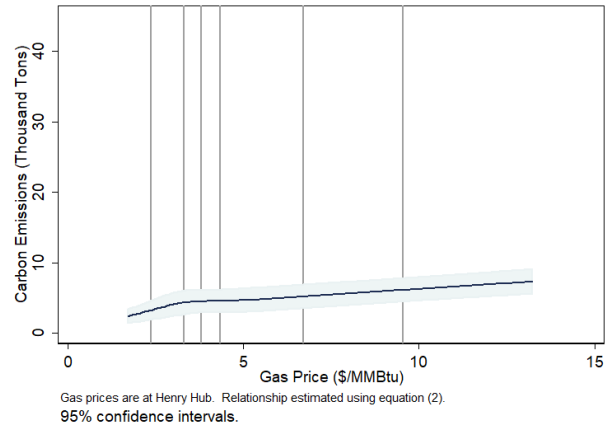
**(c) Western: 2:00 AM (Off-Peak)**



**(d) Western: 6:00 PM (Peak)**



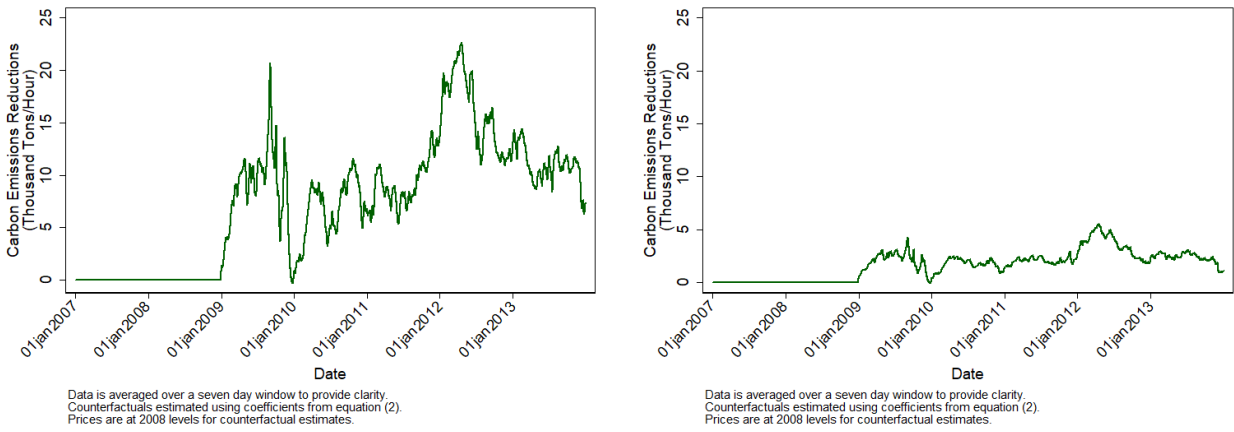
**(e) Texas: 2:00 AM (Off-Peak)**



**(f) Texas: 6:00 PM (Peak)**

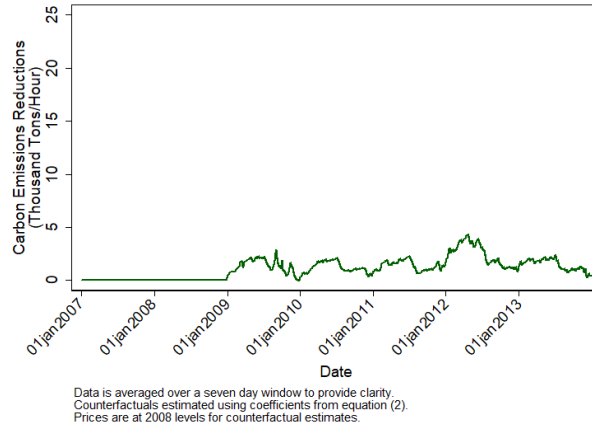
For example, the real price of natural gas on October 9, 2012 was \$3.00/MMBtu. On October 9, 2008, the real price of natural gas was \$6.72/MMBtu. In constructing counterfactual emission levels, I keep renewable production, electricity demand, and fixed effects at the levels on October 9, 2012, but use \$6.72/MMBtu as the gas price.<sup>26</sup> I choose 2008 because the gas prices from this year represent the natural gas market prior to the effect of fracking. Results using 2007 gas prices are qualitatively and quantitatively similar.

**Figure 4:** Emissions Reductions due to Lower Gas Prices



(a) Eastern Interconnection

(b) Western Interconnection



(c) Texas Interconnection

Counterfactual emissions are higher than actual emissions. This is expected – at higher gas prices, more coal is being burned. Emissions decreases are greatest in 2012, the year

<sup>26</sup>I also adjust the interaction term.



with the lowest gas prices. Decreases in 2010 are smallest (though still substantial), as this is the (post-2008) year when gas prices were highest (see Figure 11).

**Table 1**  
**Hourly Reductions in Carbon Dioxide Emissions**  
**By Year**  
**(Thousand Tons of Carbon Dioxide/Hour)**

		2008	2009	2010	2011	2012	2013
		[1]	[2]	[3]	[4]	[5]	[6]
Actual Emissions	[a]	284.7	261.3	278.3	266.0	249.0	253.0
Predicted Emissions using Primary Specification	[b]	284.3	261.9	277.6	266.5	249.2	252.7
Counterfactual Emissions (Using 2008 Gas Prices)	[c]		273.9	287.2	279.1	271.2	267.5
Emissions Reductions From Gas/Coal Switching	[d]		12.0 (0.8)	9.7 (0.8)	12.6 (0.9)	22.0 (1.1)	14.7 (0.9)
Counterfactual Emissions (Without Newly Constructed Plants)	[e]			277.6	267.1	251.0	254.9
Reduction Caused by New Power Plants	[f]			0.1 (0.0)	0.6 (0.0)	1.8 (0.1)	2.1 (0.1)
Counterfactual Emissions (With 2008 Gas Prices and Without New Plants)	[g]		273.9	287.3	279.7	272.9	269.4
Total Reductions from Low Gas Prices	[h]		12.0 (0.8)	9.7 (0.8)	13.2 (0.9)	23.7 (1.1)	16.7 (0.9)

Notes:

[d] = [c] - [b]

[f] = [e] - [b]

[h] = [g] - [b]

Standard errors are estimated using block bootstrapping with 1000 replications.

Table 1 details annual emissions decreases. All years show decreases that are substantial in magnitude. Depending on price fluctuations within a specific year, annual emissions reductions caused by low gas prices range between 9.7 and 22.0 thousand tons/hour (row [d]). This is between 3.4% and 7.7% of the 2008 total (s.e. of 0.4%).<sup>27</sup> On average, emissions have

<sup>27</sup>This estimate is a combination of effects in the three interconnections. The standard error is calculated using block bootstrapping.

been 8.2% lower than 2008, and gas prices were directly responsible for 61% of the decrease, or 5.0%. These decreases are larger in magnitude than has been previously estimated.<sup>28</sup>

Remember that this estimate does not include possible increases in emissions due to lower electricity prices (and consequently, higher electricity quantity demanded). I address what this demand response might look like in the discussion section. Additionally, the reductions discussed in this subsection are restricted to reductions from switching between gas and coal-fired power plants. I now address the effect that new capacity had on emissions.

## 4.2 Decrease in Emissions from New Natural Gas Capacity

It is important to control for the exact level of demand (by running an hourly specification) when new gas-fired capacity is operating. Figure 5 illustrates this by showing the relationship between electricity demand and carbon emissions in all three interconnections at 2:00 AM (off-peak) and 6:00 PM (peak). Marginal emissions can vary based on the level of demand or the hour of generation.<sup>29</sup>

The difference in the demand splines is subtle in the Eastern interconnection (panels (a) and (b)). The 2:00 AM spline is a little steeper than the 6:00 PM spline. This is likely because coal-fired generation is more frequently used to meet marginal demand during off-peak hours than during peak hours.

The importance of using a demand spline is most visible in the Western interconnection (panels (c) and (d)). When demand is around 50,000 MW, incremental demand causes very low incremental emissions (panel (c)). However, marginal emissions are higher at demand levels above 60,000 MW. This is largely because, in the Western interconnection, the marginal fuel switches from hydroelectric generation to gas-fired generation as demand increases from very low levels to more moderate levels.

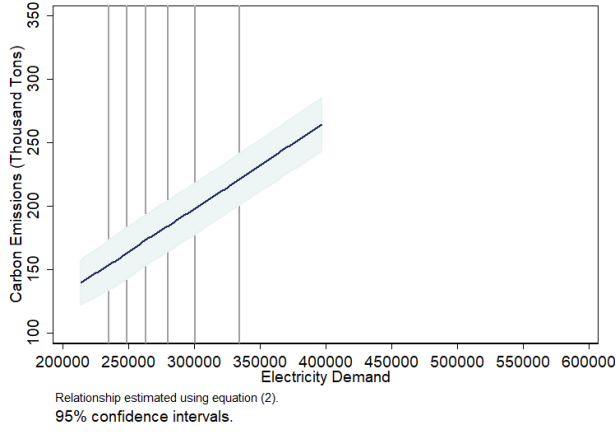
The Texas interconnection (panels (e) and (f)) shows the least variation in marginal emis-

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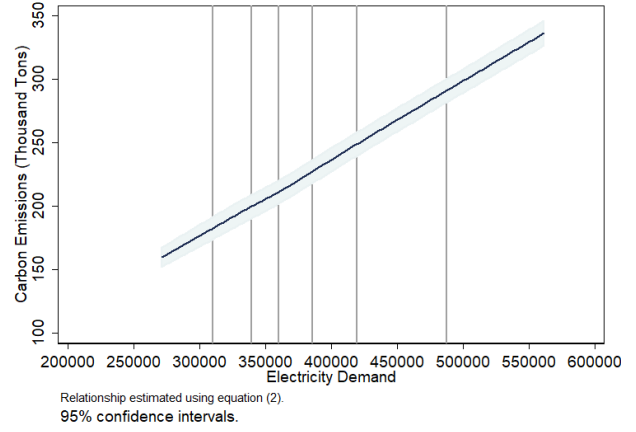
<sup>28</sup>For example, Lu, Salovaara and McElroy (2012) find that lower gas prices were responsible for a 4.3% decline. Much of the further decrease is due to a continued decline in gas prices.

<sup>29</sup>Figure 5 does not incorporate the “high gas price demand spline.”

