Online Appendices
"When Does Regulation Distort Costs? Lessons from Fuel Procurement in U.S. Electricity Generation"

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A Data Appendix

Data on Divestitures

Data on divestitures are compiled from the "Electric Utility Plants Sold/Transferred and Reclassified as Non-utility Plants" Tables across various years of the March Issue of EIA's "Electric Power Monthly" report. It is also possible to identify the month of divestiture prior to 2002 because plants cease reporting fuel costs at that time. A third source of divestiture date is a change in regulatory status reported on Form EIA-906, "Power Plant Report." In the relatively uncommon case that these dates disagree, I rely first on the cost data (a signal of operational changes at the plant), then the sale data, and finally the "Power Plant Report" data.

Table A.1 breaks down this history of coal-fired plant divestitures by state. Divestiture of utility-owned plants in a state was usually complete following passage of passing restructuring laws. Not all states that restructured have coal-fired plants to use in this study. Although California restructured its electricity markets, its IOUs did not own any coal-fired capacity. Washington, DC was also restructured but its two coal-fired plants are used sufficiently little to avoid fuel delivery reporting requirements. All New England states except Vermont restructured their electricity markets, but Maine and Rhode Island do not have coal-fired generating assets. New Hampshire did not require divestiture of the two coal-fired plants owned by Public Service of New Hampshire and these plants continue to report costs after the introduction of retail competition.

There have also been a number of divestitures in states that remain otherwise rate-regulated. The plants divested in Indiana, and Virginia were owned by IOUs based in restructured states, and were forced to sell for this reason. Montana has suspended restructuring but Montana Power Company assets were divested in 2000 after its failed telecom investments during the dot-com bust led the company in to bankruptcy. The Centralia station in Washington state was sold amidst conflict among the plant's eight co-owners.

Divestiture status in Ohio and Texas varies by utility service area. The only IOU plants in Texas that remain to be divested belong to Southwestern Electric Power Company, which is connected to a separate grid from the rest of the state. The lack of markets available in this service area has delayed divestiture. In Ohio, two Duquesne Light Co. coal-fired plants were divested in 2000 as part of Pennsylvania's restructuring program. Although Ohio implemented retail choice in 2000, FirstEnergy's plants in Ohio would not be divested until 2005. Plans to divest of the remaining IOU plants in Ohio have been tied up between the Public Utilities Commission of Ohio (PUCO) and the courts since that time. The owners of these plants remain rate-regulated and require PUCO approval to change electricity prices.

Coal Prices

This study uses detailed data on coal deliveries to power plants from the Energy Information Administration (Forms EIA-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants," and EIA-923, "Power Plant Operations Report") and Federal Energy Regulatory Commission (Form FERC-423, "Monthly Report of Cost and Quality of Fuels for Electric Plants"). This is shipment-level data, reported monthly for nearly all of the coal burned for the production of electricity in the United States (all facilities with a combined capacity greater than 50MW are required to report).[1] The data record the county or mine of origin, whether purchased on the spot market or long-term contract, characteristics of the coal (heat, sulfur and ash content), rank (bituminous, etc.), and the price per million British thermal units (MMBTU). Although data on prices are redacted from public release for non-utilities, restricted-access data on prices were made available for this study under a non-disclosure agreement with EIA.

As described in the text, deregulated plants were not required to report fuel prices to the EIA until 2002. This means that IOU plants that were divested ceased reporting from the time of divestiture until 2002. There is no gap in reporting for the limited set of plants that have been divested since 2002. An exception to this rule is for the six FirstEnergy plants in Ohio that stopped reporting once retail competition began in June of 2000, but did not resume reporting until actual divestiture at the end of 2005. All results are robust to the exclusion of these plants.

Coal delivered to combined heat and power plants (4% of reported coal deliveries after 2002) is not included in any of the analysis. These are plants that also sell steam, either for heating or industrial processes. One reason is practical: 36 of 49 coal-fired co-generation plants were not required to report until 2002, so they lack data in the pre-divestiture baseline period. The second is that it is unclear how to categorize the regulatory structure these plants face: a plant owned by an IOU may be free to privately contract for steam to nearby industrial plants. In addition, four small facilities (typically produced <50MWh/month) that were divested, but never reported post-divestiture are also dropped. They are the Hickling and Jennison plants in NY, Grand Tower in IL, and Edgewater in OH.

Figure A.1a shows the total heat content of coal deliveries reported to FERC/EIA from 1990-2009. The vertical lines represent the points at which divestitures begin in 1998, and when reporting for divested plants resumes in January 2002. There is clearly a substantial amount of non-reporting induced by divestiture. Aside from this dip, there is a 15-25% increase in coal delivered over this 20 year period.[2] It is important to note that nearly all of this came from an increase in production at existing facilities, not entry of new plants.

Another feature of Figure A.1a worthy of note is the expansion of sub-bituminous coal, both in levels and as a share of coal consumed for electric power. The Clean Air Act of 1990 created a cap-and-trade program to reduce sulfur emissions from electricity generating and large industrial units. Putting a price on sulfur increased the relative value of low-sulfur sub-bituminous coal (95% of sub-bituminous coal mined in the United States in 2009 was from the Powder River Basin [PRB] in Wyoming). Switching to PRB coal provided an alternative to building capital-intensive scrubbers to reduce sulfur emissions. Technological improvements as demand for PRB coal expanded further reduced the price of extraction, making PRB coal a potentially economical choice regardless of environmental compliance considerations. Shipments of PRB coal more than doubled over the twenty year period of study, accounting for about 40% of the coal heat delivered in 2009.

