Appendix: The Impact of Cheap Natural Gas on Marginal Emissions from Electricity Generation and Implications for Energy Policy

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This appendix provides a number of additional expositional details and robustness checks. We begin by providing a variety of evidence on the validity of our identification strategy. We first describe changes in electricity demand. We then describe how fossil fuel generation capacity evolved over our sample period. We next present a different empirical technique for identifying the date of the break between the high and low natural gas price regimes. This technique estimates a date within an about a month of the date reported in the main text. We then provide a series of tables that provide averages of estimated marginal emissions rates.

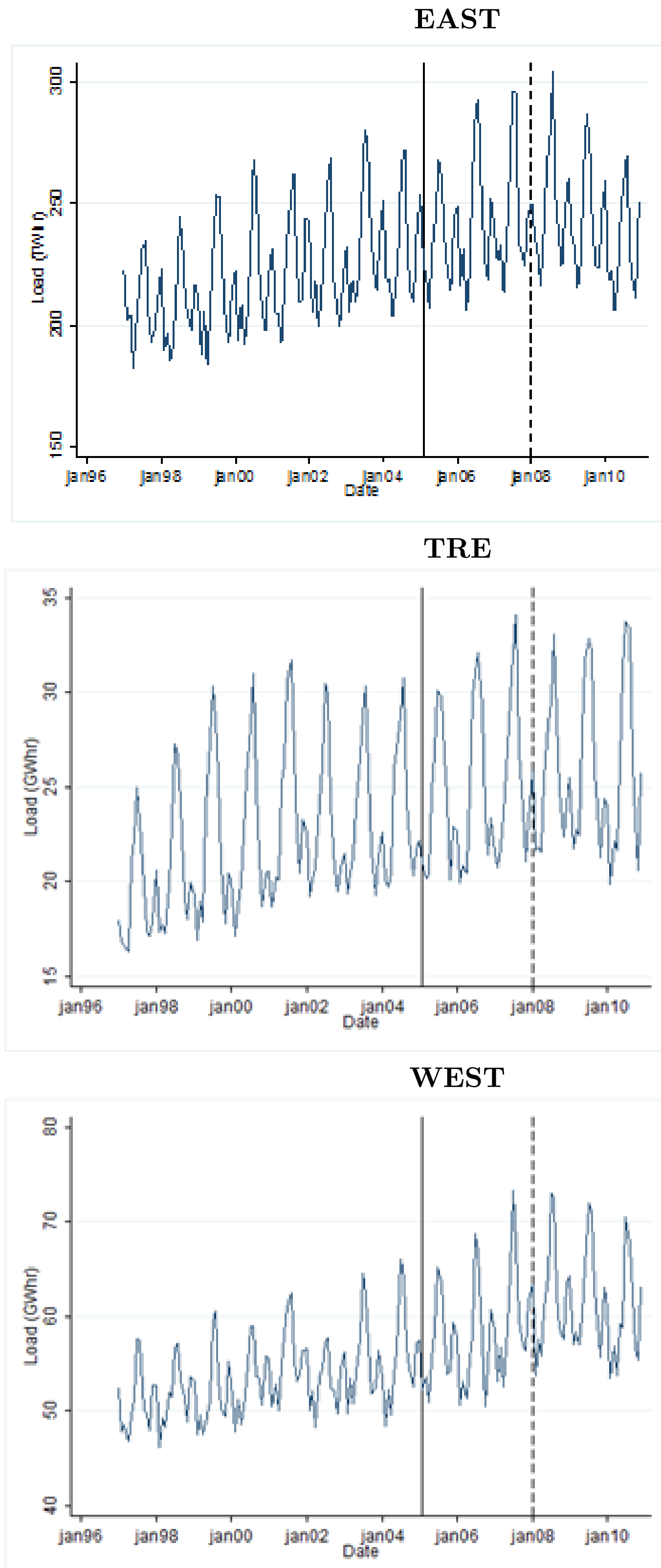
Next we present a series of robustness checks on our marginal emissions estimates. First we instrument for generation with electricity demand. We also describe the conditions under which the IV results are might be appropriate for evaluating the environmental effects of renewable generation. We then introduce a robustness check that drops six months and one year of the sample on centered on the regime change date we use in the main text. We also report results identifying marginal emissions off differences in natural gas and coal prices, rather than comparing marginal emissions rates across natural gas price regimes. In these robustness checks we rely primarily on presenting the results of simulations to conserve space, but estimated marginal emissions rates are available upon request.

Finally we report suggestive evidence that the costs of complying with the requirements of the Clean Air Act to purchase pollution permits does not have a significant impact on the changes in marginal emissions rates presented in the main text.

1 Changes in electricity demand

As noted in the main text, changes in electricity demand represent a potential threat to identification. In this section we present evidence that total demand was relatively flat across our two natural gas price regimes. Figure A1 displays monthly demand, collected from NERCs Electricity Supply and Demand (ES&D) dataset, from 1996-2010 for each Interconnection. The solid vertical line represents the beginning of our sample period and the dotted line represents the date of our regime break. Demand shows a strong seasonal component, but has been relatively flat during our sample period after a decade of steady growth. We run a simple regression comparing monthly electricity demand to a dummy for our low natural gas price regime. The results suggest that average electricity demand is down somewhat in the Eastern Interconnection, and up slightly in TRE and WECC, but none of the changes are statistically significant.

Figure A1: Electricity demand across natural gas price regimes

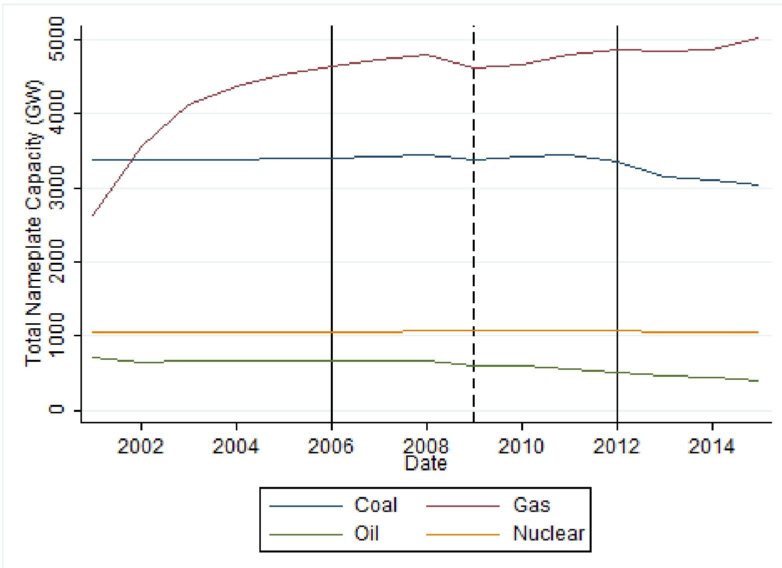


Note: Average monthly electricity demand by NERC Interconnection over 1996-2010. The solid vertical line represents the beginning of our sample period and the dotted line represents the date of the regime break. Source: NERCs Electricity Supply and Demand (ES&D) dataset

2 Changes in fossil fuel capacity

The EIA 860 data shows little change in the overall distribution of capacity shares for fuels during our sample period. Table A2 reports total capacity by fuel type from 2001-2015. We collect the data from EIA's annual 860 forms. The vertical line represents the beginning of our sample period and the dotted line represents the approximate date of our regime break. There is a significant uptick in natural gas generating capacity prior to our sample period. During our sample period coal and nuclear capacity levels are nearly constant. There is a slight decline in oil generating capacity in the last year of the sample. Most noticeably there is a noticeable increase in natural gas generating capacity, equating to a nearly six percent increase in total nameplate capacity from the beginning to the end of our sample period.[1]

Figure A2: Nameplate capacity 2001-2015



Note: Total nameplate capacity by fuel type between 2001 and 2010. Figure reports sum of all capacity across the Eastern, TRE and Western Interconnections. All data collected from annual EIA 860 forms.