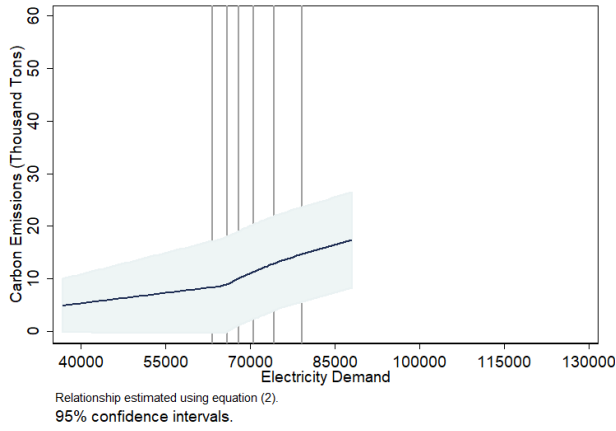
**Figure 5:** Hourly Relationship between Electricity Demand and Carbon Emissions



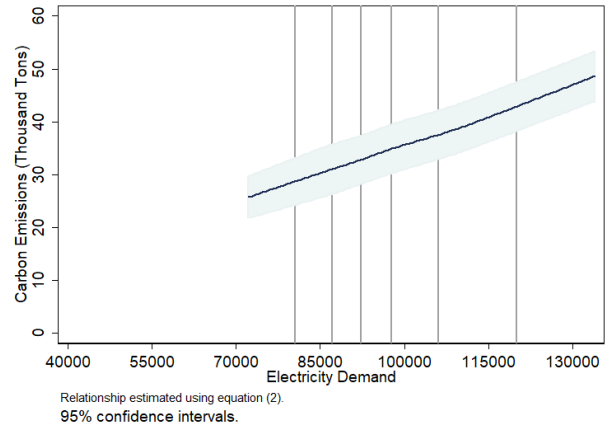
(a) Eastern: 2:00 AM (Off-Peak)



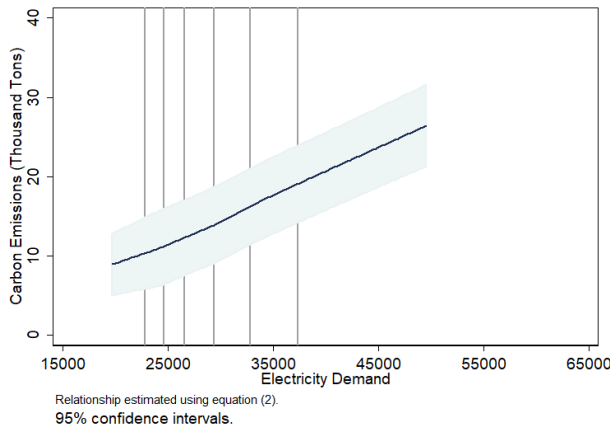
(b) Eastern: 6:00 PM (Peak)



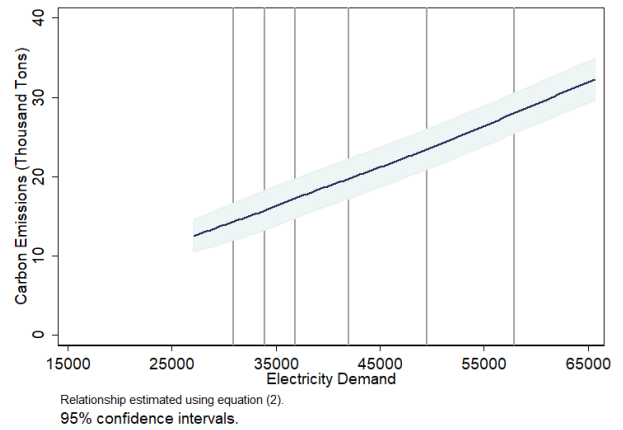
(c) Western: 2:00 AM (Off-Peak)



(d) Western: 6:00 PM (Peak)



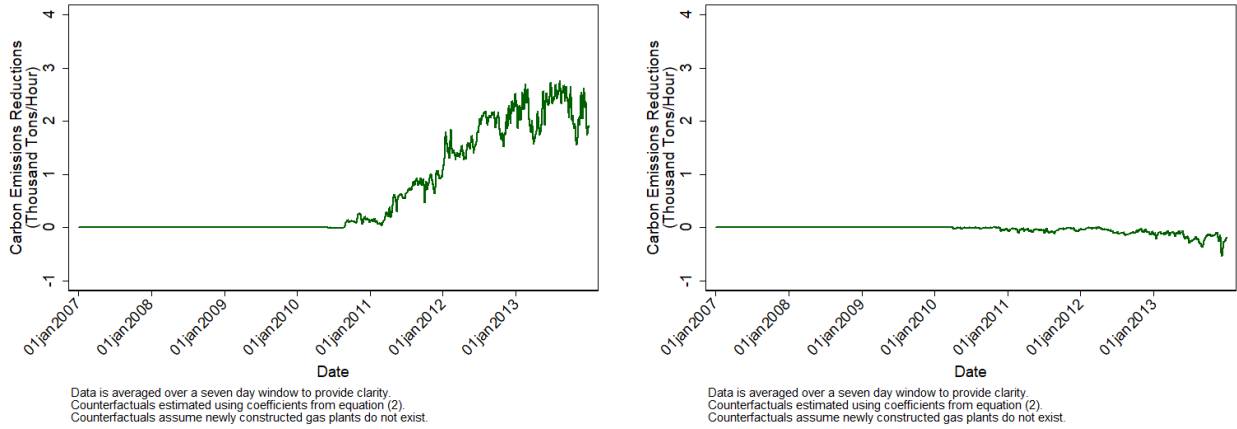
(e) Texas: 2:00 AM (Off-Peak)



(f) Texas: 6:00 PM (Peak)

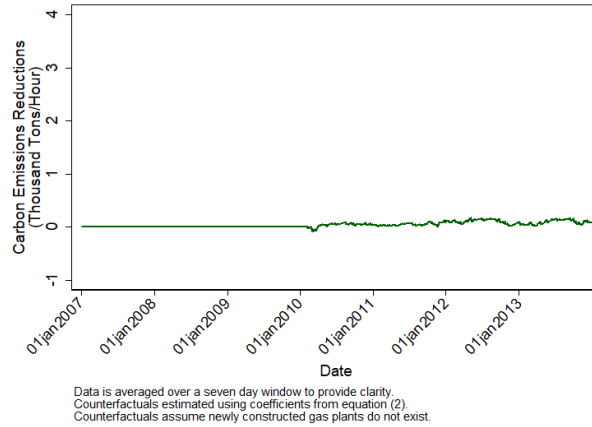
sions across hours and demand-levels, though the demand splines have some non-linearities. The majority of marginal generation is met by gas-fired plants, and changing marginal emissions are likely due to differences in generator efficiency. In particular, there is a slight increase in the slope of the demand spline when demand increases from low to moderate levels – levels when less-efficient gas-fired plants are running.

**Figure 6:** Seven Day Rolling Emissions Reductions due to New Construction



(a) Eastern Interconnection

(b) Western Interconnection



(c) Texas Interconnection

Figure 6 graphs seven-day rolling emissions reductions due to new gas-fired plant construction. Due to the lead time required to build a new gas-fired power plant, I only consider emissions reductions from plants that came online in 2010 or later. Strikingly, reductions are concentrated in the Eastern interconnection. This is largely true because the Eastern inter-

connection is the largest and has the most new plants. In 2012, the Eastern interconnection averaged 8.5 GW of generation at any time from new plants, while the other two interconnections each generated about 1 GW. Additionally, marginal emissions from incremental demand are higher in the Eastern interconnection because it is more reliant on coal-fired generation. New gas-fired generation in the Eastern interconnection is more likely to offset coal-fired generation, and corresponding emissions reductions will be larger in the Eastern interconnection.

Note that this was not a foregone conclusion. It could have been the case that the new gas-fired power plants were not running very frequently or were replacing similar gas-fired power plants. This would have led to no net emissions reductions. Figure 6 shows several places where counterfactual emissions are actually lower than actual emissions.<sup>30</sup>

Table 1 details annual emissions decreases from newly constructed capacity (see row [f]). As expected, continued additions over time cause emissions reductions to grow over time. By 2013, hourly emissions savings averaged 2.1 thousand tons. This is 0.75% of the 2008 total. As detailed in section 5, I estimate about 65-85% of the 2.1 thousand tons/hour is directly attributable to lower gas prices. Because the capital stock is brand new, these gains will likely persist for years.

Emissions reductions due to construction of new plants is less dependent upon low gas prices. Many new gas-fired power plants are very efficient. They fall below some coal plants in the dispatch order even when gas prices are moderate. Their combined-cycle technology can achieve efficiency of around 50%. In contrast, older plants are more likely to use single-cycle technology that only allows for efficiency around 33%.

2012 was warmer than average, which led to gas prices that are lower than average – and also lower than in 2013. Despite this, emissions reductions from newly constructed power plants continued to grow; 2013 emissions reductions were actually larger than those in 2012.

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<sup>30</sup>In particular, the WECC shows some emissions *increases* at the end of 2013. In contrast to the other interconnections, most of the new plants in the WECC are single-cycle “peakers” that have low capital costs, but are not very efficient. Combined with the fact that marginal emissions are lowest in the WECC, emissions increases are possible. However, the magnitude of these increases is small.

A return to pre-fracking gas prices would be unlikely to negate all of the emissions gains from the new capital stock that has been built.

### **4.3 Combined Decrease in Emissions from Low Gas Prices and New Natural Gas Capacity**

I now consider the combined effect of lower gas prices and new natural gas capacity. Specifically, I use my primary specification and adjust both the gas price to 2008 levels and electricity demand as in the previous two sections (and make corresponding changes to the interaction term).

There are primarily two countervailing effects that determine how the interaction of low gas prices with new construction will affect carbon emissions. Lower gas prices, when combined with new plant construction, mean that it is likely new plants will run more frequently than they would if gas prices remained at higher levels. This would suggest that the combined effect should be larger. Working against this is that both changes, individually, might end up causing the same adjustments to the dispatch curve. That is, e.g., building a new gas-fired plant would cause it to displace a certain coal plant. If, instead, gas prices were lower, an existing plant might also displace the same coal plant. However, it is clear that one coal plant can only be displaced once. This suggests the combined effect should be smaller.

I find that in 2013 gas prices and new gas fired capacity are responsible for a reduction of 16.7 thousand tons of carbon/hour (s.e. of 0.9), a decrease of 5.9% from 2008 levels. Table 1 again details these changes by year (row [h]). The combined effect of these two changes is slightly less than the sum of its parts. In 2013, lower gas prices reduced emissions by 14.7 thousand tons of carbon/hour, while newly constructed capacity reduced emissions by 2.1 thousand tons of carbon/hour. However, total reductions of 16.7 thousand tons of carbon/hour are 0.2 thousand tons/hour less than the 16.9 thousand tons/hour that are the sum of the parts. This suggests that potential synergies are outweighed by the inability to

displace the same dirty plant twice. However, the interaction effect is relatively small.

The next section of the analysis turns to estimating what percentage of this new gas-fired capacity, resulting in 2.1 thousand tons/hour of carbon emissions reductions, was unanticipated and built because of lower gas prices.

## 5 Cheap Gas and Gas-Fired Capacity Additions

Most forecasters and industry analysts expected only very minor gas-fired capacity increases between 2010 and 2013. Instead, 25.9 GW of gas-fired capacity was added over this time-frame. I take three approaches to estimate the precise effect of fracking on new gas-fired capacity additions, which all yield similar results. First, I examine projections made by the EIA in their Annual Energy Outlook projections. Next, I run a set of simple regressions that estimate the relationship between the gas price and construction starts. One weakness of this approach is the limited sample. Finally, I consider data about potential projects that are filed with the EIA using their EIA-860 form.<sup>31</sup> I estimate that roughly 65%-85% of these additions likely would not have happened if the gas price had remained at 2008 levels. While my analysis includes both combined cycle and conventional combustion turbines, new combined cycle plants (~65% of new capacity) likely drive the results in this paper.

A gas-fired power plant takes between 18 and 36 months to construct. Natural gas prices crashed in mid-2008, suggesting that the earliest gas plants built because of low gas prices would likely have come online in 2010. While it is likely that a few suspended projects were restarted and completed by the end of 2009, I only consider plants built in 2010 or later. To the extent that this happened, results in this paper underestimate the effect of fracking on the generation fleet.