[1]When switching to Form 923 in 2008, the EIA began collecting monthly data from a sample of plants and a census annually. Monthly data are estimated by EIA from plants that only submitted the annual form. This change applied more significantly to gas-based generators, as more than 97% of coal deliveries continued monthly reporting.

[2]The drop-off in 2009 is the combined effect of the economic downturn and displaced generation due to the fall in natural gas prices.

Plant-Level Data

Data on generator nameplate capacity and vintage come from Form EIA-860, "Annual Electric Generator Report," while data on installed abatement equipment are from Form EIA-767, "Annual Steam-Electric Plant Operation and Design Data" and EIA-923, "Power Plant Operations Report." Annual capacity factor is the annual net generation reported on Form EIA-906/759 "Power Plant Report," divided by maximum potential output as determined by facility nameplate rating. This form is also the source for analysis on changes in output at the facility-level. Utility-specific implementations of Incentive Regulation programs is from Sappington et al. (2001) with updates from Guerriero (2010). This is linked to the plant-level data by the utility identifiers in the "Power Plant Report" data.

Data on geographic coordinates of power plants are from the Environmental Protection Agency's eGrid database.

Unit-Level Data

Unit-specific characteristics are assembled using the crosswalks between unit components provided in Form EIA-767, "Annual Steam-Electric Plant Operation and Design Data" available from 1990-2005. The data on this form were later compiled on Form EIA-923, "Power Plant Operations Report" after a gap in reporting for 2006.[3] The effects of this gap can be mitigated by the fact that scrubber installation date is collected, so status in the missing year can be inferred from prior and subsequent years. Power generating stations have been required to file these forms with EIA regardless of regulatory status,[4] so this series does not suffer from the intermittent non-reporting present in the fuel price data. Unit-level generator nameplate capacity and vintage comes from Form EIA-860, "Annual Electric Generator Report."

As with the generating facilities themselves, there has also been limited entry and attrition at the unit level. As a fraction of nameplate capacity, 92% of units reporting in 2009 also reported when the series began in 1990 (85% of units). These numbers increase to 95% and 93% respectively when accounting for the expanded coverage among combined heat and power units in 2002. Attrition was similarly rare, with 96% of capacity and 87% of units reporting in 1990 continuing to report in 2009.

It is worth noting that is that it is not uncommon for facilities to have both scrubbed and un-scrubbed units operating at the same plant. This can be seen by comparing the number for *any* scrubber present at the facility in panel A of Table 1 and the unit-level statistics in panel C.[5] The differences between divested and non-divested units are otherwise similar to those found at the plant-level, and largely eliminated in the matched sample.

Mine-Level Data

Data on mine labor productivity are from the Mine Safety and Health Administration's "Quarterly Mine Employment and Coal Production Report" (MSHA-7000-2). Figure A.2 shows the trends in production and labor hours over the sample period. The main development over the last twenty years has been the explosion of production from the Powder River Basin (PRB) in Wyoming. This

[3] Plants with a combined nameplate capacity less than 50 MW are not required to report fuel prices (Form EIA-423/923), while all facilities with a capacity greater than 10 MW are required to report generating unit configurations and operations (Form EIA-767/923). The discrepancy amounts to an infinitesimal share of production and capacity.

[4] Form EIA-767 expanded coverage to a handful of combined heat and power plants in 2002.

[5] While scrubbers had only been installed on a small fraction of generating units in 1997, these units were disproportionately large. In 1997 28% of U.S. coal-fired capacity was scrubbed for sulfur emissions. This has grown to nearly half by 2009.

has more than offset the decline of output elsewhere, so that there has been a modest increase in coal production overall. The shift in output has been accompanied with a sharp decline in mining employment, which has only rebounded slightly since 2005. The 1990s saw sharp increases in labor productivity all around: from expanding output faster than employment in the PRB and by reducing employment faster than output in the East. It requires about seven times less labor to extract a ton of coal in the PRB.

Wages are calculated by adding up the quarterly hours reported in the MSHA data by FIPS county and merging this data with the quarterly wage bill in the coal mining sector as reported in the "Quarterly Census of Employment and Wages" from the Bureau of Labor Statistics.[6] Wage rates are calculated at the county level by dividing the total county wage bill by total hours.