Next we explore the geographic distribution of that increase. Figure A3 shows the spatial distribution of the increase in natural gas capacity between January 2007 and December 2011 taken from the EIA 860 and 923 forms. We limit the increase in capacity from 2007-2011 since it is implausible that futures market predictions could affect increases in natural gas capacity in 2005 or 2006. Units are displayed in 1000s of MWs.[2] Figure A3 shows that much of the increase in capacity took place in Florida (FRCC) with more modest increases elsewhere. We show below that Florida had the largest share of oil-fired generation throughout the mid-2000s in the U.S. While beyond the scope of this paper, as oil prices rose in the mid-2000s the incentive to build new more efficient natural gas price may have been sufficient to motivate new investment. Along with the information

[1] The same data reveals that retirements average around 0.5% of installed generating capacity during our sample period and that are no significant differences in retirement rates across natural gas price regimes.

[2] According to census and DOE data, per capita electricity use is .0014 MWs/hour. 1,000 MWs implies that there is enough power to supply 714,285 people with their average electricity or a bit more than .5% of the U.S. population.

provided in the main text, Figure A3 shows that there does not appear to be a large increase in installed natural gas fired capacity before December 2011. There is no evidence that there was any systematic increase in coal power plant retirements over the same period; even in 2012 after the industry had an extra year to respond to cheap natural gas net coal plant retirements were less than 8,000 MWs in capacity for the entire nation.[3] We take this as evidence that our empirical strategy isolates the intensive margin response of the electricity sector to decreased natural gas prices.

Figure A3: Change in natural gas capacity between 2007-2011

Note: Change in natural gas capacity between 2007 and 2011. Circles are located at the centroid of counties. Radius of circle corresponds to size of total change in natural gas capacity in each county. All data from EIA.

We now use the EIA 860 data to summarize the generating capacity mix at the beginning of our sample, the date of the regime break between the high and low natural gas price portions of the sample and the end of the sample period. Each of those three points in time is summarized in a separate table below. The first table is a reproduction of Table 1 from the main text. The second, Table **??** reproduces table 1 using 2009 data and the third, Table A3 reproduces Table 1 using data from 2011. Together theses tables provide evidence of our claim that the mix of generating capacities was stable across our sample period.

Over the sample period total nameplate capacity is up 0.8%, there is a small decrease between 2006 and 2009 and a corresponding increase from 2009 to 2011. Over the full sample the amount of oil capacity on the grid falls by two percent and natural gas offsets this low. The change is equally distributed across the two sub samples. Finally, gas turbine capacity falls from 53 to 48 percent of total natural gas generation. Again the change is approximately equally distributed across the two sub-sample periods.

Among the NERC regions MRO, RFC, SERC, SPP and WECC are remarkably stable. The mix

[3]See http://www.eia.gov/ Annual Electricity Summary Table 4.6 “Table 4.6. Capacity Additions, Retirements and Changes by Energy Source, 2012 (Count, Megawatts)”.

Table A1: 2006 Capacity Shares by Fuel Type and NERC Region

	FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC	Total
Coal	0.19	0.58	0.12	0.56	0.46	0.37	0.19	0.27	0.39
Oil	0.25	0.09	0.30	0.09	0.04	0.03	0.00	0.02	0.08
Gas	0.56	0.33	0.58	0.36	0.50	0.60	0.81	0.71	0.53
Gas Turbine	0.37	0.61	0.39	0.60	0.59	0.62	0.53	0.47	0.53
Comb. Cycle	0.63	0.39	0.61	0.40	0.41	0.38	0.47	0.53	0.47
Total Cap.	53.8	46.7	60.3	213.1	224.0	60.3	88.5	122.9	869.6
	53,838	46,673	60,294	213,114	223,987	60,313	88,496	122,882	869,597

Table A2: 2009 Capacity Shares by Fuel Type and NERC Region

	FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC	Total
Coal	0.17	0.59	0.11	0.57	0.47	0.35	0.21	0.28	0.39
Oil	0.24	0.08	0.29	0.07	0.04	0.02	0.00	0.01	0.07
Gas	0.60	0.33	0.61	0.36	0.50	0.62	0.79	0.71	0.54
Gas Turbine	0.28	0.65	0.37	0.56	0.59	0.60	0.43	0.43	0.50
Comb. Cycle	0.72	0.35	0.63	0.44	0.41	0.40	0.57	0.57	0.50
Total Cap.	58,960	45,348	56,102	204,308	229,136	59,532	78,824	127,153	859,363
Total Cap.	58,960	45,348	56,102	204,308	229,136	59,532	78,824	127,153	859,363

Table A3: 2011 Capacity Shares by Fuel Type and NERC Region

	FRCC	MRO	NPCC	RFC	SERC	SPP	TRE	WECC	Total
Coal	0.16	0.59	0.10	0.57	0.46	0.36	0.24	0.29	0.39
Oil	0.20	0.08	0.25	0.07	0.03	0.03	0.00	0.01	0.06
Gas	0.64	0.33	0.65	0.36	0.51	0.61	0.76	0.71	0.55
Gas Turbine	0.29	0.64	0.37	0.56	0.56	0.59	0.41	0.43	0.48
Comb. Cycle	0.71	0.36	0.63	0.44	0.44	0.41	0.59	0.57	0.52
Total Cap.	59,650	45,148	57,450	203,616	233,360	63,249	83,204	130,645	876,322
Total Cap.	59,650	45,148	57,450	203,616	233,360	63,249	83,204	130,645	876,322

of generation does not change by more than a percentage point or two in any category. TRE sees a five percent increase in coal and decrease in oil, these changes are split across the two sub-samples. NPCC Sees a seven percent increase in gas capacity with two percent coming from coal and 4 percent from oil. Again the changes are fairly stable across the two sub-samples, although most of the decrease in oil happens in the low natural gas price time period. Finally, as noted in the main text, FRCC sees an 8% increase in natural gas capacity and further shift towards combined cycle technology. The increase in gas capacity in FRCC represents the single largest change on the grid during our sample period. That shift is equally distributed across the two sub-samples, but the growth comes primarily at the expense of coal in the high natural gas sub-sample and oil in the low natural gas sub-sample.