It is difficult to disentangle the effects of natural gas prices from contemporaneous trends such as state renewable portfolio standards, changing environmental regulations, or the great recession. I briefly consider the effect each of these trends might have had on gas-fired

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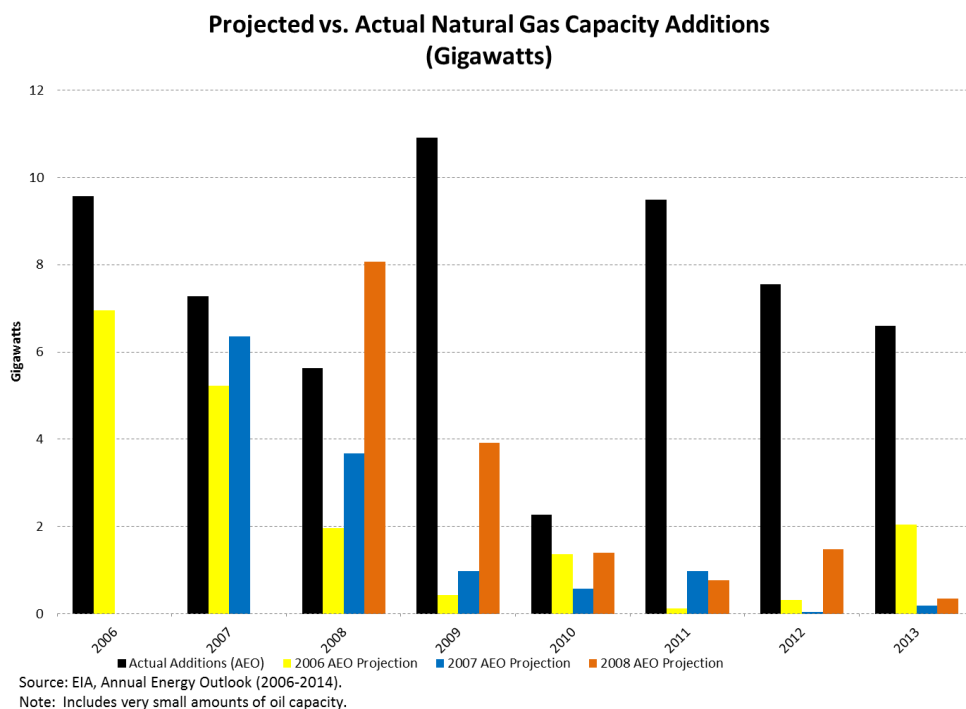
<sup>31</sup>Note that the AEO projections are based, in part, on the raw EIA-860 data.

generation construction. While not definitive, these considerations support the theory that gas prices were the major driver of gas-fired capacity additions.

## 5.1 Annual Energy Outlook Projections

In the mid-2000s, prior to the widespread adoption of fracking, the EIA estimated that there would only be very modest investment in natural gas-fired electric generation capacity. The available capital stock would be mostly sufficient to meet growth in electricity demand and it would be unprofitable to make large investments in new capacity. The 2007 Annual Energy Outlook (AEO) projections suggested that there would be roughly 2 GW of natural gas capacity added during the 2010-2013 timeframe. As Figure 7 shows, this was not a one-year aberration; projections in surrounding years were also very similar.

Figure 7



However, the solid black column in Figure 7 indicates that actual capacity additions were substantially above initial projections. The 25.9 GW of capacity that was built between 2010 and 2013 is much higher than these projections.



Table 2

### Estimated Plant Construction Due to Fracking Differences from AEO Projections (Gigawatts)

Projection Year	5-Year Projection [1]	5-Year Actual Construction [2]	Percent Constructed Above (Below) Projection [3]	Up to 10-Year Projection [4]	Up to 10-Year Actual Construction [5]	Percent Constructed Above (Below) Projection [6]
<b>Pre-Fracking Projections</b>						
AEO 2001	[a]	78.3	149.9	<b>Mostly Pre-Fracking Projections</b>		
AEO 2002	[b]	91.2	151.2	189.7	185.6	-2%
AEO 2003	[c]	49.9	97.9	195.1	186.8	-4%
AEO 2004	[d]	13.8	60.4	118.9	133.8	12%
			336%	53.0	97.2	83%
Pre-Fracking Average	[e]	58	115	139	151	<b>22%</b>

### Amount of 2010-2013 Construction (26 GW Total) Attributable to Fracking

	Projections		Projections	
	2010-2013 Projection	Adjusted for Errors	2010-2013 Projection	Adjusted for Errors
AEO 2006	[f]	3.9	16.4	4.7
AEO 2007	[g]	1.8	21.5	2.2
AEO 2008	[h]	4.0	16.0	4.9
Average	[i]		<b>18.0</b>	<b>22.0</b>

The upper panel determines how accurate previous AEO estimates of natural gas plant construction were. This information is used in the lower panel to adjust the projections for 2010-2013 construction. Because previous projections overestimated construction, these estimates are conservative relative to the baselines outlined in the 2006-2008 AEOs.

The "Projections Adjusted for Errors" columns ([2] & [5] on the lower panel) are constructed by multiplying the actual projections (in columns [1] & [4]) by the percent that previous projections were overestimated (from the upper panel).

[i]: Depending on whether I use a 5-Year or 10-Year error adjustment, I estimate between 18 and 22 GW of capacity was constructed that would not have been if gas prices were higher. See text for additional details.

Source: Annual Energy Outlook.

I next look to see how close previous AEO projections were to actual construction. It is possible that the AEO’s black box model regularly underestimates short to medium-run gas-capacity additions. To be conservative and allow for this possibility, I adjust the 2006-2008 AEO projections up by the amount that previous projections missed by. I view this as conservative in part because AEO projections are intended to be unbiased. Table 2 details this analysis.

I look at both five-year (columns [1] to [3]) and ten-year projections (columns [4] to [6]) in the same way. In the top panel I analyze projections made between 2001 and 2004 to determine how accurate they were. These projections are mostly before the advent of fracking and are mostly free from its influence. In the five-year projection, total construction averaged 147% above projection. Ten-year construction averaged 22% above projection.<sup>32</sup>

In the bottom panel, I analyze 2006-2008 projections for construction between 2010 and 2013. All three years projected minimal construction during these years. To adjust for previous underprojections, I multiply the 2006-2008 projections by ratio of actual/projected construction that I calculate in the upper panel (row [e], bolded). Even after I adjust for previous errors (columns [2] and [5]), the expected level of construction was much lower than actual construction. Adjusting for previous projection errors, this analysis suggests between 18 and 22 gigawatts of natural gas-fired capacity was constructed that would not otherwise have been.

## 5.2 Construction Starts Regression Analysis

I now consider a regression-based approach to determine the relationship between gas prices and estimated gas-fired construction starts. Prior to the regressions, I use data from Form EIA-860 to estimate construction starts.<sup>33</sup> The data summarizes construction completions

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<sup>32</sup>These results are driven in part by 2004 projections (row [d]), which are most likely to be influenced by fracking. I view the inclusion of 2004 projections as conservative.

<sup>33</sup>The disaggregated EIA-860 data on gas-fired construction starts are aggregated in the Electric Power Annual. I use aggregated data because the disaggregated data are unavailable for some years due to changes to EIA’s data collection procedures.

(e.g., 20.1 GW in 2004 and 14.8 GW in 2005); I use an 18-month lead to estimate construction starts for each year (e.g.  $(20.1+14.8)/2 = 17.4$  GW in 2003).<sup>34</sup> Using lead completions data as an estimate of construction starts instead of actual construction starts allows me to capture some intermediate effects. For example, some power plants are begun but later “indefinitely postponed.” Lead completions estimates appropriately account for plants that were indefinitely postponed and later restarted, as well as the lower likelihood of such postponements when firms expect a long-term supply of inexpensive natural gas.

The Annual Energy Outlook also reports construction completions. Their data is based on the EIA-860, though it is compiled differently. As a check, I use both the EIA-860 and AEO datasets in my analysis.

Using data from 2000-2011, I estimate the annual relationship between construction starts (in megawatts) and electricity demand growth and the price of natural gas. Specifically, I estimate:

$$\text{LoggedConstructionStarts}(C_t) = \alpha_0 + \beta_1 P_t^{NG} + \beta_2 \text{ElecGrowth}_t + \epsilon_t \quad (2)$$

The price of natural gas and electricity demand growth are the two primary drivers of gas-fired capacity investments. Gas prices determine the marginal cost of operating plants, while demand growth helps determine future wholesale electricity prices. I consider two variations of the dependent variable, using either AEO or EIA-860 data.

A limitation of this estimation is that the number of data points in this time series is only 11 or 12, depending on the data source.<sup>35</sup> More reliable estimates would result from including additional controls, making the independent variables more flexible, and adjusting the standard errors. Data limitations prevent these adjustments. Nevertheless, estimation allows for a rough look at the relationship between gas prices and construction starts. I have

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<sup>34</sup>I choose an 18-month lead because it allows for the best fit with the available micro data on construction starts. Online Appendix C provides results using a range of alternative lead times; they are similar to results in my preferred specification.

<sup>35</sup>Online Appendix C includes a scatterplot of these points, as well as a line of best fit.

summarized the results in Table 3.

Table 3

**Estimated Counterfactual Plant Construction  
Results from Regression Analysis Using an 18 Month Lag**

Item		Using Log AEO Plant Data	Using Log EIA-860 Plant Data
		[1]	[2]
Gas Price Coefficient	[a]	-0.13	-0.21
Standard Error	[b]	0.12	0.12
R Squared	[c]	0.16	0.29
Number of Observations	[d]	12	11

Counterfactual Plant Construction (Gigawatts)			
Year		Using Log AEO Plant Data	Using Log EIA-860 Plant Data
	2009 [e]	10.9	9.4
	2010 [f]	1.5	3.2
	2011 [g]	3.6	0.1
	2012 [h]	2.8	< 0
	2013 [i]	1.7	
Actual Construction (2010 - 2012/2013)		25.9	25.4
Construction Caused by Fracking		16.2	22.1

Notes:

[b]: The standard error does not address autocorrelation.

[i]: 2013 EIA-860 data is currently unavailable. Placeholder data suggests counterfactual construction is near zero and actual construction is greater than zero. This suggests I am underestimating the effect of low gas prices.

[k]: = [j] - Sum([f] to [i]) if positive & shaded. That is, [i] is construction that would not have occurred with higher gas prices.

Sources: EIA-860 data summarized in the Electric Power Annual and Annual Energy Outlook Data.

While the magnitude of the gas price coefficient varies across the regressions (including those in Online Appendix C), it is consistently negative. To determine the counterfactual construction, I first determine the difference between actual gas prices in each year and the counterfactual (no-fracking) gas price from 2008. I then adjust construction starts in each year down by the counterfactual gas price difference multiplied by the gas price coefficient. This allows me to determine counterfactual construction in rows [e] through [j].

In 2009, construction estimates do not change because of the way this analysis is constructed – it takes more than 12 months to have an effect. However, starting in 2010,

counterfactual construction is frequently lower than it otherwise would have been. Much of the time it is close to zero or negative. I interpret negative construction to mean that it is very undesirable to build a gas plant, not that gas plants are being decommissioned. Years in which there is positive construction are highlighted.

Finally, I compare actual plant construction from 2010 to 2013 with counterfactual plant construction. I take the 25.9 GW of stock that was actually constructed and subtract construction in any year with a positive counterfactual. For example, in column [2], I subtract  $(1.5 + 3.6 + 2.8 + 1.7 = )$  9.6 GW that would have been built even if gas prices remained high. Negative construction is treated as a zero.

Depending on the specification, this analysis suggests either 16.2 or 22.1 GW of gas-fired capacity was constructed that would not otherwise have been built. Note that the EIA-860 plant data do not include 2013 construction or counterfactual construction.

### 5.3 Raw EIA-860 Projections

Proposed electricity plants are required to file the EIA-860 form if “[t]he plant will be primarily fueled by energy sources other than coal or nuclear energy and is expected to begin commercial operation within 5 years.” This form details proposed plants, which are in various stages of planning or construction, but are not generally certain to be completed. When using the raw EIA-860 data, I view it as a soft cap on the possible number of projects that will be built over the next 5 years. To construct a plant within the next five years that is not already in the database, a firm would need to complete the siting, planning and construction phases. This can be done, but it requires a very smooth process.