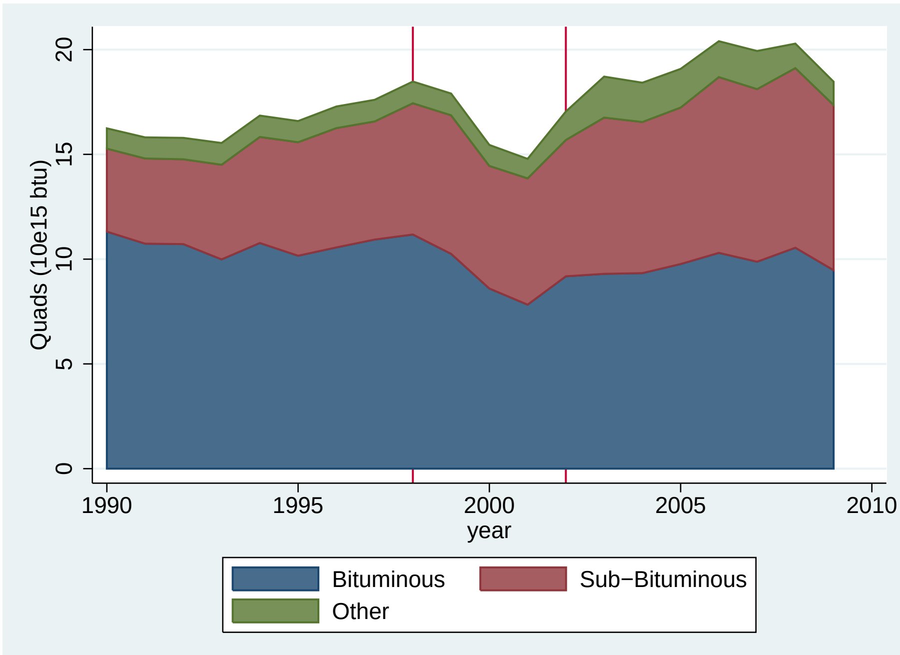
The thickness of coal seams is from MSHA's "Mine Dataset," which contains descriptive data on all mines under MSHA's jurisdiction since 1970. To calculate the depth of mine seams, I used a Perl script to collect the universe of stratigraphic data from the U.S. Geological Survey's "National Coal Resources Data System." The combined USTRAT and COALQUAL databases consist of over 200,000 geo-coded core samples taken by federal and state geologists in order to map U.S. coal deposits. Among the many parameters collected from these core samples is the depth of coal deposits. I use these points to create a surface of estimated seam depth using a spline to interpolate between points using the geoprocessing toolkit of ArcGIS 10.0. I then intersect the coordinates of mines with this surface to estimate the depth of coal deposits at each mining site.

The EIA only began collecting source mine identifiers (MSHA ID) on the fuel delivery data in 2008. From 1990-2001, I link deliveries to the name of the supplier listed in EIA's Coal Transportation Rate Database (CTRD) based on facility, county of coal origin, and the characteristics of the coal reported in both the CTRD and EIA-423 data. The name of the supplier is explicitly listed in the EIA-423 data beginning in 2002. Deliveries and mine characteristics are therefore connected at the county-supplier level.

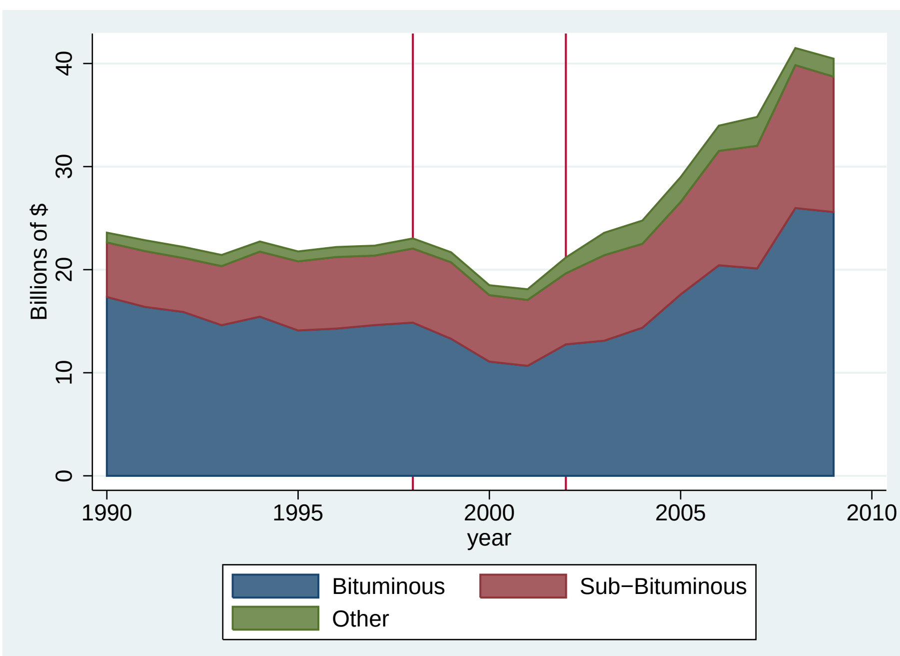
[6]Coal mining employment is reported under the four-digit NAICS code, "2121."