3 Defining natural gas price regimes

In the main body of the paper we estimate a structural break model with unknown change point using the Andrews (1993) technique. There are other options for this procedure, though, such as estimating a Markov Switching Model (MSM). We estimate a MSM to identify when the cheap natural gas era began using daily data on Henry Hub natural gas spot prices from Bloomberg, excluding weekends and holidays. We estimate the following simple switching model:

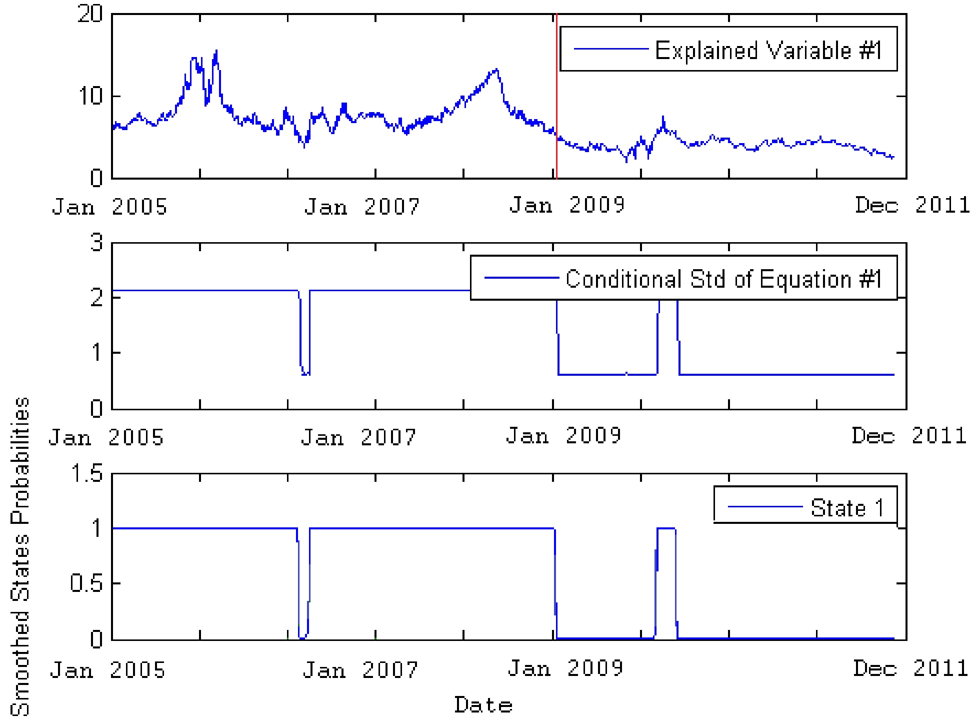
$$P_{s,t} = \mu_s + \epsilon_{s,t},\ \epsilon_{s,t} \sim N(0, \sigma_s^2) \quad s = H, L \tag{1}$$

In equation (1), s indexes the hidden state of the Markov process and t indexes time. We estimate a two by two matrix of transition probabilities (ρ_{ss} for $s = H, L$) as well. In order to ensure a global maximum, we implement a two dimensional solver in which we assign values for μ_H and μ_L manually then estimate the other six parameters (σ_s^2, ρ_{ss} for $s = H, L$). In each state, we assume draws of natural gas prices are normally distributed. We cycle through various combinations of μ_H and μ_L and choose the model with the highest likelihood as the true model. We employ this two dimensional solver to ensure the search algorithm does not find a local maximum.

The results from the Markov switching model are show in Figure A4. The top panel shows Henry Hub spot prices. The second panel shows the standard deviation in the system conditional on the estimated state. The third panel shows the probability of being in each regime. Note that the data begin on January 1, 2005. We find that $\mu_H = 8.0$ and $\mu_L = 4.0$ as the mean natural gas prices give the best model fit. ρ_{11} and ρ_{22} are both precisely estimated at nearly one. The variance across regimes are also both precisely estimated: $\sigma_H^2 = 4.463$, $\sigma_L^2 = .368$. All estimated parameters are highly significant. The relatively lower variance during the low price regime confirms the graphical depiction of lower volatility later in the data.

Starting on January 8, 2009, the model is very confident in a sustained period of low gas prices interrupted by a fifty day span in late 2009. Given the low estimated variance in regime two relative to regime one, the model selects prices in this interval to reflect the high price regime. We attribute this increase to seasonal demand for natural gas for heating. In sum, we view the MSM as broadly consistent with the Andrews (1993) technique.

Figure A4: Markov switching model for natural gas price regime



Note: Markov Switching Model estimation of regime switch. The high state is indexed by one and the low state by two. Top panel shows the price data for Henry Hub spot prices. The second panel shows the standard deviation in the system conditional on the estimated state. The third panel shows the probability of being in each regime. Note the vertical line is January 6, 2009.

4 Average marginal emissions rates

In this section we report average marginal emission rates by hour of the day and month of the year. Table A4 reports the average monthly marginal emissions rate for each month across the twenty-four hourly marginal emissions rates estimated for each natural gas price regime. Table A5 report the average marginal emissions rate for each hour across the twelve monthly marginal emissions rates estimated for each natural gas price regime. These tables provide helpful summaries of the variation in marginal emissions rates, but it is important to note that these averages hide significant variation.

5 Instrumenting for generation

Generation may be endogenous to emissions. For example, as generation levels increase less efficient plants, with higher emissions rates, are brought online. This may lead to increased dispatch of hydroelectric power or increased imports from other NERC regions. In this section we instrument for generation with demand. Electricity consumers typically pay rates based on the long run average cost of generation rather than the marginal cost of production at the time of consumption. During our sample period few electricity consumers faced real-time pricing and therefore were affected by the marginal costs of generation.

To implement the IV estimates we use electricity demand data from FERC 714 forms to instrument for generation as reported in the CEMS. We collect data on electricity demand from the Federal Energy Regulatory Commission (FERC)'s for 714 database. The demand data is reported for each of around 200 balancing authorities in the U.S.[4] Balancing authorities vary in size from mid-sized municipalities (El Paso Electric company) to entire markets (ISO New England). The balancing authorities are required to submit detailed reports on their electricity generation and consumption annually to FERC, including hourly demand for each hour of the year.

We view the IV results as complimentary to the OLS results reported in the main text. The IV approach isolates marginal emissions from changes in generation that were specifically attributable to changes in load in a particular region in a particular hour whereas OLS reports average hourly emissions given equilibrium based on electricity market dispatch. There are a number of important energy or environmental policies that should be evaluated using marginal emissions rates estimated using the IV approach, including many demand side policies. The OLS results on the other hand reflect marginal emissions rates of generators as dispatched in response to both anticipated and unanticipated changes in electricity supply and demand. This captures the behavior of generators after they have reoptimized their dispatch of hydroelectric generation and imports or exports across regions. Any energy or environmental policy that induces regular or predictable changes over the medium-run in generation are best evaluated using marginal emissions based on the OLS approach.

We argue in the main text that renewable generation is reasonably predictable over the time horizon of electricity market dispatch, around twenty-four hours. Over time the grid will respond to additional renewable capacity by reoptimizing dispatch to account for the addition of low marginal cost generation. Insofar as renewable generation is predictable in this way, the environmental benefits of renewable capacity should be estimated using the marginal emissions rates estimated by OLS. To the extent that unforecasted intermittency affects the ability of the grid to respond

[4]Balancing authorities are responsible for managing supply and demand minute-to-minute on the grid and long term resource planning to ensure sufficient generating capacity to meet peak demand.