To determine how many of these projects are completed during pre-fracking (normal) times, I look at summaries of EIA-860 data from 2001 through 2003. As Table 4 shows, on average 59% of potential projects were completed during these years. In contrast, when I look at projections from 2006 through 2008, years when the projections mostly overlap with fracking, I see that 101% of potential projects are completed. That is, during regular

Table 4

**Estimated Counterfactual Plant Construction  
EIA-860 Registered Projects  
(Gigawatts)**

Projection Year	5-Year Potential Projects	Actual Construction	Number Not Constructed	Percent Constructed
	[1]	[2]	[3]	[4]
<b>Potential Projects are Pre-Fracking</b>				
2001 [a]	285	146	139	51%
2002 [b]	160	96	63	60%
2003 [c]	88	58	30	66%
<b>Potential Projects are Mostly During Fracking</b>				
2006 [d]	40	40	(0)	101%
2007 [e]	41	42	(1)	103%
2008 (Four Years) [f]	35	35	(0)	100%
Pre-Fracking Average [g]	178	100	77	59%
Fracking Average [h]	39	39	(1)	101%
Increase in Completed Projects [i]				<b>42%</b>
Estimated Gigawatts Attributable to Fracking [j]	<b>17.5</b>			

[g]: = Sum([c] to [d]).

[1,j]: To estimate GW attributable to fracking, I compare the percentage completed during fracking (101%) with the percentage completed during normal times (59%). I attribute the 42% difference to cheaper gas prices. 2007's 5-year projection was that 41 GW were potentially under construction, 42% of this is 17.5 GW. Note that this does not account for delayed retirements or unexpected capacity increases.

Sources: EIA-860 data summarized in the Electric Power Annual and Annual Energy Outlook Data.

times, half of all projects are completed. When gas-fired plants become much more profitable because their marginal costs tremendously decline, slightly more projects are completed than were planned.

This suggests that without fracking (and lower gas prices), roughly one half of all projects would have been completed – the other half was induced by very cheap natural gas prices. Looking at the most recent projection for which I have five years of actual construction data (2007), I estimate that 17.5 GW of additional capacity were induced by cheap natural gas.

## 5.4 Alternative Explanations

There are a number of possible alternative explanations for the surge in gas-fired construction. While I am unable to conclusively rule them out, the evidence suggests that they have quantitatively limited effects.

### 5.4.1 State Renewable Portfolio Standards

Renewable Portfolio Standards have been enacted at the state level in twenty-nine of the lower 48 states (and the District of Columbia) (EIA). While standards vary across states, they broadly seek to increase renewable generation and decrease fossil fuel use. However, they could also incentivize additional gas-fired power plants (at the expense of coal-fired plants) because gas-fired generation better complements the unpredictable nature of renewable power. Using Texas data, Dorsey-Palmateer (2014) finds that the primary effect of wind generation is to reduce fossil fuel consumption. That is, the first effect likely outweighs the second, and in the absence of renewable portfolio standards, gas-fired construction would likely have been even larger.

I now look to see if a disproportionate share of construction was in states with renewable portfolio standards. The twenty-nine states with standards contained 72% of the US population. They also constructed a roughly proportional 76% of the 227 new gas-fired units built over the 2010-2013 period. This broad overview does not suggest a large effect due to renewable portfolio standards.

### 5.4.2 Great Recession

The Great Recession began in December of 2007 and ended in June of 2009. In this section, I used projections issued between 2005 and early 2008. For example, section 5.1 uses the 2007 AEO projection issued in early 2007 before the onset of the recession. Following the onset of the recession, capital expenditures across the US economy fell substantially. If the construction projections accounted for the upcoming Great Recession, they likely would have

predicted even less new gas-fired power plant construction. While the effects of the Great Recession are not captured in this analysis, it likely muted the effect of lower gas prices.

### 5.4.3 Changing Environmental Regulations

The Regional Greenhouse Gas Initiative (RGGI) involves ten states in the Northeastern US (plus PA as an observer). It began in 2009 with the goal of reducing carbon emissions. Similarly, California implemented a cap & trade program in 2013. These programs will impose a cost on carbon emissions, but the effect on natural gas-fired plants is ambiguous – they are cleaner than coal-fired generation, but dirtier than renewables. Because these twelve states comprise  $\sim 33\%$  of US population and built a proportional 38% of new gas-fired generation units, it is unlikely carbon regulations have been driving gas-fired investments.

Coal-fired power plants are the largest source of mercury emissions in the US. It is possible that changing mercury regulations have influenced the decision to build gas-fired plants. At the national level, Mercury and Air Toxics Standards (MATS) are being developed by the EPA. They were originally proposed in March 2011, but remained under revision throughout the duration of the sample period.<sup>36</sup> It is possible that these standards influenced borderline plants to continue to completion. It is unlikely that MATS caused new plants to be conceived and constructed between 2010 and 2013 because of the uncertainty surrounding the revision and the amount of time required to build a new power plant. Additionally, 2011's large amount of construction completions, which was likely unaffected by the MATS proposal, provides evidence that new construction was economic without the benefit of MATS. However, I cannot conclusively rule out MATS as a driver of gas-fired construction.

The Clean Air Interstate Rule (CAIR) was originally proposed by the EPA in 2003 with the aim of reducing emissions of particulate matter, nitrogen oxide, and sulfur dioxide. After a lengthy legal battle, CAIR was remanded in 2008 and the EPA was ordered to address several problems with the regulation. The EPA finalized the Cross-State Air Pollution Rule

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<sup>36</sup><http://green.blogs.nytimes.com/2011/12/21/e-p-a-announces-mercury-limits/>, <http://www.epa.gov/mats/actions.html>.



(CSAPR) in 2011, and phase I took effect at the start of 2015. The primary effect of the law is to reduce pollution from coal-fired power plants through additional technological controls or reduced generation. Natural gas plants emit less conventional (non-carbon) pollution when compared with coal-fired plants. As a result, I expect the net effect of the regulation to promote gas-fired and renewable generation at the expense of coal. CSAPR and/or CAIR were designed to affect 31 states and the District of Columbia. These states comprised 75% of the US population, but only 60% of the new gas-fired construction. I interpret this as evidence that CSAPR is not the primary driver of new gas-fired construction.

#### **5.4.4 Alternative Explanations Review**

There have been several important changes to the electricity sector over the previous fifteen years. State renewable portfolio standards and the Great Recession likely disincentivized gas-fired construction. Changing environmental regulations may have promoted gas-fired construction. However, the affected states do not have a disproportionate share of construction. The regulations also do not appear timed such that they would substantially affect construction projections from 2007.

### **5.5 Interpretation**

Using differences from AEO projections, I estimate total gas-fired capacity additions of 18.0 to 22.0 GW between 2010 and 2013 due to low gas prices. Using a construction regressions approach, I estimate additions of 16.2 and 22.1 GW. Finally, using the raw EIA-860 data, I estimate additions of 17.5 GW. The similarity of these estimates causes me to conclude that between 65% and 85% of total additions were prompted by low gas prices. These estimates are also consistent with the intuition that greatly reducing marginal production costs (through lower gas prices) will incentivize firms to increase production capacity. The remainder of this paper studies changes in carbon emissions from both existing and newly-constructed plants.

## 6 Discussion

### 6.1 Estimated Value of Offset Emissions

I now estimate the economic value of reduced emissions. This is important because it allows one to better understand the magnitude of the benefits. The US Government recently provided an updated estimate of the social cost of carbon based on three of the leading climate damage models; it was roughly \$35/ton (Interagency Working Group on Social Cost of Carbon, 2013) in 2013, the end of my sample period. I estimate that lower gas prices led to fuel switching that offset about 14,700 tons/hour of carbon emissions in 2013. This is worth about  $(365 * 24 * 14,700 * 35 = )$  \$4.5 billion. In addition, newly constructed gas-fired power plants reduced 2013 carbon emissions by about 2,100 tons/hour. This is worth about  $(365 * 24 * 2,100 * 35 = )$  \$0.65 billion. My estimates from Section 5 suggest that between \$0.43 and \$0.56 billion of the \$0.65 billion (65-85%) is due to fracking. Combined, I estimate the 2013 decrease in carbon emissions is worth about \$5.1 billion. Most of this benefit is a pure externality, as the market only prices carbon in the RGGI states and, starting in 2013, California.<sup>37</sup>

The value of the emissions reductions varies between 2009 and 2013. The least valuable year was 2010, with reductions worth about  $(365 * 24 * 9,700 * 35 = )$  \$3.0 billion. The most valuable year was 2012, with reductions worth about  $(365 * 24 * 23,700 * 35 = )$  \$7.3 billion.

### 6.2 Demand Response

It is important to recognize that additional electricity demand (and emissions from generation) may have been induced by lower gas prices (which led to lower electricity prices).<sup>38</sup>

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<sup>37</sup>For higher or lower values of the social cost of carbon, the reader should divide the estimated benefits by 35 and multiply by the different estimate. For example, a social cost of carbon of \$42/ton would suggest benefits of  $(\$5.1 \text{ billion} / 35 * 42 = )$  \$6.1 billion.

<sup>38</sup>This analysis assumes that consumers respond to average prices as Ito (2014) demonstrates.

Indeed, Linn, Muehlenbachs and Wang (2014) find that natural gas and electricity prices have a positive and causal relationship. Average electricity prices in 2013 were 0.78% lower than 2008 AEO projections, while electricity generation prices were 6.44% lower than projected. The difference is due to increased transmission and distribution costs, some of which could have resulted from changing generation patterns. I will use these as the bounds of the potential demand response.

Using an elasticity of -0.3<sup>39</sup>, these estimates suggest that electricity demand has increased by between 0.23% and 1.93%. I can now use my primary specification (1) to estimate the rebound effect. For the lower bound in 2013, I estimate lower electricity prices prompt increases in demand that cause carbon emissions to increase by 0.6 thousand tons/hour (s.e. of 0.005). For the upper bound, I estimate carbon emissions increase by 5.2 thousand tons/hour (s.e. of 0.04). This is between 4% and 36% of the estimated 14.7 thousand tons/hour of emissions decreases caused by lower gas prices.<sup>40</sup>

### 6.3 Life-Cycle Greenhouse Gas Effects

Even considering potential demand response, it is clear that new gas supplies have decreased carbon emissions in the electricity sector. However, drilling for natural gas can have deleterious effects on the environment. In particular, leaking methane can offset many of the carbon emissions gains. The extent to which methane leaks are eliminated will largely determine whether or not fracking has a net positive effect on US greenhouse gas emissions. For a meta-analysis and overview of the shale gas life-cycle greenhouse gas emissions literature, see Heath et al. (2014).

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<sup>39</sup>Dahl and Roman (2004) is a meta-study reporting a long-run electricity demand elasticity of -0.32.

<sup>40</sup>To the extent that other factors changed, such as increased Chinese demand for coal, these bounds may prove to be insufficiently narrow.

## 7 Conclusion

Instead of declining as projected several years ago, US natural gas production has dramatically increased since 2008. This happened in part because the federal government has allowed it to. United States governments (excluding New York's) have largely refrained from imposing regulations that would seriously curb hydraulic fracturing for natural gas. I estimate that, depending on the year, 2009-2013 electric sector carbon emissions have decreased by between 3.4% and 8.3% as a result of lower gas prices. 2013's reductions, for example, are valued at \$5.1 billion. Lower gas prices have been an important contributor to the recent decrease in US carbon emissions. These reductions are likely to grow as new plants continue to be added to the electric grid.

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# Online Appendices

## A Variation in Gas Price Data

Much of the short-term variation in the price of natural gas is driven by demand shocks due to changes in temperature or forecasted temperature. Home heating is the largest natural gas demand source in the United States. During especially cold winters, gas use and gas prices rise. The reverse is true during warmer winters. To understand this relationship, an important source of variation for the causal analysis in Section 3, I use seven-day average future continental US heating degree days (HDD) provided by the National Weather Service. I use continental (as opposed to interconnection-level) HDD because the natural gas market is national – very cold temperatures in the Northeast will cause gas prices in Texas to increase.

This analysis does not capture the full effect of forecasted temperature on natural gas prices. However, it does show that the relationship is strong. Future heating degree days will not capture gas price variation caused by unusually warm temperatures (which cause electricity demand to increase, increasing gas demand). Additionally, I am using actual future HDD as a proxy for forecasted HDD. Note that this analysis does not include variation caused by short-run supply changes.