Figure A.1: Total Heat Content and Cost of Coal Deliveries by Rank, 1990-2009

(a) Total Heat Content of Coal Deliveries



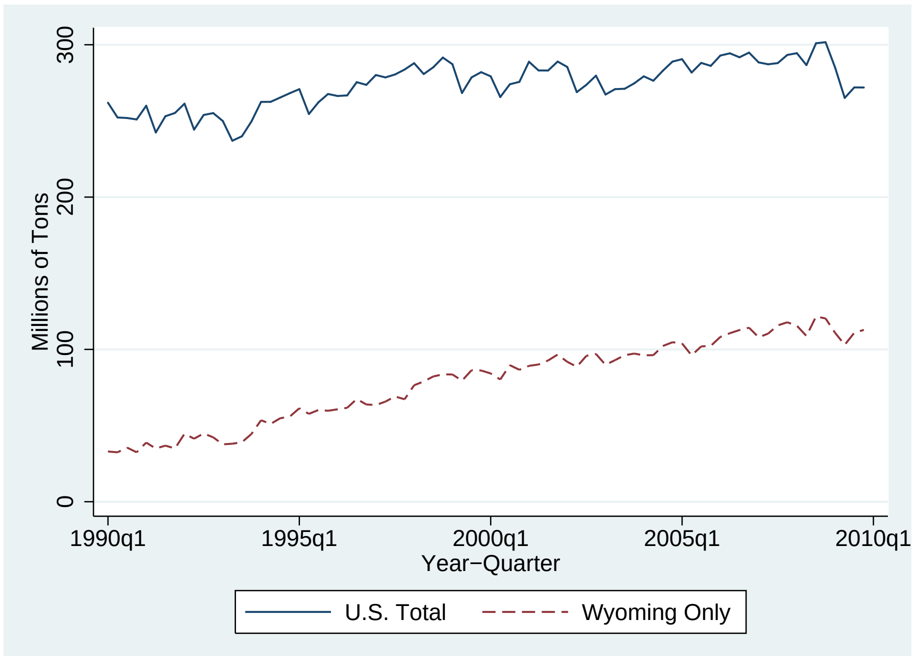
(b) Total Cost of Coal Deliveries



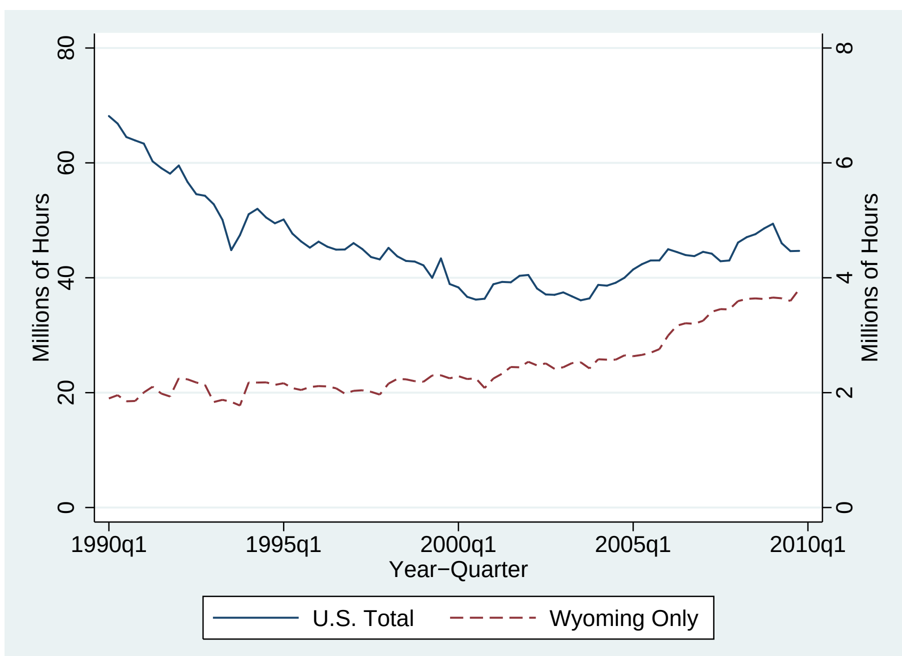
Note: Vertical lines denote the year in which divestitures begin (1998) and when reporting for non-utilities commences (2002). Source: Forms EIA-423,923 and FERC 423.

Figure A.2: U.S. Coal Production and Labor Demand, 1990-2009

(a) Production



(b) Labor Input



Source: Form MSHA-7000-2.

Table A.1: Summary of Coal Plant Divestitures by State

State	Plants (Divested)	Fraction of IOU Divested	Fraction of Capacity Divested	Mean Sale Date [s.d.]
Texas	17 (9)	0.69	0.60	8/2002 [13.69]
Connecticut	1 (1)	1.00	1.00	5/1999 [.]
Delaware	2 (2)	1.00	1.00	7/2001 [0.00]
Maryland	7 (7)	1.00	1.00	10/2000 [3.09]
Illinois	22 (19)	1.00	0.95	10/2000 [18.57]
Indiana	24 (1)	0.05	0.02	9/2001 [23.14]
Massachusetts	4 (4)	1.00	1.00	12/2000 [47.45]
Montana	3 (2)	0.67	0.98	1/2000 [0.00]
New Jersey	5 (4)	1.00	0.99	9/2002 [38.19]
New York	10 (8)	0.89	0.92	8/1999 [6.46]
Ohio	25 (8)	0.38	0.26	2/2002 [29.28]
Pennsylvania	21 (21)	1.00	1.00	7/2000 [14.09]
Virginia	9 (1)	0.11	0.10	2/2002 [29.41]
Washington	2 (1)	1.00	0.97	5/2000 [0.00]
Divest States Total	152 (88)	0.65	0.33	7/2001 [23.71]

Notes: Coal-fired cogeneration plants in CA were not affected by restructuring legislation (4 plants). Other restructured states without reporting coal plants include ME, VT, RI, and DC. NH did not require divestiture (2 plants) Sources: “Electric Power Monthly” (March, various years), EIA-423/923, and EIA-906.