Table A4: Average monthly marginal emission rates by NERC region and natural gas price level

	FRCC		MRO		NPCC		RFC		SERC		SPP		TRE		WECC	
month	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low
1	0.63	0.64	1.17	1.65	0.62	0.90	0.88	0.86	0.79	0.73	0.32	0.31	0.58	0.59	0.55	0.63
2	0.69	0.84	1.47	0.53	0.88	1.22	0.79	0.95	0.78	0.63	0.73	1.03	0.65	0.53	0.54	0.54
3	0.23	0.52	1.17	1.25	0.60	0.88	1.02	0.79	0.56	0.83	0.68	0.34	0.58	0.57	0.73	0.66
4	0.79	0.68	1.05	0.83	0.45	0.34	0.81	0.96	0.79	0.72	0.60	0.52	0.64	0.61	0.66	0.57
5	0.79	0.40	1.14	0.58	0.76	0.56	0.82	0.91	0.75	0.75	1.26	1.15	0.65	0.62	0.59	0.54
6	0.75	0.80	1.32	0.80	0.48	0.61	0.92	0.86	0.62	0.71	1.05	1.28	0.65	0.59	0.66	0.67
7	0.72	0.62	0.93	0.86	0.71	0.71	0.80	0.81	0.68	0.75	0.77	0.60	0.57	0.59	0.59	0.57
8	0.37	0.71	1.05	0.79	0.46	0.41	0.80	0.94	0.69	0.76	0.82	0.59	0.62	0.60	0.57	0.59
9	1.15	1.26	0.97	0.88	0.38	0.45	0.74	0.98	0.81	0.66	1.30	1.00	0.59	0.58	0.65	0.58
10	0.72	0.47	1.72	0.83	1.05	0.26	0.61	1.13	0.66	0.54	0.80	0.67	0.62	0.61	0.68	0.63
11	0.71	0.87	1.32	1.33	0.22	0.69	0.78	0.71	0.78	0.88	1.18	0.53	0.67	0.67	0.48	0.53
12	0.45	0.67	1.31	1.23	0.28	1.60	0.94	0.70	0.72	0.65	0.56	0.92	0.64	0.60	0.52	0.51

Note: This table reports the average of all hourly marginal emission rates by NERC region, natural gas price regime (high price versus low price), and month of the year. Marginal emissions rates are estimated as (tons of CO_2 per MWHr) across natural gas fuel price regimes for each NERC region. Each cell represents the average of the twelve estimated marginal emission rates for that hour of the day. The high natural gas price estimates represents Jan 2006 - Dec 2008 and the low natural gas price represents Dec 2008 - Dec 2011.

Table A5: Average hourly marginal emission rates by NERC region and natural gas price level

	FRCC		MRO		NPCC		RFC		SERC		SPP		TRE		WECC	
Hour	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low	High	Low
0	0.65	0.86	1.24	1.08	0.55	0.76	0.94	0.95	0.83	0.75	0.86	0.86	0.64	0.65	0.61	0.63
1	0.71	0.87	1.25	1.11	0.57	0.76	0.95	0.95	0.84	0.75	0.85	0.87	0.66	0.68	0.63	0.66
2	0.76	0.84	1.21	1.11	0.59	0.72	0.95	0.96	0.84	0.74	0.86	0.89	0.68	0.69	0.64	0.67
3	0.77	0.82	1.22	1.13	0.60	0.73	0.94	0.95	0.84	0.74	0.88	0.87	0.68	0.70	0.64	0.67
4	0.75	0.79	1.21	1.09	0.58	0.74	0.91	0.92	0.82	0.76	0.90	0.83	0.67	0.68	0.64	0.65
5	0.65	0.65	1.21	1.05	0.51	0.74	0.89	0.90	0.78	0.75	0.91	0.76	0.65	0.65	0.63	0.63
6	0.58	0.58	1.28	0.95	0.50	0.73	0.86	0.89	0.74	0.75	0.89	0.71	0.64	0.62	0.63	0.59
7	0.58	0.65	1.33	0.90	0.52	0.74	0.85	0.87	0.70	0.73	0.91	0.70	0.63	0.60	0.62	0.58
8	0.59	0.72	1.29	0.89	0.54	0.72	0.83	0.85	0.67	0.72	0.92	0.68	0.62	0.59	0.61	0.57
9	0.63	0.73	1.19	0.86	0.61	0.73	0.79	0.84	0.65	0.73	0.94	0.64	0.61	0.57	0.59	0.56
10	0.67	0.70	1.19	0.94	0.61	0.68	0.78	0.86	0.65	0.70	0.86	0.59	0.61	0.57	0.59	0.56
11	0.69	0.69	1.17	0.91	0.61	0.66	0.76	0.88	0.65	0.69	0.85	0.64	0.60	0.57	0.58	0.55
12	0.70	0.65	1.20	0.91	0.62	0.64	0.75	0.87	0.67	0.70	0.82	0.66	0.60	0.56	0.58	0.55
13	0.69	0.63	1.18	0.90	0.62	0.63	0.76	0.87	0.68	0.71	0.79	0.67	0.60	0.56	0.58	0.56
14	0.70	0.61	1.19	0.92	0.61	0.66	0.75	0.85	0.68	0.72	0.80	0.72	0.60	0.55	0.58	0.56
15	0.70	0.58	1.18	0.91	0.60	0.69	0.76	0.83	0.68	0.72	0.79	0.72	0.60	0.55	0.58	0.56
16	0.70	0.59	1.15	0.90	0.58	0.71	0.75	0.83	0.68	0.72	0.79	0.73	0.60	0.55	0.58	0.55
17	0.70	0.62	1.14	0.86	0.58	0.73	0.74	0.82	0.66	0.70	0.82	0.73	0.60	0.55	0.58	0.55
18	0.68	0.66	1.14	0.81	0.62	0.73	0.73	0.84	0.65	0.67	0.80	0.72	0.59	0.55	0.58	0.55
19	0.65	0.65	1.19	0.82	0.64	0.74	0.73	0.84	0.65	0.67	0.79	0.74	0.59	0.55	0.58	0.55
20	0.63	0.70	1.24	0.88	0.58	0.78	0.76	0.85	0.66	0.68	0.81	0.75	0.60	0.55	0.58	0.55
21	0.62	0.76	1.26	1.00	0.53	0.78	0.81	0.88	0.69	0.69	0.76	0.74	0.60	0.56	0.59	0.56
22	0.61	0.81	1.32	1.07	0.49	0.72	0.87	0.93	0.77	0.70	0.74	0.81	0.61	0.59	0.59	0.58
23	0.61	0.83	1.25	1.10	0.51	0.73	0.93	0.95	0.81	0.72	0.81	0.81	0.63	0.62	0.61	0.60

Note: This table reports the average of all hourly marginal emission rates by NERC region, natural gas price regime (high price versus low price), and hour of the day. Marginal emissions rates are estimated as (tons of CO_2 per MWHr) across natural gas fuel price regimes for each NERC region. Each cell represents the average of the twelve estimated marginal emission rates for that hour of the day. The high natural gas price estimates represents Jan 2006 - Dec 2008 and the low natural gas price represents Dec 2008 - Dec 2011.

to additional renewable capacity the IV results will be more appropriate to use in evaluating the environmental impact of renewable generation.[5]

We sum demand up to the NERC region level and merge it into the hourly generation data from the CEMS. We then re-run the baseline estimation implementing the IV estimator using two-stage least squares, where the first stage regresses hourly demand on hourly generation. We capture the fitted values from that regression and use them in the second stage in the place of actual generation. In practice we use all 48 hour-by-regime demand variables as instruments for the 48 hour-by-regime generation variables for each interconnection. We estimate the NERC sub-regions of the Eastern Interconnection by instrument Eastern Interconnection generation by demand in each of the sub-regions since theoretically demand in any NERC region could be met by generation anywhere in the interconnection.