I now conduct a Frisch-Waugh decomposition to better understand the variation in the gas price data. Specifically, I regress the residuals from each of the following equations on each other:

$$\begin{aligned} P_t^{NG} = & \alpha_0 + s(Q_t^E) + \mathbb{1}\{P_t^{NG} > med(P_t^{NG})\} * s(Q_t^E) + s(Renewables_t) \\ & + s(HDD_t^{current}) + s(CDD_t^{current}) + s(Date_t) + \gamma D_m + \epsilon_t \quad (3) \end{aligned}$$



$$\begin{aligned}
HDD_t^{future} = & \alpha_0 + s(Q_t^E) + \mathbb{1}\{P_t^{NG} > med(P_t^{NG})\} * s(Q_t^E) + s(Renewables_t) \\
& + s(HDD_t^{current}) + s(CDD_t^{current}) + s(Date_t) + \gamma D_m + \epsilon_t \quad (4)
\end{aligned}$$

The dependent variables here are the same as those in equation 1. Once I control for seasonal variation, time trends, renewable generation, and electricity demand, I am able to look at how residual variation in weather forecasts affects variation in the price of natural gas. My standard errors are calculated as in other parts of the paper; I use a Newey-West specification with seven lags.

Figure 8 displays this relationship for selected hours. Even though the average future continental HDD is a crude measure of the effect of weather on gas prices, the relationship is still strong. Forecasts with above expectation HDD (that is, unusually cold days) are associated with gas prices that are above expectation. Similarly, unusually warm days are associated with gas prices that are below expectation. This is the relationship that I expect. All 72 interconnection-hour combinations are significant at the 10% level; the t-statistics range between 1.78 and 3.43. Six t-statistics fall between 1.78 and the 5% threshold of 1.96; all six are in the Texas interconnection.

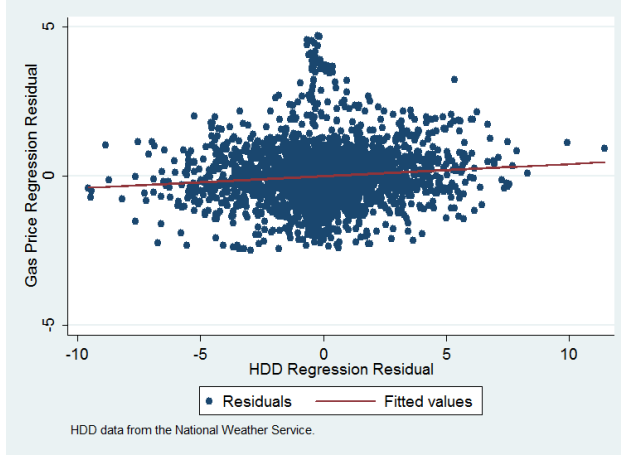
## B Background

There are a several institutional details that are important to my analysis. For the vast majority of American consumers, electricity prices do not vary in real time. Thus, electricity demand does not adjust in real-time in response to changing wholesale electricity prices – it is almost completely inelastic in the short-run. Over the medium-run, demand has the potential to adjust in response. Electricity prices have been relatively stable in real terms recently. Between 2007 and 2013 the real annual national average price of electricity fluctuated between 9.35 and 9.98 cents per kilowatt-hour (EIA).<sup>41</sup> Electricity consumption

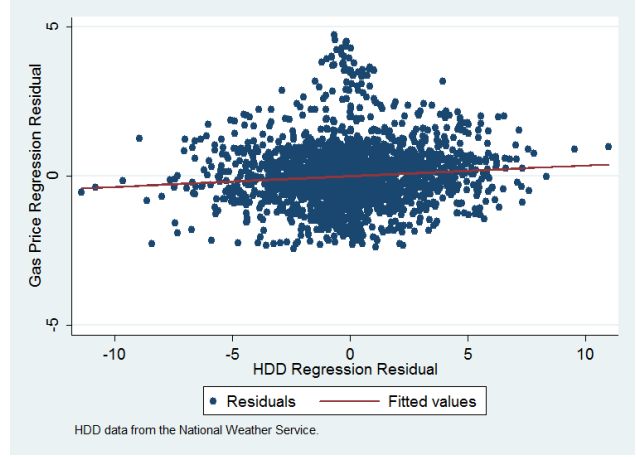
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<sup>41</sup>This is across all segments, not just residential consumption. Monthly data has a little more variation. I use 2010 price levels.

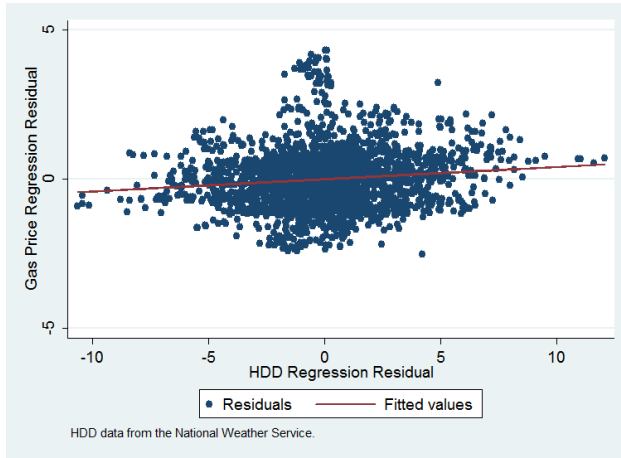
**Figure 8: Frisch-Waugh Analysis of Variation**



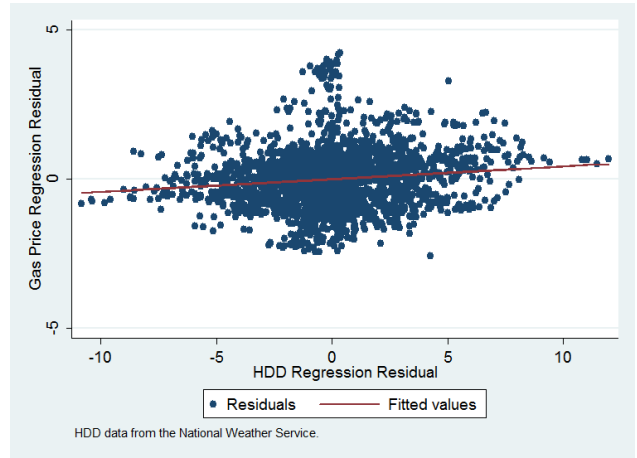
**(a) Eastern: 2:00 AM (Off-Peak)**



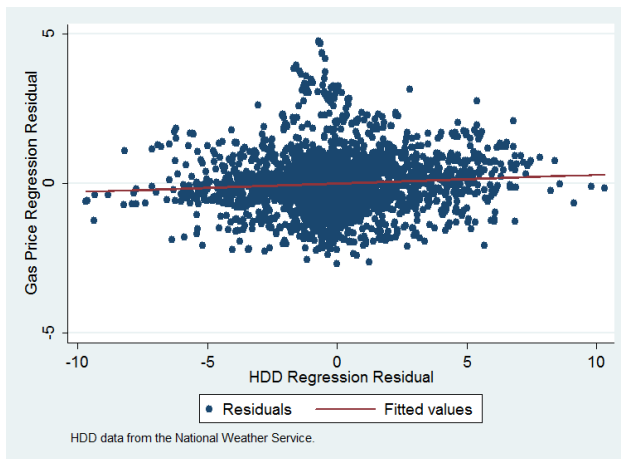
**(b) Eastern: 6:00 PM (Peak)**



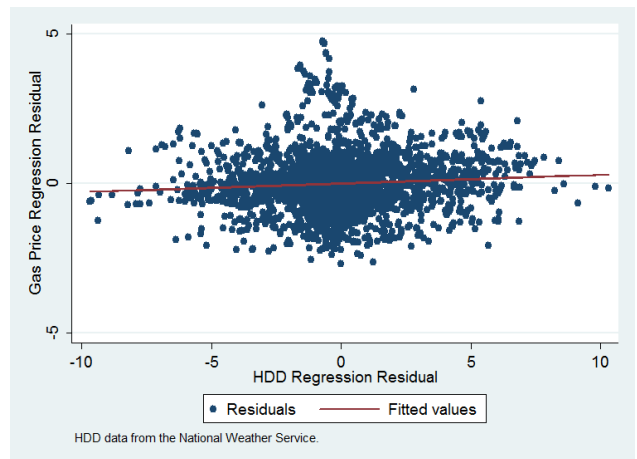
**(c) Western: 2:00 AM (Off-Peak)**



**(d) Western: 6:00 PM (Peak)**



**(e) Texas: 2:00 AM (Off-Peak)**



**(f) Texas: 6:00 PM (Peak)**

has also been relatively constant. In the discussion section, I examine the potential medium-run demand response.

It is important to note that manipulation of the price of natural gas is not a concern for my estimation. Gas power plants are price-takers and are unable to manipulate the price of natural gas. The natural gas market is large and groups of power plants are unable to substantially move the market. Additionally, it is the case that power plants with long-term contracts are not required to burn gas at any individual time. Thus, whether a plant has a favorable or unfavorable long-term contract (or no long-term contract) has little bearing on whether they decide to supply electricity. The opportunity cost of producing electricity is the spot price of natural gas that firms pay.<sup>42</sup>

## B.1 Interconnection Analysis

For my analysis, I focus on the NERC interconnection level as in Graff Zivin, Kotchen and Mansur (2014). Figure 9 illustrates the location and boundaries of the three interconnections and regions within each that the NERC oversees. The interconnections are largely separate entities, with minimal electricity trading between each interconnection. The Western interconnection (WECC) covers most of the territory from New Mexico up to Montana and west. The Texas interconnection (TRE) covers most of Texas. The Eastern interconnection is subdivided into six different regional entities that comprise the rest of the United States.

Figure 10 shows power flows between different regions. For reference, one million megawatt hours over the course of a year are equivalent to an average of roughly 115 megawatts during every hour. Electricity flows between interconnections (circled) are very small. Regions with large amounts of power trading, like the Chicago area with eastern parts of the RFC (denoted by the 102 million megawatt hours), would be inappropriate fits for my model. While Canada does trade power with the United States, the lines are primarily transmitting hydroelectrically generated electricity and are full at most hours. Thus, it should have limited

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<sup>42</sup>For more on gas markets, please see EIA (2001).