References

Guerriero, C. (2010). The Political Economy of Incentive Regulation: Theory and Evidence from US States.

Sappington, D. E. M., J. P. Pfeifenberger, P. Hanser, and G. N. Basheda (2001). The State of Performance-Based Regulation in the U.S. Electric Utility Industry. *The Electricity Journal 14*(8), 71–79.

B Additional Results and Robustness Checks

This Appendix presents additional results and robustness checks to supplement those presented in the main text of the paper. The first three tables replicate the summary statistics and core results from the main text using only Investor-Owned Utility plants as the potential matches for divested plants. Dropping Government/Municipal/Co-op-owned plants reduces the set of matched controls from 101 plants (in the main text) to 77. This exercise is useful to explain the drop in generating capacity and delivered heat between divested and non-divested plants shown in the A and B panels of Table 1. Although these differences were not statistically significant in the main text, the results here show that the differences that did exist were due to matches with non-IOU plants, which tend to be smaller.

Although Gov/Muni/Coop plants do not face any changes in regulatory oversight during this period of time, it is not obvious that the incentives facing operators of these plants would parallel those of IOUs, a necessary condition to use these facilities to form a counterfactual for divested plants. This is a testable assumption, and Figure B.1 does so using the matching methodology developed in Section 4 with $m = 10$. IOU plants not subject to divestiture are matched to Gov/Muni/Coop facilities that burned a common rank of coal in 1997 and are within 200 miles of the matched facility. The difference between the two groups is statistically significant for one month over twenty years, and they follow nearly identical paths aside from a brief convergence in 2002. This suggests that Gov/Muni/Coop plants nearby divested facilities perform equally well as IOU facilities to estimate the counterfactual prices that would have prevailed in the absence of divestiture.

What impact does the exclusion of these non-IOU plants have on the estimated relationship between divestiture and coal prices? Table B.3 replicates the main results on (log) coal prices from the paper with this sample restriction. Although Figure B.1 shows IOU and non-IOU prices track together fairly well, one might be concerned that divestiture raises pressures on nearby non-IOU plants to reduce their costs, thereby contaminating the control group.[7] With nearly 25% of the control sample removed, the estimated effect of divestiture drops from around 12% to roughly 10%, and it is not possible to reject the hypothesis that the coefficients are equal at conventional levels. It would therefore appear that such a spillover was not occurring–perhaps because divested plant fuel prices remain confidential and it was therefore difficult for the nearby municipal plants to know they were being out-performed.

Table B.4 presents an additional robustness check by re-running the core specifications of Table 2 with a constant set of divested plants. This means restricting the data to those divested plants with at least one control facility within 50 miles–the set of matched control plants will vary across specifications, since that is the point of presenting different matching criteria. Thus the third columns of the two tables are identical. This yields slightly larger coefficients, but again, they are not statistically different than those in the main text. Another point of interest is that this table

[7] I am grateful to an anonymous referee for raising this possibility.

gives further evidence in favor of the explanation of greater heterogeneity across columns (1) - (3) of Table 4 in the main text: The analogous coefficients vary less once a constant set of plants is used.

Although Figure 5 shows a relatively flat pre-trend leading up to divestiture, Table B.5 tackles the potential for pre-existing trends directly by including state-specific quadratic trends in the Matched DID specifications. This helps to account for any time-varying differential trends between treatment and control states that would bias the estimate of an effect of divestiture (the coefficients do not budge with simple linear trends and/or treatment group-specific trends). The results are not statistically different from those in the main text (if a percent or two less).

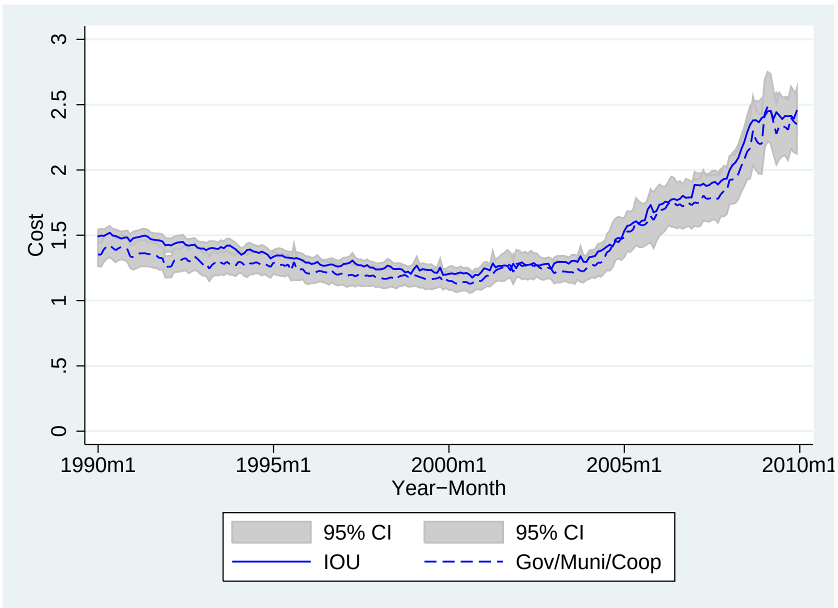
Finally, one might worry that differences in behavior between groups might be due to the differential impact of environmental regulations or access to transportation networks. Table B.7 expands upon the plant-level summary statistics of Table 1 to gauge the potential for such a scenario. The share of deliveries that arrived by barge in 1997 according to the Coal Transportation Rate Database is relatively balanced between the two groups. Divested plants are more likely to be subject to stricter ozone and particulate matter (PM) regulations, though this differential is moderated somewhat through matching. While there is not much time-variation in the PM regulations, the NOx Budget program was rolled out starting in 2003. These differences in regulation are unlikely to have affected coal procurement decisions: Reported PM emissions factors for pulverized coal are not reported separately for bituminous versus sub-bituminous coals in the EPA's official engineering studies (AP-42, 5th Edition, Vol 1, Ch 1.), nor are NOx compliance options limited based on sulfur content (though flue gas treatment configurations may vary).