As with the baseline estimation reported in the main text, we estimate each of the three inter-connections separately for each month of the year. We also estimate the NERC subregions of the eastern interconnection separately for each month for a total of forty-eight (12 months times three interconnections plus the NERC sub-regions of the Eastern Interconnection) separate IV estimates. Each of those IV estimation procedures produces forty-eight (twenty-four hours times two natural gas price regimes) marginal emissions coefficient estimates. We estimate:

$$E_t = \sum_{h=1}^{24}\sum_{r=1}^{2}\beta_{h,r}(hour_h * regime_r * \widehat{gen}_t) + \sum_{h=1}^{24}\sum_{d=1}^{7}\sum_{y=2006}^{2010}\gamma_{h,d,y}(hour * dow * year) + \epsilon_t \qquad (2)$$

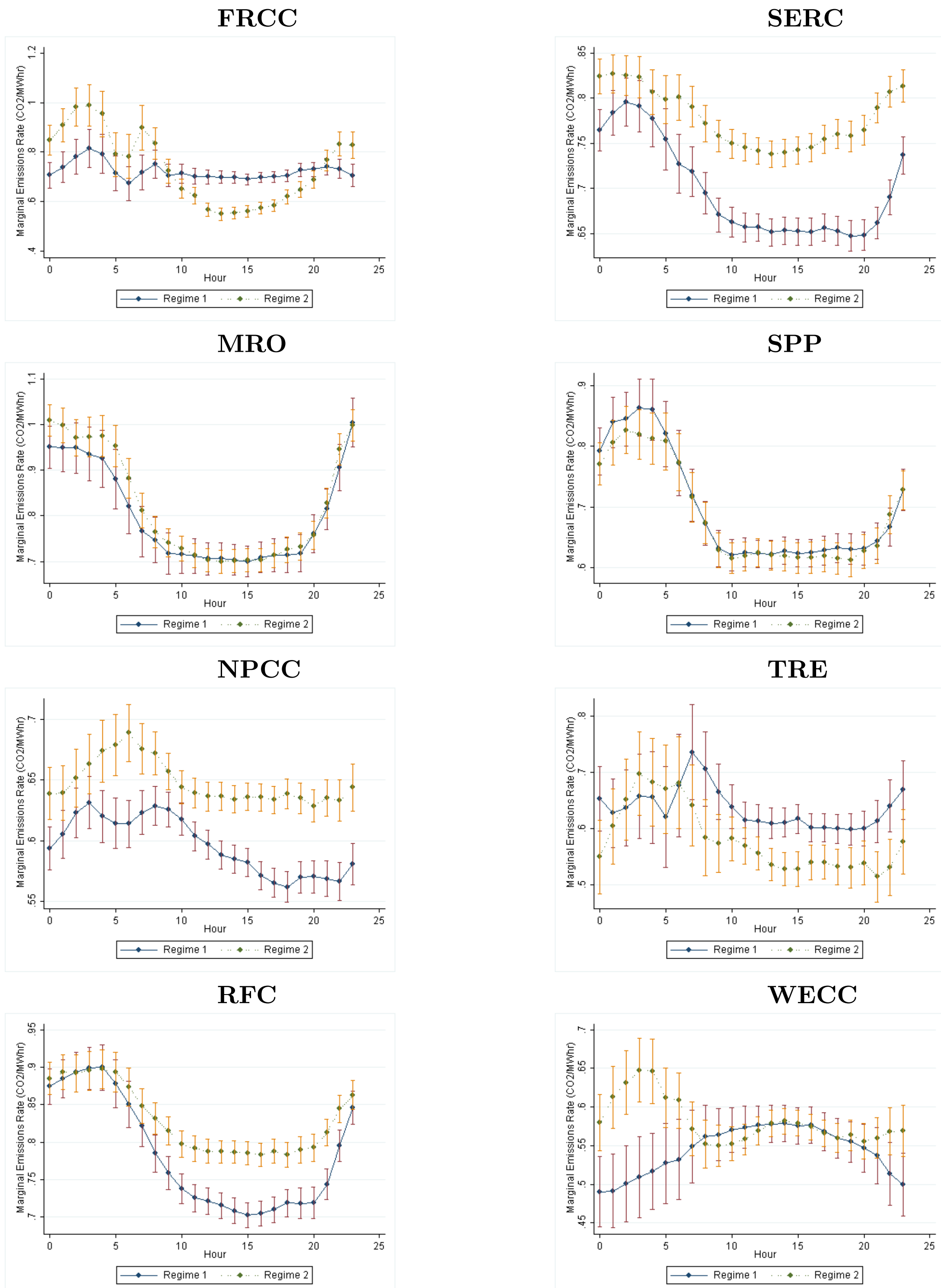
As in equation 2 in the main text, E_t represents aggregate hourly CO_2 emissions measured in tons for all generators in the interconnection at time t, h indexes hour of day and $regime_r$ is a variable denoting whether the observation occurs within the high or low natural gas price regime. The γ vector is a set of year-by-hour-by-day of week fixed effects with d indexing day of the week and y denoting year. The only difference is from the baseline specification is that we instrument for the $hour_h * regime_r * gen_t$ vector of hourly generation in each regime with demand. We run a single first stage in which all forty-eight hourly generation levels (twenty-four hours in each the high and low natural gas price regime) are instrumented by all forty-eight demand levels. We capture the fitted values from that first stage and use those in the second stage. In the Eastern Interconnection we estimate a single monthly equation for each NERC region in which generation in the region is instrumented by demand in each NERC region in the Eastern Interconnection. This results in 6x12=72 separate IV regressions to capture the full set of marginal emissions rates.

This procedure ensures that the β coefficient vector is identified off only exogenous changes in demand. The results of this estimation are presented in Figure A5.

It is somewhat difficult to compare marginal emissions rates across the graphs reported in the main text from the baseline identification strategy and those reported here. For that reason we also reproduce the simulation of the environmental impact of renewable generation capacity using the marginal emissions rates estimated using the IV approach described in this section. We implement exactly the same procedure described in the main text, but substitute the marginal emissions rates estimated from the baseline specification with the marginal emissions rates estimated with demand

[5]The literature has noted that the effects of intermittency are decreasing in the geographic scope of renewable generation. The more widely spread the additional capacity to grid, the more predictable it will be and the more appropriate the OLS estimates will be in evaluating the environmental effects of renewables.