Figure 9

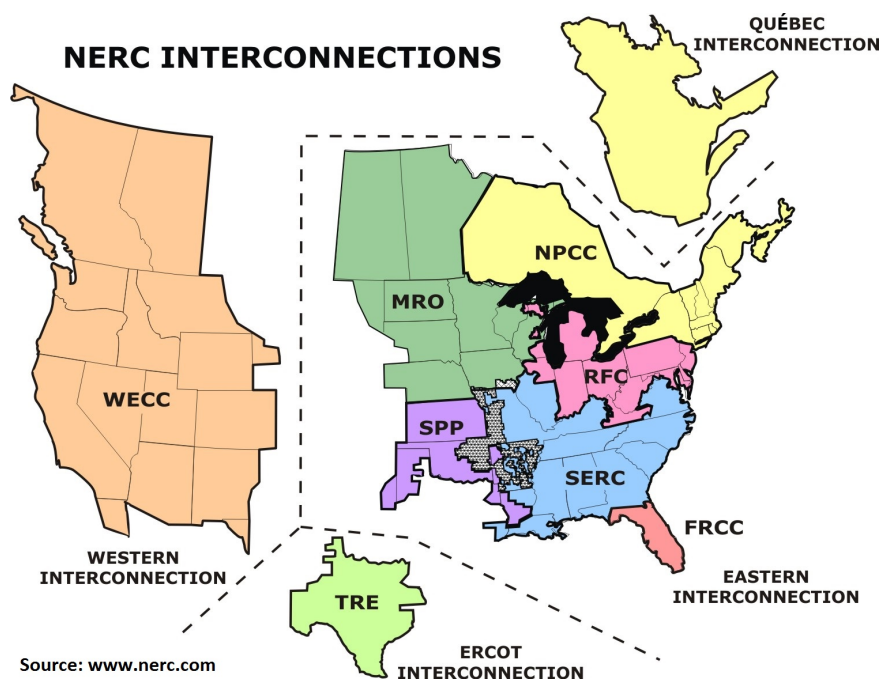
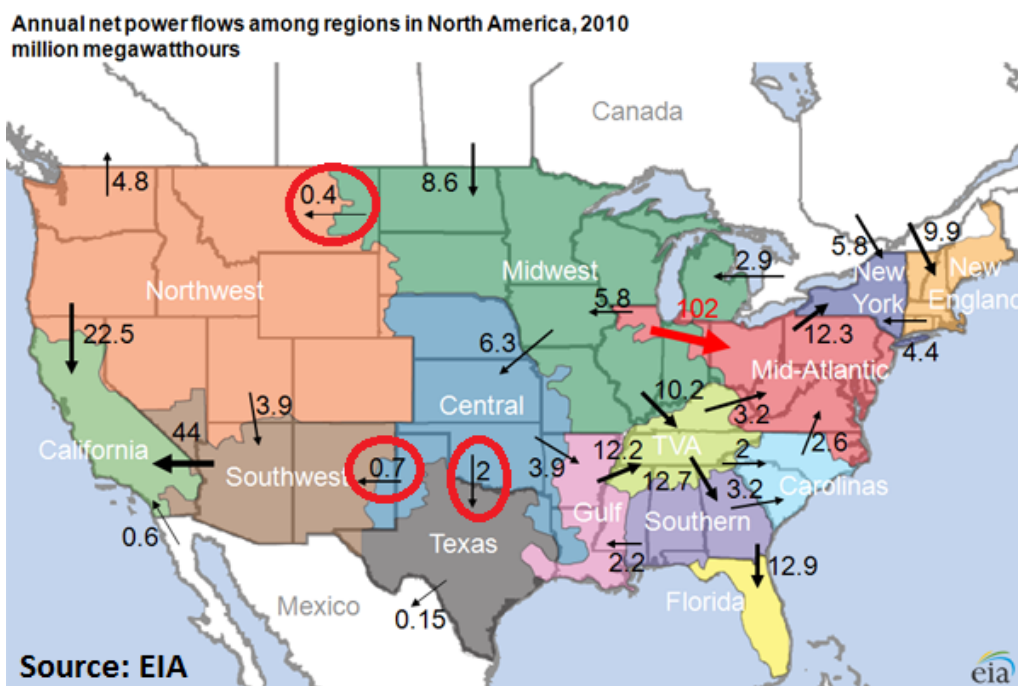


Figure 10



effect on the analysis.

A large amount of regional trading would threaten clean identification of this relationship. To understand this, consider two regions, the Midwest Reliability Organization (MRO) and

the Southwest Power Pool (SPP). MRO has large amounts of coal capacity, while SPP has a mixture of coal and natural gas. Assume that the regions trade freely and have large amounts of transmission capacity between them. Additionally, assume electricity demand remains fixed. As the price of natural gas decreases, more gas and less coal will be burnt. This would mean that in aggregate carbon dioxide emissions would decrease. However, it could be the case that power generation has increased in SPP and decreased in MRO, with SPP sending excess generation to MRO. SPP would then show an increase in emissions at lower gas prices, while MRO shows a larger than deserved decrease. A system with minimal trading prevents this potential identification issue.

## B.2 Gas Prices and the Dispatch Curve

There has been substantial variation in the natural gas price over the last several years. The spot price of gas at Henry Hub, the most important trading location, does an excellent job of capturing this variation. United States gas markets are fairly integrated, with most other locations trading at a basis against Henry Hub. For example, natural gas in Chicago is generally about 10 cents per MMBtu (2-5%) more expensive than natural gas at Henry Hub.

Figure 11

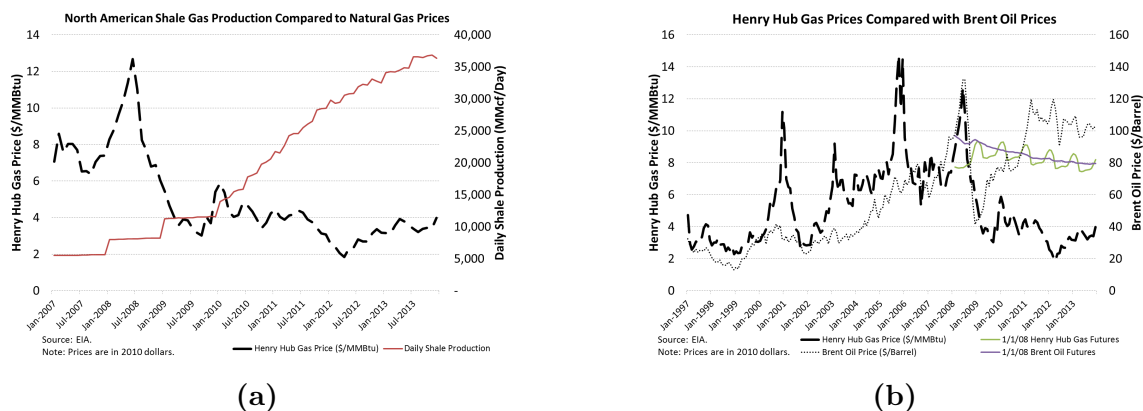


Figure 11 examines changes in the natural gas market that have been occurring since

2007. The panel on the left (a) plots the relationship between the Henry Hub Natural Gas Spot Price and the quantity of shale gas that is produced in North America. It demonstrates that as the supply of shale gas has increased, the price of natural gas has decreased. The vast majority of shale gas is drilled using hydraulic fracturing. Note that the first three years of shale data were only collected annually, though quantities are generally small. Additionally, the gas price is a monthly average. This figure depicts the long-term trend, though it obscures the day-to-day variation in gas prices that is key to my identification strategy.

The panel on the right (b) plots the price of gas at Henry Hub against the Brent oil price.<sup>43</sup> Oil and gas are energy sources that are, to a certain extent, substitutable. Prior to the large-scale implementation of fracking, oil and gas closely tracked each other, with a barrel of oil being about ten times as expensive as an MMBtu of natural gas.<sup>44</sup> The graph starts in 1997 when the EIA Henry Hub spot price time series begins, though the relationship in the early 90's (using a different measure of the natural gas price) was also strong. In 2008 there was a recession-induced decline in the prices of both fuels. Shale gas production greatly increased during the recovery, and the relationship between gas and oil prices fractured. Oil prices surged back to pre-recession levels, while gas prices continued their decline. By the end of 2013, a barrel of oil was now *twenty-five* times as expensive as one MMBtu of natural gas.<sup>45</sup>

If macroeconomic conditions were the only important changes in energy markets, gas prices would likely have rebounded similar to the oil price rebound (Hausman and Kellogg, 2015). The fractured relationship is possible because oil is traded on a global market, whereas natural gas markets are regional (Kilian, 2015). Fracking has also produced a US oil boom, but it hasn't had as large of an effect on the world price of oil because the global oil market is very large and the oil boom began later. Excess natural gas within the US is unable to

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<sup>43</sup>Brent oil is the major world oil price. Oil prices in Cushing, Oklahoma are similar, though they have been slightly lower because of pipeline constraints.

<sup>44</sup>That is, oil was about twice as expensive on a per-MMBtu basis

<sup>45</sup>For more on the relationship between oil and gas prices, please see Villar and Joutz (2006); Ramberg and Parsons (2012) and EIA (2012).

be exported in large quantities outside of North America because of a lack of infrastructure and high transportation costs. Instead, it is consumed locally at much cheaper prices.

Also included in panel (b) are futures curves from January 2008 for natural gas and crude oil. The futures curves show that financial markets expected gas and oil prices to retain their historical relationship over the 2009-2013 period. Financial markets also did not anticipate the large decline in gas prices.

As discussed in the introduction, total gas production in the US increased by 5 trillion cubic feet per year, or 20%, between 2007 and 2012. The combination of a large increase in quantity supplied and a large decrease in the price of natural gas is strongly suggestive of a large rightward shift of the natural gas supply curve.

The price of natural gas is an important factor in electric-sector carbon emissions. In some areas of the country, firms bid in real-time to determine who is going to supply the marginal kilowatt-hour. Nuclear and renewable power plants have very low marginal costs. As a result, nearly all marginal power is provided by either coal or natural gas-fired plants. In other areas of the country, a centralized dispatch authority determines which plants produce power. One of the authority's main objectives is to minimize generation costs. Changing fuel costs will prompt a dispatch authority to adjust the generation mix.

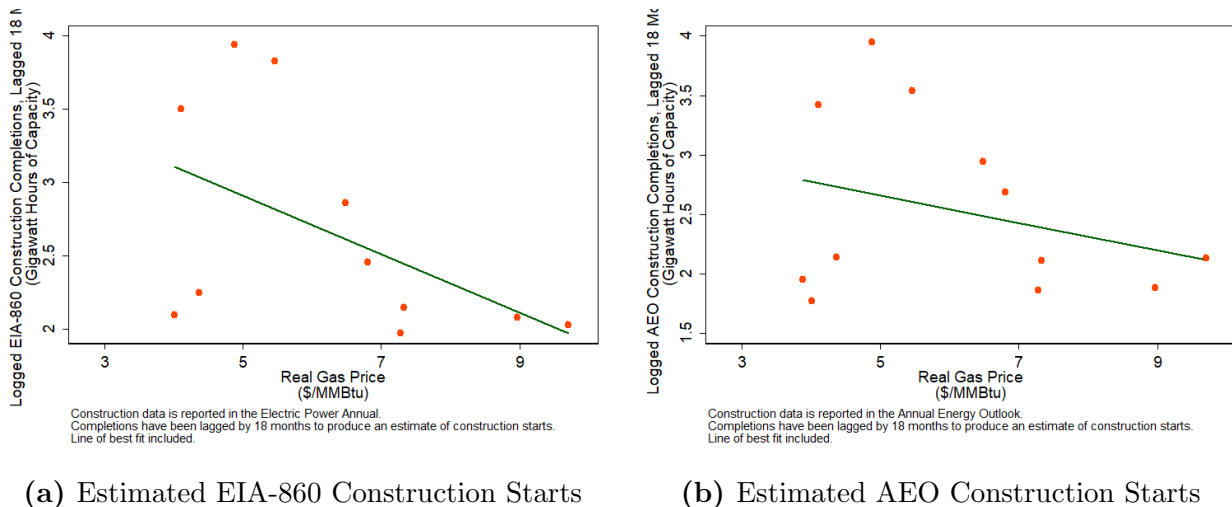
Fuel is the primary variable cost at fossil fuel power plants. Moderate to high natural gas prices usually cause coal to have lower variable costs than gas, making it the first fuel called upon to generate electricity. At lower gas prices, the marginal cost of electricity generated from gas will decrease and gas will begin to displace coal in the generation order. This switching between coal and natural gas is the key mechanism driving the results in this paper. Switching is able to happen within a period of hours.

## C Alternative Construction Regressions

This section expands on the construction regressions in section 5.2. I first present the data in scatterplot form and include a line of best fit (Figure 12). The relationship appears negatively correlated for both sources of estimated construction starts data.

I also present alternative specifications that have leads of between 12 and 36 months. I use a minimum 12-month lead, which is shorter than an 18-month construction period, to capture the fact that some paused construction could have been restarted with the advent of cheaper natural gas. The EIA-860 micro data supports this possibility; many projects are listed as “Indefinitely Postponed.”<sup>46</sup> It is highly likely that some of these postponed projects were continued after gas prices dropped. I use a maximum 36-month lead because it is the longest planned construction duration for a gas-fired power plant. Additionally, my data does not allow me to analyze longer-term construction effects.