Looking beyond the results regarding the price paid for coal, Figure B.2 shows the year-from-divestiture effects of the share of coal procured from in-state, analogous to the overall average effects presented in Table 7. This figure shows that the subsequent Matched-DID results are not an artifact of a pre-existing trend away from purchasing in-state coal in subsequently restructured states.

Because the analysis of sulfur compliance decisions excludes all plants who had already installed a scrubber before 1997, one might worry about potential sample selection problems. In particular, it might be the case that subsequently divested plants were more likely to have already installed scrubbers in the plants best-suited for their use prior to 1997. The relative lack of scrubber adoption in later years might simply be due to sample exclusion.[8] To gauge the potential for this concern, Table B.6 includes all of the units in the original analysis, plus those in both divested and non-divested groups that switch to low-sulfur coal or installed a scrubber between 1991 and 1996 and were therefore excluded from the main analysis. It appears the inclusion of additional units that would soon go on to choose an abatement strategy has a negligible effect on the estimates. The results with this larger set of units barely differs from those in the main text, suggesting that subsequently divested plants were not disproportionately installing scrubbers in the half-decade before restructuring.

[8] I am grateful to an anonymous referee for raising this concern.

Figure B.1: Matching Estimates of Delivered Coal Price at IOU and Gov/Muni/Coop Plants, 1990-2009



Note: Gov/Muni/Coop facilities receive weight $\frac{1}{m_j}$ for each matched divested facility j. Matching criteria: $m = 10$, burning the same rank of coal in 1997, subject to the constraint that distance be less than 200 miles. Confidence intervals based on standard errors clustered by facility.

Table B.1: Characteristics of Coal Deliveries to Divested and Non-Divested IOU Plants in 1997

A. All Facilities

	Divested	Not Divested	Difference of Means
Millions MMBTU	44.76	48.17	–3.41
Delivered	[42.78]	[44.48]	(5.49)
Price($/MMBTU)	1.42	1.22	0.20***
	[0.37]	[0.36]	(0.05)
% Spot Market	0.24	0.29	–0.06
	[0.29]	[0.33]	(0.04)
Yrs to Contract	5.37	5.43	–0.07
Expiry	[6.19]	[6.03]	(0.88)
% Sourced	0.41	0.28	0.13**
In-State	[0.46]	[0.43]	(0.06)
% Bituminous	0.76	0.62	0.13**
	[0.42]	[0.46]	(0.06)
Sulfur Content	1.19	0.93	0.26***
(lbs/mmbtu)	[0.72]	[0.71]	(0.09)
Ash Content	8.67	7.82	0.84
(lbs/mmbtu)	[4.83]	[3.31]	(0.56)
Mine Distance	318.10	383.93	–65.83
(mi.)	[330.64]	[319.82]	(41.53)
Facilities	88	210	298

B. Matched Facilities

	Divested	Not Divested	Difference of Means
Millions MMBTU	44.93	44.84	0.09
Delivered	[43.00]	[38.95]	(7.45)
Price($/MMBTU)	1.42	1.26	0.16***
	[0.37]	[0.29]	(0.06)
% Spot Market	0.23	0.30	–0.07
	[0.28]	[0.35]	(0.06)
Yrs to Contract	5.42	5.71	–0.29
Expiry	[6.23]	[7.89]	(1.34)
% Sourced	0.41	0.40	0.01
In-State	[0.46]	[0.44]	(0.08)
% Bituminous	0.76	0.77	–0.01
	[0.42]	[0.41]	(0.07)
Sulfur Content	1.19	1.27	–0.08
(lbs/mmbtu)	[0.73]	[0.74]	(0.13)
Ash Content	8.56	8.54	0.02
(lbs/mmbtu)	[4.75]	[3.49]	(0.78)
Mine Distance	321.01	279.19	41.82
(mi.)	[331.42]	[309.77]	(51.48)
Facilities	87	77	164

Note: Non-Divested facilities in Panel B receive weight $1/m_j$ for each matched divested facility j. Matching criterion: $m = 10$ burning the same rank of coal in 1997, subject to the constraint that distance be less than 200 miles. Standard errors clustered by facility in parentheses. * p<0.1, ** p<0.05, *** p<0.01

Table B.2: Characteristics of Divested and Non-Divested IOU Generating Units in 1997