Figure A5: IV Based marginal emissions across natural gas price regimes for August by hour of day and NERC region



Note: Marginal emissions rates (tons of CO_2 per MWhr) across natural gas fuel price regimes for each NERC region. These results differ from the baseline specification in the main text by instrumenting for generation using demand. Each panel displays estimates from a single regression with 61,296 hourly observations and robust standard errors. Regime 1 represents Jan 2006 - Dec 2008 and Regime 2 represents Dec 2008 - Dec 2011. Note that each panel is graphed on its own vertical axis to highlight the difference across fuel price regimes.

as an instrument for generation.

Table A6: Emissions averted by wind generation - IV Marginal Emissions Estimates

Natural Gas Price Regime	(1) FRCC	(2) MRO	(3) NPCC	(4) RFC	(5) SERC	(6) SPP	(7) TRE	(8) WECC	Cap. Wtd. Average
High	2,201	4,272	3,513	4,182	2,175	3,324	2,833	2,747	3,328
	(183)	(264)	(160)	(137)	(141)	(243)	(192)	(340)	
Low	2,030	4,180	3,741	4,089	2,183	3,457	2,839	2,784	3,337
	(168)	(254)	(197)	(135)	(139)	(231)	(176)	(231)	
Δ	-170	-92	228	-93	8	133	6	37	9

Note: Annual CO_2 emissions averted in tons per MW of installed wind generation capacity across NERC regions and fuel price regimes. Emissions averted based on estimated marginal emissions by month of year, fuel price regime and hour of the day. The standard errors of the estimated marginal emissions reductions are reported in parentheses below. The bottom row reports the difference in annual CO_2 reductions across the high and low natural gas price regimes. The rightmost column reports the capacity weighted average of columns 1-8. Capacity weights derived from EIA 860 data that reports nameplate capacity by NERC region.

The results are somewhat different than those reported from the baseline estimation in the main text. While the (unweighted) average environmental benefits of wind capacity are less than one percent higher across all the NERC regions, there is some variation within NERC regions of the Eastern Interconnection. The estimated benefits of wind generation fall by 2% in MRO and increase by 4% in SPP in the high natural gas price regime. Because these regions have a large share of the overall wind capacity they have a significant impact on the capacity weighted average reported in the rightmost column. The benefits of wind capacity estimated across natural gas price regimes is essentially flat under these estimates as compared to around a 6% decrease reported in the main text.

Table A7: Emissions averted by solar generation IV Marginal Emissions Estimates

Natural Gas Price Regime	(1) FRCC	(2) MRO	(3) NPCC	(4) RFC	(5) SERC	(6) SPP	(7) TRE	(8) WECC	Cap. Wtd. Average
High	1,144	1,569	1,026	1,159	1,159	1,332	1,185	1,090	1,100
	(29)	(55)	(25)	(22)	(26)	(58)	(41)	(66)	
Low	1,201	1,499	951	1,448	1,162	1,300	1,129	1,203	1,204
	(30)	(55)	(30)	(28)	(24)	(45)	(35)	(52)	
Δ	58	-69	-74	289	4	-32	-56	113	104

Note: Annual CO_2 emissions averted in tons per MW of installed solar generation capacity across NERC regions and fuel price regimes. Emissions averted based on estimated marginal emissions by month of year, fuel price regime and hour of the day. The standard errors of the estimated marginal emissions reductions are reported in parentheses below. The bottom row reports the difference in annual CO_2 reductions across the high and low natural gas price regimes. The far right column reports a solar capacity weighted average of the regional estimates from columns 1-8. Weights are produced from EIA 860 data on solar operable nameplate capacity by NERC region.

The estimated benefits of solar generation increase somewhat from the high to low natural gas price regime under this estimation strategy. In the baseline estimation the benefits of solar capacity were flat across natural gas price regimes, but table A7 reports a nearly ten percent increase in CO_2

offset. This difference is driven largely by WECC which sees a larger increase in the environmental benefits of solar under the IV estimation strategy, with emissions offsets increase by 30 to 113 tons of CO_2 per year per MW of solar capacity. WECC has the majority of installed solar capacity and thus a big impact on the capacity weighted average reported in the rightmost column.

The results of this suggestion suggest that the results of the simulation are somewhat sensitive to the decision to instrument for generation using electricity demand. We believe that these results measure slightly different concepts. We argue that our baseline results, reported in the main text, reflect an Average Treatment Effect while these results of the IV based marginal emissions estimates simulation represent an ATT. Policy questions about setting the optimal subsidy for renewable generation capacity revolve around the former measure. The gap between the two reflects the response of the electric grid to changes in natural gas prices and represents a potential area for further inquiry.

6 Identification from input price levels

In this section we identify the impact of changes in natural gas prices on marginal emissions by including fuel prices directly in the estimation rather than separating the sample into fuel price regimes. While this specification is useful we do not prefer for economic reasons: the implicit economic assumption with this specification is that coal and natural gas prices used by firms in their bidding behavior in the wholesale market reflect spot prices. However, it is well known that coal contracts especially are long lived so that prices paid by electricity generators may not reflect spot prices on commodity markets. Further, the pass through of natural gas prices in electricity markets is an open question in the economics literature. For these reasons, we are not confident in the point estimates of these specifications but the qualitative findings are instructive.

Despite these concerns, we estimate the following econometric model:

$$E_{h,n} = \beta_{h,n}(load_{h,n} * hour_h * (P_c - P_g)) + \gamma_{n,m,y,h,d}(month * year * hour * dow) + \epsilon_{h,n}, \qquad (3)$$

where P_c is the coal price and P_g is the natural gas price. Both prices are collected from Bloomberg data reported daily in dollars per mmBTU. All control variables are identical to the control variables which we use in the econometric specifications in the main body of the paper. The coefficient of interest in this specification is $\beta_{h,n}$ where h represents the hour of the day and n represents the NERC region. Using relative prices in this way eliminates the need to break the sample into natural gas price regimes. The proper interpretation of this coefficient is that for a one dollar increase in relative prices between coal and natural gas (e.g., the price of coal increases by one dollar or the price of natural gas decreases by one dollar) the estimated coefficient is the change in the emissions rate for a particular hour in a particular NERC region. As a result, a negative coefficient implies that marginal emissions rates decrease when the price of coal increases or the price of natural gas decreases.

The results are summarized in figure A6. Constant across all regions is that decreases in the price of natural gas affect marginal emissions significantly more during the nighttime hours. This is consistent with natural gas more frequently being used as a marginal fuel during night hours as the price of natural gas decreases (e.g. Figure 9 in the main document). To some extent, the results from this econometric model reflect the relative share of coal as the marginal fuel during each hour of the day in Figure 9.

The results are also consistent with the qualitative findings in the main regression specification in which we estimate marginal emissions for the high and low natural gas price regimes. Specifically, the estimated difference in marginal emissions in the "regimes" specification decreased the most during night hours and either increased or stayed constant during daytime hours. The exception to this trend is Florida (FRCC) which, as explained in the main text, never satisfied load using a significant amount of coal to begin with (10-30%) and was building significant natural gas capacity over the sample period.

7 Gas price regime definitions

The structural break model presented in the main text identifies Dec 5, 2008 as the date of the regime shift. In this section we test the robustness of the estimated marginal emissions levels to that regime shift date. We redefine our regime dates to exclude three and six months on either side of Dec 5, 2008. We then re-estimate the marginal emissions specification reported in equation 2 of the main text.