**Figure 12:** Gas Prices and Estimate Construction Starts



I consider both logged and raw construction starts as the independent variable. Tables 5 and 6 display the results of alternative specifications. Columns [2] and [7] of Table 6 are my preferred specifications.

<sup>46</sup>The results using AEO data with a 12-month lead and a logged dependent variable do not strongly support this possibility.



Table 5

### Estimated Counterfactual Plant Construction Results from Regression Analysis Using Raw Starts

Item	Using AEO Plant Data										Using EIA-860 Plant Data									
	12-Month		18-Month		24-Month		30-Month		36-Month		12-Month		18-Month		24-Month		30-Month		36-Month	
	Lag		Lag		Lag		Lag		Lag		Lag		Lag		Lag		Lag		Lag	
	[1]		[2]		[3]		[4]		[5]		[6]		[7]		[8]		[9]		[10]	
Gas Price Coefficient	[a]	-1.34	-2.57		-2.79		-2.90		-2.09		-3.47		-4.11		-3.69		-4.48		-3.24	
Standard Error	[b]	2.57	2.35		2.79		2.37		1.89		2.68		2.65		2.86		2.39		2.03	

Counterfactual Plant Construction (Gigawatts)

Year	12-Month		18-Month		24-Month		30-Month		36-Month		12-Month		18-Month		24-Month		30-Month		36-Month	
	Lag		Lag		Lag		Lag		Lag		Lag		Lag		Lag		Lag		Lag	
2009	[c]	10.9	10.9		10.9		10.9		10.9		9.4		9.4		9.4		9.4		9.4	
2010	[d]	-4.4	-4.1		2.3		2.3		2.3		-10.7		-3.7		6.5		6.5		6.5	
2011	[e]	3.3	-2.8		-4.4		2.3		9.5		-6.3		-10.0		-8.7		-1.5		9.7	
2012	[f]	0.7	-4.9		-5.3		-6.3		-2.8		-8.5		-10.7		-7.8		-12.3		-6.9	
2013	[g]	-2.0	-8.1		-7.6		-7.5		-3.0											
Actual Construction																				
2010 - 2012/2013	[h]	25.9	25.9		25.9		25.9		25.9		25.4		25.4		25.4		25.4		25.4	
Construction Caused by Fracking	[i]	21.9	25.9		23.6		21.3		14.1		25.4		25.4		18.9		18.9		9.2	

Notes: EIA-860 data for 2013 is unavailable. Gas Plants take between 18 and 36 months to construct.

[i]: = [h] - Sum([d] to [g]) if positive & shaded.

Sources: EIA-860 data summarized in the Electric Power Annual and Annual Energy Outlook Data.

Table 6

**Estimated Counterfactual Plant Construction**  
**Results from Regression Analysis Using Logged Construction Starts**

Item	Using AEO Plant Data										Using EIA-860 Plant Data									
	12-Month		18-Month		24-Month		30-Month		36-Month		12-Month		18-Month		24-Month		30-Month		36-Month	
	Lag	[1]	Lag	[2]	Lag	[3]	Lag	[4]	Lag	[5]	Lag	[6]	Lag	[7]	Lag	[8]	Lag	[9]	Lag	[10]
Gas Price Coefficient	[a]	-0.02	-0.13	-0.21	-0.19	-0.16					-0.15	-0.21	-0.21	-0.25						
Standard Error	[b]	0.13	0.12	0.13	0.11	0.13					0.12	0.12	0.11	0.10	0.10					

Counterfactual Plant Construction (Gigawatts)

Year	12-Month		18-Month		24-Month		30-Month		36-Month		12-Month		18-Month		24-Month		30-Month		36-Month	
	Lag		Lag		Lag		Lag		Lag		Lag		Lag		Lag		Lag		Lag	
2009	[c]	10.9	10.9	10.9	10.9	10.9					9.4	9.4	9.4	9.4	9.4					
2010	[d]	2.0	1.5	2.3	2.3	2.3					1.7	3.2	6.5	6.5	6.5					
2011	[e]	8.5	3.6	-0.4	5.1	9.5					3.0	0.1	-0.5	3.7	9.7					
2012	[f]	6.7	2.8	0.3	0.8	1.7					2.2	0.0	0.2	-1.8	0.8					
2013	[g]	5.7	1.7	-0.5	0.6	1.8														
Actual Construction																				
2010 - 2012/2013	[h]	25.9	25.9	25.9	25.9	25.9					25.4	25.4	25.4	25.4	25.4					
Construction Caused by Fracking	[i]	2.9	16.2	23.4	17.2	10.7					18.5	22.1	18.7	15.2	8.5					

Notes: EIA-860 data for 2013 is unavailable. Gas Plants take between 18 and 36 months to construct.

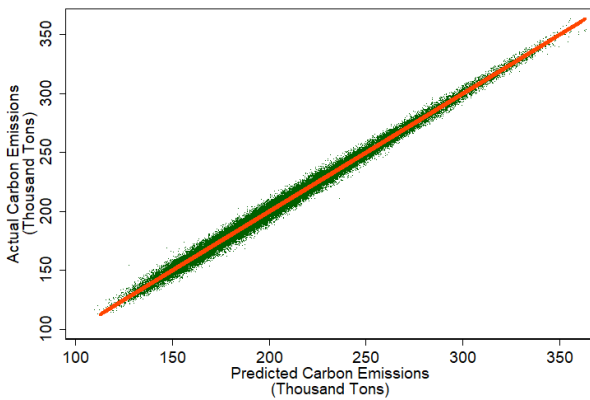
[i]: = [h] - Sum([d] to [g]) if positive & shaded.

Sources: EIA-860 data summarized in the Electric Power Annual and Annual Energy Outlook Data.

## D Primary Specification Fit

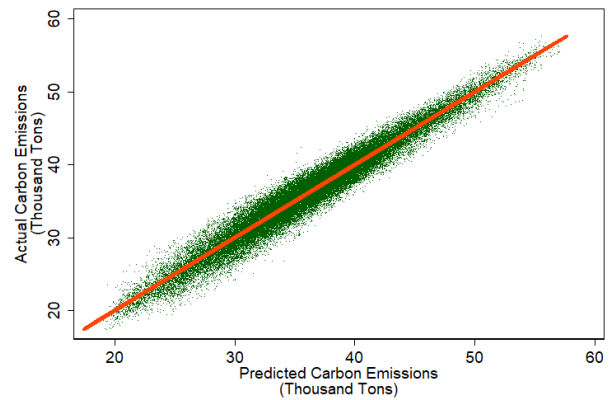
Figure 13 displays scatter plots for each interconnection with a 45° line. It maps actual carbon emissions against carbon emissions predicted by my primary specification. The relationship is very strong and most points are very close to the 45° line. There does not appear to be any bias at the aggregate level.

**Figure 13:** Actual Emissions vs. Predicted Emissions



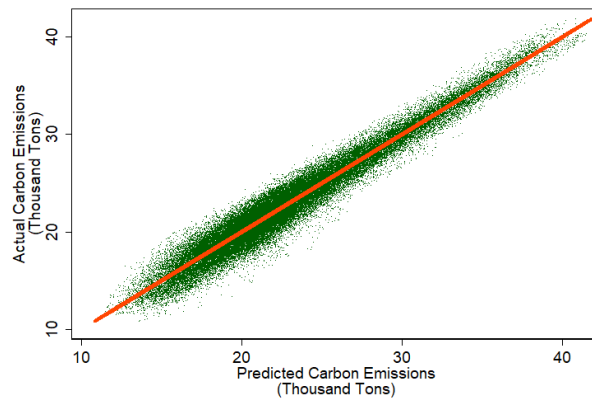
Actual emissions vs. emissions predicted using estimates from equation (2).  
Emissions data from CEMS. 45 Degree line included.

(a) Eastern Interconnection



Actual emissions vs. emissions predicted using estimates from equation (2).  
Emissions data from CEMS. 45 Degree line included.

(b) Western Interconnection



Actual emissions vs. emissions predicted using estimates from equation (2).  
Emissions data from CEMS. 45 Degree line included.

(c) Texas Interconnection

## E Robustness Checks

I consider several alternative specifications to alleviate concerns about my results being due to misspecification or chance. I focus on including daily wind generation, using additional Newey-West lags, using alternative gas prices, and using a gas/coal price ratio.

### E.1 Inclusion of Daily Wind Generation Data

It is possible that failing to control for wind causes my results to be overstated. This could be the case because windy days decrease both carbon emissions and the gas price. As more wind power is generated, less fossil-fuel generation is needed. As a result, carbon emissions will drop, as will the prices of fossil fuels. Daily wind generation is only available in the Texas interconnection. Texas has the most wind capacity as a percentage of electricity demand (the Western interconnection has about two-thirds as much and the Eastern interconnection has about one-third as much). Thus, any effects of wind generation should be smaller in the other two interconnections.

Specifically, I estimate the following regression:<sup>47</sup>

$$TE_t = \alpha_0 + s(P_t^{NG}) + s(Q_t^E) + \mathbb{1}\{P_t^{NG} > med(P_t^{NG})\} * s(Q_t^E) + s(Renewables_t) \\ + s(Date_t) + \gamma D_m + \mathbf{s}(\mathbf{Wind}_t) + \epsilon_t \quad (5)$$

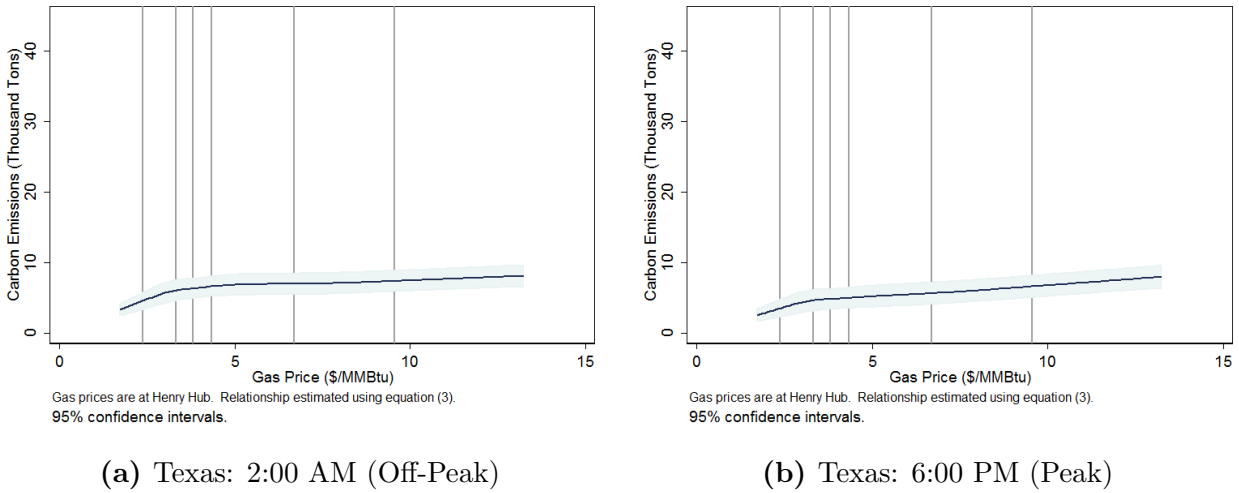
The resulting splines and counterfactual emissions reductions are similar. Figure 14 shows two splines that are comparable to those in Figure 3. There are almost no differences between the two figures. This translates into limited change in the estimates. For example, my primary specification estimates that Texas carbon emissions in 2013 were 1.46 thousand tons/hour lower than they would have been with higher gas prices (s.e. of 0.21). By including

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<sup>47</sup>I also include two dummies to account for data irregularities. Most of the data is scraped from ERCOT's website, while about 2% is directly from ERCOT. Additionally, approximately 2% of the data remains missing. To preserve the structure of the dataset for standard error calculations, I fill missing data with the observation from 24 hours prior.

wind in my specification, this estimate actually increases to 1.64 thousand tons/hour (s.e. of 0.20). I interpret these estimates as essentially the same. This suggests that the estimates presented in this paper do not have a large bias due to the failure to include daily wind generation. Any potential bias would be mitigated in the (larger) Eastern and Western interconnections by the fact that wind generation is a substantially smaller portion of the generation portfolio.