A. All Facilities

	Divested	Not Divested	Difference of Means
Capacity (MW)	799.79	891.30	–91.51
	[671.86]	[763.46]	(88.81)
Annual Capacity	0.59	0.57	0.02
Factor	[0.19]	[0.18]	(0.02)
Plant Vintage	1961.99	1963.00	–1.01
	[10.92]	[13.44]	(1.49)
% Scrubbers	0.25	0.25	–0.00
Installed	[0.44]	[0.44]	(0.06)
Incentive	0.44	0.22	0.22***
Regulation Util.	[0.50]	[0.42]	(0.06)
Facilities	88	210	298

B. Matched Facilities

	Divested	Not Divested	Difference of Means
Capacity (MW)	803.95	797.35	6.60
	[674.61]	[692.20]	(127.59)
Annual Capacity	0.59	0.59	–0.00
Factor	[0.19]	[0.18]	(0.03)
Plant Vintage	1962.14	1961.88	0.26
	[10.90]	[13.76]	(2.28)
% Scrubbers	0.25	0.26	–0.01
Installed	[0.44]	[0.44]	(0.08)
Incentive	0.45	0.10	0.35***
Regulation Util.	[0.50]	[0.30]	(0.08)
Facilities	87	77	164

Note: Non-Divested facilities in Panel B receive weight $1/m_j$ for each matched divested facility j. Matching criterion: $m = 10$ burning the same rank of coal in 1997, subject to the constraint that distance be less than 200 miles. Standard errors clustered by facility in parentheses. * p<0.1, ** p<0.05, *** p<0.01

Table B.3: IOU Only: Matched DID Estimates of Coal $Log(Price)$ and Divestiture

	(1)	(2)	(3)	(4)	(5)	(6)
Post-Divest	–0.096**	–0.120**	–0.107	–0.096**	–0.091**	–0.076
	(0.040)	(0.050)	(0.077)	(0.042)	(0.044)	(0.051)
m Nearest Neighbors				10	5	1
Proximity Threshold (mi.)	200	100	50			
Year-Month FE	Yes	Yes	Yes	Yes	Yes	Yes
Facility FE	Yes	Yes	Yes	Yes	Yes	Yes
R^2	0.690	0.611	0.601	0.691	0.687	0.663
Facilities	192	124	61	168	146	110
Divested Facilities	87	74	39	87	87	87
Obs.	39367	24025	11164	32865	29072	21324

Note: Dependent variable is $Log(Price)$ of Coal per MMBTU, including shipping costs. Non-Divested facilities receive weight $\frac{1}{m_{-j}}$ for each matched divested facility j burning the same rank of coal in 1997, subject to the indicated matching criterion. Standard errors clustered by facility in parentheses. * p<0.1, ** p<0.05, *** p<0.01

Table B.4: Constant Set of Divested Plants: Matched DID Estimates of Coal $Log(Price)$ and Divestiture

	(1)	(2)	(3)	(4)	(5)	(6)
Post-Divest	–0.152**	–0.188***	–0.152*	–0.144**	–0.148**	–0.151*
	(0.064)	(0.070)	(0.077)	(0.066)	(0.067)	(0.079)
m Nearest Neighbors				10	5	1
Proximity Threshold (mi.)	200	100	50			
Year-Month FE	Yes	Yes	Yes	Yes	Yes	Yes
Facility FE	Yes	Yes	Yes	Yes	Yes	Yes
R^2	0.655	0.690	0.668	0.658	0.658	0.664
Facilities	159	100	69	132	99	57
Divested Facilities	39	39	39	39	39	39
Obs.	30507	18592	12682	20649	16593	10045

Note: Dependent variable is $Log(Price)$ of Coal per MMBTU, including shipping costs. Non-Divested facilities receive weight $\frac{1}{m_{-j}}$ for each matched divested facility j burning the same rank of coal in 1997, subject to the indicated matching criterion. Standard errors clustered by facility in parentheses. * p<0.1, ** p<0.05, *** p<0.01

Table B.5: State-Specific, Quadratic Time Trends: Matched DID Estimates of Coal *Log*(*Price*) and Divestiture

	(1)	(2)	(3)	(4)	(5)	(6)
Post-Divest	–0.103***	–0.177***	–0.102	–0.108***	–0.111***	–0.145***
	(0.033)	(0.049)	(0.080)	(0.034)	(0.038)	(0.049)
m Nearest Neighbors				10	5	1
Proximity Threshold (mi.)	200	100	50			
Year-Month FE	Yes	Yes	Yes	Yes	Yes	Yes
Facility FE	Yes	Yes	Yes	Yes	Yes	Yes
State-Quadratic Trend	Yes	Yes	Yes	Yes	Yes	Yes
R^2	0.798	0.799	0.747	0.802	0.804	0.814
Facilities	230	146	69	198	166	121
Divested Facilities	87	74	39	87	87	87
Obs.	47024	28449	12682	37495	32958	23336