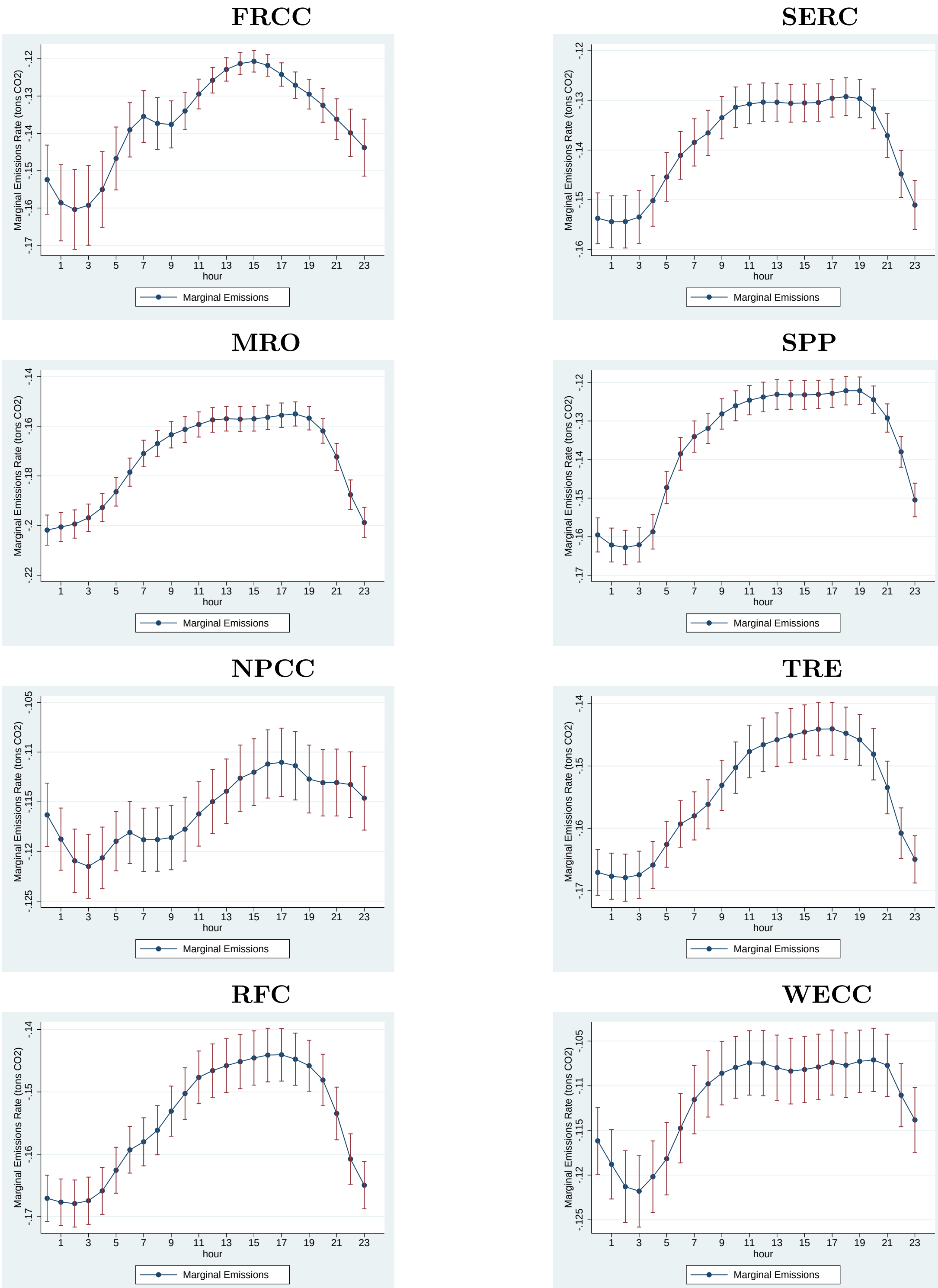
This procedure generates thousands of marginal coefficient estimates across natural gas price regimes, hours of the day, months of the year and NERC regions. Displaying them graphically is not feasible, so we summarize them into two ways. First we calculate a simple correlation coefficient comparing all the coefficients across the baseline specification, the marginal emissions estimates across the six month gap and one year gap. The correlation between the baseline and the six and twelve month gaps are 0.96 and 0.93 respectively. The marginal emissions estimates are quite similar across these three specifications.

The high correlation coefficient could be hiding level differences in marginal emissions rates across the three samples. For that reason we re-run the simulation described in the main text using the marginal emissions rates estimated here. The results are presented in four tables beginning with wind and solar offsets based on marginal emissions with a six month gap and then wind and solar offsets using a one year gap.

The results are quite similar to those reported for the baseline specification in the main text. For the six month gap estimation reported here the change in the capacity weighted average emissions offset for wind is -212 and for solar -19. The baseline estimation results were -203 and 13, respectively. The simulated emissions offsets are slightly higher for most of the NERC regions in both fuel price regimes, but the differences amount to fractions of a standard deviation. Not surprisingly the standard deviations are higher in these simulations than the baseline. Reducing the sample size reduces the precision of the marginal emissions estimates and adds variance to the simulation

The results for simulations based on marginal emissions estimates with a year gap on either side of the regime break date are reported below. Tables A10 and A11 report the results for the wind and solar simulations respectively. Again the results are fairly stable. The generation weighted average emissions offset by solar capacity drop by 268 tons a year across fuel price regimes. This is similar to the estimates of 203 in the baseline and 212 in the previous robustness check. Again the estimated impacts of renewable capacity are somewhat higher under this restricted sample and the standard deviations have expanded relative to both the baseline and the previous robustness check. The solar simulation reveals some more substantive differences. The capacity weighted average emissions offset by solar capacity additions reductions in the environmental benefits of

Figure A6: Marginal CO_2 emissions estimated from relative fuel prices



Note: Marginal emissions rates for CO_2 associated with a one unit increase in the natural gas-coal price ratio for each NERC region. Each panel displays estimates from a single regression with 61,296 hourly observations and robust standard errors.

Table A8: Emissions averted by wind generation - 6 month gap

Natural Gas Price Regime	(1) FRCC	(2) MRO	(3) NPCC	(4) RFC	(5) SERC	(6) SPP	(7) TRE	(8) WECC	Cap. Wtd. Average
High	2039	5791	3047	4117	2079	3817	2854	2843	3,675
	(1132)	(1831)	(1281)	(599)	(483)	(1556)	(180)	(180)	
Low	2074	4416	4175	4271	2031	3563	2928	2825	3,463
	(1043)	(1339)	(1532)	(631)	(444)	(1343)	(150)	(156)	
Δ	35	-1375	1128	153	-48	-254	75	-18	-212

Note: Annual CO_2 emissions averted in tons per MW of installed wind generation capacity across NERC regions and fuel price regimes. Emissions averted based on estimated marginal emissions by month of year, fuel price regime and hour of the day. The standard errors of the estimated marginal emissions reductions are reported in parentheses below. The bottom row reports the difference in annual CO_2 reductions across the high and low natural gas price regimes. The rightmost column reports the capacity weighted average of columns 1-8. Capacity weights derived from EIA 860 data that reports nameplate capacity by NERC region.