**Figure 14:** Texas Interconnection Gas Price Splines Including Wind Generation



## E.2 Additional Autocorrelation Lags

I now consider how the standard errors would change if I allowed for additional periods of autocorrelation. While my preferred specification allows for one week of autocorrelation, this section allows for one month of autocorrelation. For estimates that are composites of multiple regions or multiple hours, this means that I use larger blocks in my block bootstrap.

Table 1 displays estimates using seven days of autocorrelation. For example, my combined estimate for 2013 of 16.7 thousand tons of carbon/hour has a standard error of 0.9. Increasing the allowed autocorrelation to one month increases the standard error to 1.4. The estimate of reductions caused by new plants is 2.1 thousand tons of carbon/hour, with a standard error of 0.062. Using additional lags increases the standard error to 0.064. All estimates

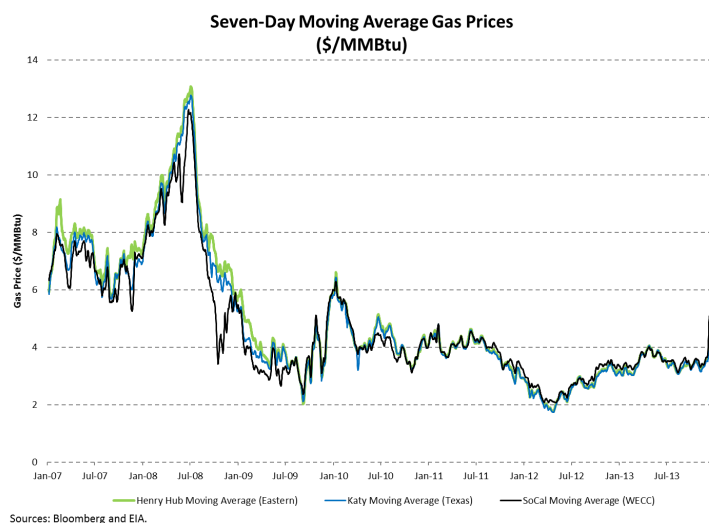
remain significant at the 1% level.

### E.3 Alternative Gas Prices

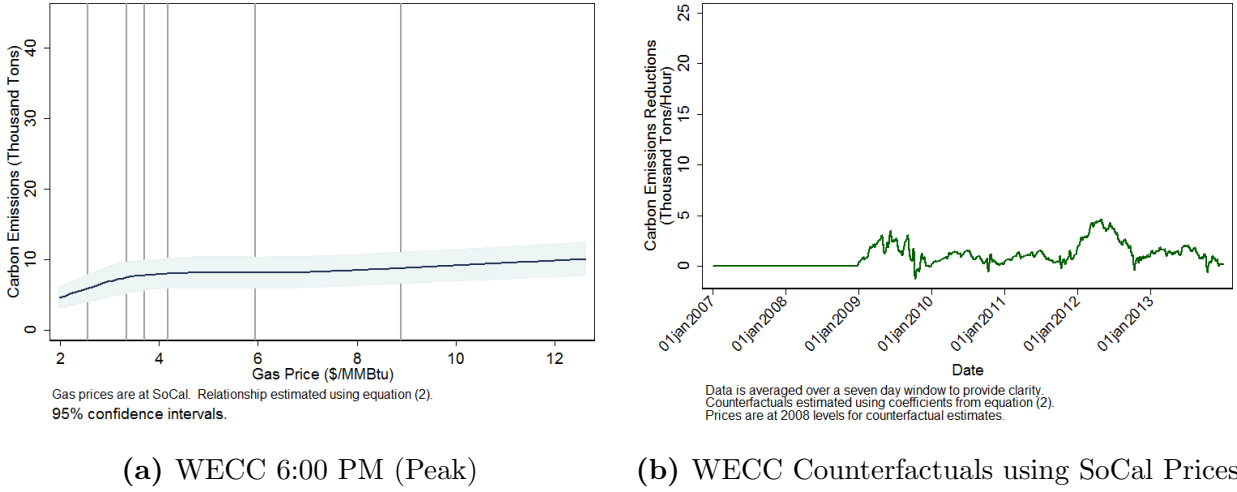
This paper uses natural gas prices at Henry Hub, the major US trading location in southern Louisiana. Using Henry Hub gas prices has several advantages. Henry Hub has been a consistent trading location for decades and most other locations trade with prices marked to Henry Hub. In contrast, many other hubs have thin trading at some times and/or can change exact terms and locations of delivery over time. Additionally, it provides a benchmark that allows for easy interpretation of the results and extrapolation. While Eastern and Texas gas prices are very closely linked to Henry Hub, Western gas prices occasionally are out of sync. This subsection analyzes the Western interconnection using gas prices at SoCal Gas, a major trading hub in California.

Figure 15 plots gas prices at Henry Hub (in the Eastern interconnection), Katy (in Texas), and SoCal (in the WECC). Generally, the three prices closely track each other, though SoCal is a looser fit. In particular, late 2008 saw SoCal deviate from the Henry Hub/Katy price. The daily correlation between Henry Hub and Katy gas prices is .996, while the daily correlation between Henry Hub and SoCal is .973.

**Figure 15**



**Figure 16:** Western Interconnection using Gas Prices at SoCal Trading Hub



I rerun my analysis with the only change being the different gas price for the Western interconnection. Figure 16 highlights two of the key results. The gas price spline in panel (a) looks similar to the spline using Henry Hub prices in Figure 3. Counterfactual emissions estimates in panel (b) look similar to counterfactual estimates using Henry Hub prices in Figure 4. Total 2013 reductions using prices at SoCal for the Western interconnection are estimated at 15.5 thousand tons/hour. Using Henry Hub gas prices for all interconnections, total 2013 reductions are estimated at 16.7 million tons/hour. The difference is primarily driven by the fact that late 2008 gas prices at SoCal were lower than at Henry Hub. Additionally, the end of 2013 saw higher prices at SoCal than at Henry Hub.

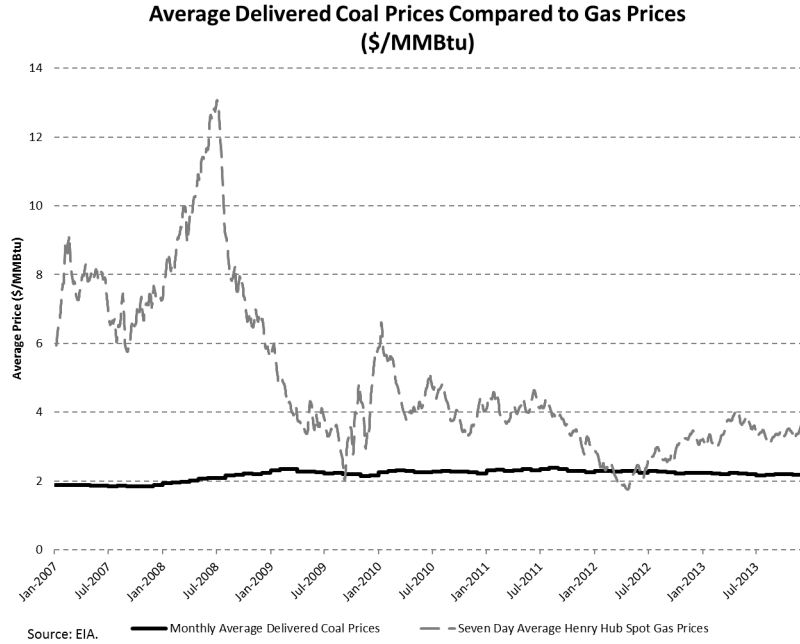
## E.4 Inclusion of Coal Prices

Coal prices are an important component of the electricity market. While my preferred specification omits them because natural gas prices influence coal prices, I consider them here. I use data from the EIA's Short-Term Energy Outlook. The EIA constructs an average price for coal delivered to electricity plants across the country. I use the delivered price because trading hubs are generally not close to coal-fired generators.

Coal is very expensive to transport, so the spot price in, e.g., Central Appalachia does

a poor job of approximating the marginal cost of burning coal for most generators (Cicala, 2014). Delivered coal prices are only available on a monthly basis. This should not be a problem because most coal contracts are medium-term and coal generators are not easily able to resell coal on the spot market because of the transportation costs.<sup>48</sup> Figure 17 plots the monthly average delivered coal price from 2007 to 2013.<sup>49</sup> I include the seven-day average Henry Hub spot price of natural gas for comparison. Delivered coal prices are much more stable than natural gas prices.

**Figure 17**



Specifically, I estimate:

$$TE_t = \alpha_0 + s(\mathbf{P}_t^{NG}/\mathbf{P}_t^{Coal}) + s(Q_t^E) + \mathbb{1}\{P_t^{NG} > med(P_t^{NG})\} * s(Q_t^E) + s(Renewables_t) \\ + s(HDD_t) + s(CDD_t) + s(Date_t) + \gamma D_m + \epsilon_t \quad (6)$$

When estimating counterfactual emissions, I estimate all emissions as if both 2008 gas prices and 2008 coal prices were realized in every other year. Table 7 displays counterfactual

<sup>48</sup>Coal plants adjust production by storing inventory at low cost and purchasing less coal in future contracts.

<sup>49</sup>Delivered coal prices are reported at the monthly level.



estimates. Results look similar to counterfactual estimates using only gas prices in Table 1. Total estimated reductions in 2013 using my primary analysis are 16.7 thousand tons of carbon per hour. When I use a gas/coal price ratio, counterfactual emissions are estimated at 16.3 thousand tons of carbon per hour (s.e. of 1.0). 2013 reductions attributable to new plant construction are 2.1 thousand tons/hour in my primary specification, and remain 2.1 thousand tons/hour when coal prices are included (s.e. of 0.06).

**Table 7**

**Hourly Reductions in Carbon Dioxide Emissions  
By Year - Using Gas/Coal Price Ratio  
(Thousand Tons of Carbon Dioxide/Hour)**

		<b>2008</b>	<b>2009</b>	<b>2010</b>	<b>2011</b>	<b>2012</b>	<b>2013</b>
		[1]	[2]	[3]	[4]	[5]	[6]
Actual Emissions	[a]	284.7	261.3	278.3	266.0	249.0	253.0
Predicted Emissions using Gas/Coal Price Ratio	[b]	284.3	261.9	277.6	266.4	249.1	252.8
Counterfactual Emissions (Using 2008 Gas Prices)	[c]		274.0	287.6	279.8	271.6	267.2
Emissions Reductions From Gas/Coal Switching	[d]		12.1 (0.9)	10.0 (0.9)	13.4 (1.0)	22.5 (1.2)	14.4 (1.0)
Counterfactual Emissions (Without Newly Constructed Plants)	[e]			277.6	267.0	250.9	254.9
Reduction Caused by New Power Plants	[f]			0.1 (0.0)	0.6 (0.0)	1.8 (0.1)	2.1 (0.1)
Counterfactual Emissions (With 2008 Gas Prices and Without New Plants)	[g]		274.0	287.7	280.3	273.3	269.1
Total Reductions from Low Gas Prices	[h]		12.1 (0.9)	10.1 (0.9)	13.9 (1.0)	24.2 (1.2)	16.3 (1.0)

Notes:

[d] = [c] - [b]

[f] = [e] - [b]

[h] = [g] - [b]

Standard errors are estimated using block bootstrapping with 1000 replications.