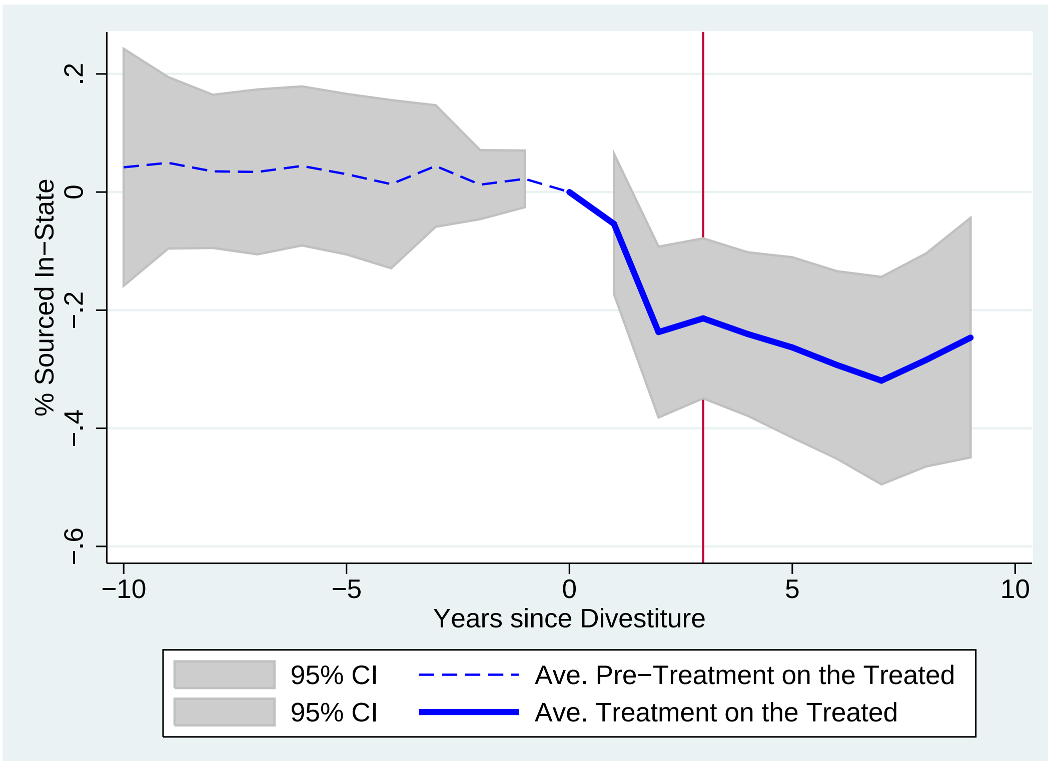
Note: Dependent variable is *Log*(*Price*) of Coal per MMBTU, including shipping costs. Non-Divested facilities receive weight $\frac{1}{m_{-}j}$ for each matched divested facility j burning the same rank of coal in 1997, subject to the indicated matching criterion. Standard errors clustered by facility in parentheses. * p<0.1, ** p<0.05, *** p<0.01

Table B.6: Units Burning Bituminous Coal in 1990 Without Scrubbers: Matched DID Estimates of Sulfur Compliance Strategy

	(1)	(2)	(3)
	Scrubber	Low Sulfur	Uncontrolled
Post-Divest	–0.061**	0.088***	–0.036
	(0.025)	(0.030)	(0.037)
Divested Unit	0.015	–0.007	–0.013
	(0.034)	(0.030)	(0.042)
m Nearest Neighbors	10	10	10
R^2	0.021	0.056	0.067
Units	457	457	457
Divested Units	219	219	219
Obs.	7929	7929	7929

Note: Sample includes all units without a scrubber and burning bituminous coal in 1997. Non-Divested units receive weight $\frac{1}{m_j}$ for each matched divested facility j within 200 miles. Matching criterion: $m = 10$. Standard errors clustered by unit in parentheses. * p<0.1, ** p<0.05, *** p<0.01

Figure B.2: Matching by Year from Divestiture: Percent Sourced In-State



Note: Non-Divested facilities receive weight $\frac{1}{m_j}$ for each matched divested facility j. m_j denotes the number of divested facilities burning the same rank of coal in 1997, and is located within 100 miles of the divested plant. Confidence intervals based on standard errors clustered by facility. The vertical line denotes the third year post-divestiture, the point at which most divested facilities resumed reporting fuel costs.

Table B.7: Modes of Transportation and Environmental Regulations at Divested and Non-Divested Plants in 1997

A. All Facilities

	Divested	Not Divested	Difference of Means
Barge Delivery	0.13	0.15	–0.02
	[0.33]	[0.32]	(0.05)
Ozone	0.67	0.31	0.36***
Non-Attainment	[0.47]	[0.46]	(0.06)
PM	0.50	0.25	0.25***
Non-Attainment	[0.50]	[0.44]	(0.06)
Nox Budget	0.86	0.47	0.39***
Program	[0.35]	[0.50]	(0.05)
Facilities	88	309	397

B. Matched Facilities

	Divested	Not Divested	Difference of Means
Barge Delivery	0.14	0.19	–0.06
	[0.33]	[0.33]	(0.08)
Ozone	0.67	0.52	0.15
Non-Attainment	[0.47]	[0.50]	(0.09)
PM	0.51	0.26	0.24***
Non-Attainment	[0.50]	[0.44]	(0.08)
Nox Budget	0.86	0.70	0.16**
Program	[0.35]	[0.46]	(0.08)
Facilities	87	101	188

Note: Non-Divested facilities in Panel B receive weight $1/m_j$ for each matched divested facility j. Matching criterion: $m = 10$ burning the same rank of coal in 1997, subject to the constraint that distance be less than 200 miles. Standard errors clustered by facility in parentheses. * p<0.1, ** p<0.05, *** p<0.01