Table A9: Emissions averted by solar generation - 6 month gap

Natural Gas Price Regime	(1) FRCC	(2) MRO	(3) NPCC	(4) RFC	(5) SERC	(6) SPP	(7) TRE	(8) WECC	Cap. Wtd. Average
High	1029	2227	872	1233	1036	1564	1041	1228	1,197
	(168)	(413)	(226)	(117)	(95)	(352)	(32)	(41)	
Low	1380	1463	911	1364	1116	1364	1271	1178	1,177
	(232)	(273)	(257)	(116)	(90)	(320)	(38)	(35)	
Δ	350	-764	40	131	79	-200	231	-51	-19

Note: Annual CO_2 emissions averted in tons per MW of installed solar generation capacity across NERC regions and fuel price regimes. Emissions averted based on estimated marginal emissions by month of year, fuel price regime and hour of the day. The standard errors of the estimated marginal emissions reductions are reported in parentheses below. The bottom row reports the difference in annual CO_2 reductions across the high and low natural gas price regimes. The far right column reports a solar capacity weighted average of the regional estimates from columns 1-8. Weights are produced from EIA 860 data on operable nameplate capacity of solar generation by NERC region.

solar in WECC, which has the majority of installed solar capacity. This change is driven by the estimated emissions offset in both the high natural gas price era, which is above the baseline and other robustness check and the low natural gas price era which is estimated to be lower than in the other simulations.

Table A10: Emissions averted by wind generation - 1 year gap

Natural Gas Price Regime	(1) FRCC	(2) MRO	(3) NPCC	(4) RFC	(5) SERC	(6) SPP	(7) TRE	(8) WECC	Cap. Wtd. Average
High	1960	6115	3089	3948	2141	3935	2827	2870	3,733
	(1253)	(1945)	(1331)	(624)	(527)	(1710)	(176)	(192)	
Low	1975	4571	3853	4329	2076	3369	2947	2825	3,465
	(1143)	(1453)	(1677)	(693)	(492)	(1451)	(161)	(175)	
Δ	15	-1544	764	380	-65	-567	120	-45	-268

Note: Annual CO_2 emissions averted in tons per MW of installed wind generation capacity across NERC regions and fuel price regimes. Emissions averted based on estimated marginal emissions by month of year, fuel price regime and hour of the day. The standard errors of the estimated marginal emissions reductions are reported in parentheses below. The bottom row reports the difference in annual CO_2 reductions across the high and low natural gas price regimes. The rightmost column reports the capacity weighted average of columns 1-8. Capacity weights derived from EIA 860 data that reports nameplate capacity by NERC region.

Table A11: Emissions averted by solar generation - 1 year gap

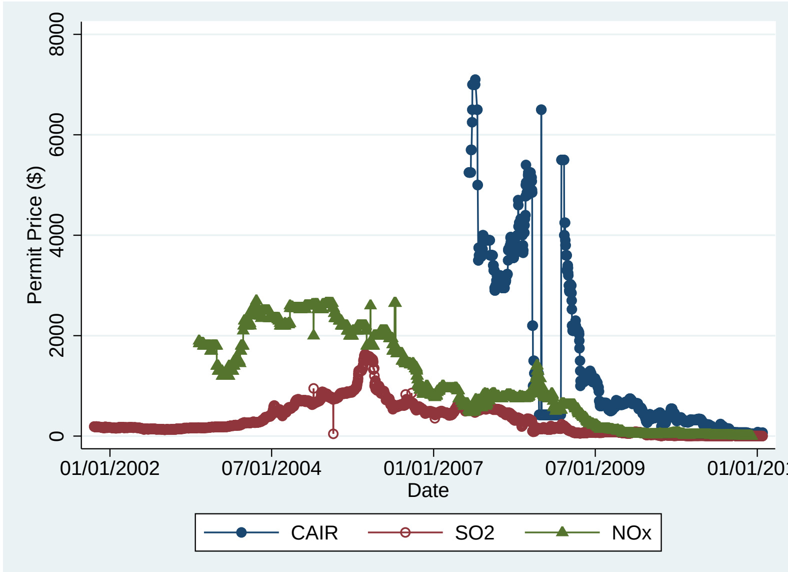
Natural Gas Price Regime	(1) FRCC	(2) MRO	(3) NPCC	(4) RFC	(5) SERC	(6) SPP	(7) TRE	(8) WECC	Cap. Wtd. Average
High	1010	2392	940	1369	1028	1607	1301	1365	1,320
	(186)	(440)	(226)	(140)	(99)	(349)	(39)	(51)	
Low	1249	1561	930	1226	1204	1321	1039	1011	1,039
	(251)	(290)	(286)	(112)	(98)	(349)	(32)	(36)	
Δ	240	-831	-10	-143	176	-286	-262	-354	-281

Note: Annual CO_2 emissions averted in tons per MW of installed solar generation capacity across NERC regions and fuel price regimes. Emissions averted based on estimated marginal emissions by month of year, fuel price regime and hour of the day. The standard errors of the estimated marginal emissions reductions are reported in parentheses below. The bottom row reports the difference in annual CO_2 reductions across the high and low natural gas price regimes. The far right column reports a solar capacity weighted average of the regional estimates from columns 1-8. Weights are produced from EIA 860 data on operable nameplate capacity of solar generation by NERC region.

8 Emissions trading programs

Changes in environmental regulation intensity could also shift the electricity fuel type mix by making natural gas fired generation relatively more attractive. If increases in environmental regulation stringency coincided with changes in natural gas prices we could mistakenly attribute the observed changes in marginal emissions rates to natural gas prices. There are three major cap-and-trade programs that electricity generators are subject to. Under the Clean Air Act and its amendments

Figure A7: Pollution permit prices



Note: Pollution permit prices over the study period for three tradeable permit programs. CAIR is the Clean Air Interstate Act which began trading in 2007. SO2 and NOx prices are part of the Clean Air Act Amendments cost containment schemes. Permit prices have fallen in tandem with natural gas prices.

power plants must purchase emissions permits to cover their emissions of SO_2 and NO_x. During our study period the EPA introduced a new cap-and-trade program known as the Clean Air Interstate Rule. The regulation was officially promulgated in 2005, but permits did not begin trading till 2007. Several court challenges have threatened the validity of the program, but permits have continued to trade. Figure A7 describes the price of pollution permits under each program over the life of the markets.

Pollution permit prices have been strongly correlated with natural gas prices over the study period. As coal fired generation has been replaced by natural gas as baseload the price of permits have fallen. SO2 permits that consistently traded over $500 during peak natural gas prices are now trading for less than $5. This suggests that the costs of complying with environmental regulation has actually fallen during the low natural gas price regime. The reduction in permit prices has actually made coal fired generation relatively more attractive in regime 2 implying that the change in marginal emissions rates described above actually understates the changes that would be expected had the firm level cost of the environmental policy regime remained constant.

References

Andrews, D. W.: 1993, Tests for parameter instability and structural change with unknown change point, *Econometrica* **61**(4), 821–856.